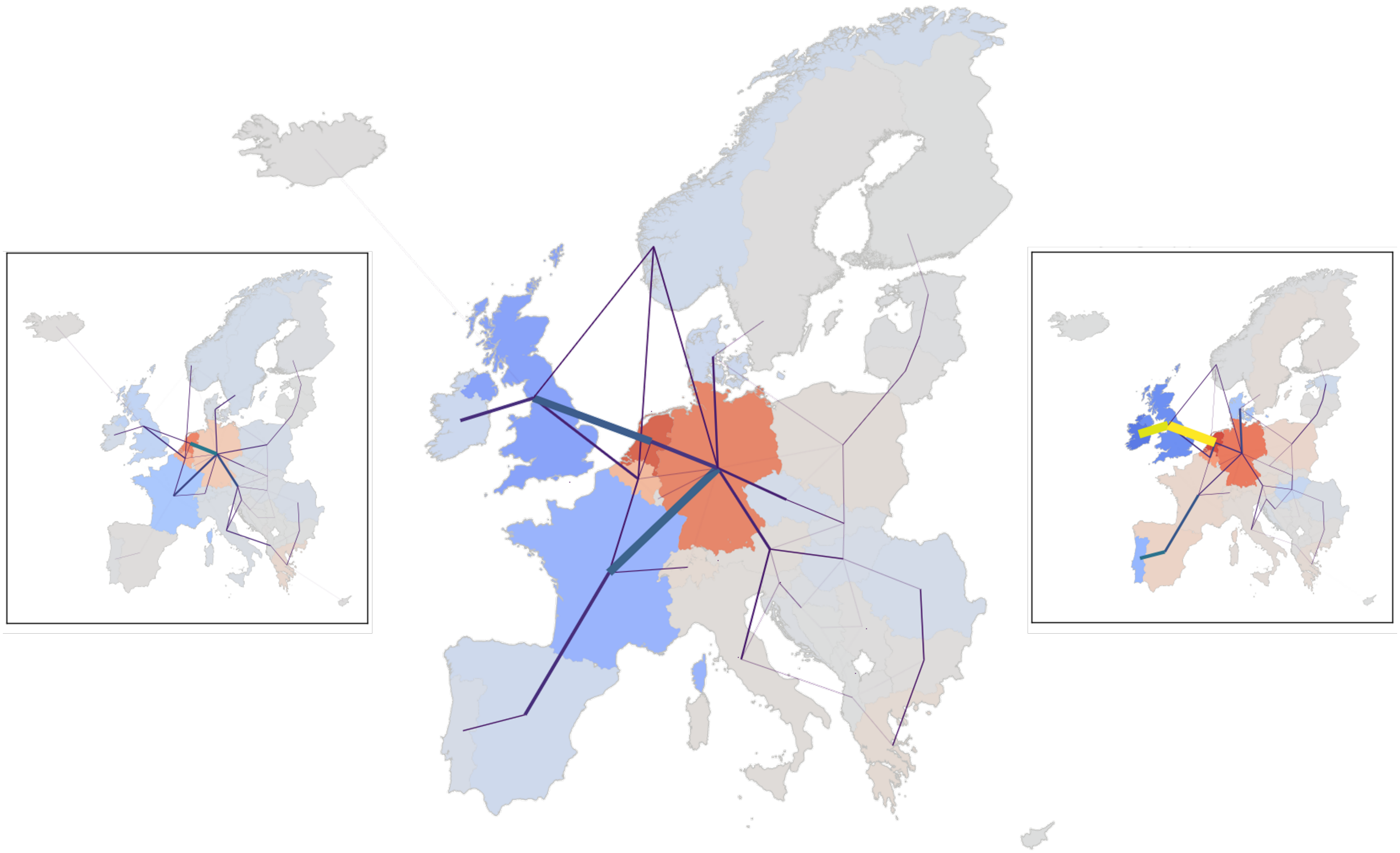
Cost-optimal European hydrogen network

Hydrogen infrastructure and storage requirements in a fully renewable scenario

Nathalia Ortiz Torres



TU Delft
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Cost-optimal European hydrogen network

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Thesis report

by

Nathalia Ortiz Torres

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Preface

With the completion of this thesis, I mark the end of my two-year master's degree in Sustainable Energy Technology. It has been an incredibly fulfilling journey, during which I have had the privilege of meeting inspiring people and forging lifelong friendships. Thanks to this journey, I gained a better understanding of the opportunities and complexities associated with the energy transition. I became aware that the integration of hydrogen into our energy systems to reach climate targets requires careful planning, informed decision-making, massive scale-up of manufacturing capacities, and collaboration between various stakeholders. I am excited to present the outcomes of this research, knowing that it represents an effort in providing some guidance for policymakers, researchers, and industry players in their pursuit of driving future developments toward a sustainable future.

I want to express my sincere gratitude to my supervisor, Stefan Pfenninger, for his guidance and support throughout the development of my thesis. His feedback and expertise were essential in shaping the direction of my research. I am also grateful to Francesco Sanvito and Francesco Lombardi for their generous assistance and willingness to address my numerous questions. I would also like to extend my appreciation to Ghislain Detienne and Ad van Wijk for providing me with valuable contributions and insightful discussions, which helped me clarify certain aspects of my research. Finally, I would like to thank my family and friends for their unconditional support during this adventure.

Nathalia Ortiz Torres
Delft, 2023

Summary

The report focuses on the analysis of a cost-optimal hydrogen network in Europe within the context of an integrated energy system. It addresses the need for understanding the required capacity and spatial distribution of hydrogen infrastructure to meet the growing demand for clean energy carriers. Previous studies often overlook the integration of a hydrogen network and lack optimized designs considering a sector-coupled energy system.

To overcome these limitations, this report models hydrogen pipelines using the Calliope energy system modeling software with the objective of determining the necessary capacity and distribution of a hydrogen grid in Europe under a fully renewable scenario. Modeling was conducted with a spatial resolution of 35 nodes and a temporal resolution of 2 hours over a full year, using the 2018 weather data. The software uses a linear optimization method to determine the optimal configuration of the hydrogen network.

This study formulates several allocation scenarios for electrolysis capacity to examine the capacity and spatial distribution of an optimal hydrogen network under different conditions. It is found that an energy system with hydrogen hubs requires the development of extensive new pipeline infrastructure, while a system with a more balanced distribution of electrolysis across Europe requires less pipeline capacity and relies mostly on repurposed infrastructure. The estimated capacity of the network ranges from 135 to 244 TWkm. This is 40% to 70% lower than what is estimated in the European Hydrogen Backbone (EHB) vision.

In the scenario with hydrogen hubs, the study identifies four hydrogen corridors that align with the vision presented in the EHB report, with Britain, Ireland, Denmark, and Portugal as key hydrogen producers. Furthermore, the analysis highlights the significant role of salt caverns as the predominant storage technology for hydrogen, despite uncertainties surrounding their capacity estimates. The optimal storage capacity in salt caverns ranges from 42 to 178 TWh when accounting for cost and weather uncertainty.

The analysis initially considered a self-sufficient energy system, but the sensitivity to international imports was also considered. To analyze this aspect, hydrogen imports from four North African countries were included. The findings revealed that international imports play a relevant role in shaping the optimal configuration of the hydrogen network. Imports increase the required investment in infrastructure but also reduce hydrogen storage capacity and its associated uncertainty. Changes in the network configuration result in a 6% reduction in total system costs due to decreased renewable energy capacity and reliance on external hydrogen supply.

Overall, this study emphasizes the need for accurate electrolysis allocation estimation, alignment with international import planning, and efficient utilization of storage technologies in the development of hydrogen infrastructures. The findings contribute to informed decision-making and the creation of sustainable hydrogen networks that integrate effectively with renewable energy systems.

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1 Introduction

In recent years, the increasing focus on decarbonizing the energy system has led to a growing interest in hydrogen as a clean energy carrier. As hydrogen projects emerge across Europe, there is a pressing need for an integrated hydrogen network. Understanding the required capacity and spatial distribution of hydrogen infrastructure is crucial for meeting future hydrogen demand. This report aims to address this need by analyzing cost-optimal solutions for the hydrogen network within the context of an integrated energy system.

The central research question guiding this study is: What is the required capacity and distribution of a hydrogen network and storage in Europe under a fully renewable scenario?

Existing studies on the European hydrogen network often lack an optimized design considering the integration of an energy system. Moreover, many large-scale energy system models overlook the inclusion of a hydrogen grid in their analyses. To overcome these limitations, this report incorporates hydrogen pipelines into the analysis using the Calliope energy system modeling software. By doing so, we can gain deeper insights into the potential benefits and challenges of hydrogen integration within large-scale energy systems. The specific objective is to identify the necessary capacity and distribution of a hydrogen grid in Europe under a fully renewable scenario.

To answer the research question, this report is structured as follows. The first section provides a comprehensive overview of existing literature on planned hydrogen infrastructure in Europe and large-scale energy system models that assess the cost-optimal hydrogen network in the region.

Subsequent sections present the results, showcasing various hydrogen network solutions based on the allocation of electrolysis capacity across Europe. Non-regret scenarios are identified, and the benefits of an optimal electrolysis allocation are assessed. Furthermore, the report examines the impacts of including hydrogen imports from North Africa and explores the model's sensitivity to technology costs and different weather years.

Finally, the findings are compared to the European Hydrogen Backbone study and other relevant literature to assess consistency and identify key differences. The report concludes by summarizing the key findings, discussing their implications, and highlighting areas for further research.

2
Background

2.1. Literature Review

2.1.1. Hydrogen network vision in the European Union

The European Commission recently recognized the importance of developing a dedicated hydrogen infrastructure in the hydrogen and decarbonized gas package, published in December 2021 [1]. Some European countries have launched their own hydrogen network planning and feasibility studies. FGSZ Ltd, Hungarian TSO, commissioned a feasibility study to evaluate the suitability of one of its pipelines in the country for partial to full hydrogen transport [2]. Great Britain has a national hydrogen network plan [3] consisting of four phases: preparing for transition, solution pilots, scaling up, and full transition. In this country, 62.5% of the total old iron pipelines have been replaced with polyethylene, which is suitable for hydrogen transport [3]. In the Netherlands, the Ministry of Economic Affairs and Climate Policy commissioned Gasunie to develop the Dutch Hydrogen Backbone. This network could be available as early as 2027 and will consist of around 85% repurposed gas pipelines [4, 5]. Germany plans a corridor from the Baltic Sea to southwest Germany, connecting five neighbouring European countries [6]. Spain submitted a hydrogen infrastructure project (H2Med) as an EU Project of Common Interest, including a hydrogen network in the country and a connection with Portugal and France [7]. Figure 2.1 shows some of the planned hydrogen networks.

Besides repurposing existing pipelines, some countries also intend to create new infrastructure across borders. The Bulgarian state company Bulgartransgaz is evaluating the construction of a dedicated hydrogen pipeline connecting Sofia (Bulgaria) and Thessaloniki (Greece) [10]. Six EU countries signed a cooperation agreement to build the Nordic-Baltic Hydrogen Corridor, connecting Finland, Estonia, Latvia, Lithuania, Poland, and Germany [11]. In Sweden and Finland, Gasgrid Finland and Nordion Energi are planning to build 1,000 km of new, dedicated hydrogen pipelines [8]. France and Spain are planning the construction of an underwater pipeline to transport hydrogen from Barcelona to Marseille, and another segment is planned to connect Celorico (Portugal) to Zamora (Spain) [9].

All the above planned infrastructure is shown in H2Inframap [1], an interactive hydrogen infrastructure map of planned European projects. In addition, the collective vision for a dedicated hydrogen pipeline infrastructure in Europe is built in the European Hydrogen Backbone (EHB) initiative, founded in 2020 by European energy infrastructure operators. The most recent paper was published in May 2022 [12]. It includes the vision of 31 Transmission System Operators (TSOs) covering 28 European countries. By 2040, the proposed hydrogen backbone is 53,000 kilometres long, with approximately 60% repurposed gas pipelines and 40% new infrastructure [12]. The total investment cost of the envisaged 2040 EHB ranges from €80 to €143 billion, including costs of new and repurposed pipelines, and compressors. The 2040 EHB vision is shown in Figure 2.2. The EHB study uses hydrogen demand and supply projections on a per-country basis. It takes into account the current gas pipeline infrastructure and storage facilities in the region. However, the study does not account for the feasibility of retrofitting existing natural gas pipelines for hydrogen transport, nor is it based on an optimization model.

[1] https://www.h2inframap.eu/

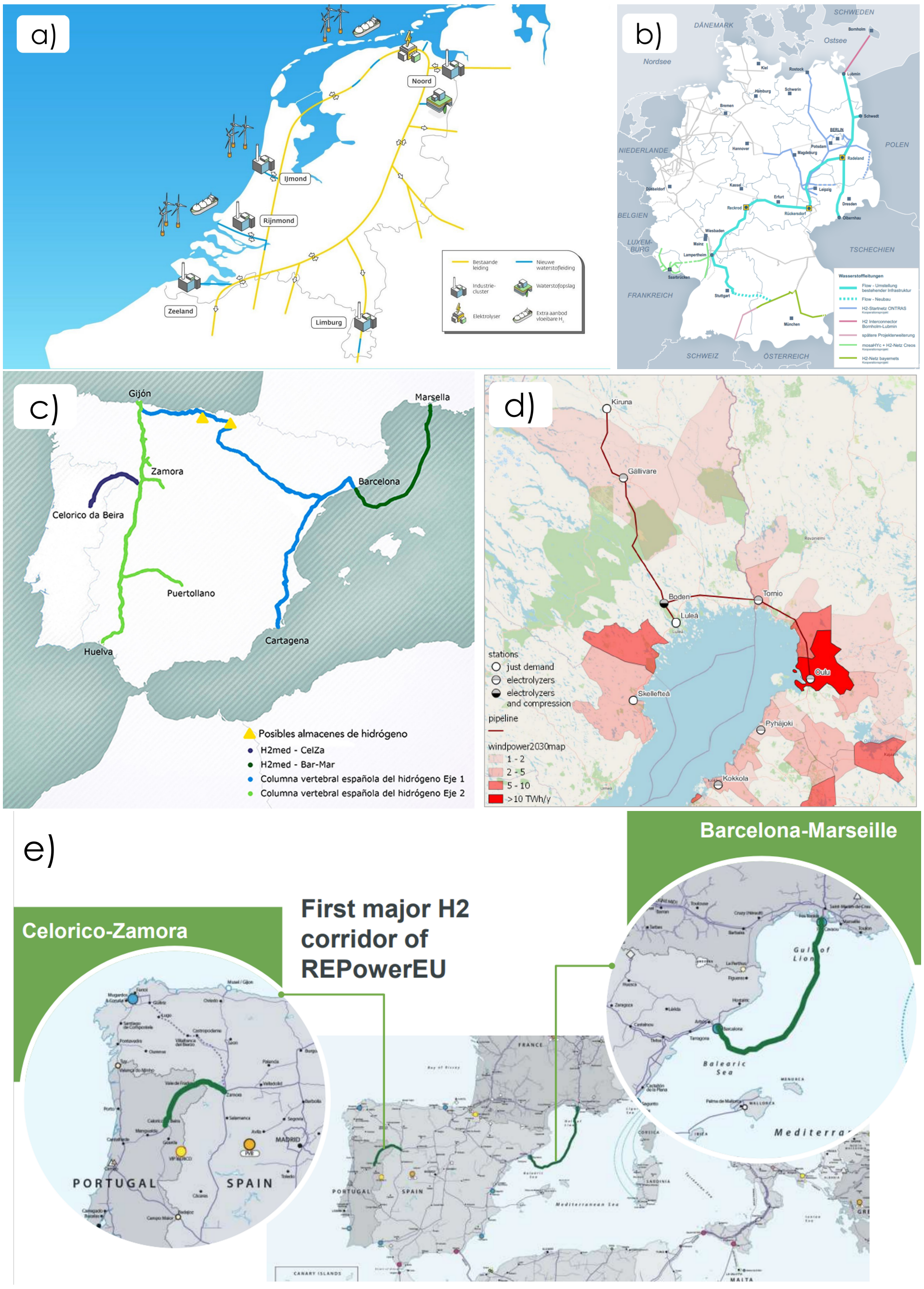

Figure 2.1: a) Dutch Hydrogen Backbone planned by Gasunie [5] b) German Hydrogen Backbone planned by Gascade[6] c) H2Med project [7] d) Swedish-Finish Hydrogen Backbone planned by Gasgrid Finland and Nordion Energi by 2030 [8] e) H2Med project connecting Portugal, Spain, and France [9].

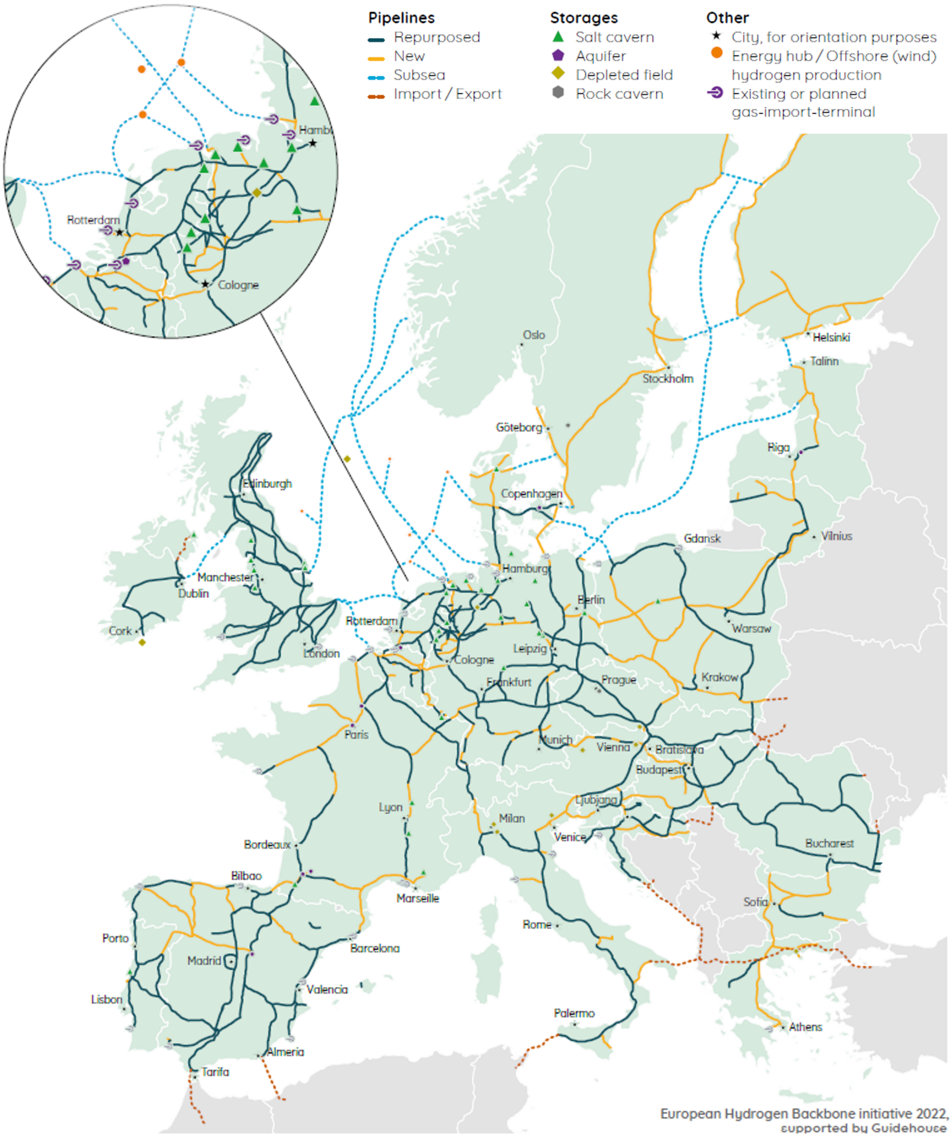

Figure 2.2: European Hydrogen Backbone vision by 2040.
[12]

2.1.2. Modelling of the hydrogen network as part of the energy system

Few studies have modelled the hydrogen network as part of the energy system at the European level [13, 14, 15]. Caglayan et al. [13, 14] created a model for a hydrogen network that operates under a fully renewable scenario. The model calculates the hydrogen grid based on the shortest possible paths between regions, which are determined using information from roadways, railways, and existing gas pipelines. This approach ensures that the resulting network is both efficient and feasible, taking into account the existing infrastructure and the need to minimize transportation costs. In their 2021 study [13], Caglayan et al. employed an iterative minimum cost-optimization approach that takes into account 38 weather-year scenarios spanning from 1980 to 2017. However, this study does not account for non-energy uses of hydrogen and does not consider the repurposing of existing gas pipelines for hydrogen transport.

To the extent of the research done in this report, Neumann et al's study [15] is the only known research that explores an optimal hydrogen network in Europe by including repurposed gas pipelines for hydrogen transport as part of an optimization model. This study analyzed the benefits of the hydrogen network by finding cost-optimal configurations under net-zero CO_2 scenarios and self-sufficient supply. The evaluation is performed with the open energy system model PyPSA-Eur-Sec (Python for Power System Analysis). It comprises 181 regions modeled every third hour of a year as a single linear optimization problem for the least-cost outcome. Five sectors are included: electricity, industry, buildings, agriculture, and transport. In addition, two types of hydrogen storage were included in the analysis: steel tanks and salt caverns.

With this study, Neumann et al. [15] examined the role of the hydrogen network in compensating for a lack of power grid expansion. The authors did this by defining four scenarios based on whether or not the power grid and the hydrogen network could be expanded. Some issues arise from their analysis:

- While the study does consider the repurposing of existing gas infrastructure, it does not address the technical feasibility of such repurposing. By omitting this assessment of technical feasibility, the study leaves a gap in understanding the viability of repurposing existing gas infrastructure for hydrogen use.
- The study assumed constant cost factors for new and repurposed pipelines. 250€/km/MW for new hydrogen pipelines (including the cost of new compressors), and 117€/km/MW for repurposing natural gas pipelines. However, sources such as the European Hydrogen Backbone (EHB) reports of 2020 and 2021 indicate that the cost of new and repurposed hydrogen pipelines vary depending on the pipeline diameter and operational capacity [16, 17].
- Another limitation of the study is the neglect of energy demand for compression. The energy required for compression represents a significant portion, ranging from 1.5% to 2.3% of the energy content of the transported hydrogen for every 1,000 km [16]. This oversight could impact the overall energy efficiency and cost-effectiveness of the hydrogen transportation system.
- The study results in a total installed electrolysis capacity that is twice the target set by the EU hydrogen strategy for a climate-neutral Europe by 2050 [18]. This overestimation of electrolysis capacity raises questions about the realism and practicality of the proposed scenarios. However, the study fails to address the uncertainty surrounding the electrolysis capacity estimate.
- Furthermore, the study primarily focuses on assessing the impact of integrating transmission lines and hydrogen pipelines on the total system cost, without delving into the broader role of hydrogen infrastructure in the integrated energy system. Relevant aspects such as the interplay between hydrogen pipelines and storage and other key components of the energy system, including solar and wind capacities, battery storage, and electricity imports on a country level, are not addressed.

2.2. Research question

To address the gaps stated above and enhance the understanding of the optimal integration of hydrogen in large-scale energy systems, this research aims to investigate the capacity and distribution of a hydrogen network in Europe under a fully renewable scenario. The main research question guiding this study is:

> What is the required capacity and distribution of a hydrogen network and storage in Europe under a fully renewable scenario ?

By considering the technical feasibility of repurposing gas infrastructure and incorporating varying cost factors based on pipeline characteristics, this research seeks to provide a comprehensive analysis of the optimal design and integration of a hydrogen network in Europe. Furthermore, it aims to evaluate the broader implications of different electrolysis capacity allocation scenarios on transmission capacity, renewable energy sources, storage technologies, and overall system integration.

The following sub-questions are also evaluated:

- How do different allocation scenarios of electrolysis capacity impact the hydrogen network and required storage?
- How does uncertainty in cost and weather years affect the optimal hydrogen network and storage?
- What is the impact on the optimal hydrogen network if international imports are considered?

3
Methods

The methods used in this study comprise several essential components aimed at modeling the hydrogen network as part of a European energy system. Since hydrogen pipelines and hydrogen storage in salt caverns were not initially included in the Calliope software, they were added to enable the modeling of an optimal hydrogen infrastructure.

The first step involved integrating hydrogen pipelines into Calliope. This was achieved by conducting a thorough literature review to identify existing gas pipelines suitable for retrofitting as hydrogen transport infrastructure. Based on the results of this review, the applicable gas pipelines were clustered into the model's regions. The capacity and length of these pipelines were then calculated to assess their potential for hydrogen transportation, and techno-economic parameters were determined based on literature review.

In the next step, the hydrogen storage potential in salt caverns for each region was evaluated. This involved specifying the storage capacity of salt caverns in each node and identifying associated costs and technical parameters, which were then added to the Calliope model.

Finally, various scenarios are defined to identify and analyze the optimal solutions for achieving a fully renewable scenario in Europe. These scenarios consider factors such as hydrogen imports, costs of hydrogen transport, and weather variability. By evaluating these scenarios, the study aims to identify the most efficient and cost-effective solutions for developing a sustainable hydrogen infrastructure in Europe.

3.1. Modelling of hydrogen pipelines

3.1.1. Assessment of the suitability of gas pipelines to transport pure hydrogen

The results of various international studies and practical tests indicate that the reuse of natural gas pipelines for hydrogen transmission is feasible [19, 20, 21, 22]. These studies suggest that the design parameters used for high-pressure natural gas pipelines are suitable for new hydrogen pipelines, as the wall thicknesses, rated pressures, and steel quality of existing pipelines are adequate for hydrogen transmission at similar rated pressures. However, hydrogen can cause the embrittlement of steel which may eventually result in pipeline failure [23]. Consequently, not all pipeline materials are suitable for transporting hydrogen. The American Society of Mechanical Engineers (ASME) recommends steel grades X42 and X52 for hydrogen transport. In addition, [24] suggests that lower-grade steel (used in pipelines built between 1980 and 2000) is less affected by hydrogen embrittlement. Nonetheless, there is ongoing research on the feasibility of using higher-grade steels [22]. A study by CeDelft [25] suggests that hydrogen embrittlement is closely related to pressure changes in the pipelines.

The Re-Stream project [22], conducted by the International Association of Oil & Gas Producers and the European Network of Transmission System Operators for Gas, assessed the technical potential in the EU for repurposing oil and gas pipelines for hydrogen transport. The study started with data collection from 65 pipeline operators in Europe, evaluating a total of 58,000 km of pipelines plus 24,200 km assessed by operators themselves. The study identifies the gas and oil network that can be repurposed based on a scoring system considering the following criteria:

- Hydrogen embrittlement + Material hardness: Following the ASME standards, the steel grade should be lower than X52. In addition, the Vickers hardness should be less than 235 HV10 for carbon steel.
- Internal pipeline condition: pipelines with non-negligible internal corrosion require more testing to be considered reusable.

- Pipeline age: The age is an indicator of the number of stress cycles of the pipeline. However, determining how the pipeline will behave in the future also requires assessing how the pipeline has been designed, built, and operated. Pipelines built before 1990 require more testing to be considered reusable.
- Transport capacity: The maximum transport velocity is assumed as 40 m/s. In addition, only pipelines with a capacity of at least 0.01 MtH2/y qualified at the screening stage.

The screening results indicate that close to 70% of the gas network's total length can be reused. The remaining length is promising for reuse but would require more testing and/or update of standards to be reusable. Consequently, the study does not discard the suitability of any pipeline section to transport hydrogen.

Data from the Re-Strean project is not publicly available. Therefore, the Re-Strean project is contrasted with the open-source data of gas grid infrastructure provided by the SciGRID Gas IGGINL dataset [26] to identify which pipelines should be suppressed. This dataset contains information of approximately 88,900 km of pipelines as well as storage, production, LNG terminals, entry points, interconnection points and compressors. Opposite to the Re-Stream project, the SciGRID-gas project includes low-capacity pipelines. Pipelines identified as infrastructure that would require more testing to be reusable are removed from the IGGINL dataset.

Figure 3.1 shows the SciGRID Gas IGGINL dataset divided into three layers based on pipeline diameter, mirroring the division used in the European Hydrogen Backbone study [12]. Most large-distance pipelines have a diameter larger than 950 mm. Whereas short distance pipelines mostly consist of small capacity pipelines (diameter smaller than 700 mm).

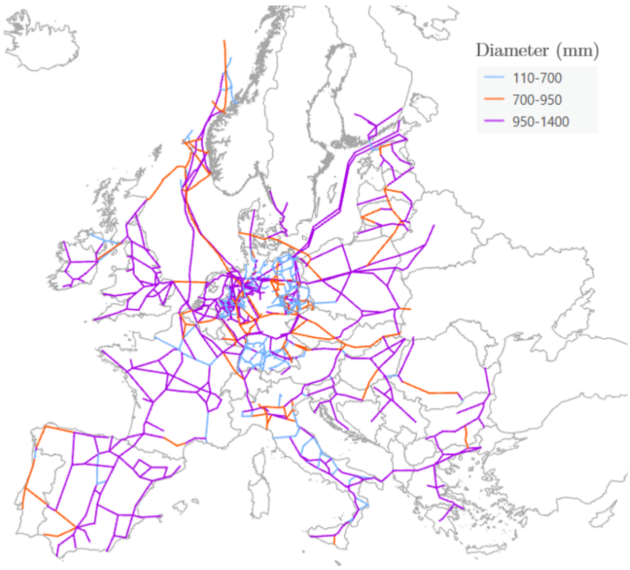

Figure 3.1: SciGRID Gas IGGINL dataset of gas pipelines. Colors indicate different diameter ranges.

Next, the collected data needs to be simplified into the regions included in the model. For this study, each country is represented as a single node in the model. The model also includes a higher resolution with a total of 98 nodes. However, due to time limitations of this study, the simplified resolution is used (one node per country). A comparison of these two resolutions is shown in Figure 3.2.

To construct the clustered network, only the pipelines that span across different regions are taken into account. This approach ensures that the resulting network is representative of the regional connections. Moreover, the network is divided into three distinct layers, mirroring the division used in the European Hydrogen Backbone study.

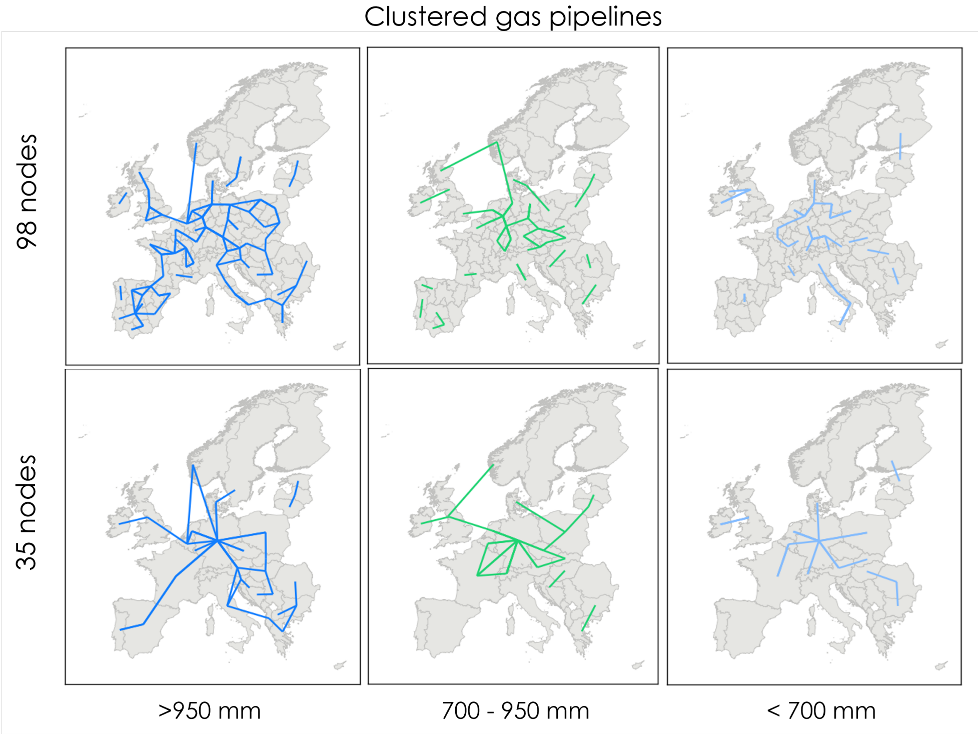

Figure 3.2: Gas pipelines clustered into the two resolutions of calliope software. Three layers are shown based on pipeline diameter: large pipelines (>950mm), medium pipelines (700-950 mm), small pipelines (<700mm).

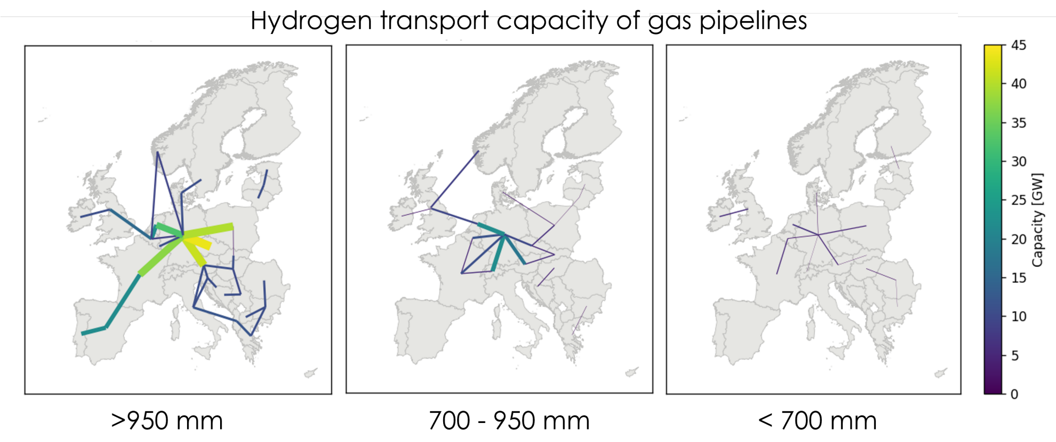

Figure 3.3: Hydrogen transport capacity of existing pipelines separated in three layers based on pipeline diameter: large pipelines (>950mm), medium pipelines (700-950 mm), small pipelines (<700mm). Capacity is given in GW, and thickness is indicative of the pipeline capacity.

3.1.2. Capacity of hydrogen pipelines

The volumetric energy density of H_2 is 3.3 times lower than methane [27]. This means that the H_2 flow velocity should be approximately three times higher to reach the same energy capacity [23]. To determine if this is technically feasible, the erosional velocity of hydrogen needs to be evaluated since the maximum flow rate in a pipeline is limited by the erosional velocity of the gas, which depends on the gas compressibility factor and specific gas gravity [28]. Under the same temperature and pressure conditions, hydrogen transport produces less flow-induced pulsations and turbulence, as well as less vibration induced by acoustics, than natural gas transmission, even when the flow rate is three times higher [20, 19]. H_2 erosional velocity is 2.9 times higher than methane [28]. Therefore, a H_2 pipeline has up to 88% the energy density of a methane pipeline, resulting from dividing the erosional velocity over the energy density ratio H_2-CH_4 [28]. New compressors are likely required when repurposing existing infrastructure due to the higher flow velocity [23].

Research done by gas TSOs [16] indicates that the maximum capacity of H_2 pipelines should be set lower than the maximum to optimize costs. By reducing the maximum capacity, pipeline investment costs per MWh are higher. However, the compressor costs and energy costs decrease significantly [16, 29]. According to [17], the optimum capacity for a 48-inch pipeline is 13 GW (LHV), 4.7 GW for 36 inches, and 1.2 GW for 20 inches, which correspond to 40 to 60% of the natural gas capacity. Nonetheless, the optimum point depends on several parameters like flow variability, pipeline thickness, distance between compressors, required pressure levels, and compressor technology choice [30].

Due to these uncertainties, the theoretical maximum (88% of the natural gas capacity) is assumed on this study. For this calculation, the maximum capacity reported in the SciGRID Gas IGGINL dataset is used when available. If not reported, a linear regression is used to estimate the transport capacity based on the diameter. However, it is worth mentioning that the maximum pipeline capacity not only depends on the diameter, but also on the material type, and pipeline thickness. The resulting average hydrogen capacity on each category is 2.0, 5.5, and 12.0 GW (LHV) for small, medium, and large pipelines respectively. The model assumes that pipelines are bidirectional, and capacities of pipelines connecting the same nodes are added together. The resulting capacities are displayed in Figure 3.3.

3.1.3. Techno economic parameters

Various factors, such as diameter, pressure, material quality, overall pipeline condition, and other considerations, determine the cost-effectiveness of retrofitting versus building new pipelines. These factors are often location-dependent, which can provide certain regions and countries with an advantage for retrofitting their natural gas grids. For instance, in the Netherlands, the parallel infrastructure of the natural gas grid enables companies to retrofit for hydrogen usage while gradually reducing the use of natural gas [31].

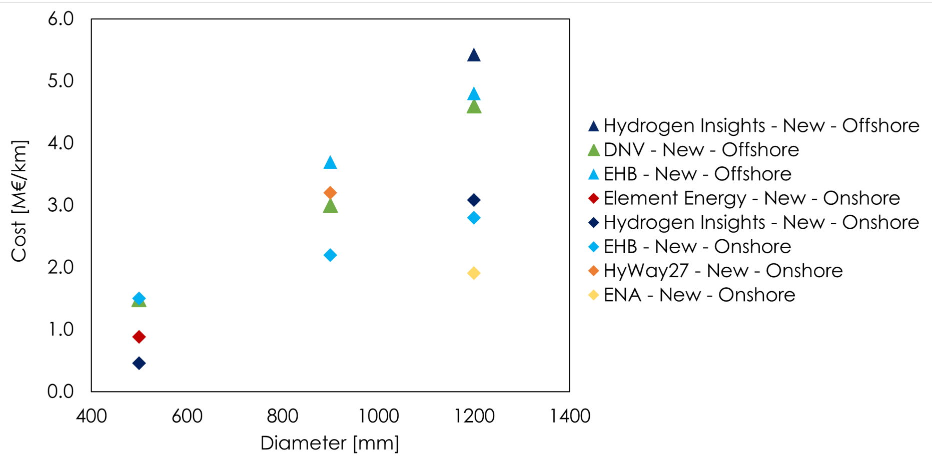

Figure 3.4: Cost of new pipelines reported in the literature. Costs given in M€/km.

Investment costs of new and repurposed pipelines from relevant sources are visually presented in figures 3.4 and 3.5. For onshore transmission networks, the typical capital expenditure (CAPEX) costs vary

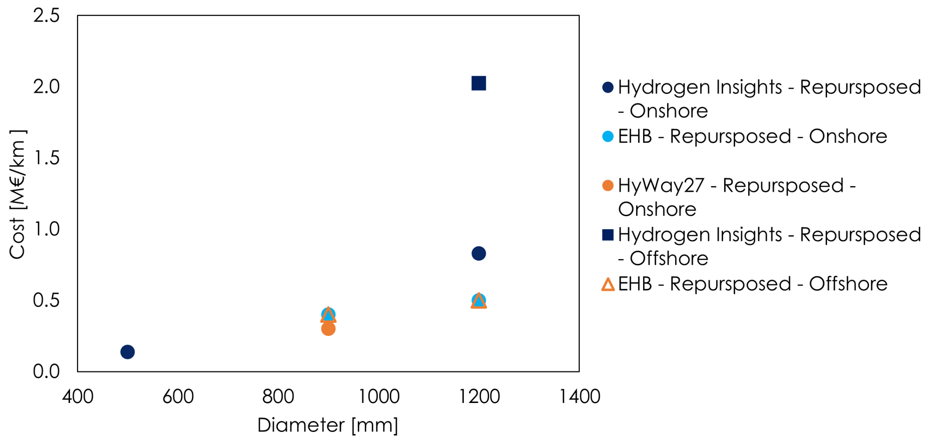

Figure 3.5: Cost of retrofitting pipelines reported in the literature. Costs given in M€/km.

between 0.1 and 0.8 M€/km for retrofitted pipelines, and between 0.5 and 3.2 M€/km for new hydrogen pipelines. The summary of investment costs is shown in table 3.1.

Offshore pipelines for hydrogen transportation are still relatively new worldwide. Consequently, there is limited experience on the subject, and cost estimates vary significantly. Currently, the DNV Joint Industry Project H2Pipe1 is studying the design, construction, and operation of offshore hydrogen pipelines that can handle pressures of up to 250 bar [33]. To the extent of the research done in this report, the EHB [12] study is the only source with an estimation of the cost of repurposing offshore gas pipelines.

In this report costs in €/km are taken from the EHB report[12]. For repurposed pipelines, these costs are then divided by the average hydrogen transport capacity of each category calculated based on the existing natural gas capacity (see subsection 3.1.2). For new pipelines, costs are divided by the average hydrogen capacity of medium pipelines (5.5 GW). Figure 3.6 shows the investment cost of hydrogen pipelines in €/km/MW, covering the CAPEX of pipelines and compressors. Pipelines that have a larger diameter (measured in inches) tend to be more cost-efficient since they can carry a greater amount of energy. This is because when the diameter is doubled, the transport capacity increases by more than double [33]. Techno-economic parameters used in the model are summarized in Table 3.2.

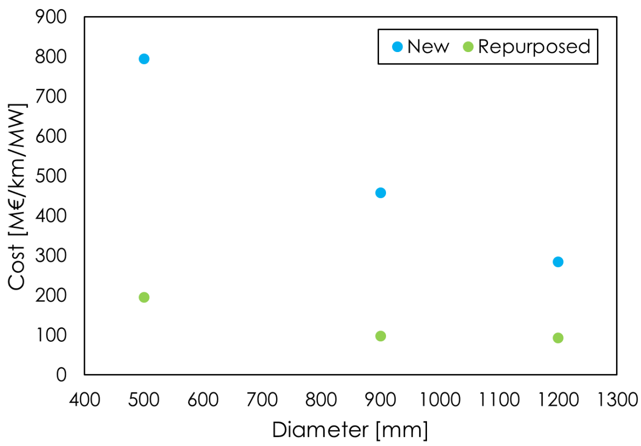

Figure 3.6: Investment costs of new and repurposed pipelines for hydrogen transport including cost of compression. Costs given in M€/km/MW. Data taken from [17].

Table 3.1: Investment costs of new and repurposed hydrogen pipelines.

Source	New /Repurposed	Type	Diameter [mm]	Cost [M€/km] Average	Low	High
Element Energy [1] [32]	New	Onshore	500	0.94		
Hydrogen Insights[2] [31]	New	Onshore	500	0.46	0.30	0.70
	New	Onshore	1200	3.08	2.20	4.50
	Repurposed	Onshore	500	0.14	0.10	0.20
	Repurposed	Onshore	1200	0.83	0.60	1.20
	New	Offshore	1200	5.43	4.70	7.10
	Repurposed	Offshore	1200	2.02	1.30	3.10
DNV [33]	New	Offshore	500	1.48		
	New	Offshore	900	3.00		
	New	Offshore	1200	4.60		
EHB [12]	New	Onshore	500	1.50	1.40	1.80
	New	Onshore	900	2.20	2.00	2.70
	New	Onshore	1200	2.80	2.50	3.40
	Repurposed	Onshore	500	0.30	0.20	0.50
	Repurposed	Onshore	900	0.40	0.20	0.50
	Repurposed	Onshore	1200	0.50	0.30	0.60
	New	Offshore	900	3.70	3.40	4.60
	New	Offshore	1200	4.80	4.30	5.80
	Repurposed	Offshore	1200	0.50	0.40	0.60
	Repurposed	Offshore	900	0.40	0.30	0.50
HyWay27[3] [34]	New	Onshore	900	3.20		
	Repurposed	Onshore	900	0.30		
ENA[4] [35]	New	Onshore	1200	2.04		

[1] Transmission network of 6,300 km in the UK
[2] Large pipeline assumed as 1200mm and small (distribution) pipeline assumes as 500mm
[3] Total cost of retrofitting estimated as 0.84 M€ /km considering asset value
[4] Operating pressure between 30-80 bar with a length of 300 km in the UK

Table 3.2: Parameters used for modelling hydrogen pipelines.

Parameter	Value	Unit	Source	Comment
CAPEX large repurposed pipelines	93	€/km/MW	EHB [12]	Including compressor CAPEX. Based on the average transport capacity of existing natural gas pipelines. Onshore and offshore retrofitting cost assumed as the same.
CAPEX medium repurposed pipelines	98	€/km/MW	EHB [12]	
CAPEX small repurposed pipelines	195	€/km/MW	EHB [12]	
CAPEX new onshore pipelines	458	€/km/MW	EHB [12]	Including compressor CAPEX. Based on costs of medium pipelines, divided by the average transport capacity
CAPEX new offshore pipelines	732	€/km/MW	EHB [12]	
OPEX	2.6	% of CAPEX	EHB [12]	Including compressor OPEX
Lifetime	40	years	EHB [12]	

3.2. Modelling of hydrogen storage in salt caverns

Besides the infrastructure to generate and transport hydrogen, large-scale storage of hydrogen will be required to compensate for the intermittency of renewable energy. Underground storage is seen as a key method to store hydrogen thanks to the large storage capacities, small surface footprint, minor effects on the environment, good safety against external risks, and low investment costs compared to above-ground storage [36]. Rock salt caverns are regarded as the best option for underground hydrogen storage [37, 36]. Its advantages include chemical inertness, low porosity and permeability, and good stability. However, large quantities of water are required to construct the cavern, producing large amounts of saturated brine [36].

3.2.1. Hydrogen storage in salt caverns potential

Caglayan et al. [38] estimated the technical potential for hydrogen storage in bedded salt formations and salt domes in Europe. According to this study, there is a total of 85 PWh H_2 of onshore and offshore technical storage potential. The highest national storage potential of 9 PWh H_2 was reported for Germany. Caverns with a size of 500,000 m^3 have pressures between 60 and 180 bar. This pressure range allows for a working gas capacity of 4 million kg of hydrogen (133 GWh) and a cushion gas capacity of 2 million kg (73 GWh) [37].

Data from Caglayan et al. [38] is clustered into each country node differentiating between on-shore and off-shore potential, resulting in Figure 3.7. According to a report published by Gas Infrastructure Europe and Guidehouse in 2021 [39], there will be a significant demand for underground hydrogen storage in the coming decades. The report estimates that by 2050, a total of 466.4 TWh of hydrogen storage will be needed. The collected data indicates that there is sufficient capacity for underground hydrogen storage on land to meet this demand. Hence, the model used in the report only takes into account the onshore storage potential, except for Norway, which has only offshore potential for hydrogen storage. In the case of the Netherlands, the onshore potential is taken from [40].

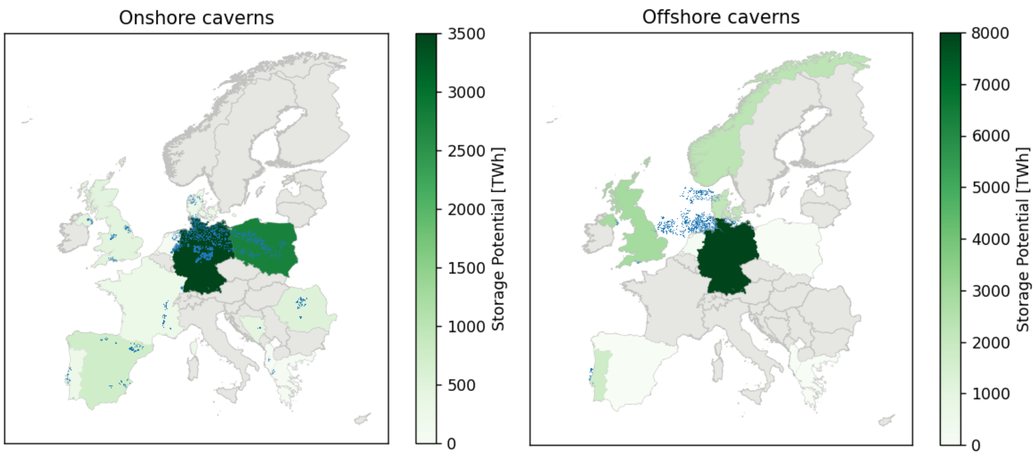

Figure 3.7: Hydrogen storage potential in onshore and offshore salt caverns. Potential given in TWh. The location of salt caverns is shown in blue, and the storage potential per country is shown in green.

3.2.2. Techno economic parameters

Injection and withdrawal mass flow rates of hydrogen for a cavern of this type is approximately 11,000 kg/h (367 MW) if the same pressure change rate as for natural gas caverns is used [37]. Nonetheless, multiple caverns are typically operated in parallel to function as a single storage unit, with flow rates several times higher than those stated. TNO [40] estimates the maximum withdrawal rate as 19,500 kg/h (650 MW) for a salt cavern of 600,000 m³. This limit is set to maintain the structural integrity of the cavern and minimize the loss of (geometric) volume caused by salt creep.

A summary of costs reported in literature is shown in Table 3.3. These estimates include exploration, drilling, leaching, first fill and all other engineering and management work. According to a report by TNO [41], the investment cost of offshore salt caverns is 1.5 -2.3 higher than onshore caverns. The Danish

Energy Agency [42] estimates the investment cost of onshore salt caverns as 70 € per kg H_2 in 2030. However, this estimate is almost three times higher than the next closest cost found on the literature review. On this report, investment and operational costs are taken from the most recent source: the The Oxford Institute for Energy Studies (OIES) [43]. Withdrawal rates are taken from [37]. These parameters are summarized in Table 3.4.

Table 3.3: Investment costs of hydrogen storage in salt caverns.

Source	Year of publication	Type	Cost [€/kg H_2] Average	Low	High
OIES[1] [43]	2023	Onshore	11.3	6.5	16.1
EBN&TNO [41]	2022	Onshore	8.0	4.9	11.1
EBN&TNO [41]	2022	Offshore	16.0	7.6	24.5
Guidehouse [39]	2021	Onshore	27.25	25.5	29.0
DEA [42]	2018	Onshore	56.0	42.0	70.0
HyUnder [37]	2018	Onshore	7.0		

[1] Based on the low heating value of hydrogen (120 MJ/kg)

Table 3.4: Parameters used for modelling hydrogen storage in salt caverns.

Parameter	Value	Unit	Source	Comment
CAPEX onshore salt caverns	11.3	€/kg H_2	OIES [43]	Average investment cost, most recent estimate from the analyzed sources
CAPEX offshore salt caverns	22.6	€/kg H_2	OIES [43]	Assumed as two times the onshore cost according to EBN & TNO [41]
OPEX	1	% of CAPEX	DEA [42]	
Withdrawal rate	11,000	kg H_2/h	HyUnder [37]	Rate for a capacity of 130 GWh. Conservative approach, max. rate estimated as 19,000 kg/h [40]

3.3. Scenarios

3.3.1. Energy system under different electrolysis capacity scenarios

To address the main research question of this study, ”What is the required capacity and distribution of a hydrogen network in Europe under a fully renewable scenario?”, several allocation scenarios of electrolysis capacity are formulated. These scenarios are designed to explore the capacity and distribution requirements of a hydrogen grid under varying conditions. The allocation scenarios are constructed by considering different limits on the total installed capacity of electrolysis.

In this study, the total electrolysis capacity is distributed among European countries based on their respective Gross Domestic Product (GDP) values. The GDP data used for allocation is sourced from the World Bank database [44]. By utilizing GDP as a basis for allocation, the scenarios account for each country’s economic strength, ensuring a more equitable distribution of electrolysis capacity across Europe. To prevent excessive installed capacity, a maximum upper limit of 150 GW per country is set in all scenarios regardless of the allocated capacity. As an example, the limits used in three scenarios are illustrated in Figure 3.8.

3.3.2. Sensitivity to weather year

To evaluate the impact of weather variability across different years, three additional scenarios are modelled for the years 2010, 2012, and 2015. Figure 3.9 provides a visual representation of the energy potential in each of these years, using the installed capacity from the least constrained scenario as a reference.

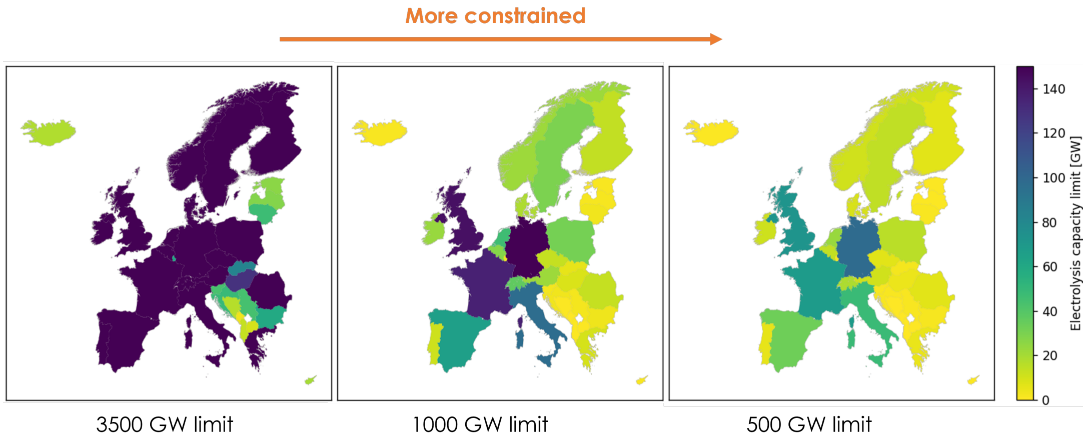

Figure 3.8: Electrolysis capacity limit in three scenarios. The electrolysis limit is distributed based on the GDP of each country, with an upper limit of 150 GW per country. Limit given in GW.

Figure 3.9: Solar and wind energy potential in different weather years. Potential given in TWh.

3.3.3. Sensitivity to imports from North Africa

North Africa possesses significant renewable energy potential, and importing hydrogen from this region could contribute to a more diversified and sustainable European energy system. To evaluate the impact of imports on the hydrogen network, four countries in North Africa are included in the model: Algeria, Libya, Morocco, and Tunisia. The model is based on the least constrained scenario (3500 GW limit).

According to the International Energy Agency (IEA) [45], the estimated cost of producing hydrogen in the North African region in 2030 ranges from 1.5 to 2 EUR/kg. Similarly, a report by PwC [46] suggests that production costs in this region will likely range from 1 to 1.5 EUR/kg. For the purpose of this study, an average production cost of 1.5 EUR/kg is assumed. A maximum amount of 6.25 million tons of hydrogen per year is considered for each African country. This assumption aligns with the high-demand scenario outlined in the study conducted by Zwaan et al. [47].

In addition, existing gas pipelines connecting North Africa with Europe are included in the model as repurposed pipelines for hydrogen transport. These are taken from the SciGRID Gas IGGINL dataset [26]. Moreover, the model allows for the installation of new pipelines if cost-optimal to meet the hydrogen transport requirements.

3.3.4. Sensitivity to cost

Given the limited experience and inherent uncertainty surrounding the cost estimates of hydrogen pipelines and salt caverns, a sensitivity analysis is conducted to assess the potential impact on the study's conclusions. This analysis aims to evaluate the capacity and distribution of the hydrogen grid, as well as the required storage capacity, under different cost scenarios.

Additionally, the sensitivity analysis serves as a means to evaluate the role of salt caverns and hydrogen pipelines and to assess the complementarity between these two technologies. By varying the costs associated with these technologies, insights can be gained regarding their relative importance and their influence on the overall system design.

The sensitivity analysis involves adjusting the costs of salt caverns and new and repurposed pipelines in two levels: a high-cost scenario, where costs are increased by 50% from the base estimates, and a low-cost scenario, where costs are reduced by 50% from the base estimates. Table 3.5 provides an overview of the modeled scenarios and their corresponding names. All scenarios are based on the least constrained model (3500 GW limit).

Table 3.5: Names of cost sensitivity scenarios.

		Hydrogen pipelines		
		Low cost	Base cost	High cost
Caverns	Low cost	LL	BL	HL
	Base cost	LB	BB	HB
	Low cost	LL	BL	HL

4
Results

A comprehensive analysis was conducted using a total of 11 scenarios to explore the required capacity and distribution of a hydrogen grid in Europe under a fully renewable scenario. These scenarios were designed with increasing constraint levels for the total limit of electrolysis capacity. The least and most constrained models have a limit of 3500 GW and 500 GW of electrolysis capacity respectively. The distribution of capacity was based on each country's Gross Domestic Product (GDP).

To ensure a balanced approach and prevent an overly concentrated deployment of electrolysis capacity, a maximum upper limit of 150 GW was set for each country across all scenarios. This constraint aimed to avoid excessive installed capacity in any single country and promote a more equitable distribution of hydrogen infrastructure.

The main results obtained from the analysis are presented in this section. These results provide valuable insights into the potential implications and benefits of different capacity allocation strategies on the European energy system. Through this comprehensive analysis, the study aims to contribute to the understanding of the complex dynamics and interdependencies between electrolysis capacity, hydrogen infrastructure, and the overall energy system. Modeling was based on the 2018 weather year, however, to account for weather variability, a sensitivity analysis is done in section 4.6. In addition, section 4.8 shows a sensitivity analysis of the cost of pipelines and salt caverns.

4.1. Electrolysis capacity and distribution

Limited range of electrolysis capacity, with two regions emerging as potential hydrogen hubs

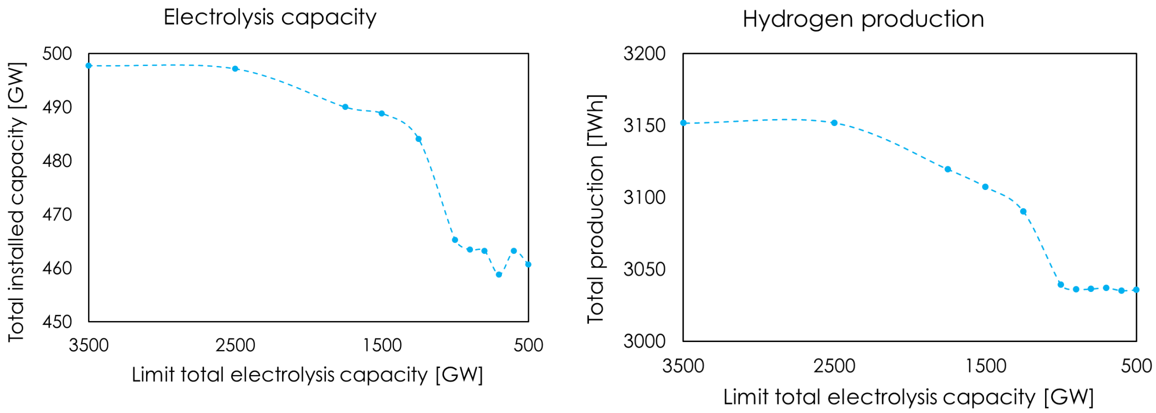

Figure 4.1: Total optimal installed electrolysis capacity (in GW) and hydrogen production (in TWh) in different electrolysis allocation scenarios based on the limit on total electrolysis capacity. Dashed lines serve as a visual aid to illustrate trends but do not represent interpolated data.

Figure 4.1 shows installed electrolysis capacity, and hydrogen production from the least constrained scenario to the most constrained. The optimal electrolysis capacity has a variation of less than 10% across all scenarios, despite a significant sevenfold difference between the limits in the least and most constrained scenarios.

The optimal electrolysis capacity ranges from 460 GW to 498 GW. As the distribution of electrolysis capacity becomes more evenly spread across Europe, the optimal hydrogen production levels decrease due to the higher cost of hydrogen production. Notably, at the 1000 GW limit, there is a significant decrease in the optimal electrolysis capacity. This is primarily influenced by the electrolysis capacity installed in Britain, which benefits from abundant wind resources, resulting in more cost-effective hydrogen production. In all scenarios, Britain reaches its limit of electrolysis capacity (see Table 4.1). Moving from the 3500 GW limit to the 1000 GW limit, the electrolysis capacity in Britain remains at the upper bound (150 GW). However, in more constrained scenarios, the capacity in Britain starts to decrease, leading to a decrease in optimal hydrogen production. Subsequently, a relatively stable capacity range is observed between the 1000 GW and 500 GW limits[1], characterized by a significant redistribution of hydrogen capacity across Europe for a more balanced distribution (see Figure 4.2).

More constrained →

	Electrolysis capacity allocation scenarios. Limit in GW											
	3500	2500	1750	1500	1250	1000	900	800	700	600	500	
ALB					2%	97%						ALB
AUT										2%	75%	AUT
BEL				6%	12%	46%	53%	72%				BEL
BGR							5%	67%				BGR
BIH					1%	8%	23%	34%				BIH
CHE									14%	72%		CHE
CYP	6%	18%	34%	47%	62%							CYP
CZE					21%							CZE
DEU										13%	63%	DEU
DNK	29%	44%	89%									DNK
ESP	18%	18%	37%	52%	81%							ESP
EST	46%											EST
FIN	0%	2%	3%	11%	21%	31%	35%	39%	45%	67%		FIN
FRA	11%	12%	31%	38%	45%	58%	76%					FRA
GBR												GBR
GRC	9%	25%	63%	97%								GRC
HRV	10%	30%	58%	85%								HRV
HUN	16%	48%										HUN
IRL	72%	91%										IRL
ISL	11%	32%	61%	84%								ISL
ITA	15%	15%	15%	16%	17%	29%	34%	39%	53%	86%		ITA
LTU									42%			LTU
LUX						6%	16%	45%				LUX
LVA			84%									LVA
MKD								3%				MKD
MNE					5%	47%	74%	98%				MNE
NLD						7%	18%	35%	92%			NLD
NOR	3%	4%	12%	27%	39%	59%	92%					NOR
POL									13%			POL
PRT	45%											PRT
ROU	3%	6%	12%	16%	35%	92%						ROU
SRB						4%	19%	63%				SRB
SVK			18%	85%								SVK
SVN								75%				SVN
SWE						14%	22%	31%	69%	81%		SWE

Table 4.1: Percentage of electrolysis limit reached per country per scenario. Country names are shown using the ISO 3166 alpha-3 code. The darkest red shade indicates that the country reaches the entirety of its limit, while cells with less than 1% are shown in white.

[1]The deviation from the electrolysis capacity trend observed in the 700 GW scenario could be attributed to the numerical characteristics of the solver employed by the software. The barrier method used by the solver, while faster than simplex, can be more sensitive to numerical issues.

The amount of installed capacity of electrolysis with respect to the limit per country is shown in Table 4.1. By examining this information, countries with the most cost-effective hydrogen can be identified. These countries, such as Denmark, the United Kingdom, Ireland, and Portugal, exhibit installed capacities that approach their respective limits across every scenario. As a consequence, as the limit is relaxed, increasing amounts of hydrogen are generated in these countries, creating hydrogen hubs. These are countries with the highest wind energy availability, which enables increased hydrogen production during winter and reduces the need for extensive storage (see Section 4.3).

To guide the reader through the analysis, three scenarios are assessed with distinct names: the 'least constrained' scenario (3500 GW limit), the 'most constrained' scenario (500GW limit), and the 'half constrained' scenario where the optimal electrolysis capacity has a sharp decrease at a limit of 1000 GW. The allocation of electrolysis capacity in these three scenarios is shown in Figure 4.2. Only countries with a production fraction higher than 5% are shown. In the least constrained scenario, Britain has the highest hydrogen production factor, with 31% of the total production, followed by Ireland with 21%, Portugal with 13%, and Denmark with 10%. In the most constrained scenario, there is a more even production across Europe because the electrolysis capacity is solely based on each country's GDP.

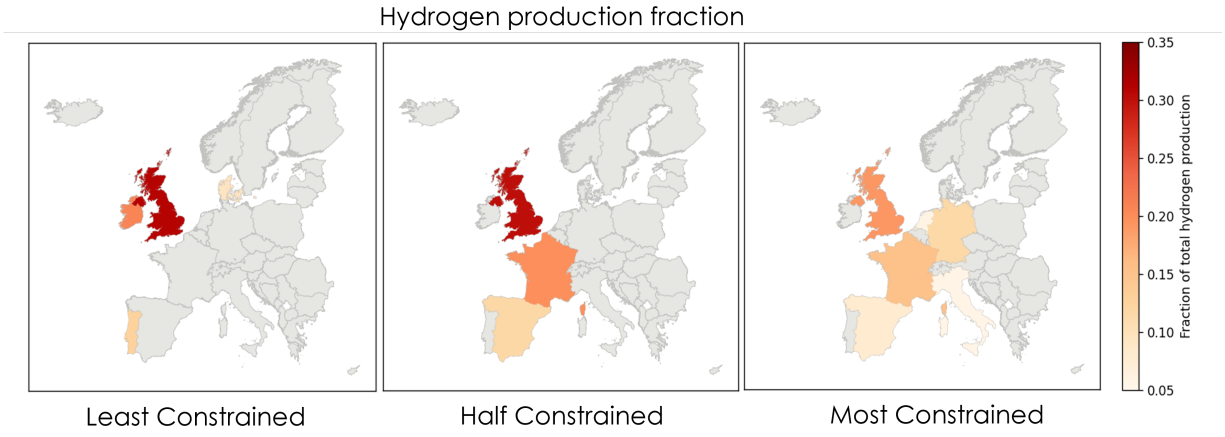

Figure 4.2: Spatial distribution of hydrogen production in three electrolysis allocation scenarios. The red shades represent the fraction of total hydrogen production per country. Only countries with a fraction higher than 5% are colored.

4.2. Hydrogen network capacity and distribution

Hydrogen network capacity depends greatly on the allocation of electrolysis, with minor influence on transmission

The results of the total capacity of hydrogen pipelines, and transmission capacity expansion are shown in Figure 4.3. As the allocation of electrolysis across Europe changes, so does the capacity of the required hydrogen network and transmission capacity. The capacity of hydrogen pipelines ranges from 135 TWkm to 244 TWkm. This broad range of capacity reflects the diverse configurations of the energy system, which in turn influence the distribution of transmission and storage capacities. The required hydrogen network capacity decreases as electrolysis is more evenly distributed across Europe.

There are two contrasting results: in the least constrained scenario there is a balanced mix of approximately 50% new and repurposed pipelines, whereas in the most constrained scenario the system heavily relies on repurposed pipelines. The scenario primarily dependent on repurposed infrastructure proves to be the least cost-efficient (refer to Section 4.5). However, this scenario has a more balanced spatial distribution of electrolysis capacity. On the other hand, the scenario with a 50/50 share of new and repurposed pipelines is the most cost-effective. It requires a similar transmission line capacity as the former scenario but requires around 10% higher electrolysis and storage capacities. Furthermore, as discussed in Section 4.2, the concentration of electrolysis capacity in countries with abundant wind resources leads to localized hydrogen production, resulting in increased hydrogen imports (see Section 4.3).

In contrast to the variability of hydrogen pipelines, transmission capacity has relatively minor fluctuations in response to changes in the allocation of electrolysis. The overall transmission line capacity ranges between 430 TWkm and 470 TWkm, with a peak of approximately 8% higher than the lowest value. This peak correlates with a decrease in storage capacity (see Section 4.3).

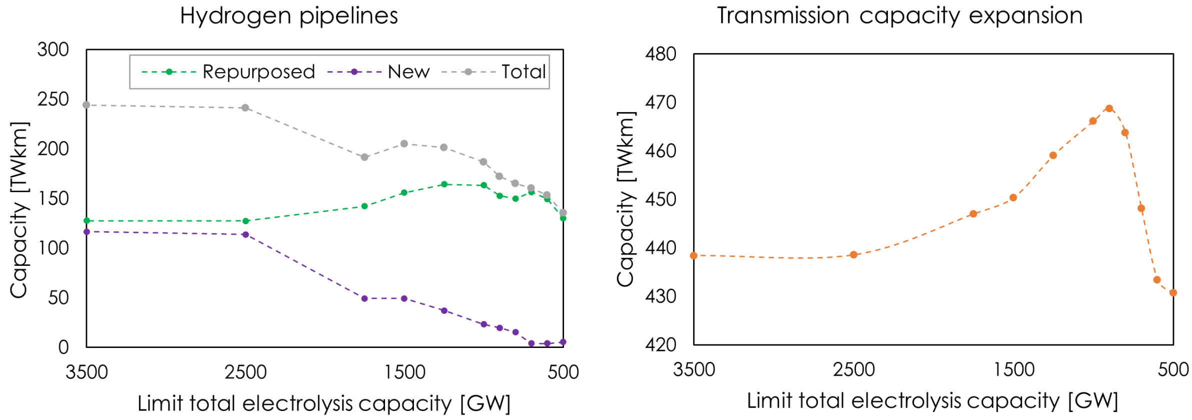

Figure 4.3: Total optimal installed capacity of new and repurposed hydrogen pipelines (in TWkm), and transmission capacity expansion (in TWkm) in different electrolysis allocation scenarios based on the limit on total electrolysis capacity. Dashed lines serve as a visual aid to illustrate trends but do not represent interpolated data.

Establishing hydrogen hubs requires extensive hydrogen network capacity in Britain and the Iberian Peninsula

Figure 4.4 presents an overview of the system's topology, showing the capacity and spatial distribution of transmission lines, pipelines, hydrogen and electricity imports. This Figure focuses on three distinct scenarios: the least (3500 GW limit) and most (500 GW limit) constrained scenarios, and a half-constrained scenario (1000 GW limit).

Substantial changes are observed in the topology of the hydrogen network as the allocation of electrolysis capacity changes. In the least constrained scenario, most hydrogen is produced in hydrogen hubs in northern and western Europe. In this scenario, there is a significant required pipeline capacity connecting Ireland-Britain-Netherlands, and Portugal-Spain-France-Germany. These key connections create hydrogen corridors, which are discussed in chapter 5. In more constrained scenarios, the capacity of the main hydrogen corridors decreases due to a decreased reliance on hydrogen imports. Conversely, the capacity between Germany and countries like the Netherlands, Poland, Switzerland, and Austria increases.

The most notable change between scenarios is observed in the capacity of two key pipelines: the pipeline connecting Britain to the Netherlands and the pipeline connecting Portugal to Spain. In the least constrained scenario, the GBR-NLD pipeline has a capacity of 110 GW, while in the most constrained scenario, it is reduced to only 10 GW. Similarly, the ESP-PRT pipeline capacity decreases from 42 GW in the least constrained scenario to 1 GW in the most constrained scenario.

Key transmission lines enable cheaper hydrogen production

The majority of transmission lines show minimal changes in capacity across different scenarios. However, one notable exception is the connection between Iceland (ISL) and Great Britain (GBR). Specifically, the capacity of the ISL-GBR transmission line doubles in the least constrained scenario compared to the most constrained.

The observed increase in transmission capacity between Iceland and Britain is influenced by several factors, including the wind profiles of these countries. Analysis of the 2018 weather data reveals that Iceland has higher wind capacity factors during the summer months compared to Britain. This implies that during periods of lower wind availability in Britain, such as in the summer, there is a greater need to import electricity from Iceland to meet the electricity demand for both general consumption and hydrogen

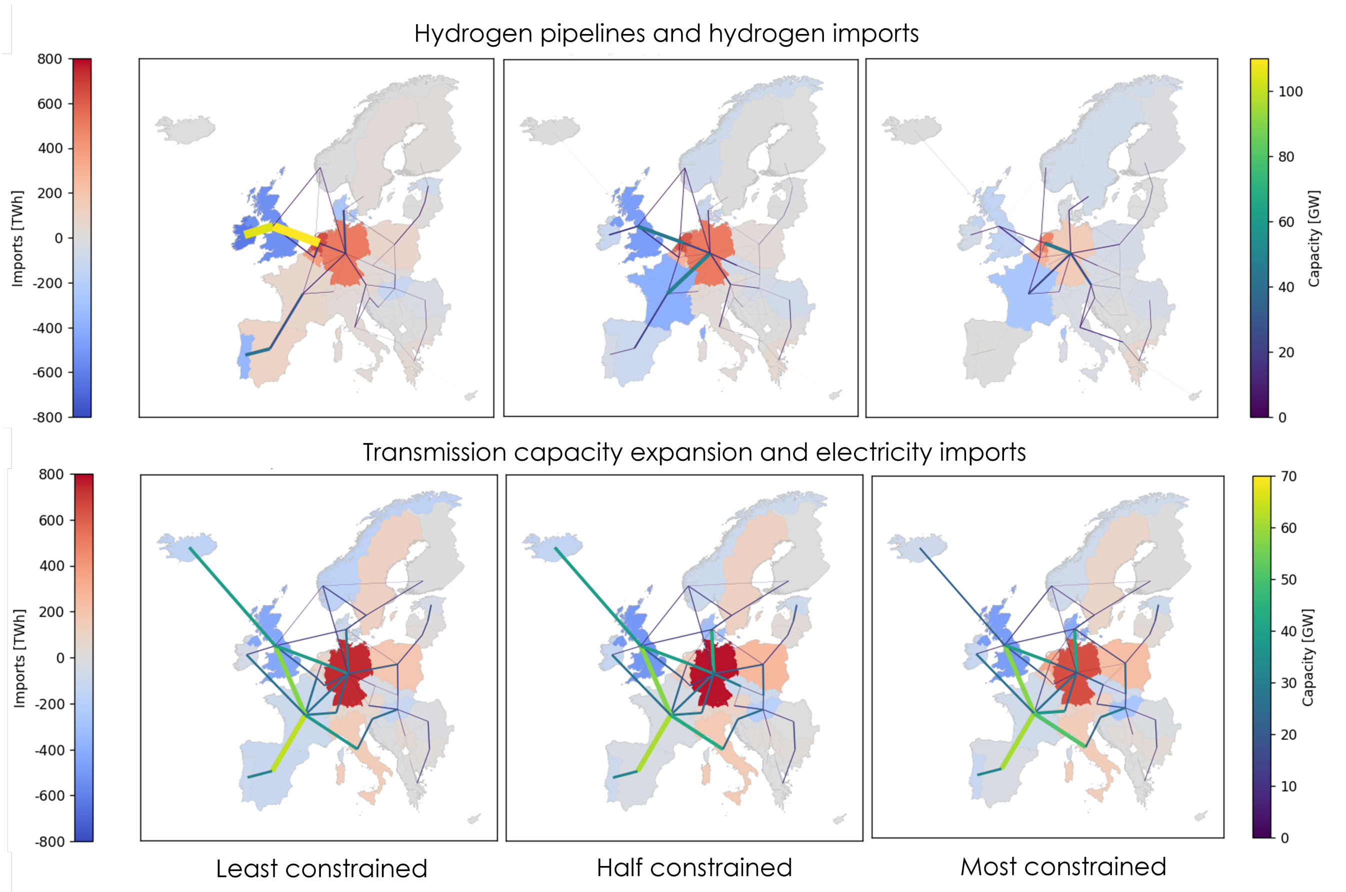

Figure 4.4: Upper graph: hydrogen pipeline capacity (in GW) and hydrogen imports (in TWh); lower graph: electricity transmission capacity expansion (in GW) and electricity imports (in TWh). Results are shown for three electrolysis allocation scenarios. The line thickness and color of the hydrogen pipelines and transmission lines indicate their respective capacities. Hydrogen and electricity imports are represented by color shades per country, where red indicates a net importer and blue indicates a net exporter.

production. It is important to note that both countries reach their respective limits on electrolysis capacity in most scenarios. However, capacity in Britain is two orders of magnitude higher than in Iceland due to its higher GDP. This helps to explain why, instead of producing more hydrogen in Iceland and transporting it by pipeline to Britain, electricity is transported to Britain to produce hydrogen due to the higher capacity in this country.

Although most transmission lines have minimal changes in capacity across the scenarios analyzed, the doubling of capacity in the ISL-GBR connection emphasizes the importance of considering cross-border connections and their role in facilitating the integration of renewable energy sources, specifically for hydrogen production.

4.3. Storage and imports

Salt caverns dominate storage technologies, accounting for over 99% of total storage capacity. Optimal capacity varies by 15%

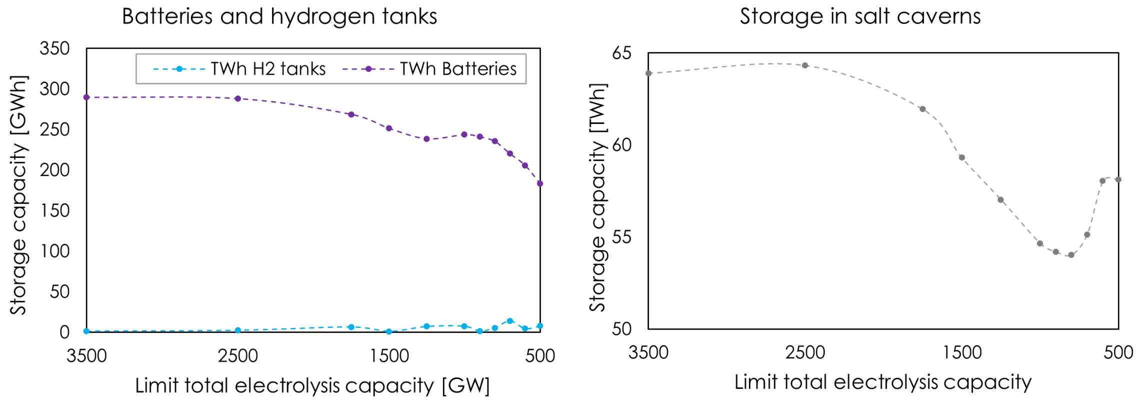

Figure 4.5: Total optimal storage capacity of batteries, H_2 tanks (in GWh) and salt caverns (in TWh) in different electrolysis allocation scenarios based on the limit on total electrolysis capacity. Dashed lines serve as a visual aid to illustrate trends but do not represent interpolated data.

Two technologies were modeled for hydrogen storage: storage in tanks and storage in salt caverns. The total capacity of these storage technologies and also storage in batteries is shown in Figure 4.5. The stored hydrogen in tanks remains relatively low, with a capacity under 15GWh, representing less than 0.01% of the storage capacity in salt caverns. In contrast, battery storage is an order of magnitude higher, with capacity ranging from 183GWh to 290GWh. However, battery storage still accounts for less than 1% of the total storage capacity. Therefore, storage in salt caverns remains the preferred storage technology across all examined scenarios.

Salt cavern storage capacity follows a similar trend as for hydrogen production when comparing the least constrained (3500 GW limit) and half constrained (1000 GW limit) scenarios. As hydrogen production decreases due to capacity constraints (see Figure 4.1), the required storage capacity also decreases. However, in more constrained scenarios, where hydrogen production remains the same, the required storage capacity increases. This change can be attributed to the allocation of hydrogen production in countries with lower renewable energy availability during winter. In these constrained scenarios, the energy system faces more challenges in aligning supply with demand, resulting in a larger storage capacity to compensate for seasonal imbalances. However, the variation of the optimal storage capacity in salt caverns remains relatively low compared to the variation in pipeline capacity, with 15% variation from the highest to the lowest value.

Establishing hydrogen hubs requires concentrated hydrogen storage and large quantities of hydrogen imports, while a more evenly distributed scenario relies more on electricity imports

Figure 4.6 shows the spatial distribution of salt cavern storage capacity in three scenarios. In the least constrained scenario, salt cavern capacity is concentrated in the United Kingdom, Portugal, and Denmark.

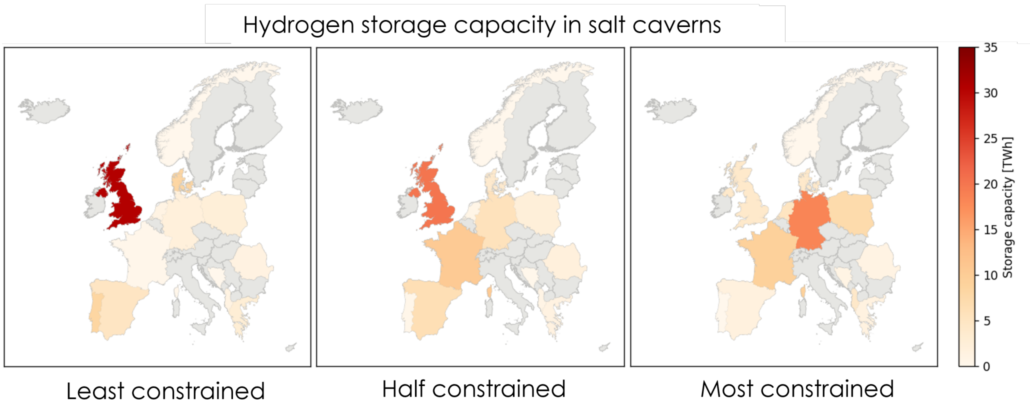

Figure 4.6: Optimal spatial distribution of storage in salt caverns in three electrolysis allocation scenarios. The red shades represent the storage capacity in salt caverns per country (in TWh).

This result is a direct consequence of larger hydrogen production in these countries. Notably, although Ireland lacks salt cavern potential, it produces 21% of the total H_2 production.

As the limit of electrolysis capacity is more constrained, storage capacity is more evenly distributed among regions. It is relevant to notice that the amount of hydrogen storage capacity in each country does not necessarily correlate directly to the amount of hydrogen produced within that country. In the most constrained scenario, Germany stands out with the highest fraction of total storage capacity, accounting for 31% of the overall storage capacity. However, in terms of hydrogen production, Germany contributes only 12% to the total. This result indicates that there is a greater seasonal imbalance in Germany.

The effect on the total hydrogen and electricity imports is illustrated in Figure 4.7. As the scenarios transition from least constrained to most constrained, hydrogen imports decrease due to a more balanced distribution of hydrogen production across Europe. This shift reduces the reliance on cross-border hydrogen trade. However, a corresponding increase in electricity imports is observed, as local electricity generation for hydrogen production becomes insufficient to meet the demand.

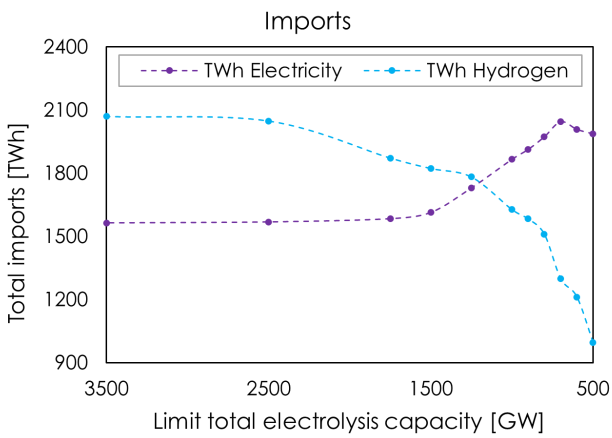

Figure 4.7: Total imports of electricity and hydrogen (in TWh) in different electrolysis allocation scenarios based on the limit on total electrolysis capacity. Dashed lines serve as a visual aid to illustrate trends but do not represent interpolated data.

4.4. Common features across scenarios

Repurposed pipelines are required in all scenarios, whereas new pipelines are only necessary when hydrogen production is concentrated

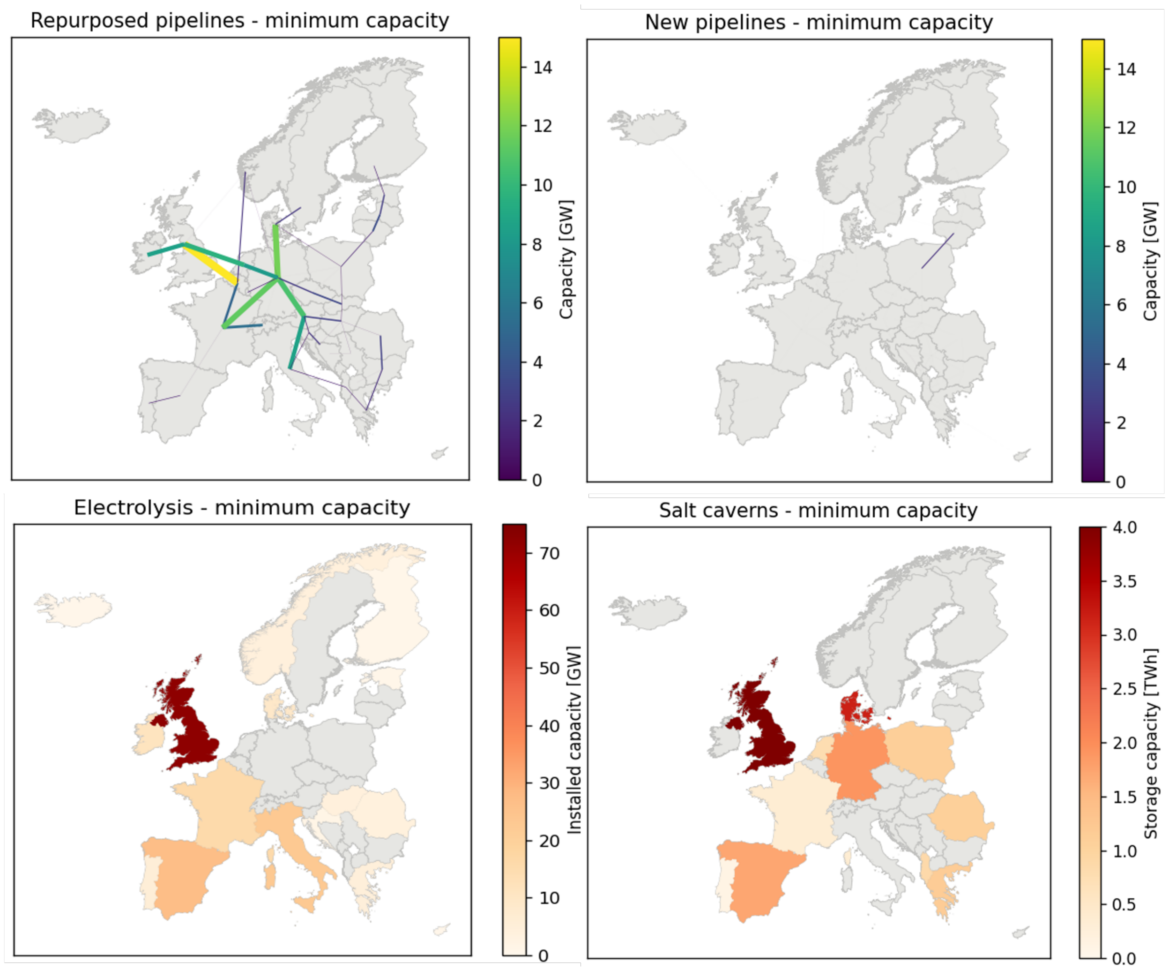

Figure 4.8: Spatial distribution of minimum installed capacity of repurposed pipelines, new pipelines, electrolysis, and hydrogen storage in salt caverns across scenarios. The line thickness and color of the hydrogen pipelines indicate their respective capacities. Electrolysis and salt cavern capacities are represented by color shades per country.

Common features are identified by comparing results across scenarios. These consist in no-regret scenarios that serve as an indication of the minimum capacity of technologies that should be installed in the path to net zero regardless of the allocation of electrolysis. Four technologies are analyzed: repurposed and new pipelines, electrolysis capacity per country, and H_2 storage in salt caverns. the spatial distribution and capacity of said technologies are shown in Figure 4.8.

Firstly, while it is possible to largely depend on repurposed pipelines, a new pipeline with a capacity of 2.1 GW between Poland and Lithuania is needed in all scenarios, highlighting the necessity for new infrastructure in the Baltic region. Nonetheless, it is important to note that the least constrained scenario has a total new pipeline capacity of 288 GW, emphasizing the requirement for additional infrastructure in the presence of concentrated hydrogen production hubs.

The summed-up minimum capacities of repurposed pipelines amount to 130 GW. Common features between scenarios indicate that there are always three corridors present: Northern Europe, the Baltic region, and South-East Europe. The minimum capacity connecting Germany to Australia, Denmark, and France amounts to 11, 12, and 11.5 GW respectively. Another relevant pipeline is the one connecting Belgium to Britain, with a minimum capacity of 15 GW.

Secondly, as seen in Table 4.1 the limit of electrolysis capacity in Britain is always reached, therefore, the minimum capacity in this country is equal to the limit set on the most constrained scenario (72 GW). Countries with a minimum installed capacity higher than 15 GW are Spain, Italy, and France with 27, 22, and 16 GW respectively. These capacities correspond to what is installed in the least constrained scenario. The minimum capacity of electrolysis per country adds up to 186 GW in total.

Lastly, the minimum capacity of salt caverns per country adds up to 16 TWh in total, which is only 30% of the capacity in the scenario with the least storage (half constrained scenario). This gives an indication of the spatial variability of the modeled scenarios. Britain and Denmark have at least 4 and 3 TWh of salt caverns respectively in all scenarios. Even though Germany is not a hydrogen hub, it has a minimum of 2 TWh of salt cavern storage in all scenarios. This allows Germany to store imported hydrogen and ensure a stable supply.

4.5. Benefits of an optimal allocation of electrolysis

Establishing hydrogen hubs leads to cost savings and curtailment reduction

The least constrained scenario brings a number of benefits when compared to less efficient allocation scenarios. The quantitative advantages resulting from this optimal allocation are shown in Figure 4.9, which shows the change in both total system cost and curtailment.

Going from the most to the least constrained scenarios, one of the primary benefits is the reduction in total system cost, which amounts to a 2% decrease equivalent to approximately 19 billion €/year. This reduction is particularly significant, as it is comparable to the combined cost of hydrogen pipelines and transmission lines. Particularly, there is a significant cost reduction as more electrolysis capacity is allocated in Britain. However, once Britain reaches its limit of 150 GW, the subsequent scenarios show diminishing cost reductions.

Another substantial benefit lies in the reduction of curtailment. Curtailment refers to the amount of energy that is not used due to oversupply. With the optimal allocation of electrolysis capacity, curtailment is effectively reduced by 50 TWh. To put this into perspective, this reduction is approximately equivalent to half of the electricity consumption of the Netherlands in 2021 [48]. By minimizing curtailment, the overall energy system becomes more efficient and sustainable, as renewable energy resources are more optimally operated.

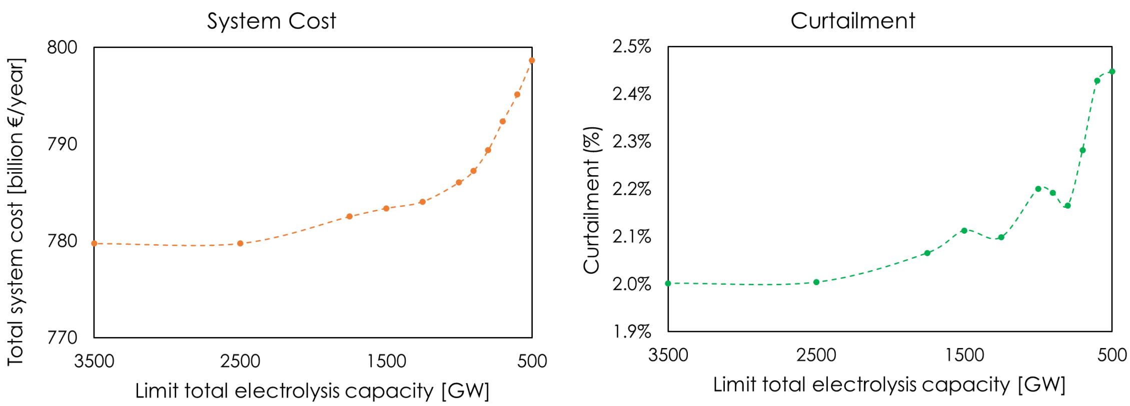

Figure 4.9: System cost and curtailment in different electrolysis allocation scenarios based on the limit on total electrolysis capacity. Dashed lines serve as a visual aid to illustrate trends but do not represent interpolated data.

4.6. Sensitivity - Weather years

Significantly more storage capacity is likely required to adjust to weather year variations

To incorporate weather variability into the analysis, the model was run using data from three additional weather years: 2010, 2012, and 2015. The hydrogen production profiles resulting from these weather years are illustrated in Figure 4.10 for the least constrained, half constrained, and most constrained scenarios.

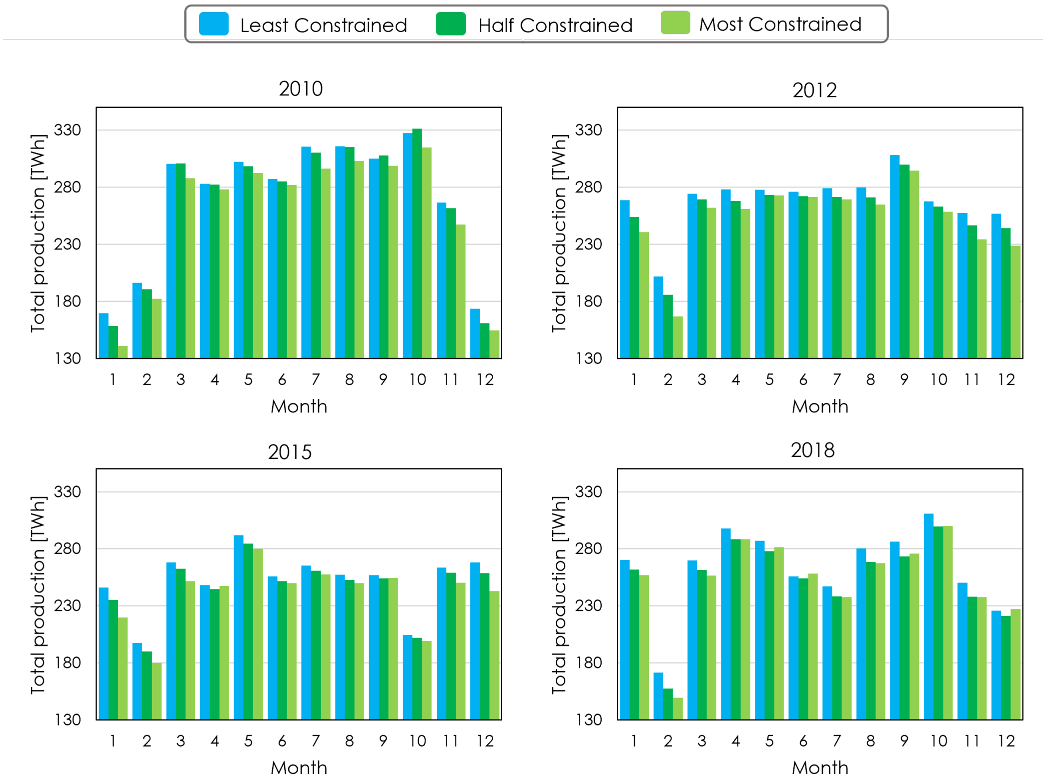

Figure 4.10: Sensitivity of hydrogen production profile in different weather years and electrolysis capacity allocation scenarios. Hydrogen production is shown in TWh.

In the 2018 weather-year, particular emphasis is placed on the production levels observed in February, which stand out as the lowest compared to other months throughout the year and can be considered an outlier in the overall trend. Similarly, the production in February for the other three weather years remains consistently low. As a result, the production levels observed in February of the 2018 weather-year can be considered a reliable approximation for the system.

Examining the monthly variations in hydrogen production across the different weather years, we observe fluctuations ranging from -45% to +35% compared to the 2018 values. This variability has implications for the required infrastructure capacities, including pipelines and hydrogen storage, as depicted in Figure 4.11. The required capacity of hydrogen pipelines is influenced by the fluctuating production levels, leading to deviations in the range of -15% to +20% when compared to the 2018 scenario. However, despite the variations in production and infrastructure capacity, the fundamental behavior of the system remains consistent across the different weather years. As the electrolysis capacity limit is relaxed, the model consistently allocates more capacity in Northern Europe, where there is higher availability of wind power resources.

The analysis reveals contrasting patterns of uncertainty when considering storage and pipeline capacity within the hydrogen network (see Figure 4.11). In terms of storage capacity, the least constrained scenario exhibits a narrower range of uncertainty, ranging from 50 to 140 TWh. In comparison, the most constrained scenario has a wider range, spanning from 40 to 180 TWh. On the other hand, pipeline capacity uncertainty follows an inverse trend. The least constrained scenario has higher uncertainty, ranging from 170 to 290 TWkm, while the most constrained ranges from 130 to 150 TWkm.

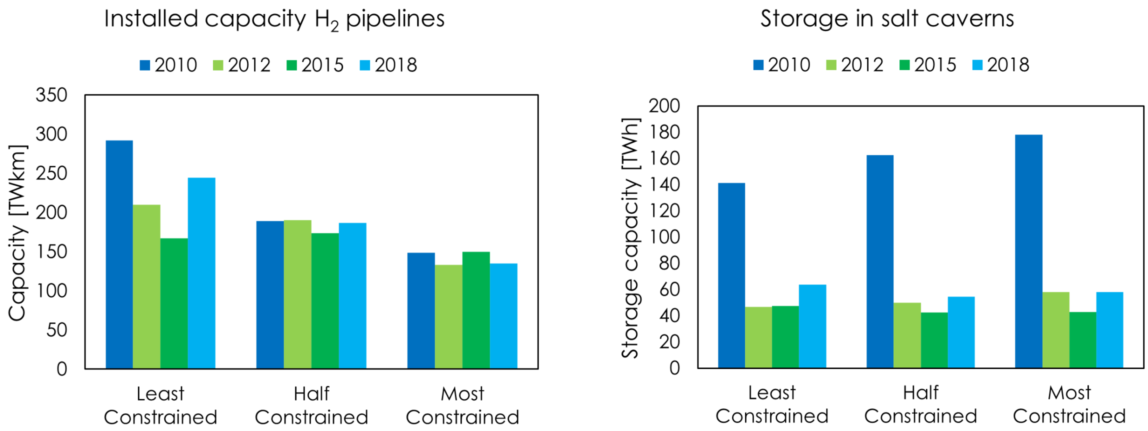

Figure 4.11: Sensitivity of capacity of hydrogen pipelines (in TWkm) and hydrogen storage in salt caverns (in TWh) in different weather years and electrolysis capacity allocation scenarios.

These findings can be attributed to the flexibility of the model in reallocating electrolysis capacity to optimize hydrogen supply based on the availability of renewable energy. In the most constrained scenario, electrolysis capacity and distribution remain constant. As a result, pipeline capacity remains unchanged, and the system relies more on storage to compensate for seasonal imbalances. This leads to less uncertainty in pipelines and high uncertainty in storage. In contrast, the least constrained scenario allows for the optimization of electrolysis capacity distribution according to weather-year conditions. This introduces more uncertainty in pipeline capacity as the location of electrolysis capacity changes. However, there is less uncertainty in storage because pipeline capacity and distribution are optimized.

The high uncertainty in storage capacity observed in the 2010 weather-year can be attributed to the availability of renewable energy during that period. In 2010, there was less wind availability in winter and slightly higher availability in the summer, resulting in a greater seasonal imbalance in the system. Consequently, more hydrogen is produced in the summer and less in winter, leading to increased storage requirements. In this weather-year, the storage capacity required is up to three times higher compared to the 2018 weather-year.

While the 2018 data provides a reasonable approximation for the system, the inclusion of other weather years highlights the potential impact of different weather conditions on hydrogen production and the corresponding infrastructure needs. Higher storage capacities are likely to be needed in comparison to the 2018 results. The capacity of hydrogen pipelines is also likely to be higher depending on the electrolysis allocation per country and production profile.

4.7. Sensitivity - Imports from North Africa

With imports from North Africa, the required investment in H_2 infrastructure increases by 55%, required H_2 storage decreases by 40%, renewable energy capacity decreases by 10%

Imports from four North African countries (Algeria, Libya, Morocco, and Tunisia) are included in the model for the least constrained scenario. With the cost advantage of hydrogen production in North Africa, each country reaches the maximum allowed capacity, resulting in a total production of 833 TWh (25 million tons of H_2). The total hydrogen demand remains relatively stable. However, since 25% of the demand is now supplied by imports from North Africa, the required electrolysis capacity decreases by the same percentage, primarily affecting Ireland, Italy, and Portugal. In addition, renewable energy capacity decreases by 10%.

The inclusion of imports from North Africa also brings changes to the hydrogen infrastructure capacity and topology (see Figure 4.12). As the production in Ireland decreases, there is a reduced need for pipeline capacity connecting Ireland to Britain and the Netherlands. However, overall, there is a 30% increase in pipeline capacity when accounting for pipelines to North Africa. The expansion of pipeline capacity is not solely attributed to the pipelines installed in North Africa. The two key corridors facilitating the transport of imported hydrogen to the rest of Europe are also reinforced. Specifically, the Spain-France-Germany corridor has a higher capacity, as well as the Italy-Albania-Greece corridor. Overall, investment cost in pipelines increases by 55%.

Hydrogen imports from North Africa reduces required storage capacity and mitigate storage uncertainties related to weather-year fluctuations

The monthly hydrogen production decreases by an average of 25%, which is consistent with the reduction in electrolysis capacity. To compensate for this decrease, the shortfall is met through constant imports of hydrogen from North Africa. As a result, the reliance on imports covers the 25% monthly reduction in hydrogen production. The introduction of constant hydrogen imports from North Africa brings an important benefit: it reduces the need for extensive storage capacity. With a constant supply of hydrogen from Africa, the fluctuations in hydrogen supply are minimized. Consequently, the storage requirements in salt caverns see a significant decline of 40%. The collective reduction in electrolysis capacity, renewable energy capacity, and storage yields a substantial cost reduction of 6%. This cost decrease surpasses the benefit achieved through the optimal allocation of electrolysis capacity in Europe, which amounts to only 2%.

The reduction in required storage capacity serves as a valuable mitigation strategy for addressing the uncertainties associated with weather-year fluctuations. To assess more closely this benefit, weather sensitivity of the external imports scenario is analysed. The results indicate that the salt cavern capacity ranges from 34 to 90 GW across the weather years 2010, 2012, and 2015. This capacity range is lower than the required capacity in the less restricted scenario, which ranges from 50 to 140 GW when accounting for weather year variation.

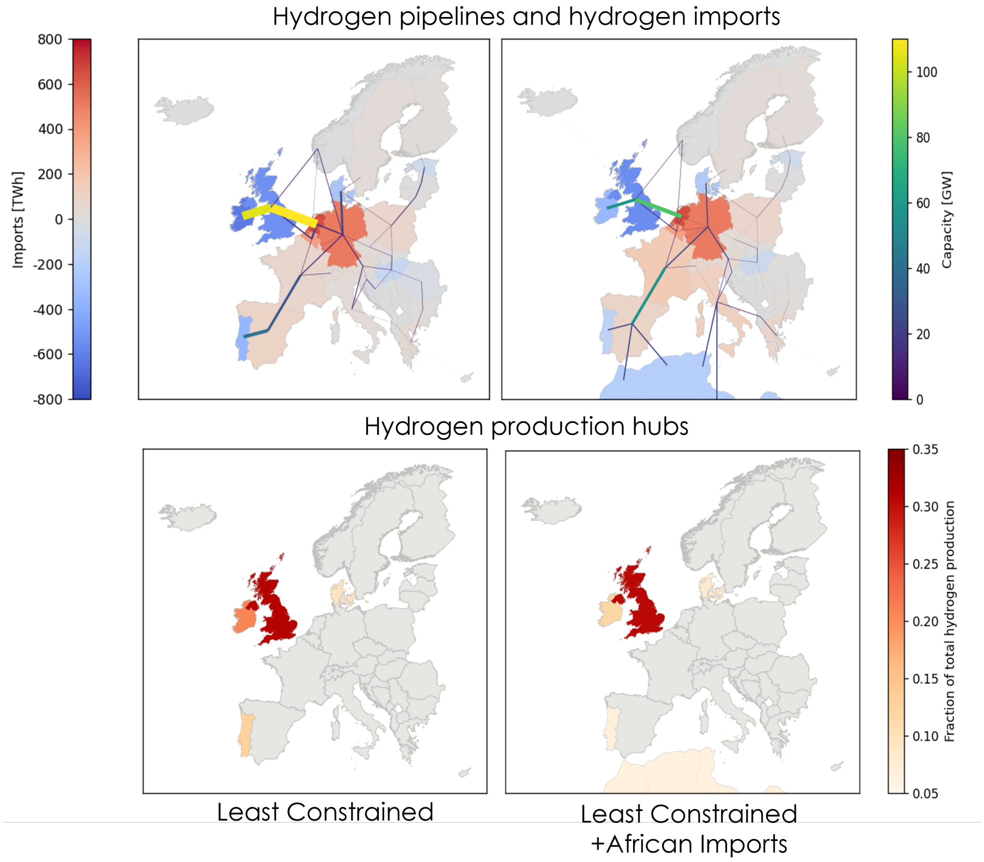

Figure 4.12: Hydrogen pipeline capacity (in GW), hydrogen imports (in TWh), and fraction of total hydrogen production in the least constrained scenario before and after adding African imports. The line thickness and color of the hydrogen pipelines indicate their respective capacities. Hydrogen imports and hydrogen production fractions are represented by color shades per country. Only countries with a hydrogen production fraction higher than 5% are colored.

4.8. Sensitivity - Cost of technologies

Changing pipeline costs significantly shifts the optimum new pipeline capacity, and salt cavern cost does not significantly affect pipeline capacity

Figure 4.13 presents the percentage change in total installed capacity of both new and repurposed pipelines in the different cost sensitivity scenarios. All these scenarios are based on the least constrained model, the description of each scenario is shown in Subsection 3.3.4. Figure 4.13 also includes the corresponding variations in total hydrogen imports and electricity imports, as these parameters are closely related to changes in hydrogen pipelines. It is important to note that hydrogen production and electrolysis capacity remain relatively stable across all sensitivity scenarios, with changes of less than 2%.

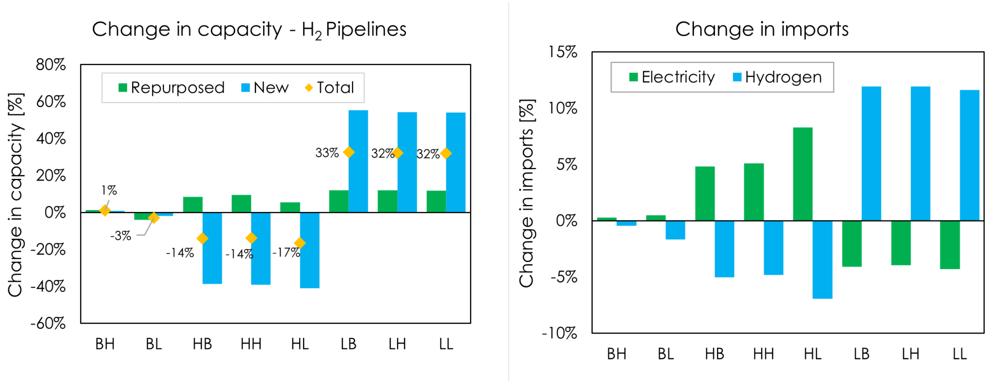

Figure 4.13: Sensitivity of total capacity of H_2 pipelines and imports of hydrogen and electricity in different cost scenarios. Cost scenarios are based on the least constrained scenario.

In the high-cost scenario, where pipeline costs increase by 50%, there is a noticeable reduction of 14% to 17% in the total installed capacity of pipelines. On the other hand, when pipeline costs decrease by 50% (low-cost scenario), there is an additional capacity of approximately 32-33%, and both new and repurposed pipelines experience an increase in capacity. In addition, changing the cost of salt caverns does not significantly affect the capacity of pipelines.

Across all scenarios, the total capacity of repurposed pipelines shows a range of -4% to +12%. Consequently, the conclusions regarding the required repurposed infrastructure remain relatively consistent, even when accounting for cost uncertainties. However, the total installed capacity of new pipelines exhibits a wider range of -41% to +55%, closely aligned with the percentage change in costs. This indicates that the results related to new pipeline infrastructure are significantly influenced by cost assumptions and should be interpreted with caution. Therefore, the presented solutions should be considered indicative, as significant changes may occur based on cost variations.

Figure 4.14 shows the spatial distribution of hydrogen pipelines and transmission lines in two sensitivity scenarios. In the high-cost scenario, there is a decrease in the installed capacity of pipelines connecting Britain and Ireland. Conversely, the low-cost scenario enables a significant increase of approximately 40% in capacity between Ireland and Britain, as well as between Britain and the Netherlands. Additionally, the lower cost makes it feasible to install a pipeline connecting Iceland to Britain, facilitating the transportation of cost-effective hydrogen from Iceland to inland Europe. This indicates that hydrogen pipeline topology is also sensitive to pipeline cost.

While the total newly installed capacity of transmission lines shows minimal variation, with changes of less than 0.05%, the total imports of electricity exhibit variations between -4% and +8% across different sensitivity scenarios (see Figure 4.13). These changes reflect the dynamic nature of the system, influenced by the cost of technologies. For instance, in the high-cost scenario, France transitions from being a net exporter of electricity to a net importer. This shift occurs as electricity is increasingly used for local hydrogen production and subsequent storage in salt caverns, but this happens only in scenarios where the cost of salt caverns is low.

Considering the impacts on hydrogen pipelines and transmission lines, it is evident that varying cost assumptions can influence the spatial distribution of these technologies, connectivity between regions, and trade patterns.

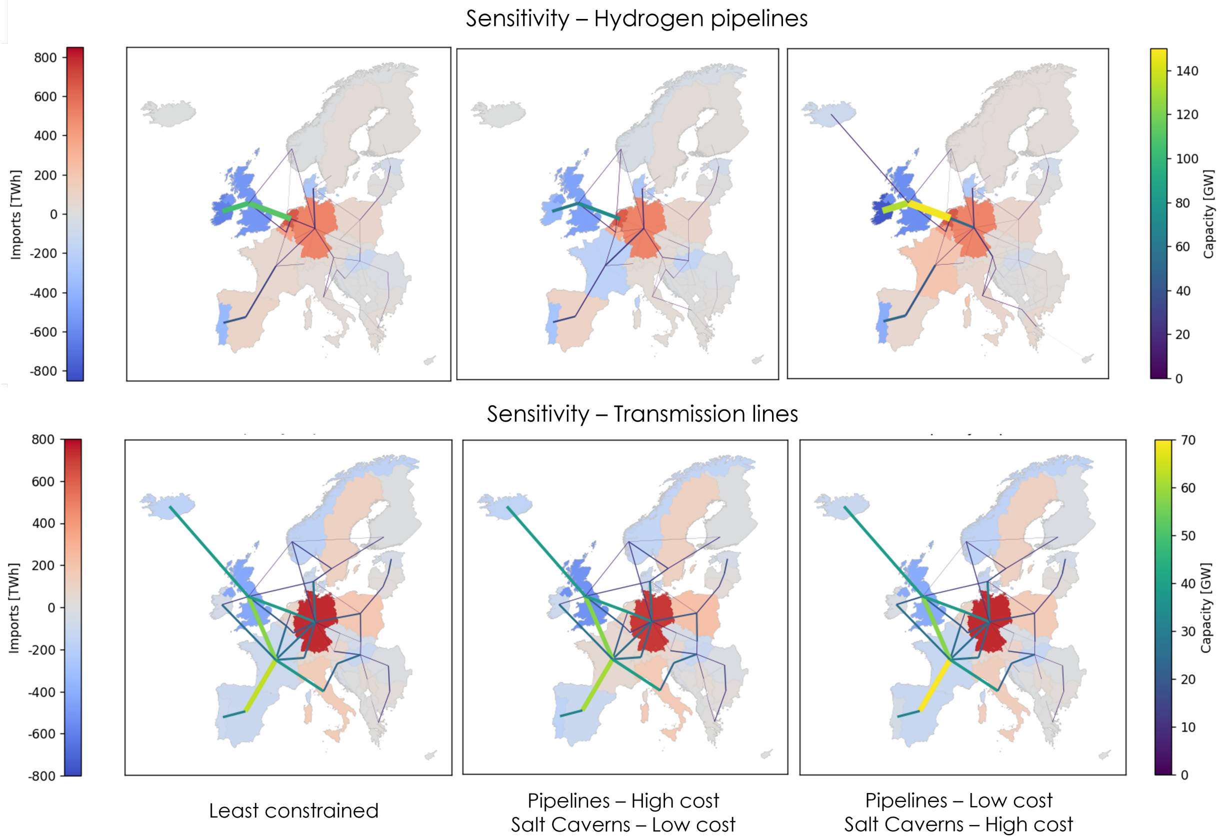

Figure 4.14: Sensitivity of H_2 pipelines and transmission lines spatial distribution in different cost scenarios. The line thickness and color of the hydrogen pipelines and transmission lines indicate their respective capacities. Hydrogen and electricity imports are represented by color shades per country, where red indicates a net importer and blue indicates a net exporter. Cost scenarios are based on the least constrained scenario.

The cost of salt caverns has a significant impact on hydrogen storage capacity, particularly when the cost of hydrogen pipelines is high

The percentage change in the capacity of storage technologies is shown in Figure 4.15. When the cost of salt caverns is low, hydrogen storage capacity ranges from 67% to 115% more capacity compared to the base cost scenario. This difference is most significant when the cost of hydrogen pipelines is high. On the other hand, in scenarios where caverns are more expensive, the change in salt cavern capacity is less than -15%. Furthermore, the capacity of hydrogen tanks exhibits significant changes with variations in technology costs. However, the magnitude of this change is not relevant in the model since storage in hydrogen tanks remains low, with less than 0.02% of the total share of hydrogen storage.

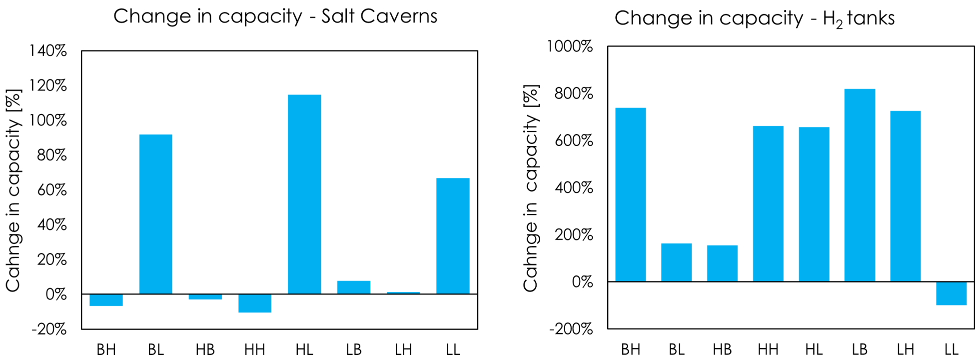

Figure 4.15: Sensitivity of total capacity of H_2 storage in different cost scenarios. Cost scenarios are based on the least constrained scenario.

Figure 4.16 shows the spatial distribution of hydrogen storage in salt caverns in the base, low, and high-cost scenarios. Irrespective of pipeline costs, the presence of low-cost storage prompts the installation of substantial storage capacity in various countries. This highlights the importance of affordable storage solutions for supporting the efficient operation and balancing of the hydrogen system.

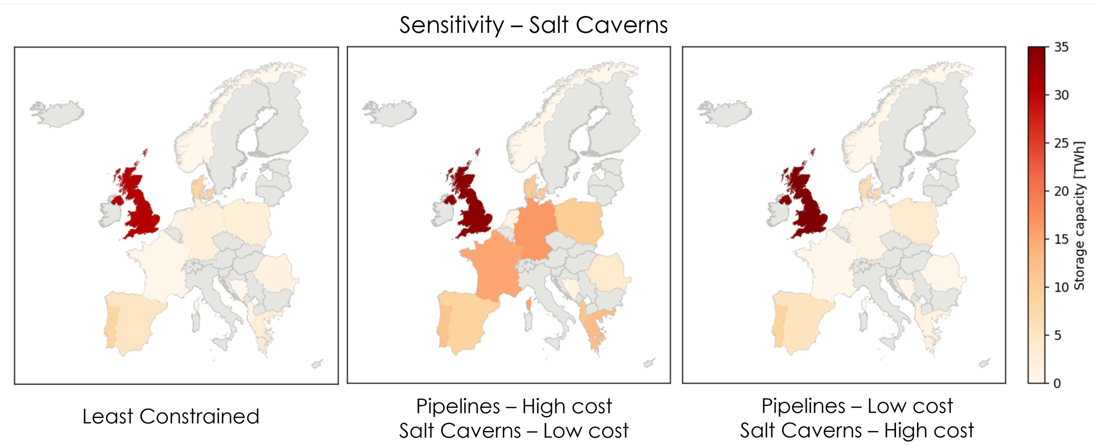

Figure 4.16: Sensitivity of salt caverns spatial distribution in different cost scenarios. The red shades represent the storage capacity in salt caverns per country (in TWh). Cost scenarios are based on the least constrained scenario.

In summary, the analysis demonstrates the interplay between cost factors and storage technologies in the hydrogen system. Lower costs for salt caverns lead to increased capacity, particularly when pipelines are expensive. Conversely, when storage costs are high, the change in storage capacity is not significant regardless of pipeline cost.

5
Discussion

5.1. Comparison to related literature

Results indicate a higher hydrogen demand compared to other literature sources, however electrolysis capacity is close to the target set by the EC for a net-zero scenario

To provide a comprehensive comparison of this study's results, hydrogen demand is first compared to existing literature. In this study, hydrogen demand from the industry as feedstock was included as part of the electricity demand, as outlined in Calliope [49]. Therefore, this is added up to the hydrogen demand and electrolysis capacity given by the model.

After adding up the hydrogen demand from the industry as feedstock, the electrolysis capacity in this study ranges from 510 to 550 GW [1], which is slightly higher than the European Commission's goal of 500 GW of electrolysis capacity by 2050 [18]. Currently, announced projects in Europe add up to 54 GW by 2030 [50]. This means that capacity will need to increase ten times from the 2030 levels to reach the modeled capacity. The current manufacturing capacity is not enough to fulfill this need. However, in 2022 the European Commission set a target to increase the European electrolyzer manufacturing capacity tenfold by 2025, amounting to 17.5 GW per year [51].

On the other hand, the projected hydrogen demand is higher than in other literature sources (see Figure 5.1). In the research conducted by Neumann et al. [15], hydrogen production is approximately 27% lower than the estimates in this study. Interestingly, the electrolysis capacity in Neumann et al. is more than twice that of this study, with an install capacity of 1057 to 1297GW, which significantly deviates from the European Commission's goal of 500 GW of electrolysis capacity by 2050 [18]. Furthermore, Neumann et al. did not include a limit on electrolysis capacity, leading to capacity higher than 300GW installed in Britain (more than half the target set by the EU by 2050).

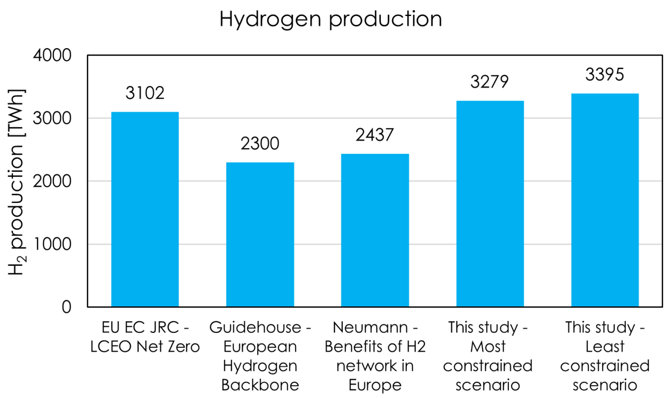

Figure 5.1: Hydrogen demand (in TWh) by 2050 in different scenarios.

Additionally, this study's hydrogen demand is approximately 45% higher than that estimated in the EHB study [52]. This difference in demand should be taken into account when comparing the required capacity for hydrogen pipelines.

[1] The estimated hydrogen demand from the industry as feedstock in 2050 is 244 TWh/year. This translates to approximately 50 GW of electrolysis assuming 6600 full load hours and an efficiency of 71%.

The least constrained scenario is the most similar to the EHB vision for a hydrogen network. The most constrained scenario has a larger share of repurposed infrastructure and comes with higher system costs and increased curtailment

A similar share of new and repurposed pipelines than the one shown in the European Hydrogen Backbone (EHB) vision is achieved in the least constrained scenario. This is the most cost-optimal scenario and relies on hydrogen production hubs. In this scenario, there is an equal share of new and repurposed hydrogen pipelines.

On the other hand, when electrolyzer capacity is more evenly distributed across Europe, the required pipeline capacity is significantly reduced, and the system relies predominantly on repurposed infrastructure. The trade-offs of such distribution relate to the system cost and curtailment. While the decrease in required pipeline capacity is advantageous, there is a 2% increase in system cost due to the need for additional renewable capacity. Additionally, there is a 0.4% increase in curtailment, equivalent to half of the electricity consumption of the Netherlands in 2021 [48]. Despite these changes, the required capacity for electricity transmission and storage remains relatively stable compared to the least constrained scenario. This finding indicates that the optimization of electrolysis spatial allocation has a more substantial impact on pipeline infrastructure, while electricity transmission and storage requirements experience lesser changes.

Hydrogen corridors are in line with the EHB report and recent developments

In the least constrained scenario, two primary hydrogen corridors emerge. The first corridor extends from Ireland and Britain to Germany. The second corridor runs from Portugal to Western Europe. Additionally, two other corridors with lower capacity are observed: the Nordic-Baltic corridor and the South-East corridor. These findings align with the European Hydrogen Backbone (EHB) study [53], which identifies the North Sea and the Iberian Peninsula corridors as the main hydrogen corridors in Europe, followed by the Nordic and Eastern Europe corridors. The EHB study also identifies an import corridor from North Africa. The comparison of the least constrained scenario with and without imports from Africa, and the EHB vision is shown in Figure 5.2.

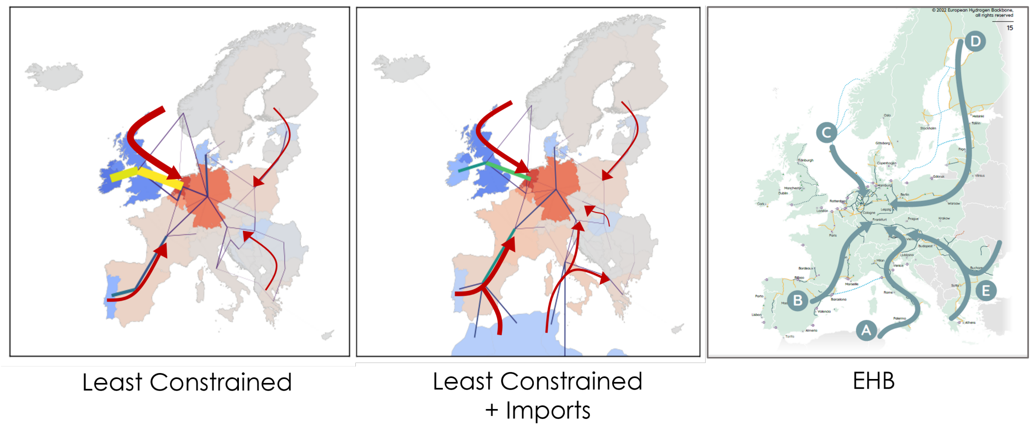

Figure 5.2: Comparison of hydrogen corridors in the least constrained scenario, the least constrained including imports from North Africa, and the EHB study. Red arrows are indicative of the direction of hydrogen flow and the capacity of the corridors.

The North Sea, including Denmark, Britain, and Ireland, was identified as a key hydrogen hub for the optimal deployment of hydrogen electrolysis. This is in line with recent announcements of projects. The majority of announced clean hydrogen projects, amounting to 75%, are concentrated in the North Sea region, with a capacity of 40GW by 2030 [50].

It is worth noting that the inclusion of imports from North Africa brings significant changes to the hydrogen network. As a result, the North Sea hub's volume decreases, and capacity in the Iberian Peninsula expands. The South-East corridor (Corridor 'E' in the EHB study) is not needed in this scenario. Furthermore, a new corridor, Italy-Albania-Greece, emerges to facilitate the transportation of African hydrogen through Italy to Greece. This corridor was not accounted for in the EHB study.

Estimated hydrogen network capacity is lower than the EHB vision

Turning to pipeline capacity, this study estimates a capacity of 135 TWkm when electrolysis capacity is evenly distributed (most constrained scenario), and a capacity of 244 TWkm when there are hydrogen hubs (least constrained scenario). These estimates are lower than those reported in the EHB study (412 TWkm) and the study conducted by Neumann et al. [15] (342-422 TWkm). Table 5.1 provides a comparison distinguishing between repurposed and new pipelines.

Table 5.1: Comparison of the total capacity of new and repurposed hydrogen pipelines in Europe as reported in this study and other sources.

Scenario	Repurposed [TWkm]	New [TWkm]	Countries included
European Hydrogen Backbone [12]	247	165	25 EU Member States plus GBR, CHE, and NOR
Neumann et al. [15]	199-277	143-145	26 EU Member States plus GBR, CHE, NOR, ALB, BIH, MKD, MNE, SRB
This study - most constrained scenario	130	5	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB
This study - least constrained scenario	128	117	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB
This study - least constrained scenario - high cost	140	71	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB
This study - least constrained scenario - low cost	143	181	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB
This study - least constrained + imports	161	158	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB, and 4 African countries (MAR, DZA, TUN, LBY)
	153	133	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRBB
This study - least constrained scenario + weather sensitivity	108-176	59-117	26 EU Member States plus GBR, CHE, NOR, ISL, ALB, BIH, MKD, MNE, SRB

The hydrogen demand in this study is approximately 45% higher than the estimations in the EHB. Thus, a higher capacity of hydrogen pipelines would be expected in comparison. However, the opposite result is obtained: in all the scenarios examined, the required capacity of repurposed pipelines is found to be lower than what is reported in the EHB. This difference may be attributed to the resolution used in the model, which considers only one node per country, while there are extensive networks of repurposed infrastructure within countries like Germany, Spain, the United Kingdom, and Romania.

In terms of new pipelines, similar capacities to the EHB are reached when pipeline and storage costs are lowered. This implies that the new pipelines proposed in the EHB study might be cost-optimal only when the costs are significantly reduced (by 50% in this case). With imports from North Africa, the required new pipeline capacity rises in comparison to the base scenario. However, it is still lower than the EHB results.

The 2022 EHB report estimates a cost of hydrogen infrastructure of €80-143 billion, which corresponds to an annual cost range of €4-10 billion/year[2]. In comparison, the investment cost estimate in this study ranges from €1 billion/year when electrolysis capacity is evenly distributed to €5.5 billion/year when hydrogen hubs are present.

When accounting for uncertainty in the cost and weather year conditions, the cost of hydrogen infrastructure ranges from €4.3 to €5.7 billion/year when hydrogen hubs are present (least constrained scenario). Additionally, if imports from North Africa are included, the investment costs in hydrogen infrastructure rise to €8.5 billion/year. Overall, the cost range of the least constrained scenario, including sensitivity analysis and imports, falls within the cost range reported in the EHB study.

[2] Assuming a 50-year lifetime and a 5% interest rate

Hydrogen storage in salt caverns is consistently the dominant storage technology, despite its highly uncertain capacity

An estimated capacity of 62 to 66 TWh of hydrogen storage in salt caverns was projected in a study by Neumann et al. (2022) [15]. Our study's estimate falls within a similar range, ranging from 54 to 64 TWh, indicating consistency with Neumann et al.'s findings. However, when considering weather and cost sensitivities, the range of storage capacity expands significantly to 42 to 178 TWh, highlighting the wide variability in the optimal storage capacity.

Furthermore, an important finding in this study is that including imports has a notable impact on the required hydrogen storage capacity. When imports are considered, the necessary storage capacity decreases by 40% compared to the base scenario, with a reduced capacity of 38 TWh compared to the initial estimate of 64 TWh. This demonstrates the significance of considering imports when planning for hydrogen storage infrastructure.

Finally, across all scenarios analyzed, hydrogen storage in tanks represents less than 1% of the total storage capacity. This aligns with the observations made by Neumann et al. (2022), who also indicated the negligible role of tank storage when hydrogen pipelines are efficiently utilized. Consequently, storage in salt caverns emerges as the predominant hydrogen storage technology in a fully renewable scenario.

5.2. Conclusions and recommendations

This study provides insights into the design of an optimal hydrogen network, emphasizing the need for accurate electrolysis allocation estimation, alignment with international import planning, and efficient use of storage technologies. These findings help inform policymakers, industry stakeholders, and researchers in their efforts to create sustainable and robust hydrogen infrastructures. The answers to the research questions are outlined below:

What is the required capacity and distribution of a hydrogen network and storage in Europe under a fully renewable scenario?

We have identified that the presence of hydrogen hubs may require the development of extensive new infrastructure, especially in Northern and Western Europe, while a scenario with a more even distribution of electrolysis capacity relies almost entirely on repurposed infrastructure. The total estimated optimal capacity of the hydrogen network ranges from 135 to 244 TWkm. In comparison, the European Hydrogen Backbone (EHB) report estimates a required capacity of 413 TWkm.

In total four corridors were identified: Northern Europe, Iberian Peninsula, Nordic-Baltic, and South-East corridors. This is consistent with the vision presented in the EHB report. Moreover, the identified hydrogen hubs align with recent developments in electrolysis projects.

Our analysis also highlights the key role of hydrogen storage in salt caverns. Despite the considerable uncertainty surrounding the optimal storage capacity estimates, salt caverns consistently emerge as the predominant storage technology, with optimal capacities ranging from 42 to 178 TWh.

How do different allocation scenarios of electrolysis capacity impact the hydrogen network and required storage?

We have observed that small changes in the allocation of electrolysis capacity have a substantial impact on the design of a hydrogen network, while electricity transmission and storage capacity remain close to constant.

In the least constrained scenario, the electrolysis allocation is concentrated in Northern and Western Europe, creating hydrogen hubs. In this scenario, there is an equal share of new and repurposed infrastructure. As the model becomes more constrained, the electrolysis capacity is more evenly distributed across Europe. This shift in spatial allocation reduces the required pipeline capacity by up to half. However, despite the decrease in required pipeline capacity, the total system cost increases due to a larger required renewable energy capacity

Furthermore, our study highlighted the relationship between levels of imports and the size of pipelines and storage capacity. The creation of hydrogen hubs translates to higher imports, in turn, higher levels of imports between regions need larger pipelines to accommodate the transportation of hydrogen, along with increased storage capacity in the producing countries. By considering the interconnections of these components, decision-makers can develop comprehensive strategies that optimize the efficiency and reliability of the hydrogen network.

How does uncertainty in cost and weather years affect the optimal hydrogen network and storage?

Besides the allocation of electrolysis capacity, uncertainty on the cost of pipelines and salt caverns is a critical factor affecting the cost optimization of hydrogen storage and pipeline capacity. Our analysis has revealed that fluctuations in these costs have significant impacts on the overall design of the network. For example, a 50% reduction in the cost of pipelines increases total pipeline capacity by 30%. Also, a 50% reduction in the cost of salt caverns doubles the optimal storage capacity. Increasing costs of pipelines and caverns by 50% has a lesser effect, changing pipeline and salt cavern capacity by -14% and -11% respectively

Furthermore, when considering the variability of weather conditions across years, we have found that the network should be designed to accommodate these fluctuations as the required pipeline capacity has a variation between -15% and +20%, and up to three times more storage could be needed. It is therefore important to approach these uncertainties with caution, as our findings indicate high sensitivity to cost and weather variations. Robust planning and decision-making processes should take into account these uncertainties and factor them into the overall analysis to arrive at reliable and optimal network designs.

What is the impact on the optimal hydrogen network if international imports are considered?

With imports from North Africa, the required investment in H_2 infrastructure increases by 55% compared to a self-sufficient scenario. The capacity of the northern corridor decreases significantly. The Iberian peninsula corridor is reinforced, and a new corridor of Italy-Albania-Greece emerges. These changes in the system cause a reduction of 6% in total system cost mainly thanks to a reduction in renewable energy capacity since 25% of the hydrogen demand is now supplied externally. This emphasizes the importance of considering international imports in the planning of an integrated hydrogen network.

It was also found that international imports significantly reduce the required storage capacity and mitigate uncertainties related to weather-year fluctuations. Salt cavern capacity varies from 34 to 90 GW, which is below the required capacity range of 50 to 140 GW in the least constrained scenario when imports are not considered.

5.3. Limitation and possible future research

This study has identified limitations and areas for future research that can enhance our understanding of the hydrogen network in net-zero scenarios.

An important aspect to address is the limited model space in which optimization was conducted, focusing solely on changing one variable, namely the limit on electrolysis capacity. Modeling spatially-explicit practically optimal results (SPORES [49]) would allow for a more comprehensive evaluation of the hydrogen network. This approach would enable the identification of diverse solutions that align with various preferences and targets, ensuring a more robust and flexible hydrogen network within the larger context of sustainable energy transitions. In addition, the resolution of the model should be increased to reach a more detailed representation of the hydrogen network and facilitate more accurate simulations, leading to more robust findings and recommendations.

On the more technical side, the non-linearity of electricity and hydrogen flow should be considered in more detailed designs. In addition, flow fluctuation in hydrogen pipelines should be considered in the model as this is a significant source of embrittlement [25]. Incorporating these aspects would provide a more accurate depiction of the system's behavior, enabling the identification of potential bottlenecks or inefficiencies and guiding the development of strategies to address them effectively.

Some further improvements could also be considered. For example, additional storage options, such as gas fields and aquifers, is another point for future exploration. Incorporating these storage technologies would offer a broader understanding of the role of different types of hydrogen storage in the energy system. In addition, international hydrogen imports by ship are an important aspect to consider. Global trade dynamics play a significant role in the hydrogen supply chain, and incorporating international imports would provide a more realistic representation of the network and its interaction with the global market.

Finally, disaggregating hydrogen demand from the industry, currently aggregated under electricity demand, would enable a more detailed analysis of sector-specific requirements. This would optimize the allocation of hydrogen resources and allow for tailored solutions to meet the diverse demands of different sectors. Furthermore, future research should consider the direct use of hydrogen in fuel cell vehicles instead of relying solely on internal combustion vehicles and battery electric vehicles.

6 Data and code

The final model developed in this thesis, which can be directly used in Calliope, can be accessed through the following link:

https://surfdrive.surf.nl/files/index.php/s/MwtPg6trwuzQzVu

Besides providing access to the model, this link includes all the results presented in this report, as well as the code used for clustering gas pipelines and assessing storage potential in salt caverns. The folder is organized as follows:

- **Clustering code**: This section contains the code used to cluster the gas network and salt cavern potential into two resolutions: Europores (98 nodes) and National (35 nodes). Each resolution has a dedicated folder, and a readme file is included to provide an overview of the content and structure.
- **PreBuilt-EuroCalliope-July2023**: This folder contains the modified pre-built model that is ready to be used in Calliope. A readme file is provided to explain the structure of the model. It is important to note that the modifications made to the base version are currently implemented only for the 2050 projection year. The additions of the hydrogen grid and hydrogen storage in salt caverns are specific to this year and the national resolution. The pre-built model before modifications can be found here: https://energysystems-docs.netlify.app/tools/sector-coupled-euro-calliope-hands-on.html
- **Results**: This folder contains all the outputs generated by the model, which were shown in this report. Additionally, codes for processing the outputs and generating tables and plots are included here.

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