HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

EU-scale hydrogen system scenarios

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Executive summary

The aim of the theme 'Techno-economic assessment of EU scenarios for hydrogen storage' is to investigate the role of hydrogen storage in porous reservoirs within a future European hydrogen system using a spatio-temporal energy system optimization model. Preparatory activities were performed earlier, including the quantification of the spatially resolved potentials for green hydrogen production from renewables and demand in European countries, hydrogen import potentials, the evaluation of possible hydrogen transport infrastructure, and potential locations and capacities for underground hydrogen storage sites. The results have been reported in Groß et al. (2022), and Cavanagh et al. (2022, 2023). The techno-economic parameters were collected and described in de Maigret and Viesi, (2023). The findings of these research activities were used as inputs for the energy system model presented in this report.

This report describes the European energy system model and the modeled technologies and energy commodities. The optimization model seeks the cost-optimal solution for minimizing the total annual costs of the system to reach 2050 decarbonization targets, based on the cost estimates that are provided to it as input, while considering technical and environmental constraints.

Model Description

Electricity, natural gas, and hydrogen are classified as energy carriers in the model, modeling supply, demand, conversion, storage, and transport between regions of each of these. The geographical scope of the model covers the EU-27 as well as the UK, Switzerland, and Norway, which are represented by 100 regions based on administrative boundaries (NUTS-1). Additionally, 76 offshore regions are included to represent offshore wind power generation and connections. Optimizations were carried out for three target years on an hourly basis to cover the energy transition up through greenhouse gas-neutrality. As target years 2030, 2040, and 2050 were selected, taking into account different carbon dioxide emission limits to simulate the energy transition. The optimization results comprise the cost-optimal design and operation of the energy system components and include, amongst other aspects, the energy mix in each modeled region and the transmission and storage capacities for electricity, natural gas and hydrogen required to match supply and demand for each hour of the modeled year. The techno-economic parameters are taken from de Maigret and Viesi (2023) and supplemented by own cost assumptions for additional technologies. It is assumed that hydrogen storage in underground will be technically and legally feasible in future, i.e. UHS is allowed in salt caverns and porous reservoirs. The considered potentials include existing natural gas storage sites, which can be repurposed, and possible new storage sites based on literature and the findings of Cavanagh et al. (2022, 2023). The model is used to address the question of the potential role of porous reservoir storage capacities to store hydrogen in Europe.

Scenario selection

To answer this question, 18 scenarios were created per each target year, summed up to 54 scenarios in total. In all scenarios, carbon dioxide emission limits were defined. For 2030, the limit was chosen based on the fit-for-55 package (European Council, 2023). For 2050, no carbon dioxide emissions were allowed. Carbon capture and storage (CCS) was not included as an emission reduction technology in the model, hence negative emission technologies, e.g. bioenergy in combination with CCS, and the production of so-called blue hydrogen, that relies on CCS, were not included either. Per each target year, one baseline scenario was defined, characterized by assuming the average hydrogen demand projection for the industry and mobility sector described in Groß et al. (2022)and the average cost projection described in de Maigret and Viesi (2023). It was assumed that the exogenously fixed demand for hydrogen remains constant over time for the year under consideration. However, there may be fluctuations in hydrogen demand if it is re-electrified to supply electricity as this is part of the optimization results and not exogenously fixed. There were no restrictions assumed in the baseline scenarios regarding the amount of extra-European hydrogen imports, geostrategic storage reserves and the future energy generation mix. The sensitivity scenarios shed light on various aspects, including:

i) the impact of the future hydrogen demand, based on demand projections described in Groß et al. (2022) leading to a higher or lower future hydrogen demand,
ii) the impact of different cost projections for the modeled technologies, based on cost projections described in de Maigret and Viesi (2023),
iii) the impact of extra-European hydrogen imports,
iv) the impact of different weather conditions and national targets for the expansion of renewable energy sources affecting the renewable energy supply,
v) the impact of technological storage restrictions, and
vi) the impact of limited grid expansion of the electricity and hydrogen grid.

Results

The model results of the baseline scenarios show the increasing importance of renewable energy sources (RES). Fossil-fueled powerplants will be phased-out by 2050.The electricity generation in Europe will be dominated by onshore wind power, with a share of more than 60%, and the electricity grid's capacities will be doubled by 2050. In order to meet the increasing demand for hydrogen, a hydrogen grid is developed, whereas the natural gas grid is significantly downsized. The repurposing of more than 75% of the existing natural gas grid to a hydrogen grid is a prominent feature, enabled by the declining demand for natural gas. In 2030, the main hydrogen production locations will include the northern UK, Denmark, and Norway, which reflects their most favorable wind conditions. The hydrogen grid will be used to transport hydrogen across Europe from North to South. Therefore, a considerable expansion of grid capacities in the important corridors connecting northern Europe will be necessary between 2030 and 2050 to allow more hydrogen to be transported from the UK and Denmark to Germany, the Netherlands, France, and southern Europe to meet the overall increasing hydrogen demand. In the baseline scenarios, hydrogen is primarily produced domestically in Europe, with additional pipeline imports from North Africa. Several countries produce a share of their hydrogen demand domestically. In 2030, about 50 TWh of hydrogen storage capacity will be required, which will primarily rely on the use of repurposed salt caverns. This number is in line with the findings of the EU-wide alliance H2eart for Europe (Peterse et al., 2024). As hydrogen demand and electricity supply by variable RES increase, the need for storage capacity also will significantly after 2030, reaching almost 160 TWh in 2040, of which 80 TWh of capacity will be provided by repurposed pore storage installations. In 2050, hydrogen storage capacity reaches about 260 TWh, with pore storage accounting for more than 60% of the storage capacity for hydrogen, implying that half of the considered pore storage potential (described in Cavanagh et al. (2022, 2023)) is repurposed for hydrogen storage. By 2050, hydrogen storage in pore storage will be realized to some extent in all countries with available pore storage potential. The demand for storage capacity is primarily determined by the balance of surplus or missing residual electricity for hydrogen production. Re-electrification of hydrogen only plays a subordinate role in the results by generating 10 TWh electricity in 2050, which accounts for less than 0.1 % of the total electricity generated. This might be because the hydrogen demand is assumed to be at a constantly high level, and electricity demand can therefore be balanced out more cost effectively by expanding the electricity grid and installing electricity storage systems, e.g. battery storage. In times of low renewable feed-in throughout Europe, so-called Dunkelflaute, re-electrification might be necessary as a backup solution to ensure security of supply. This might also affect the sizing and allocation of required hydrogen storage to retain strategic reserves.

To gain further insights into the potential role of UHS in future energy systems, 51 sensitivity scenarios are defined next to the three baseline scenarios.

The scenarios assuming variations in the future hydrogen demand display a linear relationship between required UHS capacity and hydrogen demand, i.e., an increase in hydrogen demand results in an increase in the necessary storage capacity. There is no significant change in storage locations.

The cost-optimal UHS capacity is strongly influenced by the assumed techno-economic parameters as it can be observed in the two scenario variations assuming different techno-economic parameters. In the case of a more pessimistic cost development for all energy systems components, which is described in D7.1, the share of conventional powerplants in the electricity generation, including coal and gas power plants, is higher in 2030 and 2040 as renewable energy is more expensive, and hydrogen storage capacity is significantly lower than in the baseline scenarios. In 2050, about 100 TWh of hydrogen is additionally imported from North-Africa compared to the baseline scenario, and the installation of new cavern storages is avoided. In the case of a more optimistic cost development, which is described in D7.1, the optimization opts to import less hydrogen than in the baseline scenario as the costs for domestic hydrogen production is also reduced. The share of solar PV and offshore wind in the electricity generation increases. In 2050, Spain and Italy become hydrogen exporters, which is leading to the emergence of a strong south-north hydrogen corridor and an increase in the hydrogen storage capacities along this corridor. The total hydrogen storage capacity decreases about 100 TWh compared to the baseline scenario of 2050. Furthermore, a change in storage operation can be observed, which leads to a minimum storage level in February, as the share of solar PV as a source for hydrogen production increases.

To analyze the value of pore storage as hydrogen storage, two scenarios are modeled, which exclude pore storage or repurposed cavern storage as option for hydrogen storage. If pore storage is not an available option for future hydrogen storage, more newly installed salt caverns would be required to fulfill storage needs. The total capacity of UHS would remain on the same level, with about 250 TWh of storage capacity in 2050. The UHS sites will become more centralized due to limited potential areas for new salt caverns. Furthermore, it implies that roughly 1000 caverns would be required for hydrogen storage, i.e., four times as many caverns as are currently used for natural gas. From a cost perspective, it appears that pore storage capacities are not indispensable for the future European energy system, yielding total annual cost improvements of approximately 0.4% (2 billion euro/year). However, implementing pore storage capacities enables a more decentralized approach to UHS across Europe. This enhances resilience and accessibility within the hydrogen infrastructure while reducing the need for the implementation of new salt caverns for hydrogen storage. If existing salt caverns cannot be used for hydrogen storage, more new salt caverns need to be created. The impact on the other components of the energy system is marginal, i.e., the electricity mix, the hydrogen production locations and the observed hydrogen transport corridors do not change. In both restrictive cases, the total annual costs marginally increase by the same magnitude to about 0.4%.

Electricity generation by renewable energy sources is highly influenced by the prevailing weather conditions. Calculating the generation potential of solar PV and wind turbines with different historic weather years and considering them as inputs for the optimization shows the impacts on the system design. Model runs are done for the weather years 2015 (baseline scenario), 2016, 2017, and 2018 to represent different weather conditions. Depending on the wind and solar conditions, the cost-optimal UHS capacity will be between 83 TWh and 260 TWh in 2050. This range is heavily influenced by the balance of surplus or missing residual electricity for green hydrogen production. The weather year variations exhibit higher hydrogen imports ranging from 1000 to 1400 TWh, which further contribute to the lower required storage capacity as constant imports and constant hydrogen demand is assumed in the model.

The impact of hydrogen imports is analyzed based on four additional scenarios per target year. These scenarios include forcing imports based on the REPowerEU (European Commission, 2022), excluding extra-European hydrogen imports, and fluctuating hydrogen imports from North Africa via pipelines.
To balance the missing hydrogen import, slightly more generation capacity is needed in Europe, which also leads to a slight increase in optimal storage capacity from 260 TWh to 270 TWh in 2050. In 2040, this effect is more pronounced and hydrogen storage capacity increases from 160 TWh to 210 TWh if hydrogen imports are prohibited. Enforcing imports to 30% of annual hydrogen demand reduced the required hydrogen storage capacity by about 10% in 2050 reducing the required new cavern storage installations. If hydrogen imports are not assumed to be constant but modeled with the generation profile from the exporting country and directly transported to Europe, imports costs are reduced and result in higher amounts of hydrogen imports from North Africa, importing 1200 TWh hydrogen in 2050 compared to 400 TWh in the baseline scenario of 2050. Seasonality of imports do not lead to a significant change in overall optimal storage capacity, but storage locations are shifted closer to the import pipeline in Italy.

Enforcing the expansion of renewable energy sources according to announced capacity targets in 2030 leads to a shift of hydrogen production locations. Having more renewable energy capacity in the system than cost-optimal necessary leads to a decrease in hydrogen storage capacity by 20 TWh in 2030 as more hydrogen can be produced on demand. Limiting the expansion of renewables per country in 2040 and 2050 results in increased amounts of hydrogen imports, and, thus, in a reduction of optimal storage capacity. To compensate for the expansion restrictions of other renewable energy sources, more offshore wind capacity is built in 2050, which represents an increase of 50% compared to the baseline scenario.

Another scenario integrates a 4-days synthetic Dunkelflaute in Northwestern Europe in January. In 2030 and 2040, conventional powerplants are used as backup to cover the electricity deficit. In 2050, the installation of renewable energy capacities is slightly shifted to regions outside the affected ones to cover the electricity deficit during the Dunkelflaute. The hydrogen production is reduced to almost zero during this period. Hydrogen re-electrification is not observed but might play a major role if the duration of the Dunkelflaute is longer.

If the expansion of hydrogen and electricity grid is limited, the resulting hydrogen production is more decentralized. Limiting the grids expansion prevents large amount of hydrogen imports from North-Africa or production in the UK as hydrogen transport is limited by the maximum capacity expansion. To circumvent the grid restriction, the results show a more branched out hydrogen network, and the hydrogen grid appears more homogeneously developed throughout Europe. Due to the grid restrictions, pore storages have to be utilized increasingly to also cover short-term fluctuations, i.e., the average number of storage cycles of pore storage sites increases to 3.
The last scenario variation combines seasonal, fluctuating imports, minimum amount of hydrogen imports of one third of the annual hydrogen demand, limited renewable capacity expansion per region, synthetic Dunkelflaute with limited grid expansions. Due to the grid limitations, the pipeline imports from North Africa are not able to cover the minimum import requirement entirely, thus, liquefied hydrogen is imported by ship in Belgium due to its proximity to hydrogen demand centers. The optimal storage capacity is reduced by more than 40% in 2050 compared to the baseline scenario as the constant imported liquid hydrogen can directly supply the constant hydrogen demand after regasification. UK and Ireland do not export significant amounts of hydrogen to central Europe anymore, so that the hydrogen production is less dominated by the weather conditions in the UK, which changes the storage levels throughout the year.

Limitations of the model

Due to the cost-minimization approach, the model computes the ideal system from a techno-economic perspective, neglecting political constraints and assuming full cooperation between countries. That means that constraints imposed by socio-economic and geo-political considerations, e.g. limitations to expanding the European electricity grid, and requirements for a minimum storage capacity per country for reasons of securing supply and energy independence, are not included. The results should therefore not be seen as a forecast of a future state of Europe´s energy system and the final role of underground hydrogen storage (UHS) in reservoirs in that system, but rather as outcomes of model-based thought experiments that can help to understand what factors govern the technical feasibility and affordability of UHS in reservoirs and salt caverns in Europe.

While the model provides valuable insights into cost-optimal system configurations for UHS based on assumed cost projections and weather conditions, it is crucial to acknowledge the boundary conditions of the modeled scenarios. The presented results, while insightful, may not align with realistic system configurations as they do not consider additional factors such as legislative decisions of individual countries, operational storage reserves, and macro-economic considerations. Interpretation of the presented results should be done with a mindful consideration of these limitations and the potential impact of external factors that the model does not encompass. It should also be noted that the results are highly dependent on the cost assumptions, as the model is designed to minimize costs. The assumed technical and economic parameters have a direct impact on the cost-optimized electricity mix and thus on the allocation of hydrogen production and storage, as well as on the role of hydrogen imports.

Conclusion

All scenarios show that UHS is required for a successful and affordable transformation of the European energy system to greenhouse gas neutrality due to the increasing prominence of hydrogen in the energy transition. The share of pore storage as hydrogen storage increases to more than 60% of the required hydrogen storage capacity by 2050, and all countries with available pore storage potential develop it to some extent, leading to a more homogenous distribution of storage across Europe.

This study affirms that hydrogen storage, both in caverns and porous reservoirs, can play a pivotal role in balancing the supply and demand dynamics of the evolving European energy system. As hydrogen continues to gain prominence in the energy transition, these findings underscore the importance of strategic planning for storage infrastructure and conducting further research on large-scale UHS. Stakeholders should collaboratively devise cohesive strategies, considering factors like grid expansion, renewable energy integration, security of supply and evolving hydrogen demand patterns. The cultivation of a comprehensive perspective in planning is imperative, as it renders the integration of UHS a cohesive element within a resilient, sustainable, and adaptive future energy system. Decisions related to site-specific realizations and capacities must be made individually for each site, taking into account the specific restrictions and requirements of that particular location. Continued investment in research and development is crucial to refine storage technologies and address safety concerns.

About HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

The HyUSPRe project researches the feasibility and potential of implementing large-scale storage of renewable hydrogen in porous reservoirs in Europe. This includes the identification of suitable geological reservoirs for hydrogen storage in Europe and an assessment of the feasibility of implementing large-scale storage in these reservoirs technologically and economically towards 2050. The project will address specific technical issues and risks regarding storage in porous reservoirs and conduct an economic analysis to facilitate the decision-making process regarding the development of a portfolio of potential field pilots. A techno-economic assessment, accompanied by environmental, social and regulatory perspectives on implementation will allow for the development of a roadmap for widespread hydrogen storage towards 2050; indicating the role of large-scale hydrogen storage in achieving a zero-emissions energy system in EU by 2050.

This project has two specific objectives. Objective 1 concerns the assessment of the technical feasibility, risks, and potential of large-scale underground hydrogen storage in porous reservoirs in Europe. HyUSPRe will establish the important geochemical, microbiological, flow and transport processes in porous reservoirs in the presence of hydrogen via a combination of laboratory-scale experiments and integrated modelling, establish more accurate cost estimates and identify the potential business case for hydrogen storage in porous reservoirs. Suitable stores will be identified and their hydrogen storage potential will be assessed. Objective 2 concerns the development of a roadmap for the deployment of geological hydrogen storage up to 2050. The proximity of hydrogen stores to large renewable energy infrastructure and the amount of renewable energy that can be buffered versus time varying demands will be evaluated. This will form the basis to develop future scenario roadmaps and prepare for demonstrations.

Document information, revision history, approval status

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HyUSPRe lead scientist	R. Groenenberg	
HyUSPRe consortium manager:	H. Cremer	2024.06.27

Table of Content

Abbreviations

ABEX .... *Abandonment expenditures*
AC .... *Alternating curent*
AEL .... *Alkaline electrolysis*
CAPEX .... *Capital expenditures*
CCGT .... *Combined cycle gas turbines*
CHP .... *Combined heat and power*
CO2 .... *Carbon dioxide*
DC .... *Direct current*
EEZ .... *Exclusive economic zones*
ETHOS .... *Energy Transformation paTHway Optimization Suite*
FINE .... *Framework for INtegrated Energy system assessment*
FLH .... *Full load hours*
GHG .... *Greenhouse gas*
HyUSPRe .... *Hydrogen Underground Storage in Porous Reservoirs*
LCOH .... *Levelized Cost of Hydrogen*
LH2 .... *Liquid hydrogen*
LNG .... *Liquefied natural gas*
LOHC .... *Liquid organic hydrogen carrier*
NH3 .... *Ammonia*
NUTS .... *Nomenclature of territorial units for statistics*
OCGT .... *Open-cycle gas turbine*
OFPV .... *Open-field PV*
OSM .... *Open street map*
PEM .... *Proton exchange membrane*
PEMFC .... *Proton exchange membrane fuel cell*
PR .... *Porous reservoir*
RES .... *Renewable energy source*
RESKit .... *Renewable Energy Simulation toolkit for Python*
RTPV .... *Rooftop PV*
SOFC .... *Solid oxide fuel cell*
UHS .... *Underground hydrogen storage*

1 Introduction

To assess the role of hydrogen storages in porous reservoirs within a future European hydrogen system, a European energy system model has been developed that covers the transition from 2030 to 2050, incorporating the greenhouse gas emission reduction targets. This optimization model minimizes the total annual costs of the system designs including infrastructure and enables a techno-economic assessment of the European energy system with high spatial and temporal resolution. For this report, it is assumed that the hydrogen storage in porous reservoirs is technically and legally feasible and an available option for the future energy system. Due to the cost-minimization approach, the model computes the ideal system from a techno-economic perspective, neglecting political constraints and assuming full cooperation between countries. That means that constraints imposed by socio-economic and geo-political considerations, e.g. limitations to expanding the European electricity grid, and requirements for a minimum storage capacity per country for reasons of securing supply or energy independence, are not included. The results should therefore not be seen as a simulation or forecast of a future state of Europe´s energy system, but rather as outcomes of model-based thought experiments that can help to understand what factors govern the technical feasibility and affordability of underground hydrogen storage in reservoirs and salt caverns in Europe.

The model is used to answer the question of what role porous storage systems can play as potential underground hydrogen storage facilities in Europe's future energy system.
Furthermore, conclusions can be drawn regarding the storage operation and placements of all modeled energy technologies depending on the selected spatial resolution.

This report is structured as follows:
Chapter 2 describes existing scenarios and roadmaps to provide context for the results. Chapter 3 describes the optimization model of the European energy system including all considered technologies and demands. Techno-economic input parameters have been taken from HyUSPRe deliverable 7.1 (de Maigret and Viesi, 2023). Potentials for underground hydrogen storage in porous reservoirs are based on the results of HyUSPRe work package 1 (Cavanagh et al., 2022; 2023). Chapter 4 describes the selection of scenarios. In addition to the baseline scenario for each modeled year, several sensitivity variations are optimized in order to explore different effects on the system design, e.g., the impact of the weather year and the range of future hydrogen demand. Model results are presented in Chapter 5, with a focus on the role of underground hydrogen storage (UHS) in the different scenario variations. These results are discussed critically in Chapter 6, where other developments in the field of hydrogen use and production to reduce greenhouse gas emissions are also considered. Conclusions are presented in Chapter 7.

The scenario results and conclusions are used as inputs for HyUSPRe deliverable 7.3, which will evaluate the levelized cost of hydrogen and hydrogen storage, and HyUSPRe deliverable 7.5, that will provide a roadmap for developing underground hydrogen storage in porous reservoirs across Europe.

2 Existing scenarios and roadmaps

The following section provides an overview of existing energy system modeling scenarios with a European focus.

In recent years, numerous studies have conducted energy system modeling in a European context. Prominent modeling tools at the European level include the PyPSA model family (Neumann et al., 2023), Calliope (Pickering, 2022), REMix , ETHOS.FINE (Caglayan et al., 2021) or the LUT Energy System Transition model (Bogdanov et al., 2021).

UHS is considered in most recent studies, with a few exceptions: Publications that used the LUT and Calliope model (Pickering, 2022; Bogdanov et al., 2021; Breyer et al., 2022), do not mention hydrogen storage. Earlier studies only consider above-ground hydrogen storage (Brown et al., 2018). Several studies address the sub-European level and investigate energy systems in specific countries (Gils 2021; Cárdenas et al., 2021; Kondziella et al., 2023; Ruhnau and Qvist, 2022) or multiple countries in Europe (Martínez-Gordón et al., 2022; Gea-Bermúdez et al., 2023). Studies that consider UHS in their modeling mostly focus on new cavern storage. Most of these studies focus on the year 2050. Optimal UHS capacities vary widely across the investigated literature ranging from 0 TWh to 802 TWh as displayed in Figure 2-1. It should be noted that optimal storage capacity is influenced by several factors such as assumed weather conditions and underlying hydrogen demand.

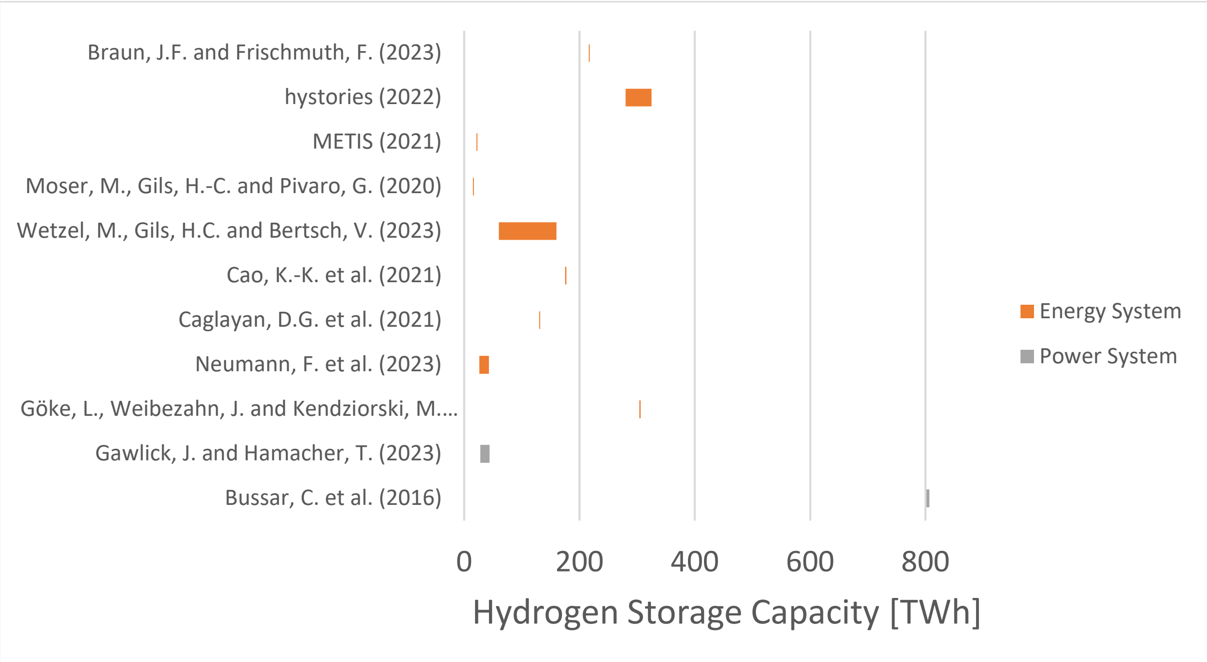

Figure 2-1. Projected hydrogen storage capacity requirements for Europe for the year 2050 from modeling studies reported in the literature.

Using a multi-nodal optimization model, Göke et al. (2023) found optimal cavern storage capacities of 304 TWh. Neumann et al. (2023) used the PyPSA model to find optimal cavern storage capacities in the range of 26–43 TWh. Using the energy system modeling framework urbs at country level resolution, Gawlick and Hamacher (2023) found optimal hydrogen cavern storage capacities of 28–44 TWh. Caglayan et al. (2021) used the ETHOS.FINE framework and found an optimal cavern storage capacity of 130 TWh over a range of different weather years. Using the energy system model REMix with a country level resolution, Cao et al. (2021) found an optimal cavern storage capacity of 175 GWh, whereas Wetzel et al. (2023) noted cavern storage capacities ranging from 60 to up to 160 TWh depending on the scenario. Other examples include Moser et al. (2020), who did not fully consider the EU-28. They found optimal cavern storage capacities of 15 TWh. Additionally, Bussar et al. (2016) employed a planning

tool, estimating a hydrogen storage demand of 802 TWh. The METIS study (European Commission, Directorate General for Energy, 2021) reported 21 TWh of hydrogen storage capacity.
Some studies stated that hydrogen cavern storage is considered, but did not provide numbers on the optimal storage capacities (e.g., Neumann, 2021; Victoria et al., 2022; European Commission, Directorate General for Energy, and Fraunhofer Institute for Systems and Innovation Research, 2023).

The aforementioned studies do not take into account the option of dedicated hydrogen storage and hydrogen storage in porous reservoirs at the European level as part of an energy system model. One exception is the model employed in the Hystories project[1] ,in which the optimal storage capacities for 2050 consisting of both cavern and pore storage capacities of between 280 and 325 TWh were found (Michalski and Kutz, 2022).
A recently published study by Artelys and frontier economics (2024) investigated the role of different UHS options in 2030 and 2050 considering salt caverns, hard rock caverns, depleted gas fields and aquifers. Their results show a need for 45 TWh of UHS storage in 2030 with an injection capacity of 59 GW, which is also used as base for the recommendation of the EU-wide alliance H2eart for Europe (Peterse et al., 2024). In 2050, Artelys and frontier economics (2024) observed the need for 270 TWh of UHS capacity and 300 GW of injection and withdrawal capacity.
A study conducted by the Fraunhofer CINES (Braun and Frischmuth, 2023) considered both repurposed and new hydrogen cavern storage. They noted a hydrogen storage capacity of 216 TWh for 2050 that mainly consisted of new cavern storages.
It should be noted that most of the aforementioned studies - with the exceptions of the Hystories project and the study by Artelys and frontier economics - did not specifically focus on the role of UHS. Such publications exist, but they usually target specific countries such as Germany or the UK (Kondziella et al, 2023; Ruhnau and Qvist, 2022; Cárdenas et al., 2021).

In summary, existing literature mostly considers new cavern storage systems as a large-scale hydrogen storage option. The range of optimal hydrogen storage capacities observed in the literature, ranging from a few TWh to several hundred, which highlights the sensitivity of these estimates to contextual factors, including weather conditions, underlying hydrogen demand, cost assumptions, temporal and spatial resolutions, and modeling frameworks. The fact that hardly any studies take into account the potential for repurposing natural gas storage to hydrogen and specifically underground storage in porous reservoirs at the European scale points to a notable gap in the current research landscape and emphasizes the need for more comprehensive assessments that encompass both new and repurposed facilities for hydrogen storage.

[1] Hystories project: https://hystories.eu/

3 Model description

The following chapter describes the European energy system model used to assess the role of hydrogen storages in porous reservoirs within a future European hydrogen system. A general overview about the regional scope and considered components can be found in Figure 3-1 as well as in Figure 9-1 in the appendix.

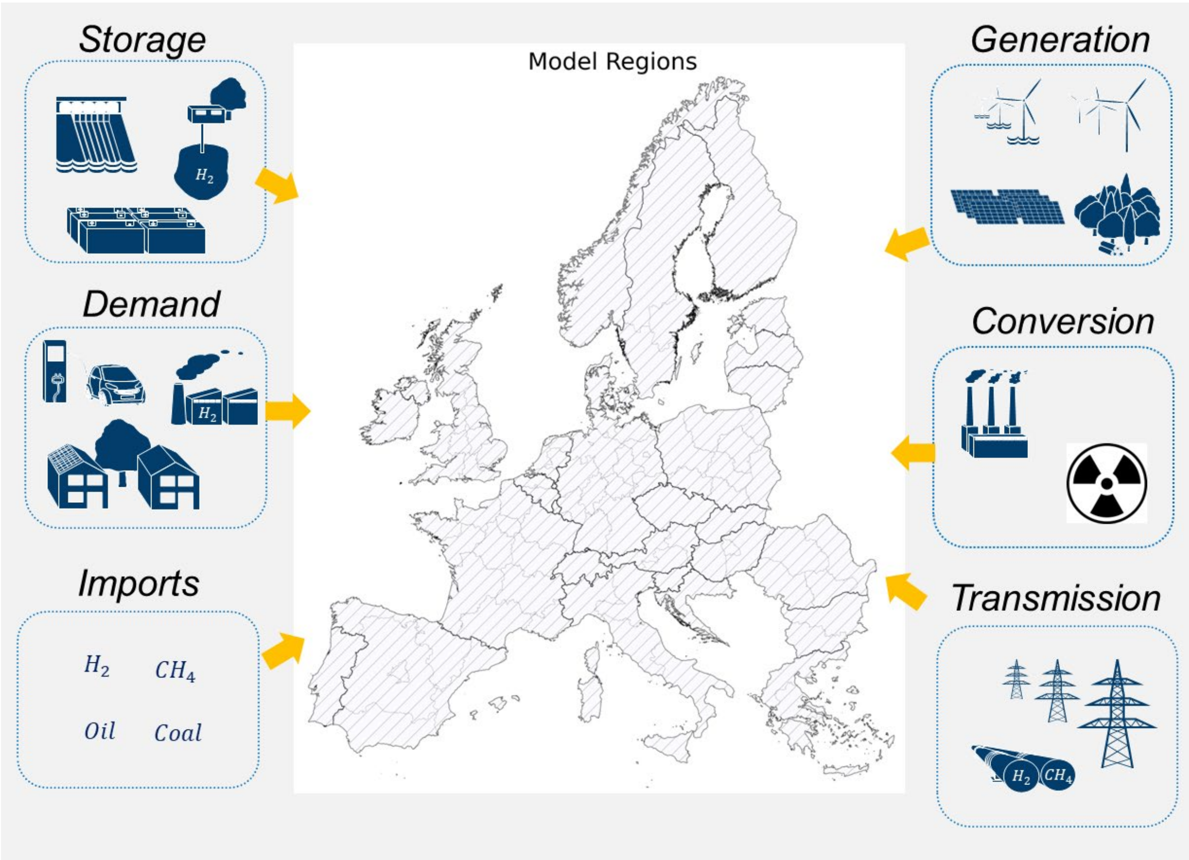

Figure 3-1. Spatial scope and technology portfolio of the European energy system optimization model.

3.1 Model scope

The European energy system model is part of the ETHOS (**E**nergy **T**ransformation Pa**th**way **O**ptimization **S**uite) model suite[2]. The implementation of the model is carried out as an optimization process and is based on the open-source framework ETHOS.FINE (**F**ramework for **In**tegrated **E**nergy System Assessment)[3] developed at Forschungszentrum Jülich (Groß et al., 2023). The objective function is to minimize the total annual cost of the system design and operation incorporating technical, environmental, e.g., reduction of CO2 emissions, and further user-defined constraints.

The geographical scope of the model covers 30 European countries (EU27 + UK + Norway + Switzerland). These are modeled by a total of 176 regions, of which 100 are onshore regions and 76 offshore ones. The onshore regions follow the NUTS-1 (Nomenclature of territorial units for statistics) classification, whereas the offshore ones correspond to the region definition of the exclusive economic zones (EEZs). Each optimization run covers one year at an hourly resolution. To reduce the computational complexity of the model, time-series aggregation methods are employed that cluster the time-dependent input data, e.g., the demand and

[2] ETHOS Model Suite: https://www.fz-juelich.de/en/iek/iek-3/expertise/model-services
[3] ETHOS.FINE: https://github.com/FZJ-IEK3-VSA/FINE

generation profiles, into 40 typical periods and 12 segments (Hoffmann et al., 2022). The optimization is performed for the target years of 2030, 2040, and 2050. Each year is optimized independently, i.e., the resulting system designs might differ between them. The capacities and operation parameters of all of the technologies are optimized and part of the model results.

The model takes into account today´s existing energy infrastructure such as fossil fuel power plants and installed renewable energy sources including photovoltaics (PV), wind turbines and hydropower plants. Furthermore, the capacities of the existing natural gas transmission grid and electricity grid as well as existing natural gas storage sites are included in the model. Three main energy carriers are considered which can be exchanged between model regions. These are electricity (via the electricity grid), natural gas (via pipelines), and hydrogen (via pipelines). Fossil energy carriers including hard coal, lignite, oil, and uranium are available in every modeled region for given costs. Further commodities include hydrogen derivatives such as methanol, liquid organic hydrogen carriers (LOHCs), liquid hydrogen (LH2) and ammonia, which can be used as alternative storage options, biomass, and CO2.

The model is set up using regions and therefore does not allow for the exact locations and characteristics of assets to be defined individually. If there are several assets of the same type, e.g., coal-fired power plants, in a region, their capacities and operating parameters are aggregated. The techno-economic parameters are taken from HyUSPRe deliverable D7.1 (de Maigret and Viesi, 2023). Missing data is taken from various sources listed in Table 3, Table 4 and Table 5 in the appendix.

3.2 Model components

The following subsections will provide an overview of the considered components and technologies. These components can be categorized into energy supply and conversion components and energy transmission components. The energy supply and conversion components consider imports, renewable energy sources (RES), and conventional power plants. The energy transmission components include technologies for natural gas, electricity, and hydrogen transmission. Furthermore, different energy storage technologies for the short-, medium- and long-term storage of the model's main energy carriers are modeled. Time-dependent demand profiles for the main energy carriers, including electricity, natural gas, and hydrogen, are exogenously given for every region as a constraint that must be met by the model. Finally, boundary conditions such as emission limits and user defined constraints are presented.

3.2.1 Energy supply and conversion

In terms of energy supply and conversion, three main categories of energy sources are considered, namely the import of energy from outside the model scope, RES, and conventional power plants. The import of fossil and nuclear fuels is available in every region at certain costs depending on the modeled target year. These include hard coal, lignite, oil, and uranium. Imports for the three main energy carriers are modeled in further detail. Electricity imports from outside the model scope are not considered, i.e., electricity supply to meet demand can only take place within the model´s boundaries. Natural gas imports are limited to current pipeline import locations and terminals for liquefied natural gas (LNG). The capacities and locations of LNG terminals are taken from *Global Energy Monitor* (Global Energy Monitor, 2022e). The import quantities are limited by today's transmission or terminal capacities. Furthermore, the intra-EU production of natural gas is possible at current natural gas production sites within the today's limits. Natural gas production locations and limits are taken from Global Energy Monitor (2022b). The assumed costs are given in Table 2 in the appendix.

Figure 3-2. Hydrogen import locations in the model.

The underlying methodology for hydrogen import has been adapted compared to the methodology described in HyUSPRe deliverable D1.2 (Groß et al., 2022). While D1.2 only considers LH2 imports, for this report additional hydrogen imports via pipeline from North-Africa are considered as well, i.e., the import of hydrogen is possible via pipeline and LH2 shipping. Pipeline imports are possible from North Africa at today's natural gas pipeline import locations (Gibraltar, Almeria, and Sicilia). North-African hydrogen-exporting countries from where hydrogen pipeline transport is assumed possible include Morocco, Algeria, and Libya. Furthermore, LH2 import is possible at four major European ports with existing LNG terminals (Rotterdam, Huelva, Barcelona and Revithoussa) as is shown in Figure 3-2. At the time of model setup, no German LNG terminal had been built. Therefore, no German LNG terminal is considered. Furthermore, the hydrogen import route in eastern Europe has not been considered, i.e., hydrogen imports from Ukraine are not part of the model. Depending on the import location, import type (gaseous or liquid hydrogen), the target year under consideration and the selected cost scenario, different import costs are incurred. These are determined by first deriving hydrogen export cost curves following a methodology from Franzmann et al. (2023). In a second step hydrogen import costs at specified European import locations are calculated by calculating the transport costs to every import location and using the cheapest option available at an annual export amount of 2000 TWh. The resulting costs are displayed in Figure 3-3. For most scenarios it is assumed that hydrogen is imported at a constant rate, which reduces import flexibility, i.e., there are no fluctuations in the import profiles. For the scenarios *seasImports* the pipeline imports do have an import profile that matches the hourly hydrogen production in the respective export country. In this case it was assumed that no hydrogen storage in the export country is built, and the produced hydrogen is directly transported via pipeline to Europe.

Both fossil and renewable energy generation sources are available for electricity generation in the model, which takes into account both the capacities available today and the option of building additional conventional power plants. Seven types of conventional power plants are considered: hard coal-fired power plants, lignite-fired power plants, nuclear power plants, combined cycle gas turbines (CCGTs), open cycle gas turbines (OCGTs) and oil-fired power plants. The locations and capacities of existing conventional power plants are taken from *Powerplantmachting* (Gotzens et al., 2019), *Global Coal Plant Tracker* (Global Energy Monitor, 2022a), and *Global Oil and Gas Plant Tracker* (Global Energy Monitor, 2022c) and are supplemented by national sources. The considered techno-economic parameters and emission factors are given in Table 3 in the appendix. The capital expenditures (CAPEX) for existing power plant capacities are set to zero, as the model only considers new investments. Announced decommissioning dates for conventional power plants are considered by removing conventional power plants from the model setup if the decommissioning date falls prior to the modeled target year. The decommissioning date are derived from the commissioning date and the assumed technical lifetime of each type of conventional power plant. The technical lifetimes of the conventional power plant types are derived from Farfan and Breyer (2017). Announced coal and nuclear exit targets, if extant, are considered on country level by removing existing conventional power plants from the model and prohibiting new capacity expansions in the respective country.

Modeled RES include onshore and offshore wind turbines, open-field PV (OFPV), rooftop PV (RTPV), hydropower and bioenergy. The locations, capacities and turbine specifications of existing onshore and offshore wind farms are taken from the thewindpower.net database (The Wind Power, 2022). Locations and capacities of existing OFPV and RTPV facilities are taken from *Powerplantmatching* (Gotzens et al., 2019), *Global Solar Power Tracker* (Global Energy Monitor, 2022d) and supplemented by various national sources. The locations of potential future wind turbines and OFPV parks are based on land eligibility analyses by Ryberg et al. (2019) and Caglayan et al. (2019).

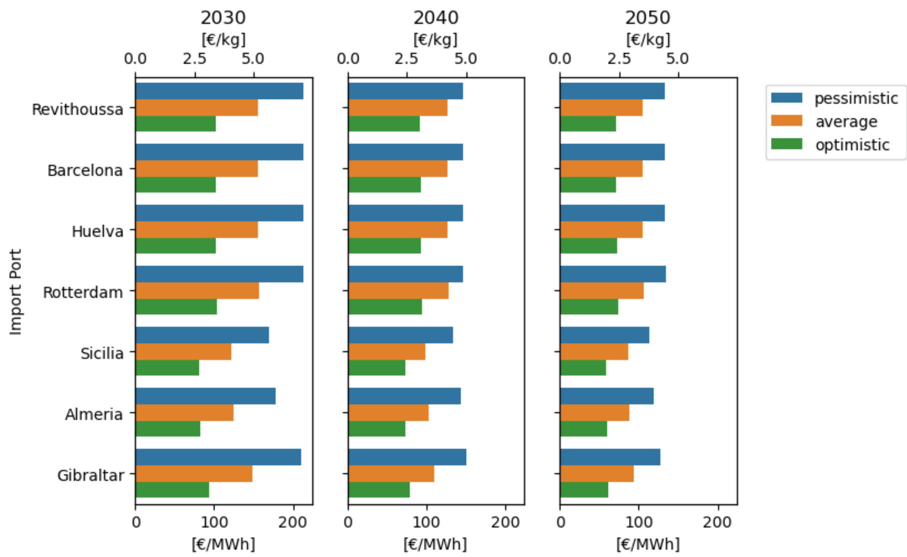

Figure 3-3. Import costs at the selected import locations for the different target years and costs scenarios.

The location and turbine/panel-specific time series of renewable electricity generation are simulated for different weather years using the Renewable Energy Simulation toolkit for Python (RESKit)[4] (Ryberg et al., 2019). Unlike the methodology described in D1.2, the reanalysis weather source has been changed from MERRA2 to ERA5, as ERA5 provides a higher resolution. Together with the different assumed techno-economic parameters, this will result in different levelized cost of hydrogen (LCOH) than those shown in D1.2. The weather years 2015, 2016, 2017 and 2018 are used for this study. Hydropower capacities, including run-of-river, reservoir, and pumped hydro storage, as well as maximum feed-in time-series for run-of-river and reservoir storage are taken from Syranidou et al. (Syranidou et al., 2020). The CAPEX of existing plants is set to zero. All other cost parameters are taken from D7.1 (de Maigret and Viesi, 2023).
The ENSPRESO database (Ruiz et al., 2019) is used to determine maximum biomass potentials and the associated biomass costs for each individual model region using the '*ENS_Med'* scenario. Biomass potentials include forestry, agricultural and waste biomass sources. Biomass can be converted into electricity in existing or new biomass combined heat and power (CHP) plants. Furthermore, biogas plants and treatment plants can be built to first process municipal waste into biogas and then into natural gas. The assumed cost parameters are described in Table 6 in the appendix.

As the focus of this project is on green hydrogen, hydrogen can only be produced from electricity via water electrolysis. Two main electrolysis options, namely proton exchange membrane (PEM) electrolysis and alkaline electrolysis (AEL), are available for hydrogen production. The re-electrification of hydrogen is possible using PEM fuel cells (PEMFC), solid oxide fuel cells (SOFC), H2-CCGT and H2-OCGT. All technical parameters, e.g., efficiencies, and cost parameters are taken from D7.1 (de Maigret and Viesi, 2023).
Furthermore, the model includes conversion options for converting hydrogen into and from hydrogen derivatives. These options include LOHC hydrogenation, H2 liquefaction, methanol synthesis and ammonia (NH3) production via the Haber-Bosch process to convert hydrogen derivatives. Modeled reconversion options include LOHC dehydrogenation, LH2 regasification and methanol, and NH3 cracking.

[4] RESKit: https://github.com/FZJ-IEK3-VSA/RESKit

3.2.2 Energy transmission

Energy exchange between regions is possible for electricity, natural gas, and hydrogen via existing, repurposed, or new grid infrastructure. The lines and corresponding capacities of the electricity transmission grid are taken from Syranidou et al. (2020) who used Gridkit[5] and open street map (OSM) data to extract the lines. The transmission capacities of the today´s existing alternating current (AC) and direct current (DC) grid between model regions are determined by aggregating cross-border capacities. The AC grid capacities are fixed at the current capacities and cannot be expanded due to non-linearities in order to keep the model complexity low. Additional DC grid capacities can be built via the model between any two neighboring regions that are already connected by an electricity transmission line. It should be noted that additional transmission capacity could also be realized through AC grid expansion. Cost parameters for pipelines are taken from D7.1 (de Maigret and Viesi, 2023). Cost parameters for the electricity grid are given in Table 4 in the appendix.

Data on the today´s existing natural gas transmission grid are obtained from Global Energy Infrastructure (Global Energy Infrastructure, 2022). The capacity was calculated using the given pipeline diameter following (Gas for Climate, 2020). In case of missing diameters, data was estimated for national or international pipelines using the respective mean diameter over the dataset. Transmission capacities between regions are then calculated by aggregating cross-border capacities.
The model also offers the option of repurposing the natural gas grid for hydrogen transmission. The capacities of the resulting hydrogen pipelines are assumed to be 80% of the existing natural gas pipeline assuming low-calorific natural gas (Haeseldonckx and D'haeseleer, 2007; Gas for Climate, 2020). For potential routes of new hydrogen pipelines the results from D1.2 are used: It is assumed that new pipelines will be built next to existing natural gas pipelines, roads, or railways. Based on these routes, the shortest connection between regions is used to determine possible connections and the corresponding lengths of potential pipeline connections between regions. The cost parameters of repurposed and new hydrogen pipelines are taken from D7.1 (de Maigret and Viesi, 2023). To reduce complexity and ensure feasibility of the model, binary decisions are not implemented. In terms of pipeline modeling, this means that existing pipeline transfer capacities can also be partially repurposed to be suitable for hydrogen, such that the same pipeline routes can be used for the transmission of natural gas and hydrogen. For example, 70% of the capacity of one certain pipeline connection is repurposed and is available for hydrogen transport, whereas 30% of it is still used for natural gas transport. This limits the accuracy of pipeline modeling but still allows conclusions to be drawn for repurposing pipeline connections. Additional compressors are considered to increase the pressure level of hydrogen produced via electrolysis from 30 to 100bar for pipeline transport. Cost parameters are described in Table 4 in the appendix.

3.2.3 Energy demand

The energy demand for electricity, natural gas and hydrogen for the household, service and industrial sectors are given exogenously as inputs into the model. The electricity and natural gas demands for the different sectors are taken from the ExtremOS project (Forschungsstelle für Energiewirtschaft e. V. (FfE), 2021). They are provided as hourly time series at regional level and are dependent on the target year. They are independent of the selected weather year due to the lack of such data from the ExtremOS project.

Hydrogen demand is taken from deliverable D1.2 (Groß et al., 2022). D1.2 provides annual hydrogen demand at regional level for industrial feedstock, high temperature process heat, and the transport sector. Some additions and corrections are made to the data, given that, e.g., data from Switzerland was missing in the original dataset. Furthermore, updates to the

[5] GridKit: https://github.com/bdw/GridKit

underlying third-party databases (e.g., steel plants), that took place after publishing D1.2, have also been included. Consequently, the modeled hydrogen demand slightly differs to the one presented in D1.2.
There is no hydrogen demand assumed for residential sector, i.e. it is assumed that the residential sector will use other energy carriers for, e.g., room heating. Exogenously given hydrogen demand is assumed to be constant throughout the year for all end-use sectors including industry and transport sectors. This does not apply for hydrogen re-electrification which is freely optimized by the model.

The electricity, natural gas, and hydrogen demand in the conversion processes, e.g., for re-electrification power plants and electrolysis, are part of the optimization results.

3.2.4 Energy storage

Various energy storage options are included in the model. For electricity storage, the model considers lithium-ion batteries. Hydropower storage options include pumped hydro and reservoir storage. It is assumed that the storage capacities of hydropower plants in the EU cannot be expanded, as hydropower has only experienced limited growth in recent years and environmental standards are high. Storage options for hydrogen derivatives include LH2, LOHC, NH3 and methanol storage tanks. The techno-economic parameters are taken from D7.1 (de Maigret and Viesi, 2023).

The existing natural gas storage locations and capacities of aquifers and depleted gas fields are included in the model based on the findings of (Cavanagh et al., 2022). Existing locations and capacities of salt caverns are based on the *GIE Storage Database* (Gas Infrastructure Europe, 2021).

Hydrogen storage options include both surface and subsurface storage technologies. Above-ground pressurized hydrogen storage is available as a surface storage technology. Underground storage options include storing hydrogen in salt caverns and porous reservoirs. For both storage options, existing natural gas sites can be repurposed, or new capacities can be built. The capacities of existing natural gas porous reservoir storage sites as well as the resulting hydrogen storage capacities are taken from D1.3. The "*Working Gas Capacity – Hydrogen, low-end estimate (WGC-ED)*" is used for the capacity estimation. Capacity additions at porous reservoirs sites are assumed to be possible based on D1.3 (Cavanagh et al., 2022, p.3): "[…]*, given the dominance of depleted gas field storage, it is reasonable to assume that inventory doubling could be achieved in most cases by operators either acquiring a depleted gas field close to their existing site or by increasing the capacity of the existing site."* For the model, it is therefore assumed that a capacity expansion of factor 3 is possible for existing porous reservoir storage sites. Closed or planned sites can also be used to build new porous reservoir storage sites. Hydrogen salt cavern potential is drawn from Caglayan et al. (2020), considering a location constraint of a 50 km maximum distance from shore to account for economic and environmental constraints regarding brine disposal.

Both hydrogen salt cavern and porous reservoirs are modeled in such a way that surface and subsurface components are modeled with independent capacities. The optimal sizing of both surface and subsurface capacities is part of the optimization. To prevent unreasonably high surface capacities corresponding to an unreasonably high number of wells, a maximum ratio of surface and subsurface capacity is set. Associated parameters including discharge rates, cushion gas ratios, energy use for charge and discharge, and charge and discharge efficiencies, and cost parameters are taken from D7.1 (de Maigret and Viesi, 2023). Abandonment expenditures (ABEX) are not considered but will be covered in D7.3. The investment costs for cushion gas are calculated based on the cushion gas ratio of the respective technology and the hydrogen costs of 2 €/kg (optimistic), 3 €/kg (average) and

5 €/kg (pessimistic). The costs for repurposed storage sites are calculated based on the methodology that will be presented in the upcoming HyUSPRe deliverable D7.3. In short, the subsurface CAPEX is set to 60% of new storage sites. ABEX expenses for the dismantling of existing facilities are not considered as they are not considered expenses of the new facility.

3.2.5 Additional constraints and boundaries

Further environmental, technical, or user-defined constraints can be considered by the model: The model considers country-level CO2 emission limits for the power sector. The Fit-for-55 package specifies a 62% emission reduction for 2030 compared to 2005 sources covered by the EU-ETS (European Council, 2023). Drawing on the 2005 emissions of the power sector for each country (United Nations Climate Change, 2023), an emission limit is calculated for 2030. For 2050, no greenhouse gas (GHG) emissions are allowed from the power sector. Therefore, the emissions are set to zero for 2050. The values for 2040 are calculated based on a linear interpolation of the 2030 and 2050 values. The emission limits are set as additional constraints on a country level that the model must keep. This constraint is considered in all modeled scenarios.

In order to adhere to the national targets for the expansion of renewable energy generation, minimum and maximum values for the capacity expansion of the individual technologies can be defined in the model settings. Figure 3-4 depicts the national targets for renewable energy generation in 2030 based on ("Global Renewable Power Sector Targets 2030", 2024). For 2040 and 2050 maximum expansion rates of 1.25% per year of the available potential per country can be set to limit concentrated expansion in single countries. This constraint is not considered in the baseline scenarios.

A synthetic Dunkelflaute (e.g., Stolten et al., 2022; 2023) can be integrated into the model. For representation of a Dunkelflaute, a reduction of renewable energy production in Northwestern Europe to 30% of its original value for four days in the beginning of January was chosen. This constraint is not considered in the baseline scenarios.

A target for hydrogen import into the model scope can be set, imitating the REPowerEU target of 10 Mt of hydrogen import for 2030 (European Commission, Directorate General for Energy, 2022). If this target is enabled, the sum of all imports of all regions must be above or equal to the set target value. For 2040 and 2050, an artificial constraint is set that forces minimum hydrogen imports equivalent to 30% of the annual hydrogen demand. This constraint is not considered in the baseline scenarios.

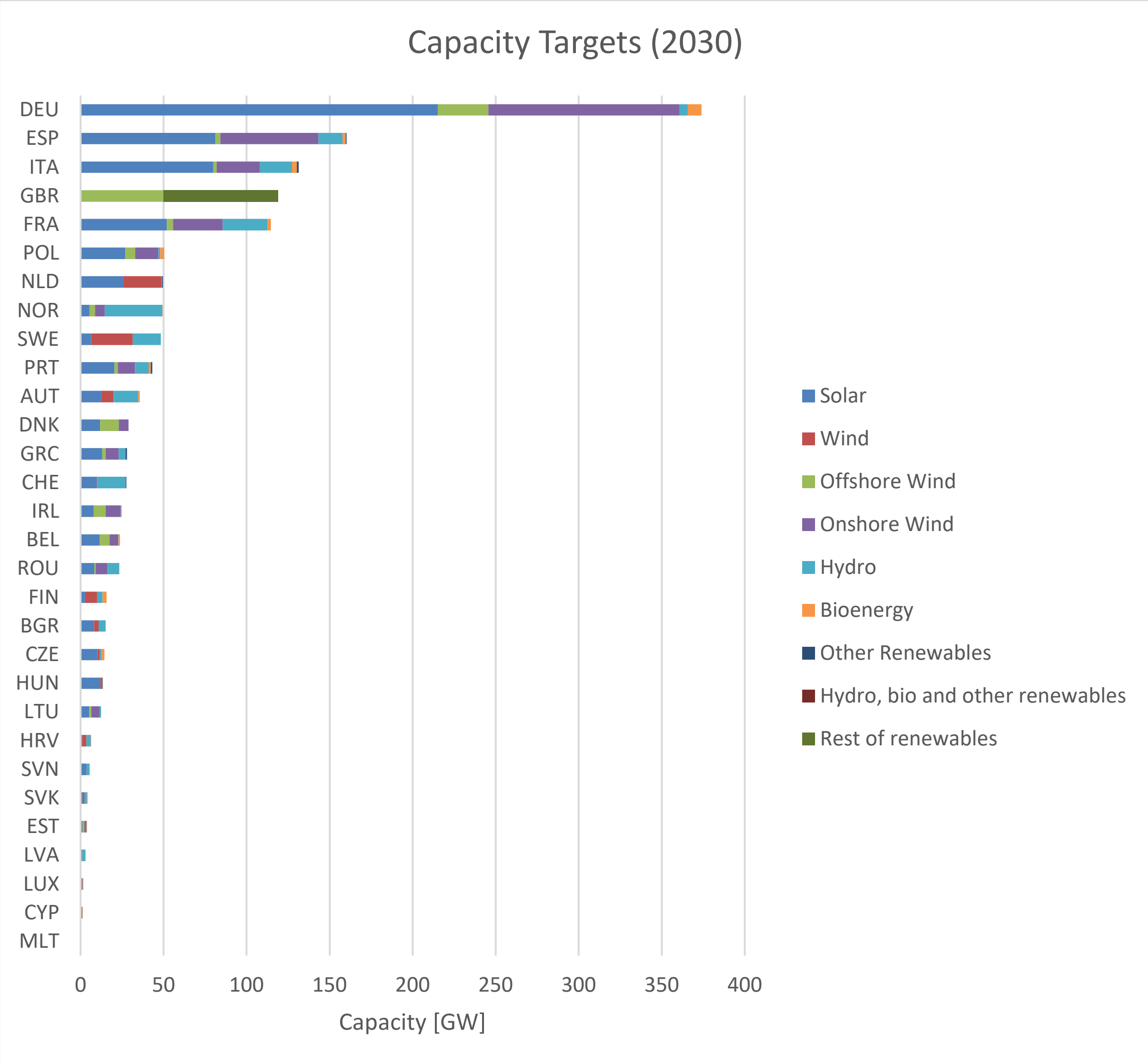

Figure 3-4. National targets for renewable energy generation capacities in 2030 (based on ("Global Renewable Power Sector Targets 2030", 2024)).

Further, limitations on grid expansion can be set which limit the maximum expansion of electricity and hydrogen grid, both new and repurposed capacities, to 0.2GW per year between two regions in order to represent possible bottlenecks in grid expansion. For 2050, this results in a maximum expansion of the electricity grid of 5.2 GW between two regions. Same is true for the hydrogen grid expansion. These constraints are not considered in the baseline scenarios.

4 Scenario selection

Multiple scenarios are created to address the research question of what role porous storage systems can play as potential UHS facilities in Europe's future energy system. To answer this question for the whole energy transformation path, different target years must be considered. Three different target years, including 2030, 2040, and 2050, were determined to be sufficient to capture the distinct phases of UHS implementation in Europe.

For each of these target years, a baseline scenario was created. Based on these baseline scenarios, different sensitivity scenarios are added to investigate the robustness and the impact of certain restrictions on the results. Furthermore, the sensitivity scenarios enable the posed research question to be answered in greater detail, as dependencies and limitations regarding porous reservoir (PR) storage can be explored.
The sensitivity scenarios aim to explore impacts of different demands, techno-economic parameters, weather years and national RES targets, technological storage restrictions as well as import limitations on PR storage. An overview of the different scenario categories is shown in Figure 4-1.

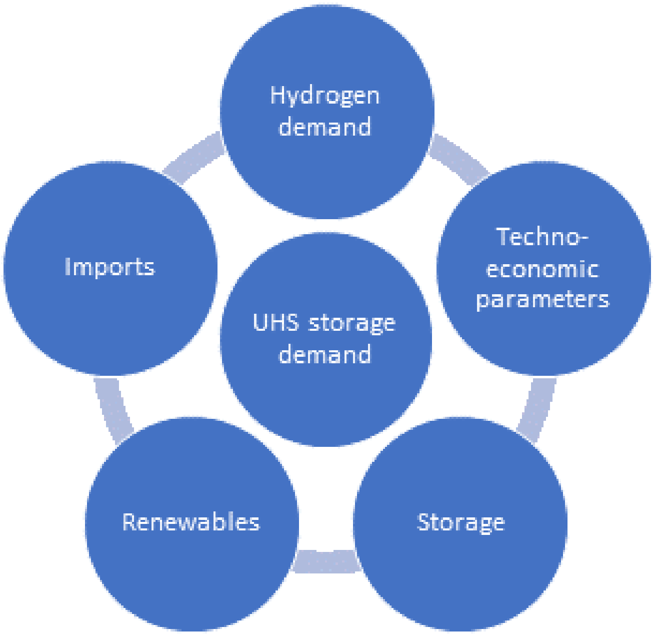

Figure 4-1. Overview of scenarios.

4.1 Baseline scenarios

The baseline scenarios represent the reference cases and the least restrictive scenarios on which the sensitivity scenarios can be built upon. The baseline scenarios use the techno-economic parameters of the “average” scenario from D7.1 (de Maigret and Viesi, 2023). For the exogenously defined hydrogen demands from D1.2 the “baseline” scenario is chosen (Groß et al., 2022). The year 2015 is chosen as the weather year for renewable power generation and thus corresponds to the same assumption as in Hystories project (Michalski, 2022). It should be mentioned that this year represents rather favorable climatic conditions, i.e., renewable energy generation is not negatively influenced by occurrences of Dunkelflauten (see ENTSO-G and ENTSO-E (2021)). All technologies and options are available in this scenario. Hydrogen storage is possible in both repurposed and new pore storages and cavern storage systems.

4.2 Sensitivity scenarios

The sensitivity scenarios are used to explore differences that could potentially impact the optimal hydrogen storage capacities and implementation year. Five major dimensions have been identified and selected (see Figure 4-1).

Hydrogen demand
Different hydrogen demand levels might have a significant impact on hydrogen storage needs. Therefore, they are varied between the “reduced”, “baseline” and “ambitious” scenarios of D1.2 (Groß et al. 2022). The results of these scenario runs are described in Section 5.2.1.

Techno-economic parameters
In D7.1 (de Maigret and Viesi, 2023), three techno-economic parameter scenarios (“optimistic”, “average” and “pessimistic”) were created based on the literature. The “optimistic” and “pessimistic” scenarios represent upper and lower values of the found data based on the first and third quantiles (de Maigret and Viesi, 2023). These scenarios represent the different cost developments. The results of these scenario runs are described in Section 5.2.2.

Renewables
To investigate the impact of different weather conditions on renewable energy generation and thereby the hydrogen storage needs, different weather years are used. A total of four different weather years from the last 10 years are chosen (2015, 2016, 2017, and 2018) to account for various weather conditions. Preliminary analysis shows that 2015 has the highest full load hours (FLH) for wind compared to all selected weather years. In turn, 2016 has the lowest, with a 9% diminution compared to 2015. The FLH for PV do not show such strong deviations over the years. The results of these scenario runs are described in Section 5.2.4.

As the future greenhouse gas neutral European energy system need to rely on a high share of RES, a synthetic Dunkelflaute, i.e., a period of low electricity feed-in by RES, with a duration of 4 days is assumed for Northern Europe in an additional scenario.
Furthermore, the impact of national RES targets is investigated in an additional scenario. Therefore, the national targets of 2030 are considered as minimum RES capacities. For the scenario calculations of 2040 and 2050, a maximum expansion rate for RES is assumed for each country to avoid the dependency from single countries for electricity and hydrogen production. The results of these scenario runs are described in Section 5.2.6.

Storage
The sensitivity scenarios aim to determine the value of pore storage for the future European energy system. Two scenarios are explored in the storage sensitivities. The first considers the technological storage restrictions addressing scenarios where hydrogen storage in porous reservoirs is entirely not feasible. The second is seen as counterpart excluding the hydrogen storage in existing salt caverns. The results of these scenario runs are described in Section 5.2.3.

Imports
The last sensitivity dimension investigates the impact of hydrogen imports on the storage need by restricting or forcing hydrogen imports into the solution space. A selection of previous sensitivity scenarios is run without an import option to entail a direct comparison between a scenario with and without an import option (see Table 1).
Another scenario investigating the opposite direction is created to consider the impact of EU legislative targets defined in the REPowerEU package. For 2030, the model is forced to import 10 Mt of hydrogen, as defined in the REPowerEU targets. To investigate the impact of forced imports also on later target years a similar approach is taken for 2040 and 2050. The model is

forced to import at least 30% of the total annual hydrogen demands. Imports can be realized by either LH2 shipping or hydrogen imports from North Africa by pipelines.
The results of these scenario runs are described in Section 5.2.5. Additional scenario variations investigate the impact of fluctuating hydrogen pipeline imports from North Africa, assuming that the produced hydrogen cannot be stored in Africa, and of limitations on grid expansion, limiting the expansion of the electricity and the hydrogen grid. The results of these scenario runs are described in Section 5.2.6.

The resulting scenarios are listed in Table 1. For each target year, 18 scenarios are created, which add up to a total of 54 scenarios. In summary, the scenarios created in this study examine the drivers for developing storage capacity for hydrogen in porous reservoirs in Europe. Three target years, 2030, 2040, and 2050, are chosen to represent distinct phases of the implementation of UHS in Europe. The baseline scenarios serve as a reference point, utilizing average demands and cost projections, and allowing for the exploration of sensitivity scenarios. The sensitivity scenarios enable us to understand the robustness and limitations of porous reservoir storage for hydrogen in the future, shedding light on the dependencies and restrictions that may influence optimal capacities and timing of development. The findings from these scenarios will provide valuable insights for policy makers and energy planners as they work towards developing a sustainable and reliable hydrogen energy system in Europe.

Table 1. Scenario overview and short names.

Scenario name			Explanation
2030	2040	2050	
01_baseline_2030	20_baseline_2040	39_baseline_2050	Baseline scenario
02_demand_2030	21_demand_2040	40_demand_2050	'reduced' demand
03_demand_2030	22_demand_2040	41_demand_2050	'ambitious' demand
04_TEP_2030	23_TEP_2040	42_TEP_2050	'pessimistic' costs
05_TEP_2030	24_TEP_2040	43_TEP_2050	'optimistic' costs
06_REPowerEU_2030	25_REPowerEU_2040	44_REPowerEU_2050	H2 imports forced: 2030: 10 Mt 2040: 30% of demand 2050: 30% of demand
07_imports_2030	26_imports_2040	45_imports_2050	No imports allowed
08_RES_2030	27_RES_2040	46_RES_2050	Weather year: 2018
09_RES_2030	28_RES_2040	47_RES_2050	Weather year: 2017
10_RES_2030	29_RES_2040	48_RES_2050	Weather year: 2016
12_storage_2030	31_storage_2040	50_storage_2050	No pore storage
13_storage_2030	32_storage_2040	51_storage_2050	No repurposed salt caverns
14_seasImports REPowerEU_2030	33_seasImports REPowerEU_2040	52_seasImports REPowerEU_2050	Combination of: - Seasonal H2 pipeline imports - REPowerEU scenario
15_seasImports_2030	34_seasImports_2040	53_seasImports_2050	Seasonal H2 pipeline imports
16_resTargets_2030	35_resTargets_2040	54_resTargets_2050	2030: national targets 2040: RES expansion max. 1.25% of potential per year and country 2050: RES expansion max. 1.25% of potential per year and country
17_limitGridreg_2030	36_limitGridreg_2040	55_limitGridreg_2050	Max. 0.5 GW per year and region (h2 and electricity), only along existing grid
18_dunkelflaute_2030	37_dunkelflaute_2040	56_dunkelflaute_2050	RES production reduced by 70% for 4 days in January in Northwestern Europe
19_combi_2030	38_combi_2040	57_combi_2050	Combination of: - seasImportsREPowerEU - resTargets - limitGridreg - Dunkelflaute

5 Results

The following chapter describes the results of the model runs. Section 5.1 presents the results for the baseline scenarios for the three target years. The focus is on the power sector and hydrogen sector, including production, transmission infrastructure and storage. Section 5.2 describes the results of the sensitivity scenarios which are used to explore differences that could potentially impact the optimal hydrogen storage capacities, locations, and implementation year. The results and their limitations are discussed in Chapter 6.

It should be noted that the optimization model seeks the cost-optimal solution for minimizing the total annual costs of the system targets based on the cost estimates that are provided to it as input, while considering technical and environmental constraints. Due to the cost-minimization approach, the model computes the ideal system from a techno-economic perspective, neglecting political constraints and assuming full cooperation between countries. That means that constraints imposed by socio-economic and geo-political considerations, e.g. limitations to expanding the European electricity grid, and requirements for a minimum storage capacity per country for reasons of securing supply or energy independence, are not included. The results should therefore not be seen as a simulation or forecast of a future state of Europe´s energy system and the final role of underground hydrogen storage in reservoirs in that system, but rather as outcomes of model-based thought experiments that can help to understand what factors govern the technical feasibility and affordability of underground hydrogen storage in reservoirs and salt caverns in Europe.

5.1 Baseline scenarios

The objective of the baseline scenario is to elucidate the prospective evolution of the European Energy System from 2030 to 2050.

5.1.1 Power sector

This section presents a concise overview of the power sector within the framework of the baseline scenarios. Both electricity and hydrogen demand exhibit a clear upward trend between 2030 and 2050, which necessitates an increase in electricity generation capacity. By 2030, renewable electricity sources have a dominant position, accounting for more than 73% of total electricity generation. Concurrently, conventional power plants contribute to 26% of total electricity generation in 2030, gradually diminishing over the subsequent two decades (see Figure 5-1).

Most emissions in 2030 are generated by Germany, the Czech Republic, Italy, the United Kingdom, and Poland. This is due to the continued operation of existing coal-fired power plants. By 2050, all conventional power plants, except for a small share of nuclear power plants, have been phased out in accordance with established emission limits; a trend depicted in Figure 5-2. Over the entire period under review, onshore wind power emerges as the primary source of electricity generation, accounting for more than 61% of total electricity generation in 2050 due to the assumed cost advantage of onshore wind turbines over other renewable energy sources (de Maigret and Viesi, 2023).

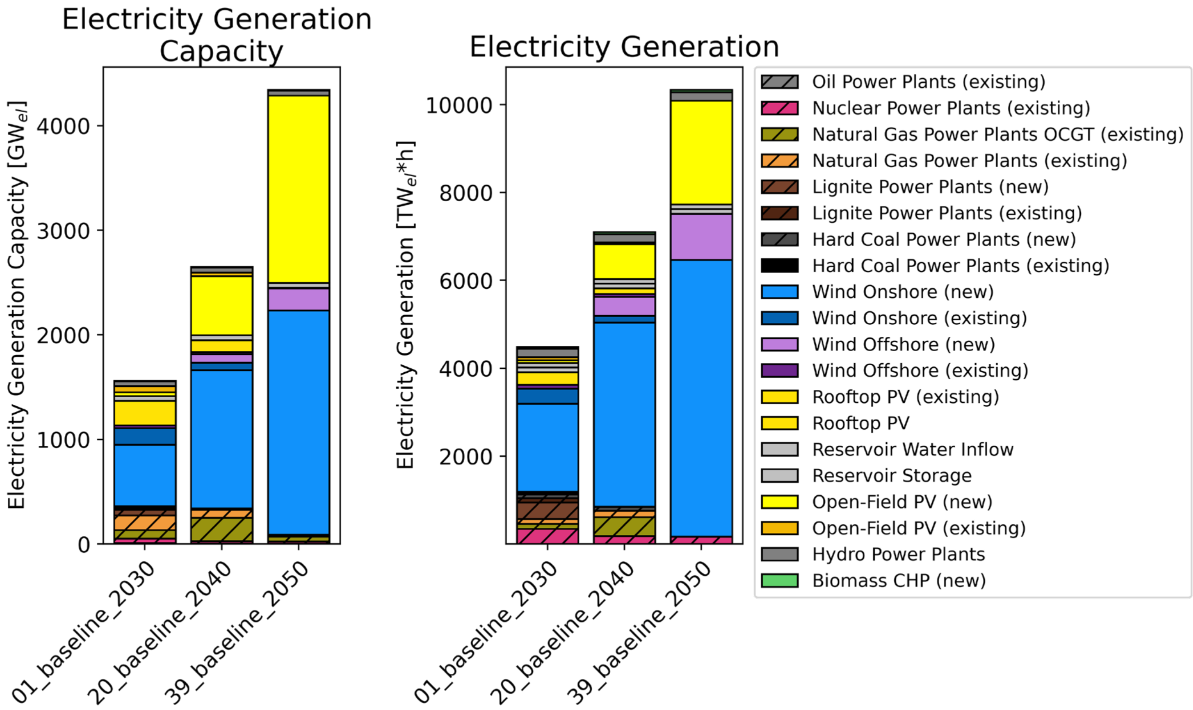

Figure 5-1. Electricity generation capacity of the baseline scenarios (left) and electricity generation (right).

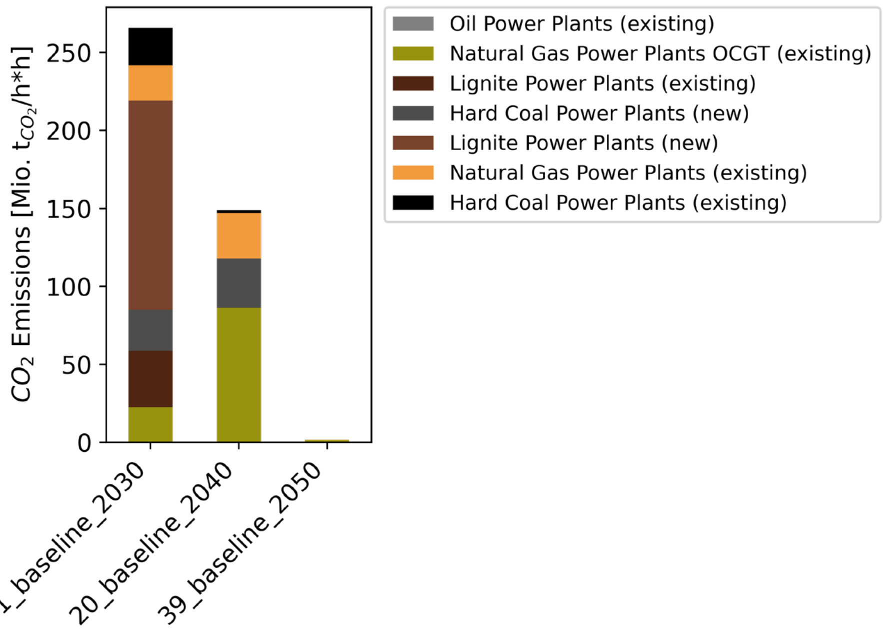

Figure 5-2. Emissions of fossil-fueled power plants in baseline scenarios.

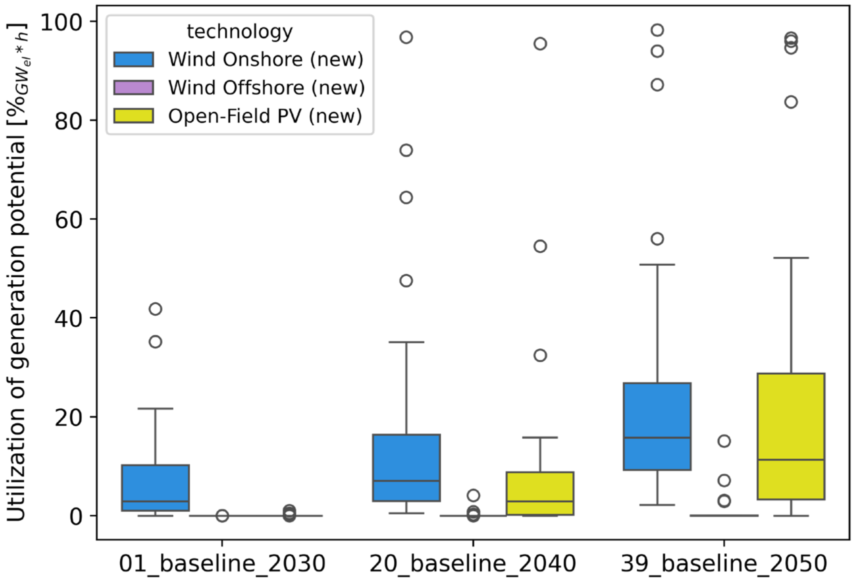

Figure 5-3. Utilization of generation potential per country in the baseline scenarios for the three target years. Each circle represents one country.

In 2030, PV technology holds a marginal share of 9.2%, which subsequently increases to 23% by 2050. The growth in renewable capacities from 2030 to 2050 consequently leads to increased utilization of the available generation potential, as is shown in Figure 5-3. The data is presented at the country level, i.e., each circle represents one country. Onshore wind stands out as the technology with the largest increase in the utilization of available generation potential. In some countries, the utilization of onshore wind potential is more than 80%.

On a European level, overall utilization of onshore wind potentials surges from 4% in 2030 to 17% in 2050. In contrast, the utilization of offshore wind potential remains limited to 2% in 2050, whereas PV sees a utilization of up to 15% of its potential by the same year. However, it should be noted that the assumed wind offshore potential is comparably large (11.3 TW), leading to low utilization values. Noteworthy disparities emerge in the utilization of onshore wind resources, with countries such as Denmark, the Netherlands, and Belgium approaching nearly 100% utilization. This variation can be attributed to the proximity to the North Sea, where higher FLH are achieved compared to mainland Europe, resulting in utilization rates ranging from a few percent to full saturation between European countries.

In the baseline scenarios, negligible re-electrification of hydrogen of 10 TWh in 2050 is observed. This phenomenon can be attributed to the high share of renewable energy technologies and investments in electricity transmission infrastructure. Periods of low electricity generation in a few regions are mitigated through an interconnected electricity grid that facilitates the transfer of surplus electricity from regions with overproduction. The advantageous impact of augmenting electricity grid capacities for grid balancing was already observed by Neumann et al. (2023). The scenario input for renewable energy generation profiles in this study does not show any Europe-wide Dunkelflaute, referring to extended periods characterized by overcast skies and minimal to no wind (e.g., Stolten et al., 2022; 2023). The impact of such a Dunkelflaute is explored in one of the sensitivity scenarios presented in section 5.2.6.

The resulting capacities of the transmission grids are depicted in Figure 5-4. The graph reveals that the total capacity of the existing electricity grid will more than double by 2050 to balance supply and demand.

In short, the power sector faces a steep increase in renewable capacities by 2050, generating 10,000 TWh of electricity, as well as a synchronized expansion of the transmission grid. Most of the electricity is generated by wind turbines, with a significant portion designated to producing hydrogen which is needed in the industrial and transport sectors.

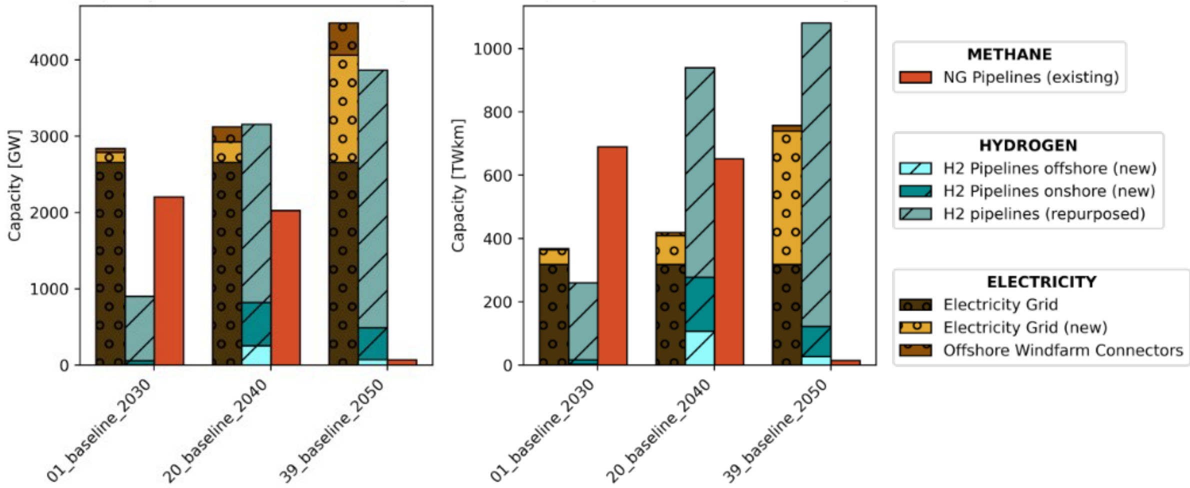

Figure 5-4. Resulting capacities of transmission technologies for electricity, hydrogen, and methane in the baseline scenarios. Left: Capacities given in GW; right: Capacities given in TWkm.

5.1.2 Hydrogen

In this section, hydrogen is examined in detail as part of the energy system model of the baseline scenarios. The overall hydrogen demands for the selected target years are presented in Figure 5-5. Additional data is accessible in D1.2 (Groß et al., 2022).

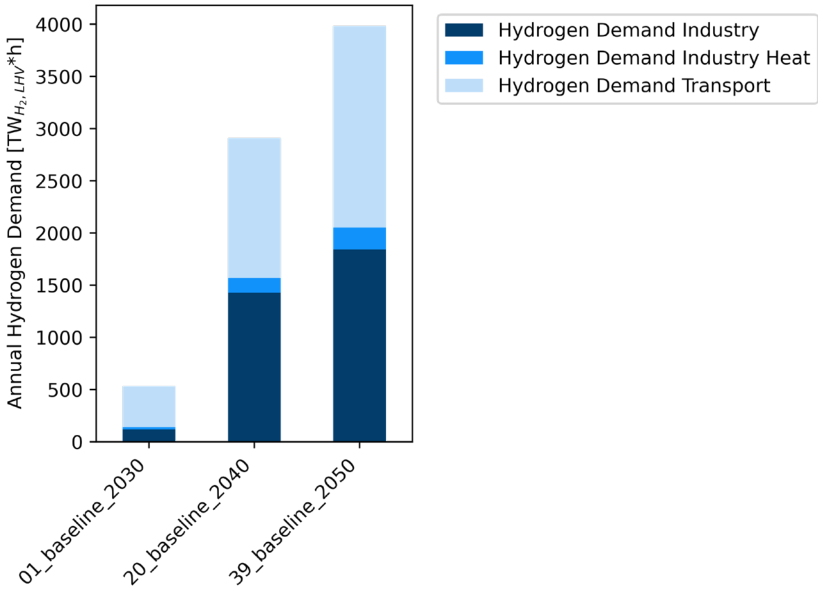

Figure 5-5. Annual hydrogen demand in the baseline scenarios.

Hydrogen production

Hydrogen is mainly locally produced within Europe through electrolysis, with a noteworthy reliance on wind turbines as the dominant power source for this technology. Hydrogen imports are observable in the baseline scenarios for the years 2040 and 2050. These imports are channeled through pipelines originating from North Africa, amounting to 1200 TWh and 370 TWh of hydrogen in 2040 and 2050, respectively, as detailed in Figure 5-6.

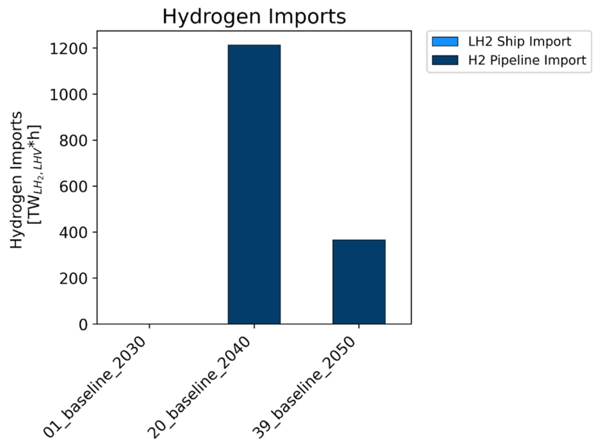

Figure 5-6. Extra-European hydrogen imports in the baseline scenarios.

Hydrogen production exhibits distinct variations from one country to another, as shown in Figure 5-7, which presents a breakdown of hydrogen imports and exports by country as well as hydrogen production per country. Figure 5-7 reveals the substantial hydrogen production in the United Kingdom, a nation that concurrently emerges as a prominent hydrogen exporter,

with 40% of its produced hydrogen destined for other European countries. France occupies the position of the second-largest hydrogen producer in 2050 with 180 TWh of exports. This highlights the domestic consumption of the produced hydrogen within France.

In contrast, countries characterized by pronounced hydrogen demand centers (see D1.2), such as Germany, Netherlands and Belgium rely on hydrogen imports from within Europe to meet their demand. Germany and Netherlands however produce also large shares of hydrogen themselves. For instance, in 2050, Germany produces approximately 300 TWh of hydrogen and needs to import additional 600 TWh of hydrogen from other countries in Europe.

The baseline scenarios reveal the substantial differences among the European nations as well as their distinctive role in the European energy system. The UK, Norway, Denmark, Ireland, and Sweden can be identified as hydrogen exporters. Meanwhile, countries such as Germany, and the Netherlands, with prominent hydrogen demand centers, exhibit a hybrid approach, producing a substantial portion of their hydrogen domestically but still relying on imports to bridge the demand-supply gap. In contrast, Belgium is almost entirely dependent on imports to cover its hydrogen demand.

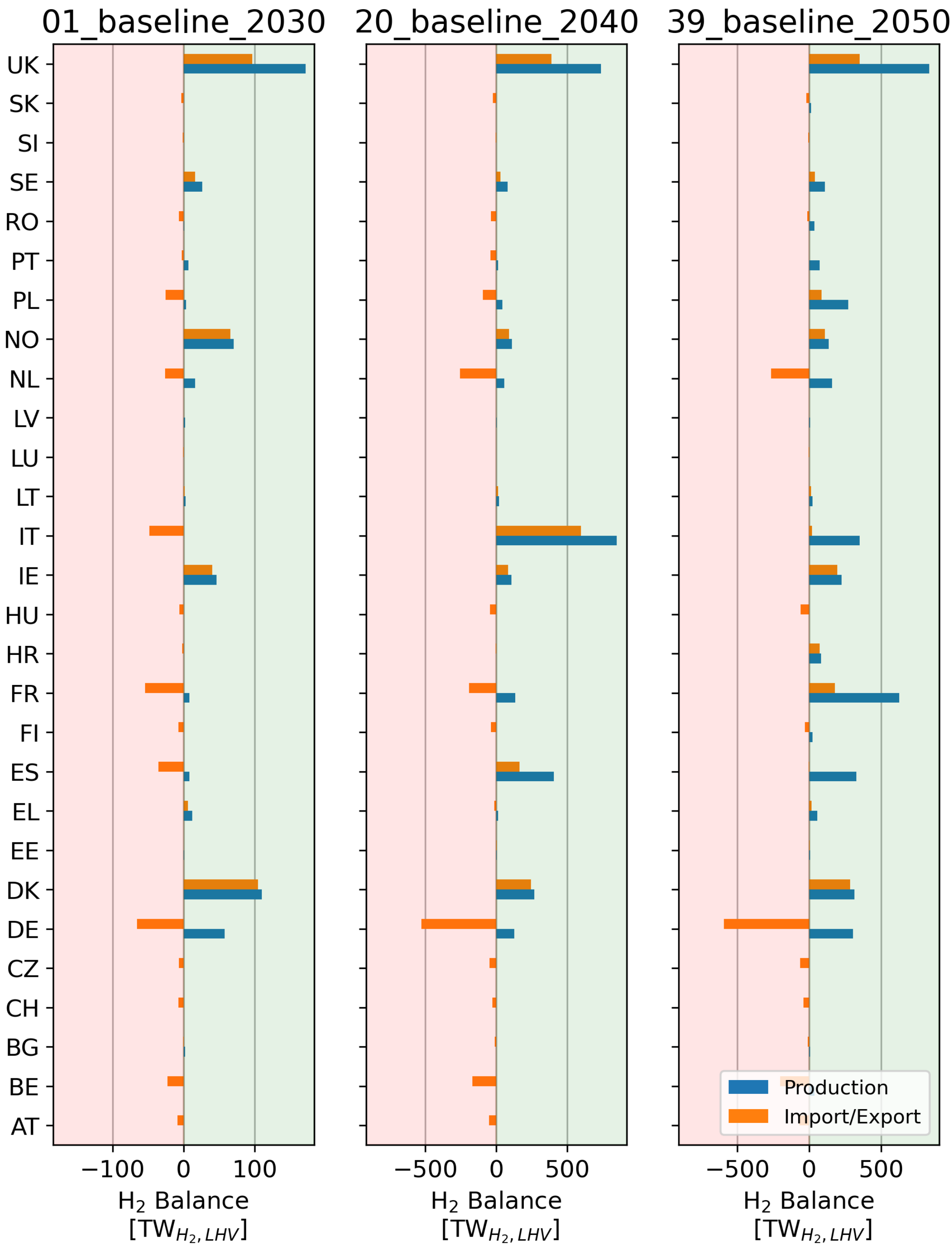

Figure 5-7. Intra-European hydrogen imports and exports and hydrogen production inclusive extra-European imports per country in the baseline scenarios.

Hydrogen transport infrastructure

In this section, we present an analysis of the potential hydrogen transport infrastructure needs. In general, the baseline scenarios foresee hydrogen grid expansions of up to 3900 GW through 2050 as is shown in Figure 5-8.

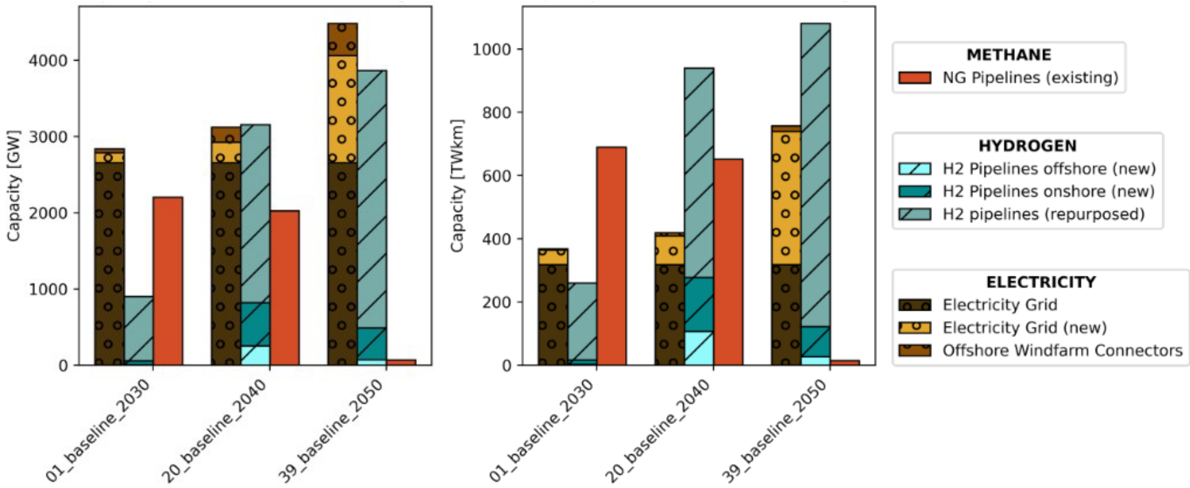

Figure 5-8. Resulting capacities of transmission technologies for electricity, hydrogen, and methane in the baseline scenarios. Left: Capacities given in GW; right: Capacities given in TWkm.

Notably, already by 2030, 900 GW of hydrogen pipelines are anticipated to be in operation, predominantly comprised of repurposed natural gas pipelines. The transformation of the natural gas pipeline grid is a prominent feature, constituting roughly 78% of the hydrogen grid by 2050, and driven by the diminishing demand for natural gas.

The primary hydrogen production locations are in the northern UK and Denmark as already identified in the previous section. Two reasons for this can be identified: First, a general reliance of hydrogen production from electricity sourced by wind turbines can be observed in the baseline scenarios. Second, coastal regions in Northern Europe and the North Sea are identified as advantageous locations for wind turbines, as detailed described in D1.2 (Groß et al., 2022). From here, hydrogen is transported via pipeline southwards to regions of demand. Unlike 2050, where a clear hydrogen demand valley has formed, in 2030, hydrogen demand is distributed more evenly throughout Europe. This results in the emergence of a hydrogen grid by 2030 with a North–South transport corridor that spans across the whole of Europe.
Multiple distinct corridors can be observed in 2030, with bulk hydrogen production concentrated in the northern UK, Denmark, and Norway (see Figure 5-9). From there, hydrogen is transported to mainland Europe first to Germany, France, and the Netherlands. From France, the hydrogen is further transported to both Spain and Italy. From Germany, hydrogen is further transported southwards by an additional corridor through the Czech Republic, Slovakia, and Austria to Italy.

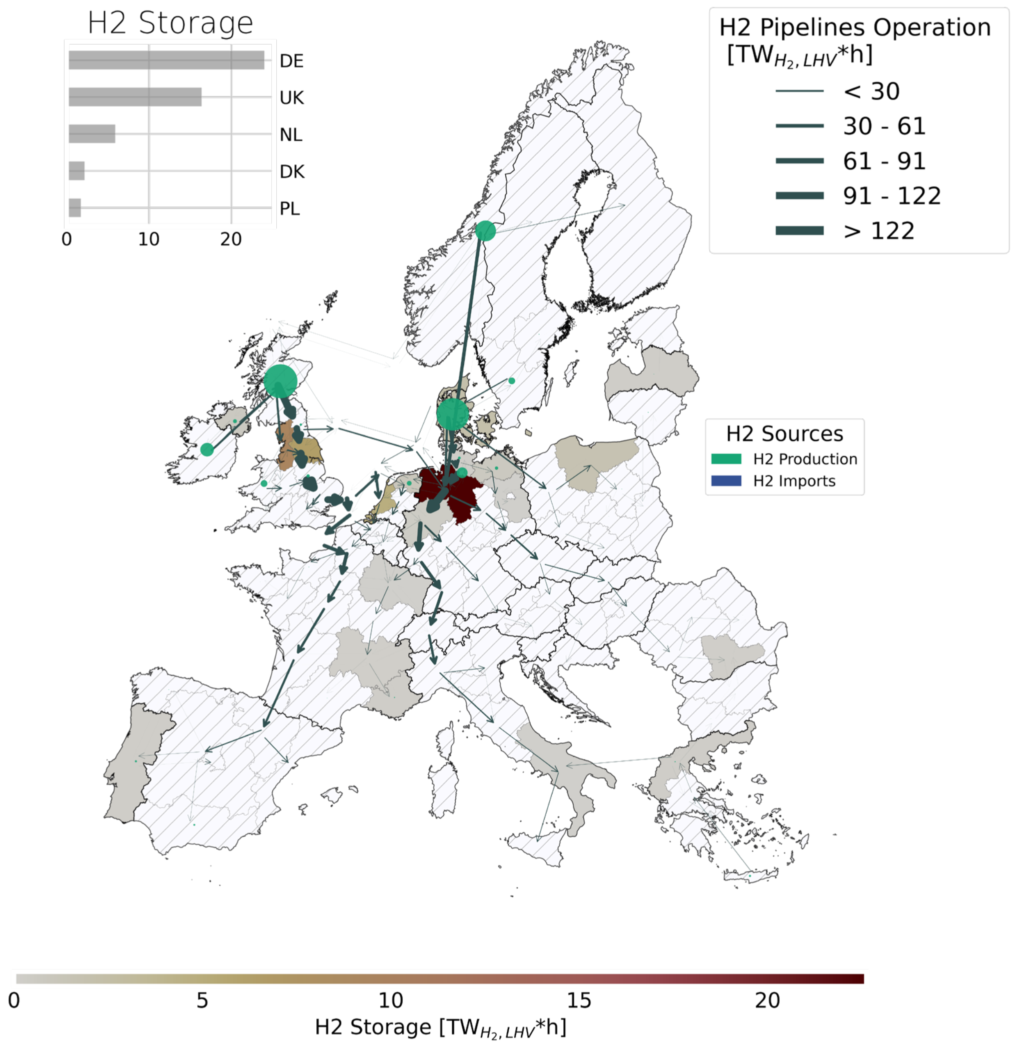

Figure 5-9. Hydrogen transmission (arrows), hydrogen storage capacity (areas) and hydrogen production (filled circles without quantities) in the baseline scenario for 2030.

Due to the emergence of more distinct hydrogen demand centers by 2040 certain corridors experience a significant capacity expansion and a higher utilization (see Figure 5-10). Notable examples include the corridors connecting the UK and mainland Europe as well as the Denmark-Germany and the eastern Europe corridor. The latter can be attributed to the hydrogen production dynamics detailed in Figure 5-7, indicating low hydrogen production levels in Slovakia and Austria, and leading to a reliance on hydrogen imports to meet demand. However, the reliance on imports is not limited to these countries. Due to the higher amount of extra-European hydrogen import from North Africa (see Figure 5-6), an additional hydrogen transport route from South to North Italy can be observed. Around one third of the total hydrogen demand is sourced by North African imports in 2040. The extra-European imports are of similar magnitude as the hydrogen production in the UK. The usage of the corridors from Scandinavian countries to the mainland remain at the level of 2030.

Figure 5-11 depicts the optimal UHS locations along with the optimal operation of hydrogen pipelines as well as hydrogen production centers in 2050. The observed hydrogen transport corridors remain similar to the those in 2040. As the extra-European hydrogen imports decrease (see Figure 5-6), hydrogen transport routes from the south to the north are less pronounced.

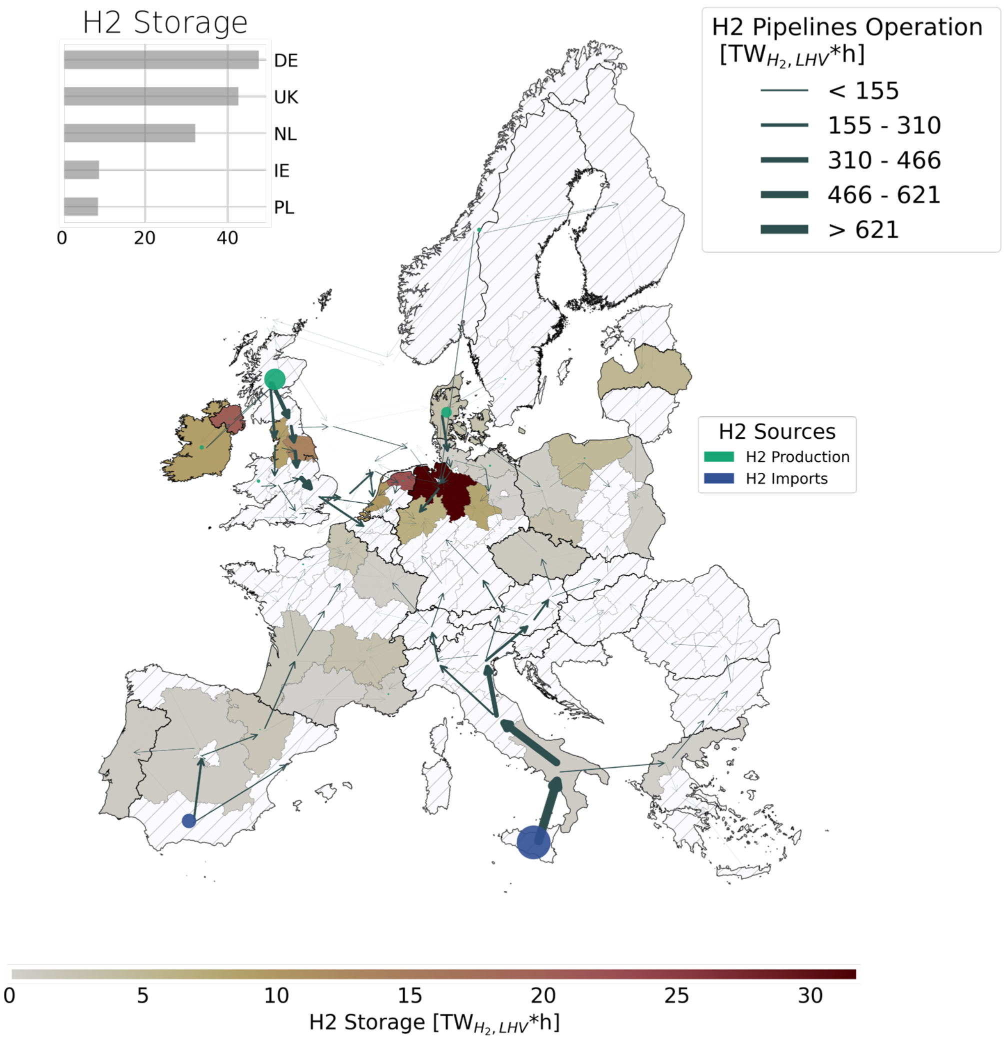

Figure 5-10. Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in the baseline scenario for 2040.

Most of the regions in 2030 rely on hydrogen imports from European neighbors as Figure 5-7 shows. Exceptions include identified hydrogen production centers in Northern Germany, as well as certain peripheral regions with low hydrogen demand. Over the period from 2030 to 2050, this reliance on imports gradually decreases, where in 2050 mostly central Europe is not net hydrogen self-sufficient. It should be noted that hydrogen exchange still occurs between regions to cover intra-annual fluctuations in production, which underscores the balancing of hydrogen supply and demand as one of the key purposes of the hydrogen grid.

In essence, by 2030, an emerging north–south corridor connects hydrogen production centers in the northern UK, Denmark, and Sweden to diverse demand centers across Europe. Significant capacity additions throughout 2030–2050 in key corridors including a South-North corridor for North-African hydrogen imports address increasing demand. There are two primary function of the hydrogen grid that can be observed: firstly, the hydrogen grid, mainly evolving from repurposed natural gas infrastructure, serves as a crucial mechanism for the short- to medium-term balancing of supply and demand. Secondly, it is used for bulk hydrogen transport from production centers to regions with growing hydrogen demand.

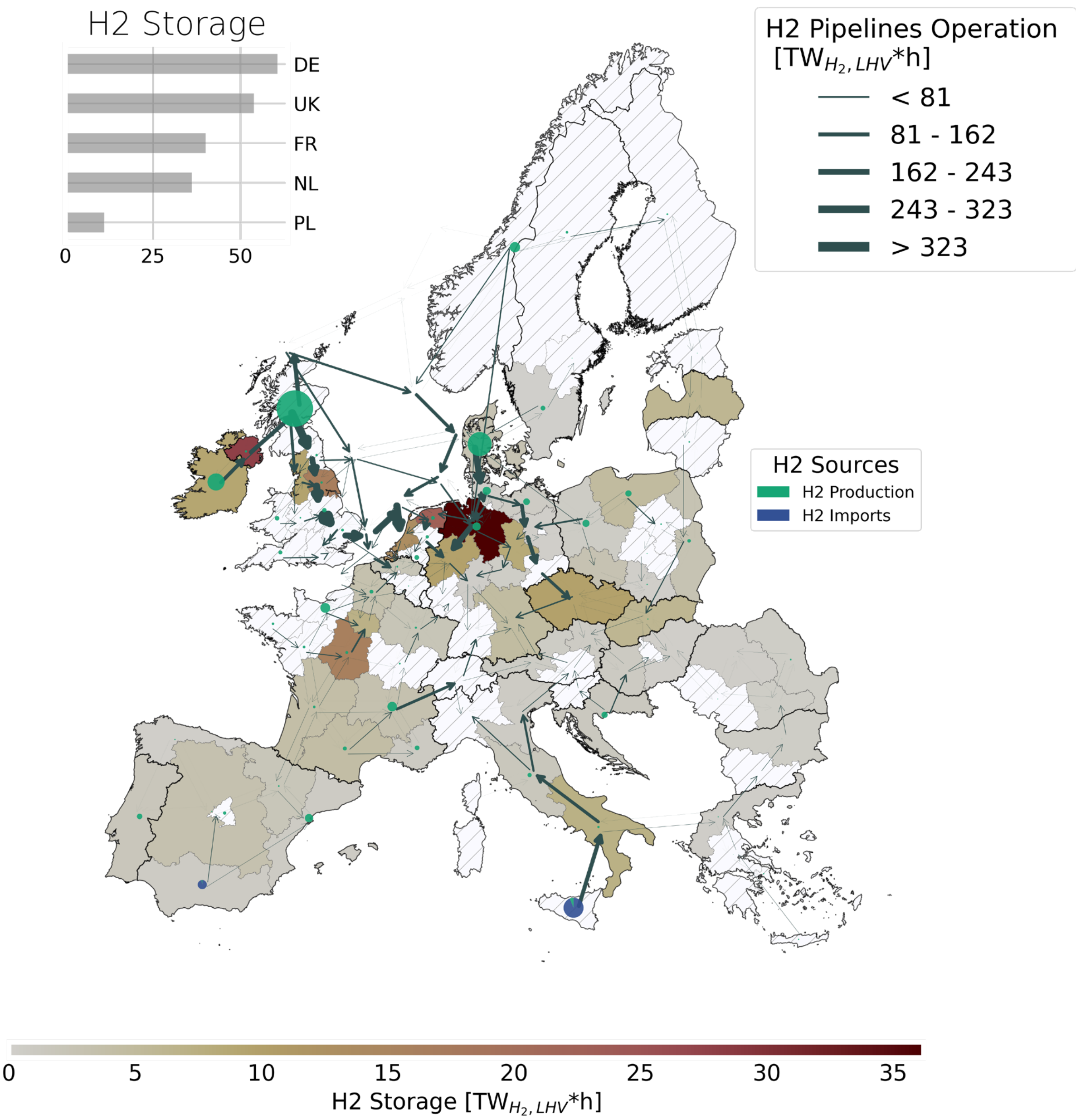

Figure 5-11 Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in the baseline scenario for 2050.

Hydrogen storage

The following section explores the significant role of large-scale UHS in the European energy landscape within the baseline scenarios as a crucial element for enhancing energy security, supply reliability and the transition towards a greenhouse gas neutral energy system. It seeks to offer a comprehensive perspective, addressing the fundamental research questions of UHS. This section serves as a foundational overview before the subsequent discussions on sensitivity scenarios (see Section 5.2).

Subsurface components

Figure 5-12 illustrates the evolution of optimal UHS capacity in the baseline scenarios spanning the period from 2030 to 2050. In 2030, the required hydrogen storage capacity stands at approximately 50 TWh and is primarily reliant on repurposed salt caverns. As the hydrogen demand rises substantially (as is shown in Figure 5-5), the need for storage capacity increases significantly by 2040, reaching ca. 160 TWh.

Salt caverns constitute roughly half of the total storage capacity in 2040. As the repurposed hydrogen cavern storage potential is almost exhausted, new cavern storage sites are developed, contributing an additional 20 TWh. Approximately 80 TWh of the total storage capacity in 2040 can be attributed to pore storage, primarily stemming from repurposed natural gas storage facilities. By 2050, the overall storage capacity further increases to around 260 TWh, with the augmented capacity mainly attributed to an increase in repurposed pore storage. Consequently, hydrogen pore storage in 2050 constitutes more than 60% of the optimal storage capacity.

By 2050, almost 100% of the existing salt cavern storage areas are converted into hydrogen storage facilities, as Figure 5-13 illustrates. At the same time, around 55% of the potential of

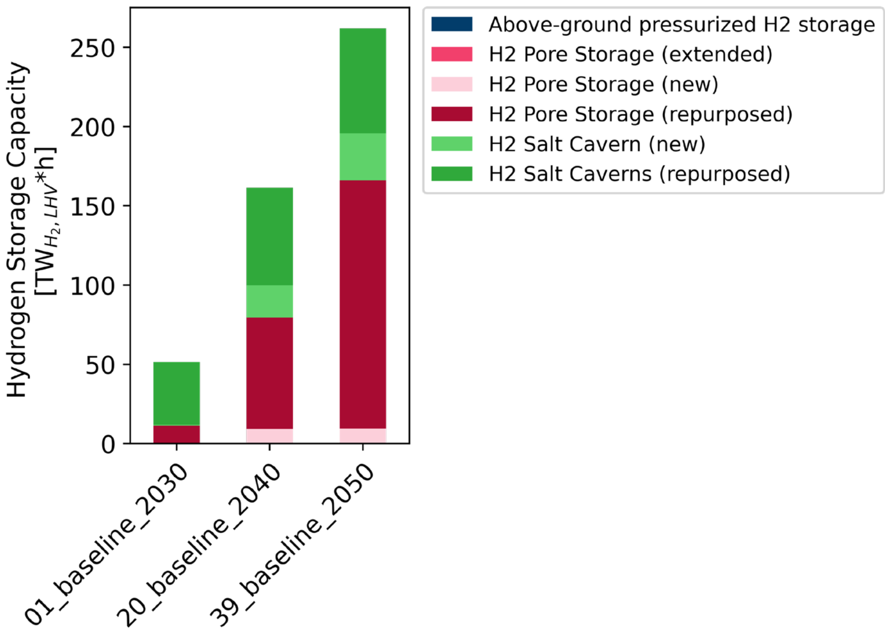

Figure 5-12. Hydrogen storage capacity in the baseline scenarios.

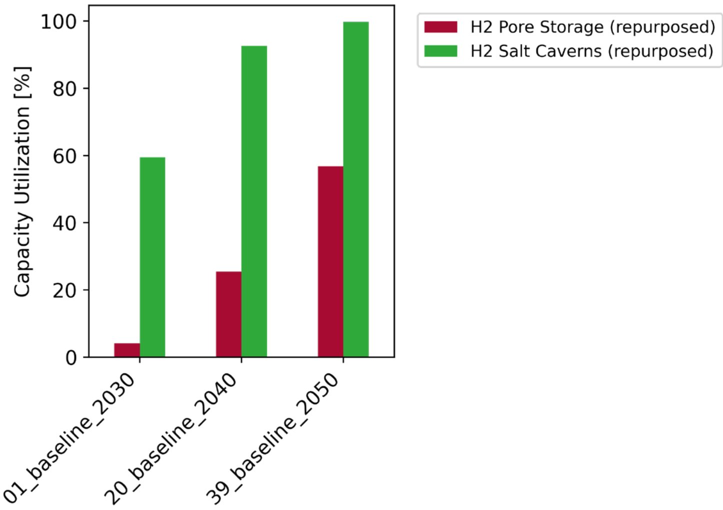

Figure 5-13. Utilization of available repurposed (subsurface) storage capacity for salt caverns and pore storage in the baseline scenarios.

the considered repurposed pore storages is utilized. This also explains the elevated capacity share of new salt caverns in Figure 5-12 which is built primarily in the UK. As the available capacity of re-assignable salt caverns is almost depleted in the UK, the model incorporates additional new salt cavern storage capacities.

In terms of storage operation, pore and cavern storage play different roles within the energy system. Figure 5-14 depicts the average annual storage cycles for pore and cavern storage mediums for different countries and target years. Pore storage sites demonstrate the lowest storage cycles, typically ranging from 1.5 to 2.3 cycles per year. In contrast, cavern storage sites are characterized by a larger number of storage cycles, varying from 2 to as 4.3 cycles annually.

The spread is even larger when comparing individual values for different countries (see Figure 9-42, Figure 9-43, and Figure 9-44). Here, some countries exhibit cavern storage cycles of up to 9. A total of 150 TWh of hydrogen is discharged from underground storage sites in 2030, as depicted in Figure 5-15. This represents roughly 28% of the annual hydrogen demand. In 2050, the discharged amount of hydrogen reaches a value of 750 TWh annually – corresponding to around 19% of the annual hydrogen demand.

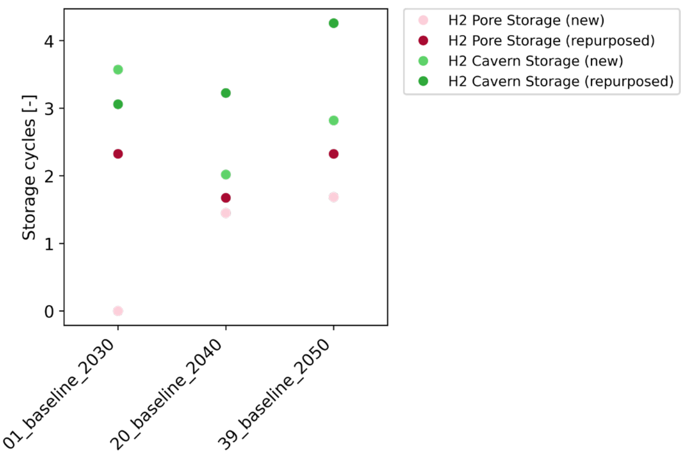

Figure 5-14. Average storage cycles across all regions for the different UHS storage options in the baseline scenarios.

Here, the larger numbers of storage cycles of repurposed cavern storage sites are reflected, as more hydrogen is discharged from cavern storage sites despite their lower overall capacity. This differentiation underscores the fact that pore storage sites predominantly function as seasonal solutions, whereas cavern storage facilities are primarily employed to manage shorter fluctuations of a sub-seasonal nature.

Annual storage levels can be found in Figure 5-22 as well as in the appendix. The effect of the different storage cycles, however, is less visible in this aggregated form. Fluctuations in salt cavern operation occur at a scale that cannot be captured by the figure.

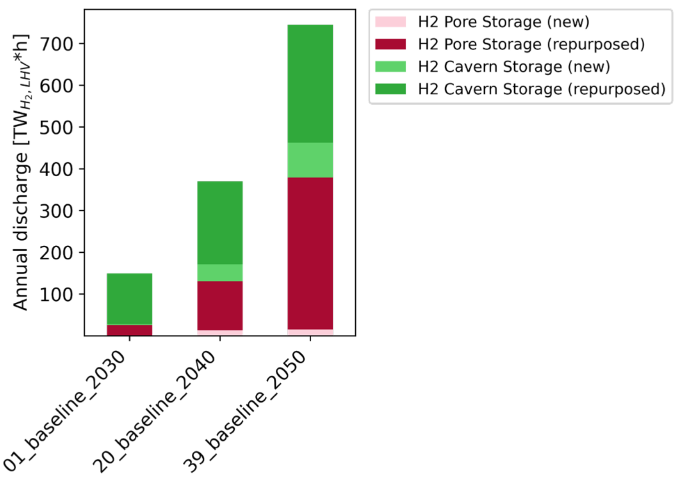

Figure 5-15. Annual discharge from UHS in the baseline scenarios.

Surface components

In terms of surface facility requirements, salt cavern storage areas exhibit higher withdrawal and injection capacities reflecting the higher observed storage cycles. Figure 5-16 depicts the total storage injection and withdrawal capacities across the baseline scenarios. In 2050, the required total injection capacity for cavern storage is 195 GW, and the total withdrawal capacity is 250 GW. At the same time, the injection capacity for pore storage is substantially lower, at 138 GW, and the withdrawal capacity is 120 GW. Notably, cavern storage sees higher withdrawal capacities, whereas pore storage sees higher injection capacities, reflecting the role of cavern storages as medium- and short-term buffers for hydrogen.

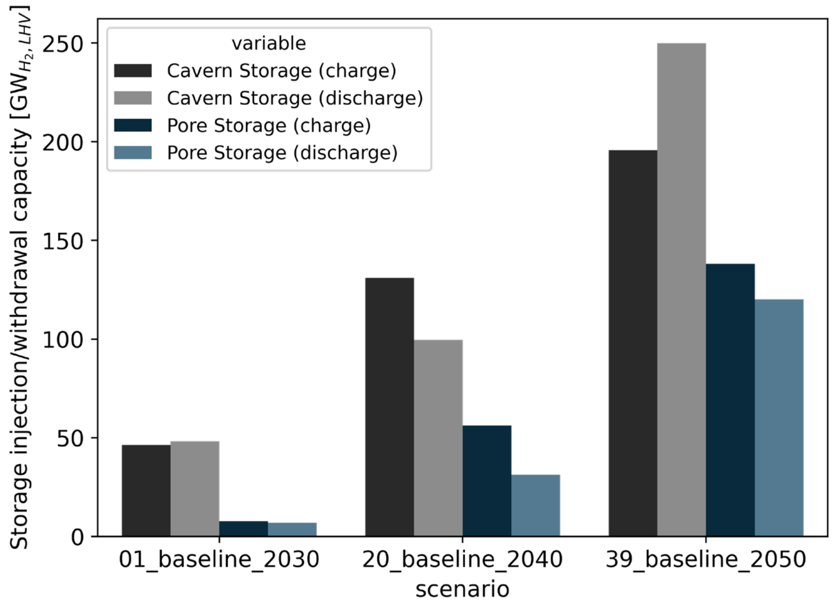

Figure 5-16. Total storage injection and withdrawal capacity in the baseline scenarios.

A more detailed overview is presented in Figure 5-17. Here, the withdrawal capacity as well as the storage capacity for 2050 are shown for every region. A linear relationship between the withdrawal and storage capacities can be identified. As already observed, cavern storage sites exhibit much higher withdrawal capacity per storage capacity than pore storages. Notably, several storage sites operate at the maximum withdrawal to storage capacity (see Section 3.2.4). Furthermore, most regions exhibit comparably small hydrogen storage capacities of up to 10 TWh and withdrawal capacities of up to 10 GW.

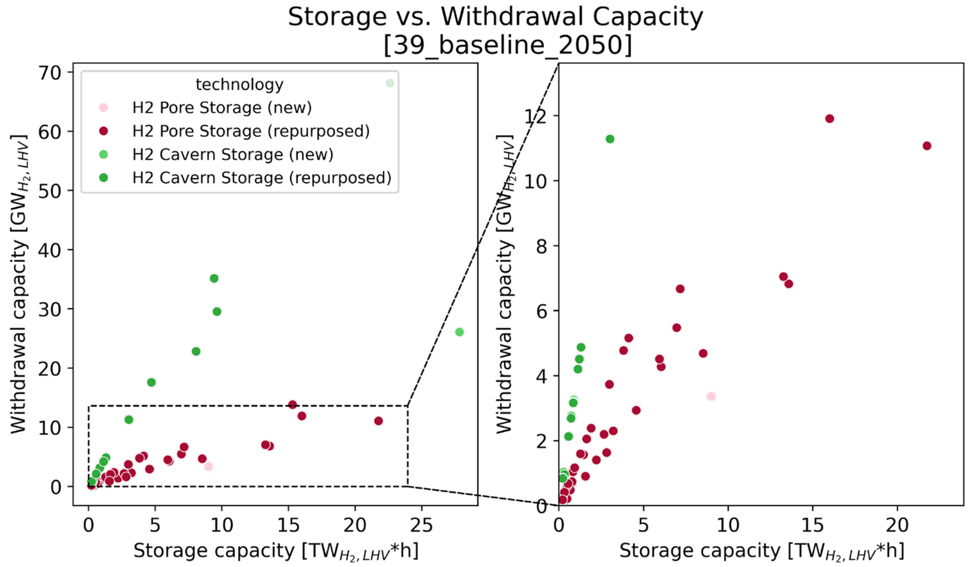

Figure 5-17. Storage capacity over withdrawal capacity per region in the baseline scenario for 2050. The right plot shows the enlargement of the dashed area.

UHS compared to other storage technologies

The main electricity storage option in the model is battery storage with 1120 GWh of storage capacity for the 2050 baseline scenario. The total storage capacity, including pumped hydro and reservoir storage is 1270 GWh and depicted in Figure 5-18. In comparison with UHS, with optimal capacities of 260 TWh, battery storage capacity is roughly 0.5% of the hydrogen storage capacity. The 1120 GWh of battery storage constitutes 0.02% of the electricity demand (4900 TWh), while the 260 TWh of hydrogen storage constitutes 6.5% of the annual hydrogen demand (4000 TWh). This emphasizes the distinct roles that battery and hydrogen storage play in the energy system. Figure 5-19 presents the electricity balance for a region in Italy during a summer week in 2050. Batteries are charged during periods of peak electricity surplus from PV during the day and discharged during periods of supply bottlenecks during evening hours, typically lasting only a few hours. In short, battery storage is mainly used as a short-term energy storage solution to cover intra-day fluctuations, rather than as a bulk and long-term energy storage option like hydrogen storage.

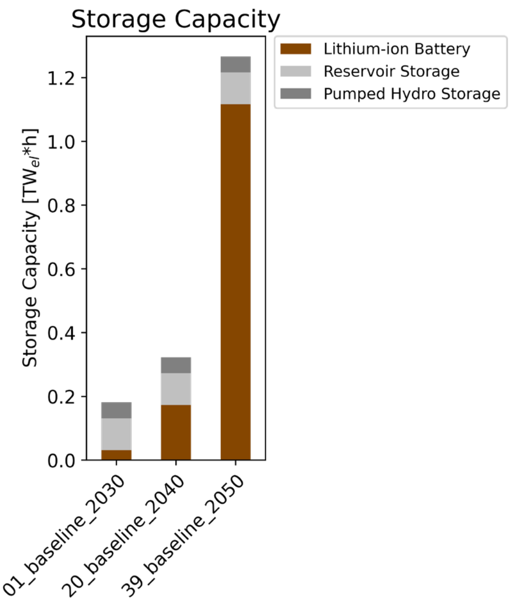

Figure 5-18. Electricity storage capacity in the baseline scenarios.

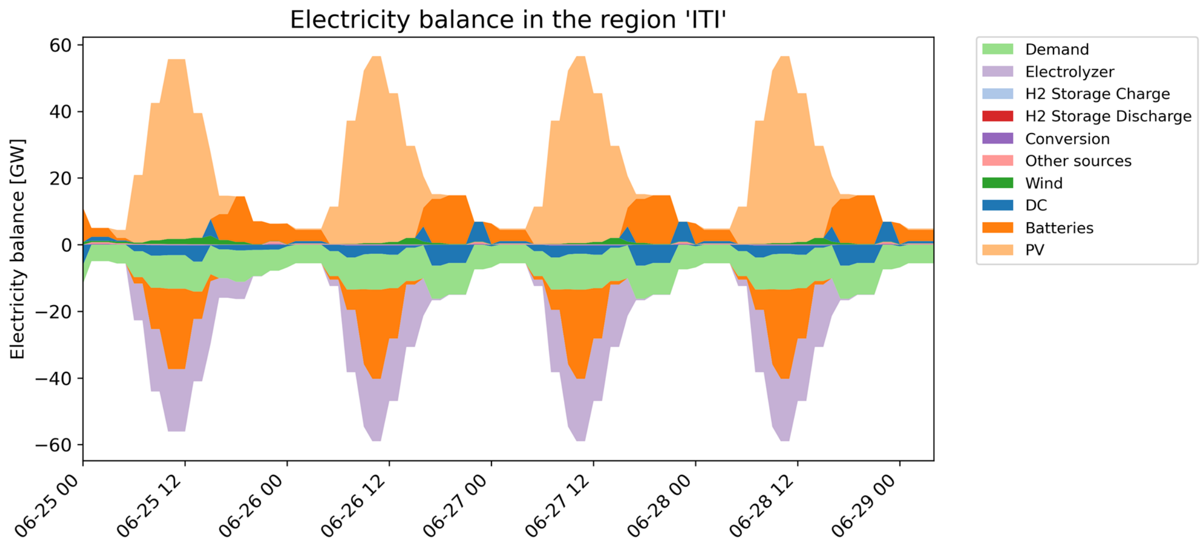

Figure 5-19. Electricity balance in an Italian region ("ITI") in a week during summer in the baseline scenario for 2050.

Cost contribution of underground hydrogen storage

The average cost contribution of the UHS components to the annual system costs is considerably low. In 2050, the overall contribution of hydrogen underground storage components is 2.4% (0.7% subsurface components, 1.7% surface components). It should be noted that the model dimensions the storage to minimize costs tailored to the given boundary conditions including, e.g., weather and cost parameters. There are no strategic or operational reserves included as additional constraints. The storage would have to be larger dimensioned to account for fluctuations in the weather conditions and corresponding changes in demand or for unforeseen operational disturbances. Due to the small cost contribution, it might therefore be advisable to strive for more than the optimized storage capacity.

Resulting UHS locations

In the previous section, the different roles of cavern and pore storage sites regarding operation were explored. Figure 5-20 and Figure 5-21 (figures for 2030 and 2050 can be found in the appendix: Figure 9-13–Figure 9-18) reveal the spatial evolution of optimal storage locations. First and foremost, these figures reveal the spatial differences between the two storage types. Due to their limited locational availability, most hydrogen salt cavern storage capacities are built in the UK and northern Germany. Most regions with the option for salt cavern storage capacity realize it to a certain extent. The picture is different for pore storage sites, which are available and used across Europe (see Figure 5-21).

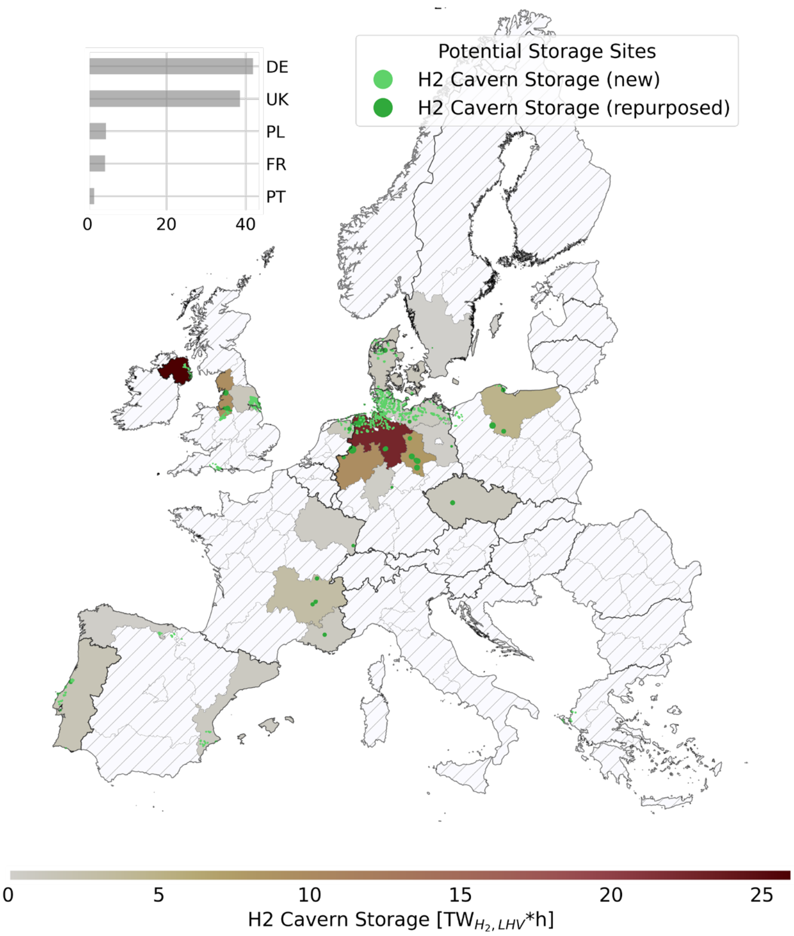

Figure 5-20. Map with resulting and potential hydrogen cavern storage capacity locations in the baseline scenario for 2050. The total storage capacity in caverns is 96 TWh of hydrogen.

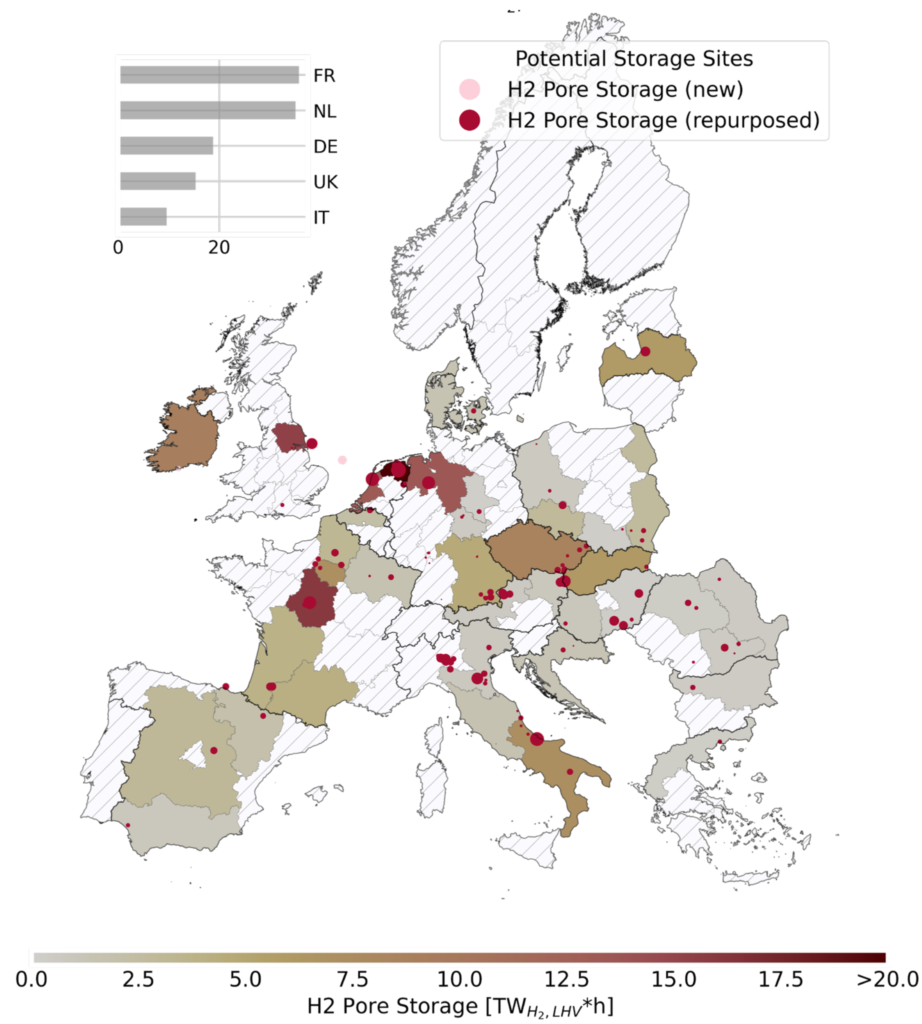

Figure 5-21. Map with resulting and potential pore storage locations in the baseline scenario for 2050. The total storage capacity in pore storages is 165 TWh of hydrogen.

In 2030, cavern storages are primarily realized in two countries, namely Germany and the UK. This capacity will be further expanded by 2040, with capacity in the UK more than doubling against 2030. In 2050 slightly more optimal capacity is needed, while the locations do not significantly change.

As already noted, pore storage sites mainly come into action after 2030. In 2040, most capacity is realized in the Netherlands. Further locations include eastern European Countries, Germany, the UK, and Ireland. By 2050, notable new capacity additions are located throughout all of Europe including France, southern Germany and Italy. By 2050, all countries with available pore storage potential develop it to some extent, leading to a more homogenous distribution of storage across Europe, with the most storage capacity needed in the Netherlands and France.

Figure 5-12 reveals that repurposed cavern storage is preferred by the model due to its lower costs. Once this potential has been depleted, natural gas pore storage sites will be repurposed. Exceptions include locations in the UK where the model selects to build new salt cavern storages. Figure 9-35 in the appendix reveals that the utilization of the repurposed pore storage potential is not evenly spread throughout Europe. In many countries, such as the UK, the Netherlands, Belgium, France, Spain, Greece, and Poland, the available convertible pore storage potential is fully utilized by 2050. Austria and Italy, which have comparably high potentials for repurposed hydrogen pore storage, only utilize around 20% of their available potential.

Relationship between hydrogen storage, production, and demand

Although the differences between cavern and pore storage along with their optimal locations are highlighted, the question of optimal UHS locations with respect to hydrogen demand centers and production sites is explored in the following. The role of the hydrogen grid as bulk hydrogen transport option and tool to balance supply and demand has been already discussed. However, the resulting benefits are only realizable by utilizing storage and vice versa.

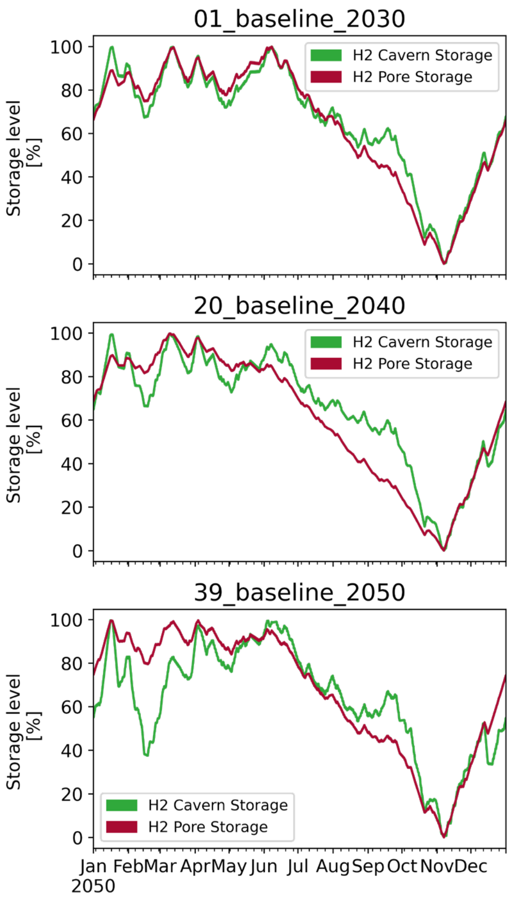

Figure 5-22. Aggregated storage levels in % throughout the year for pore and cavern storage in the baseline scenarios.

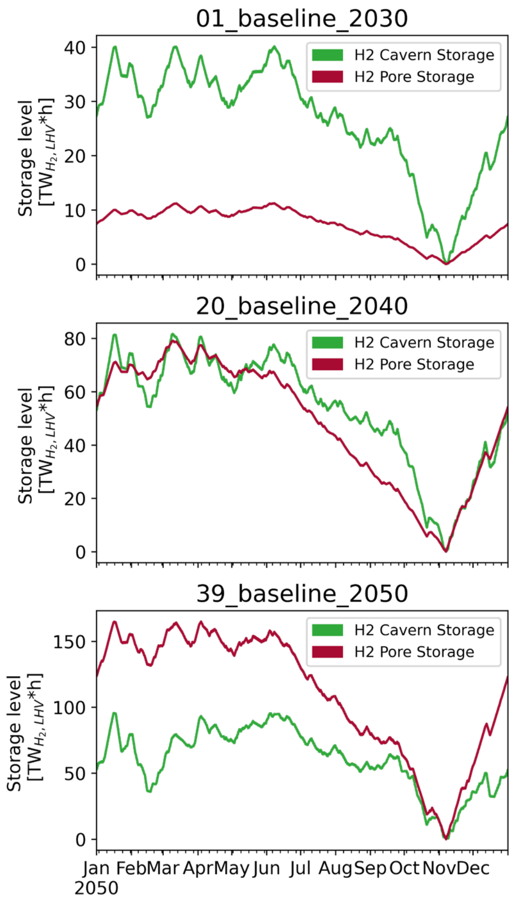

Figure 5-23. Aggregated absolute storage levels throughout the year for pore and cavern storage in the baseline scenarios.

The overall storage profiles in Figure 5-22 and Figure 5-23 provide an indication of the task of underground storage. In general, UHS will be needed to bridge seasonal fluctuations in production. In the baseline scenarios, the hydrogen storage sites are almost full in the first half of the year. Starting in June, they gradually empty until November. For the last two months of the year, a steep increase in storage levels can be observed.

From November until the end of January, storage levels increase from around 0 to almost 100% filling levels. As hydrogen demand is assumed to be constant throughout the year, these seasonal fluctuations can be attributed to fluctuations in the production of hydrogen. In the winter months, more electricity and the resulting hydrogen is generated by wind turbines, which is used to fill the storage sites and bridge the summer and fall months in which hydrogen production cannot meet demand. During periods of surplus generation, the hydrogen grid is used to continuously transport the hydrogen from the production sites to the storage ones.

During deficit production times, hydrogen storage sites are utilized to discharge hydrogen and supply demand centers via the hydrogen grid. It should be noted that for these baseline scenario results the weather year 2015 was used. However, the observed hydrogen storage and production characteristics highly depend on the weather conditions. A further analysis of this sensitivity is therefore conducted in Chapter 5.2. From Figure 5-22, it is evident that UHS not only covers seasonal fluctuations but also weekly or daily ones in production.

With regard to the optimal storage location, hydrogen storage is observed to be placed along hydrogen transit routes. A prominent example for this is given in Figure 5-24 and Figure 5-25 for weekly periods during summer and winter. Here, the hydrogen flows for Northern Ireland are shown. In this region, large amounts of storage capacity are realized. Furthermore, it is used as a transit region to transport hydrogen produced in Ireland to the UK. During winter, hydrogen being produced in Ireland is imported and stored underground. In the summer, during periods of general hydrogen supply deficit, the stored hydrogen is discharged and transported along the hydrogen transit routes to the demand centers. In this way, the utilization of the hydrogen grid is ensured for the whole year.

All further decision factors are only based on cost competition between the elements of the hydrogen supply chain. Where to build storage along the supply chain is solely based on the interplay between operational and economic factors.

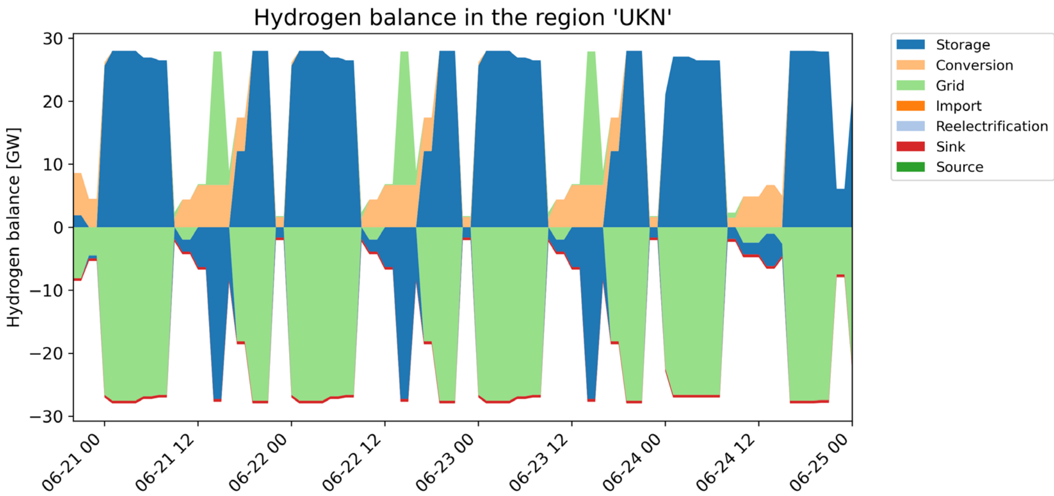

Figure 5-24. Hydrogen balance for Northern Ireland (“UKN”) in the baseline scenario for 2050 during a week in the summer.

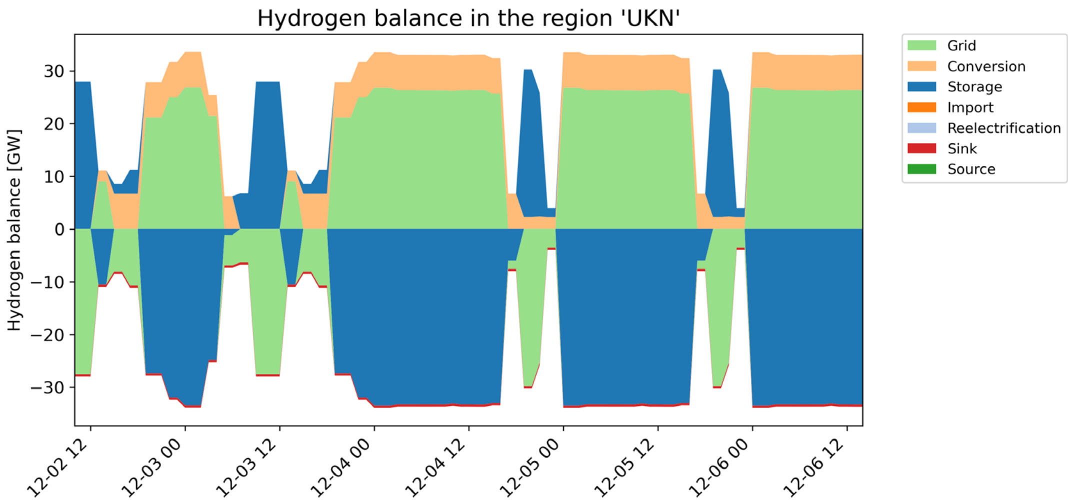

Figure 5-25. Hydrogen balance for Northern Ireland ("UKN") in the baseline scenario for 2050 during a week in the winter.

Figure 5-26 shows the pore storage level profiles in Spain, Italy, and Ireland together with the share of PV and wind for the 2050 baseline scenario. The overall storage profiles for the three countries do not differ significantly, i.e., all storages are empty in November, which is attributable to the balancing of the hydrogen pipeline grid. However, notable differences can be observed depending on the share of PV and wind. The profile for Ireland with the largest share of wind is much smoother than the other profiles, with less weekly or monthly fluctuations. The higher the share of PV in the country, the more fluctuations are observable in the storage profile. This can be attributed to the higher variability in PV based electricity which generally exhibits clear fluctuations during a day with peak generation during the day and no generation during the night. Further notable is the period during May and the end of June, where the storages in Spain and Italy are filled, suggesting that during this time hydrogen is produced from surplus PV electricity.

In summary, while the overall trend of storage levels appears to be independent of the proportion of PV and wind due to the strong interconnections of the regions via the hydrogen transmission grid, significant variations can be observed in the intra-seasonal operation of hydrogen storage, depending on the proportion of PV and wind.

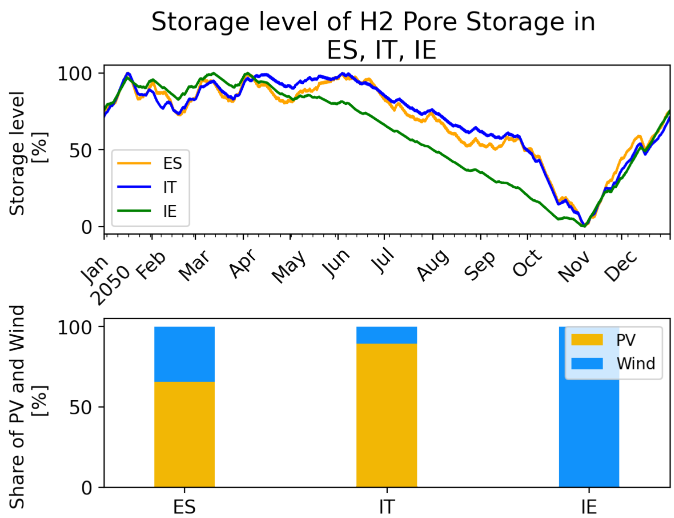

Figure 5-26 Storage level profiles in % in Spain, Italy, and Ireland for the baseline scenario for 2050.

Conclusions from the baseline scenarios

The baseline scenarios project a significant increase in renewable capacities, with onshore wind emerging as the primary source, accounting for a substantial share of electricity generation by 2050. The transition towards renewable energy is accompanied by the phased-out use of fossil-based sources, aligning with established emission limits.

The hydrogen sector, which is closely interwoven with the energy system model, shows a decentralized hydrogen production approach based mainly on electrolysis and wind turbines. The spatial distribution of hydrogen production and demand centers, coupled with an evolving hydrogen grid, underlines the intricate interplay between regions. Notably, countries such as the UK, Norway, Denmark, Ireland, and Sweden emerge as hydrogen exporters, whereas Germany, the Netherlands, and Belgium adopt a hybrid approach in which domestic production is supplemented by imports from other countries.

Furthermore, the spatial distribution of optimal storage locations reveals a strategic placement along hydrogen transit routes, ensuring efficient transport from production centers to demand ones. Notably, cavern storage sites in the UK and northern Germany will play a pivotal role, particularly due to their lower costs, whereas hydrogen storage in pore storages will become increasingly relevant after 2030, with notable capacity expansions in the Netherlands, France, Italy, and southern Germany by 2050. Despite the low cost contribution of 2.4% to annual system costs in 2050, it is noted that real-world implementations may require larger capacities for operational resilience.

In conclusion, this study affirms that hydrogen storage, both in caverns and porous reservoirs, will play a pivotal role in balancing the supply and demand dynamics of the evolving European energy system. As hydrogen continues to gain prominence in the energy transition, the findings underscore the importance of strategic planning for storage infrastructure.

Chapter 5.2 will further explore potential impacts regarding the scale and timing of UHS implementation.

5.2 Sensitivity scenarios

In the following, the results on the sensitivity scenarios will be presented. Section 5.2.1 investigates the impact of different levels of hydrogen demand on the UHS capacity; section 5.2.2 explores the role of different techno-economic parameter assumptions; section 5.2.3 investigates the role of pore storage; section 5.2.4 investigates the impact of the assumed weather year on the required storage capacities; and section 5.2.5 examines the optimal storage capacities with regard to additional restrictions. The comparison of the results on the hydrogen storage capacities for all of the considered scenarios can be seen in Figure 9-2–Figure 9-4 in appendix.

5.2.1 Hydrogen demand

The hydrogen demand sensitivities investigate the impact of different hydrogen demand scenarios (“baseline”, “reduced” and “ambitious” from D1.2 (Groß et al., 2022)) on the optimal UHS capacity. Figure 5-27 reveals an almost linear relationship between demand and total UHS capacity within the same target year. An increase in demand results in an increase in the necessary UHS capacity. Figure 5-27 also shows that this is not necessarily true for the

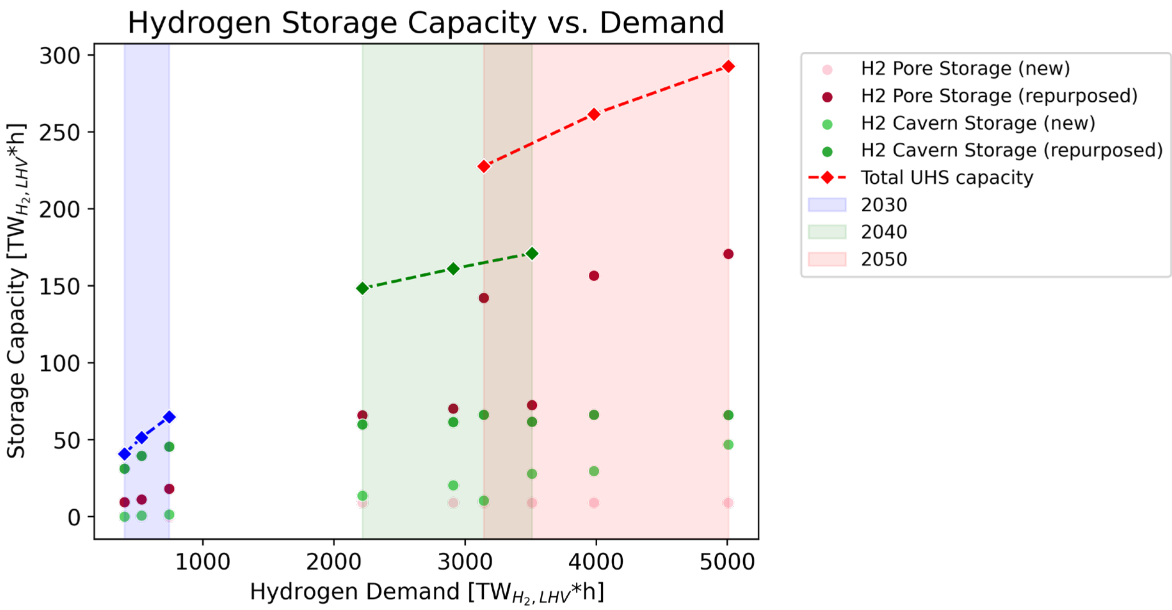

Figure 5-27. Hydrogen storage capacity over the hydrogen demand for the different UHS options in the demand sensitivities.

individual storage technologies. In different demand scenarios, the total UHS capacities range from 41 to 64 TWh in 2030. For 2050, the total storage capacities range from 228 to 293 TWh. When comparing the spatial distribution of pore storages in 2050 for the *baseline* and *ambitious* demand scenarios the locations do not differ significantly as shown in Figure 5-28, Figure 9-32 and Figure 9-18. A slight increase in optimal storage capacities can mainly be observed in southern Germany, Italy, and Slovakia.

Figure 5-29 reveals that most of the additional hydrogen demand is covered by additional extra-European imports imported via Italy. In summary, a linear relationship between hydrogen underground storage demand and hydrogen demand with no significant change in storage locations can be observed.

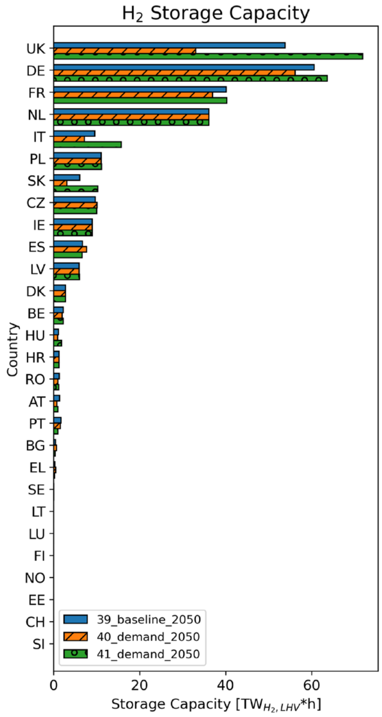

Figure 5-28. Underground hydrogen storage capacity in the demand sensitivity scenarios in 2050.

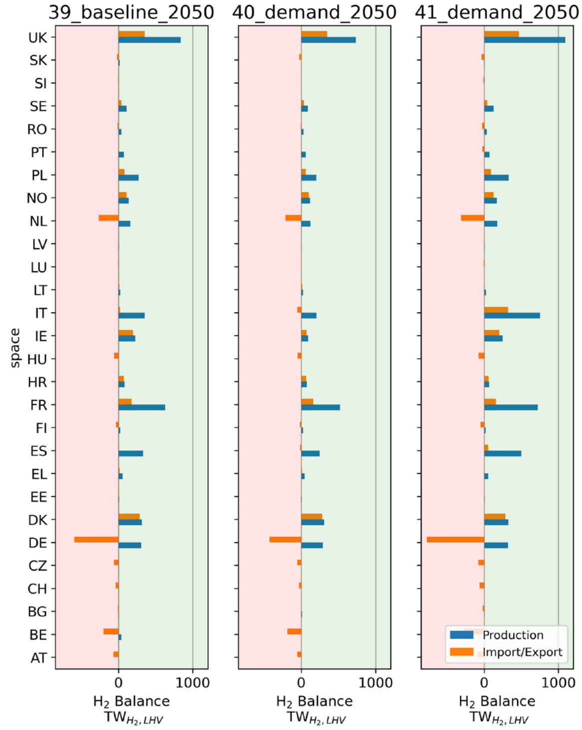

Figure 5-29. Intra-European hydrogen imports and exports per country in the demand sensitivity scenarios in 2050.

5.2.2 Impact of different costs

The impact of varying cost assumptions on the optimal storage capacity is depicted in Figure 5-30. The different costs scenarios correspond to the different techno-economic parameters from D7.1 as described in Chapter 4.2. Both the total storage capacity and the distribution between pore and cavern storage are notably influenced by the chosen techno-economic cost scenario.

It is crucial to acknowledge that alterations in cost scenarios not only consider storage costs but also affect the costs associated with various storage technologies, consequently leading to diverse energy system configurations. Due to the large variety of observed system configurations, only the main results with an impact on underground storage are pointed out in the following. Figure 5-30 shows the range of optimal hydrogen storage capacities obtained for the different cost scenarios ranging from 166 to 261 TWh for the year 2050.

The 2030 and 2040 “pessimistic” cost scenarios see a notable increase in electricity production from conventional power plants (see Figure 5-32) which leads to a strong decrease in optimal storage capacity. In 2030 the required storage capacity is almost zero while in 2040 it more than halves. Given these low storage capacities it cannot be ruled out that a portion of hydrogen is produced from electricity from conventional power plants.
The 2050 “pessimistic” scenario foresees an increase in hydrogen imports from North-Africa and a higher storage capacity for pore storages in Austria, Bulgaria, and Slovakia.

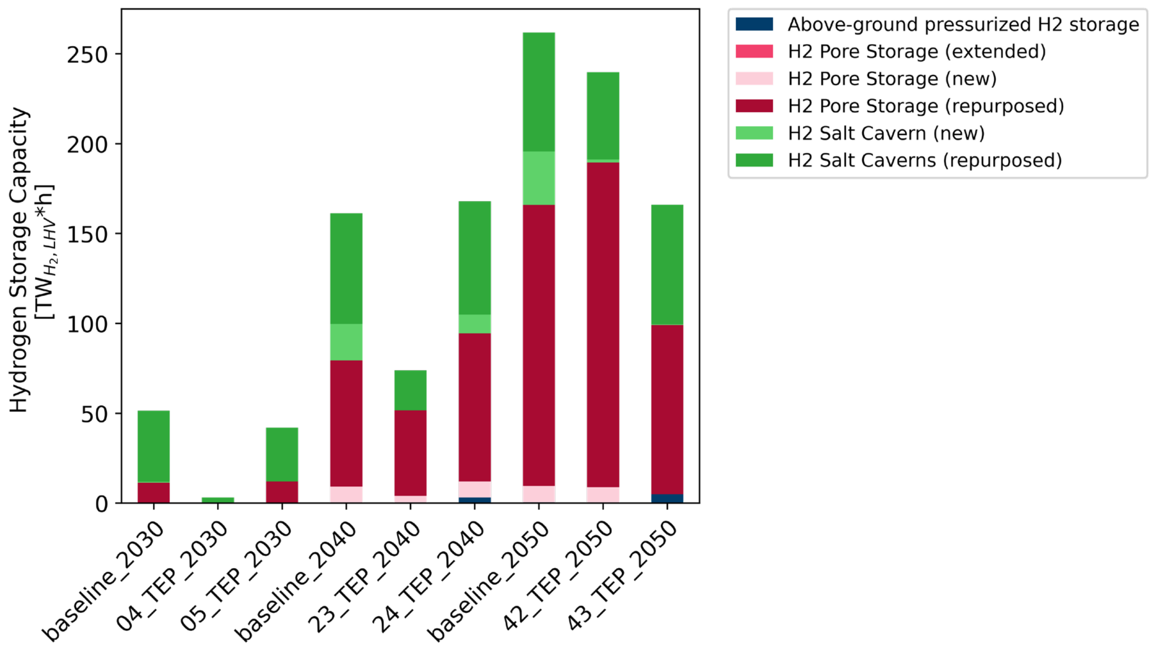

Figure 5-30. Optimal hydrogen storage capacity for the cost sensitivity scenarios in 2030, 2040, and 2050. The scenarios 04_2030_TEP, 22_2040_TEP, and 42_2050_TEP refer to the "pessimistic" cost assumptions scenario; the scenarios 05_2030_TEP, 23_2040_TEP, and 43_2050_TEP refer to the "optimistic" cost assumptions scenario. See also Table 1.

A large effect on the energy system can be observed in the 2050 "optimistic" scenario. PV and wind offshore electricity generation increase significantly. The large share of PV in the system leads to 125 TWh of hydrogen re-electrification. The large share of PV impacts the optimal storage capacity as well as storage operation as shown in Figure 5-30, Figure 5-35 and Figure 5-36. The optimal storage capacity is reduced from 260 to 166 TWh. A notable change in the storage levels can be observed (see Figure 5-35 and Figure 5-36). In the optimistic cost scenario, the storage is filled from March to October as well as from November to February and emptied during a short period in February. This reveals the significant impact of the share of PV and wind on the resulting storage operation. Due to the increased share of PV, more hydrogen is generated from surplus PV-based electricity in the spring and summer months leading to a gradual increase in storage levels.

Figure 5-33 reveals that most of the hydrogen from PV is produced in Italy and Spain, leading to the emergence of a strong South-North hydrogen corridor. Here Spain emerges as the second largest producer of hydrogen with similar production amounts to the UK (1050 TWh). It further becomes the largest hydrogen exporter. Italy becomes third largest hydrogen producer with around 470 TWh produced annually while using most of the produced hydrogen domestically. Notably, an increase in the hydrogen storage capacities along the South-North corridors can be observed. Most pore storage capacities are realized in France and Italy as shown in Figure 5-34. Furthermore, due to the diminished amount of hydrogen transported from the UK, the optimal storage capacities in Ireland, the UK and the Netherlands are reduced significantly.

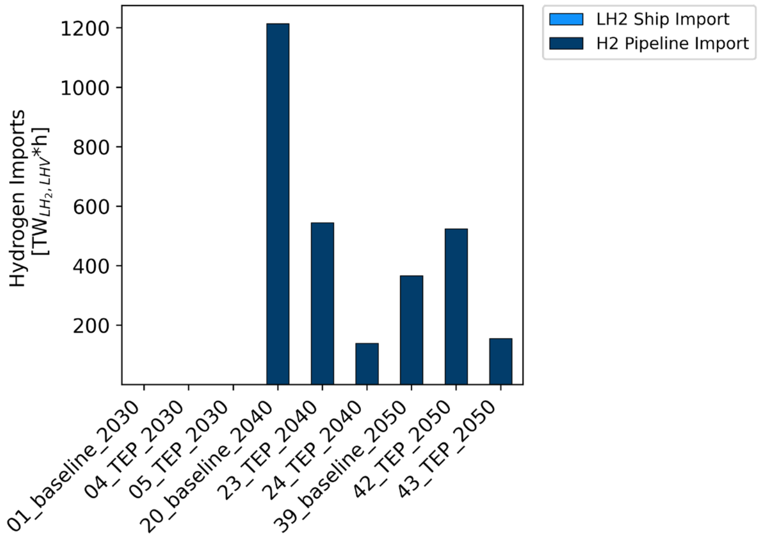

Figure 5-31. Hydrogen imports into Europe in the cost sensitivity scenarios. The scenarios 04_2030_TEP, 22_2040_TEP, and 42_2050_TEP refer to the "pessimistic" cost assumptions scenario; the scenarios 05_2030_TEP, 23_2040_TEP, and 43_2050_TEP refer to the "optimistic" cost assumptions scenario. See also Table 1.

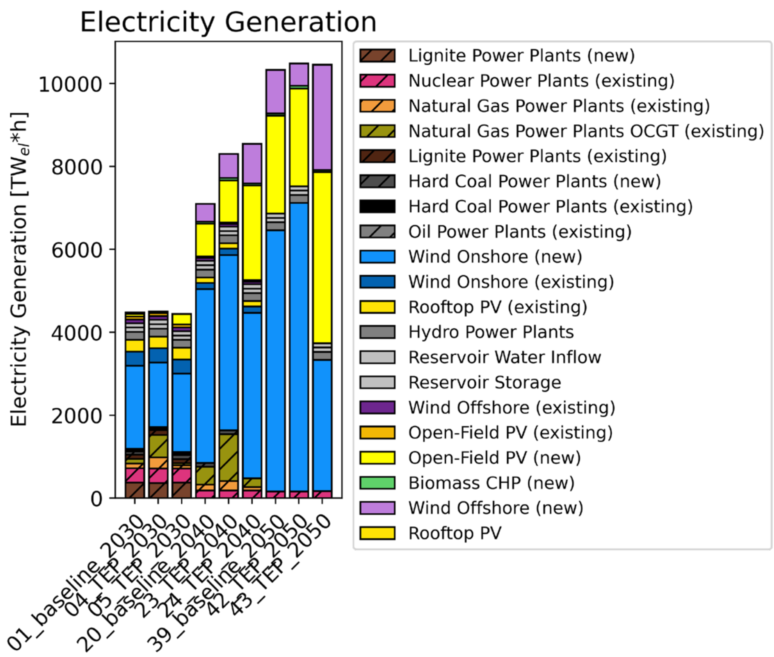

Figure 5-32. Electricity generation in the cost sensitivity scenarios for 2030, 2040 and 2050. The scenarios 04_2030_TEP, 22_2040_TEP, and 42_2050_TEP refer to the "pessimistic" cost assumptions scenario; the scenarios 05_2030_TEP, 23_2040_TEP, and 43_2050_TEP refer to the "optimistic" cost assumptions scenario Table 1.

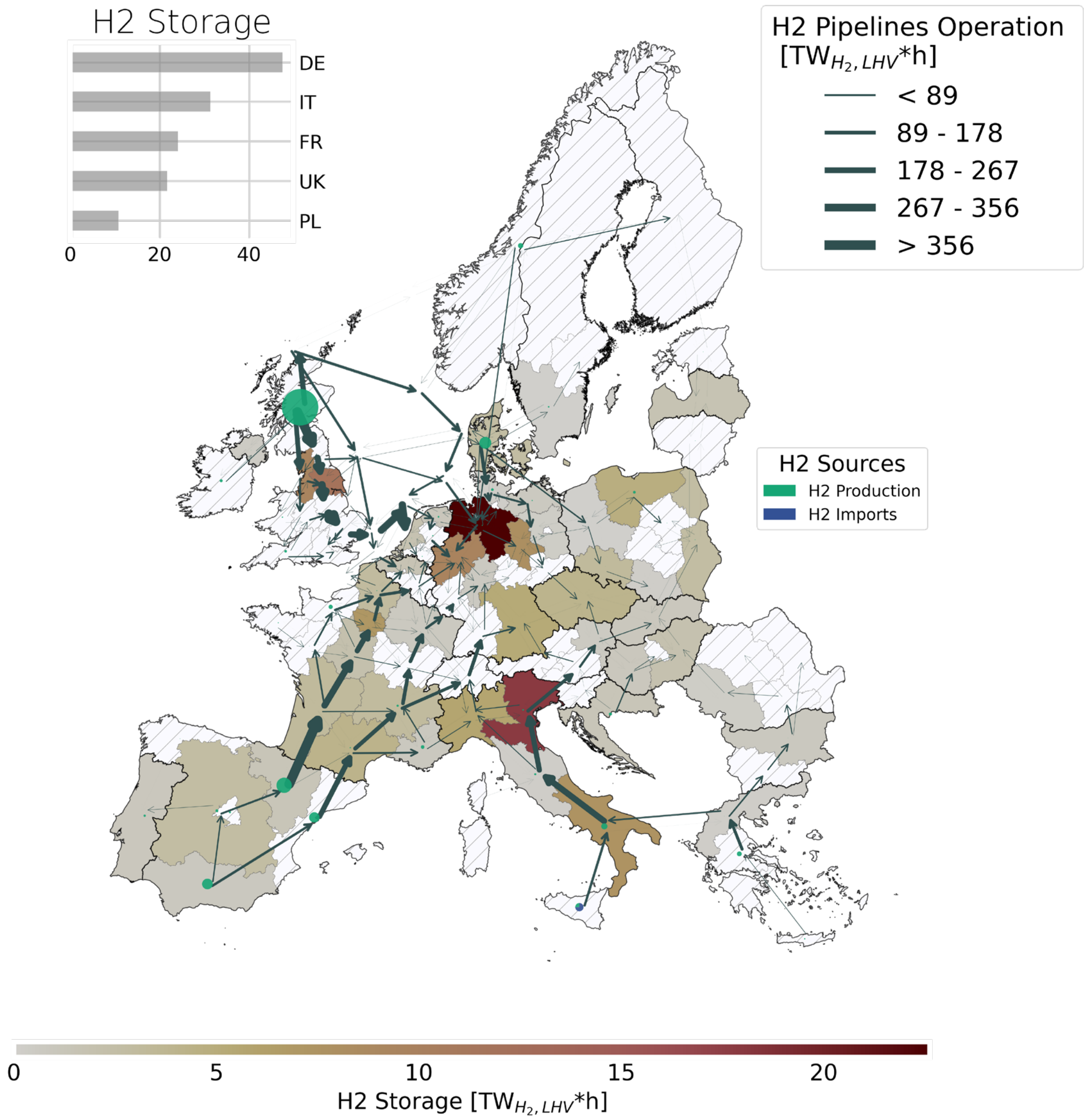

Figure 5-33. Hydrogen transmission, hydrogen storage capacity, and hydrogen production locations in the 2050 “optimistic” costs scenario.

The pessimistic scenarios of the years 2030 and 2040 in Figure 5-30 reveal, that a larger share of conventional power plants can also significantly impact the optimal storage capacity.
The reason for this can be illustrated at the example of Spain. The baseline scenarios foresee a large share of hydrogen imports. As a result, electricity generation capacities within Spain are lower than without imports. Additional necessary hydrogen is produced primarily during periods of surplus electricity generation, particularly from photovoltaic (PV) sources during the daytime resulting in daily production patterns. Furthermore, due to the lower generation capacity, hydrogen production is more sensitive to both seasonal and daily fluctuations in electricity generation. As a result, hydrogen storage is necessary to balance periods of deficit and surplus generation.

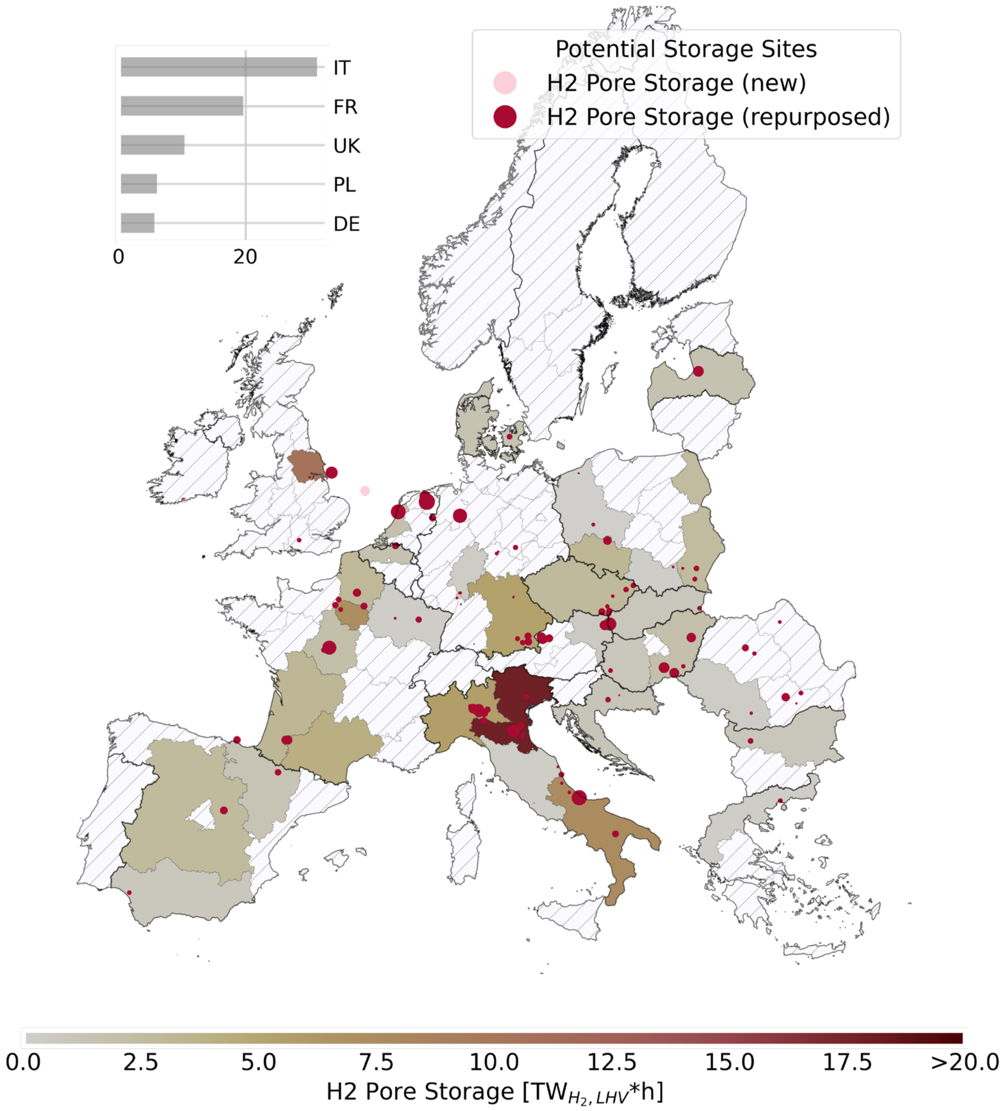

Figure 5-34. Hydrogen pore storage capacity in the "optimistic" costs scenario in 2050. In total, 94 TWh of storage capacity for hydrogen are installed.

In the pessimistic scenario, less imports are used. Consequently, a higher share of generation capacity, particularly PV and conventional power plants in the form of gas-fired power plants, is observed in Spain. Flexible conventional power plants are used to cover electricity demand during the evening hours while the RES generation is reduced. As a result, hydrogen production can be produced almost constantly instead of being decreased due to missing electricity, reducing the hydrogen storage capacity in Spain to almost zero. It should be noted that during some periods, especially when both wind and PV generation is low, hydrogen is also produced in parts with electricity originating from conventional power plants.

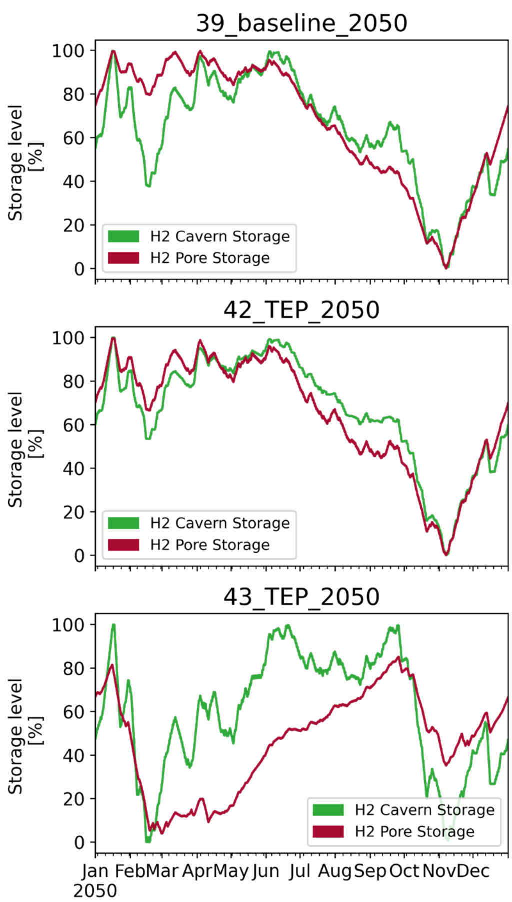

Figure 5-35. Aggregated storage levels in % throughout the year for pore and cavern storage in the baseline and the cost sensitivity scenarios.

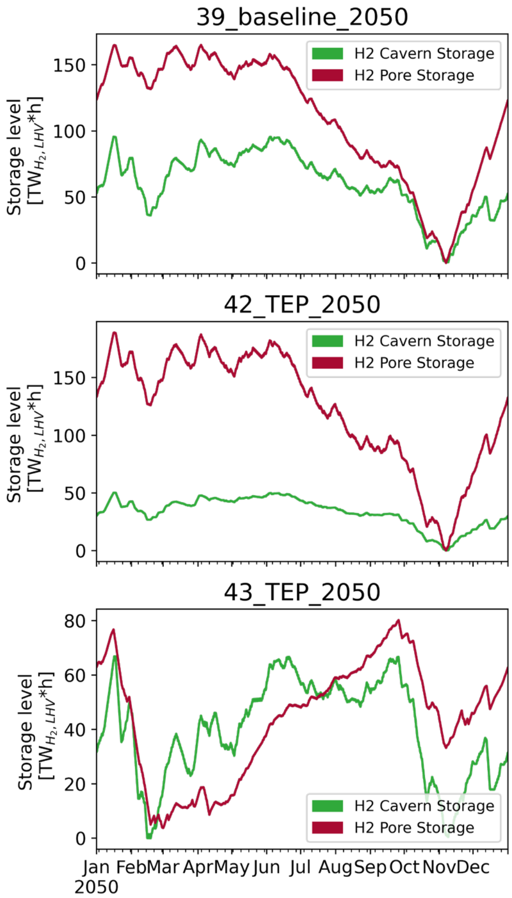

Figure 5-36. Aggregated absolute storage levels throughout the year for pore and cavern storage in the baseline scenarios and the cost sensitivity scenarios.

In conclusion, the optimal energy system configuration is significantly influenced by cost assumptions which leads to considerable fluctuations in storage requirements for various reasons. Conventional power plants significantly reduce the required storage capacity due to their flexibility. An increase in PV in the system leads to more PV-based hydrogen production. Consequently, storage operation, optimal storage locations and hydrogen corridors change significantly.

5.2.3 Value of pore storage

In this scenario dimension, the value of pore storage is examined by comparing against scenarios in which pore storage is not or only partially available. Optimal hydrogen storage capacity is shown in Figure 5-37 for the target year of 2050. The optimal UHS capacity does not change as significantly as in previous sensitivity scenarios (see, e.g., Figure 5-30). The total capacities in the scenarios considered here are between 250 and 260 TWh.

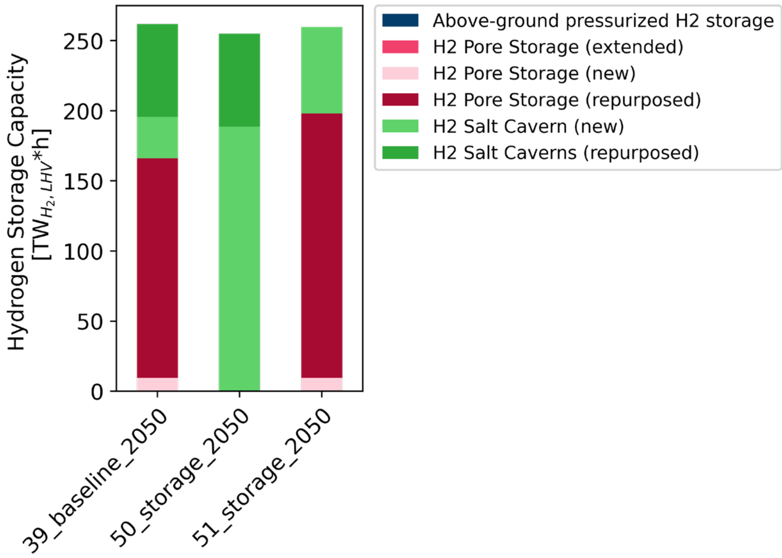

Figure 5-37. Hydrogen storage capacity in the value of pore storage scenarios for 2050. In scenario 52_2050_storage, new pore storage capacities cannot be installed; in scenario 53_2050_storage, pore storage is not available for hydrogen storage. See also Table 1.

Prohibiting pore storage does not change the optimal storage capacity. Missing pore storage capacity is covered by additional new salt cavern capacity. Similarly prohibiting repurposed salt cavern storage does not either. We find that the impact on the other components of the energy system is marginal. The electricity mix does not change, nor do the hydrogen production locations or the observed hydrogen corridors. When pore storage is prohibited, UHS locations become more centralized due to the locational restriction of available cavern storage capacities. No significant impact on the resulting hydrogen grid can be observed. This can be explained by the fact that the amount of hydrogen being stored is comparably low to the overall production. Since the hydrogen grid is sized to meet bulk transport demand, fluctuations that require charge and discharge from storage sites are comparably low and can be handled by the grid without any grid expansion. In both restrictive cases, the total annual costs marginally increase by the same magnitude to about 0.4%.

The results suggest that, based on the model assumptions made here, pore storage facilities as well as repurposed cavern storage are not essential for the European energy system and only lead to cost reductions of about 0.4%. Rather, the existence of a certain amount of bulk hydrogen storage is of importance. However, the implementation of pore storage enables more distributed UHS across Europe, enabling most countries to establish their own underground storage facilities. This decentralized approach contributes to enhanced resilience and accessibility within the hydrogen storage infrastructure.
Finally, the results suggest that if a pronounced hydrogen grid is developed, the siting of storage capacity, e.g. due to pore storage not being available, does not have a significant impact on the overall system costs.

5.2.4 Impact of weather

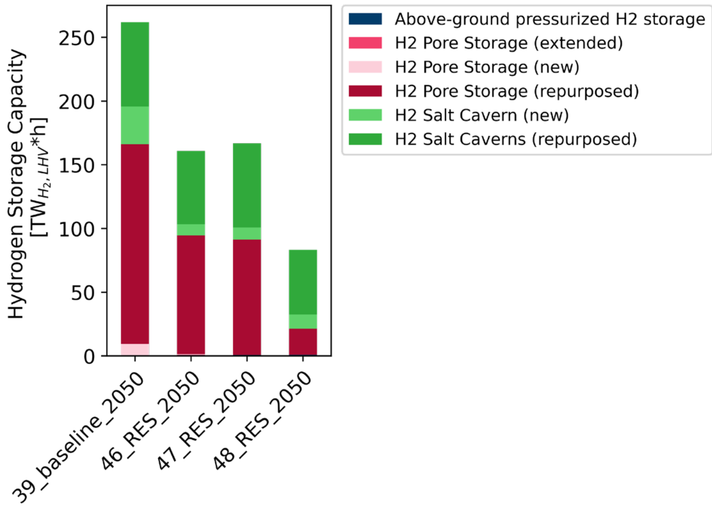

Figure 5-38. Hydrogen storage capacity in the 2050 weather scenarios. For information on scenario descriptions see Table 1.

The following investigates the impact of the weather years on renewable power generation and consequently the storage demand. Three additional different weather years are considered. The resulting optimal UHS capacities for 2050 are given in Figure 5-38. The baseline scenario with the weather year 2015 exhibits the highest optimal storage capacity. Here, an optimal storage capacity of 260 TWh can be observed, whereas for the weather year 2016 (scenario name: *48_2050_RES*) an optimal storage capacity of around 83 TWh is shown.
Notably, all other weather years exhibit higher hydrogen imports ranging from 1000 to 1400 TWh, which can further contribute to the lower required storage capacity since constant imports and a constant hydrogen demand is assumed in the model.

It should be noted that the needed storage capacity is predominantly determined by the deficit or surplus of residual electricity that can be used for hydrogen production on which the weather conditions have a significant impact.
This is explained by two extreme example cases. In the first, surplus residual electricity occurs mostly in two consecutive months in the wintertime, whereas for the rest of the year, deficit residual electricity is observed. The resulting storage capacity must be dimensioned in such a way that most of the residual electricity can be converted during these months and stored underground to cover the times of deficit residual electricity. This necessitates a comparably high hydrogen storage capacity. In the second, a constant surplus of residual electricity throughout the entire year is observed that is sufficient to cover the hydrogen demand. Here, the resulting necessary hydrogen storage capacity will be marginal.

In a less extreme way, this can also be observed in the different weather year scenarios 2015, 2018 and 2016. It should be noted that 2018 and 2016 have similar amounts of hydrogen imports and are therefore more directly comparable. In 2015, the summer is characterized by constant deficit residual electricity followed by a winter with very high surplus residual electricity generation. In 2018 (scenario name: *46_2050_RES*) a similar but less extreme surplus period can be observed. In 2016 (scenario name: *48_2050_RES*), significant fluctuations can be observed throughout the year in the cavern storage profiles while the pore storage exhibits a smoother seasonal pattern. Due to the surplus electricity being spread over the year in 2016

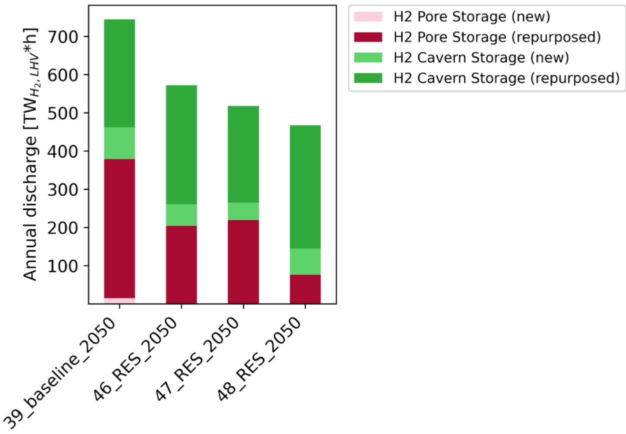

Figure 5-39. Annual discharges in the weather scenarios in 2050. For information on scenario descriptions see Table 1.

compared to the more concentrated periods in 2015 and 2018, this leads to a reduction in hydrogen storage capacity needs. Notably due to the higher fluctuations within the year, the weather years 2018 and 2016 exhibit higher storage cycles (see Figure 5-40). The respective storage levels for the different weather year scenarios are given in Figure 5-41 and Figure 5-42. The total annual discharge for the scenarios with similar imports (*46_RES_2050* and *48_RES_2050*) do not change significantly. This illustrates that the annual discharge is also determined by the intra-seasonal fluctuations in production.

The results show that optimal storage capacity is significantly influenced by the weather conditions for two reasons. First, the weather conditions within Europe impact the optimal sizing of storage components. Second, due to more favorable weather conditions in the extra-European countries, more hydrogen is imported leading to a reduction in the required storage capacity.

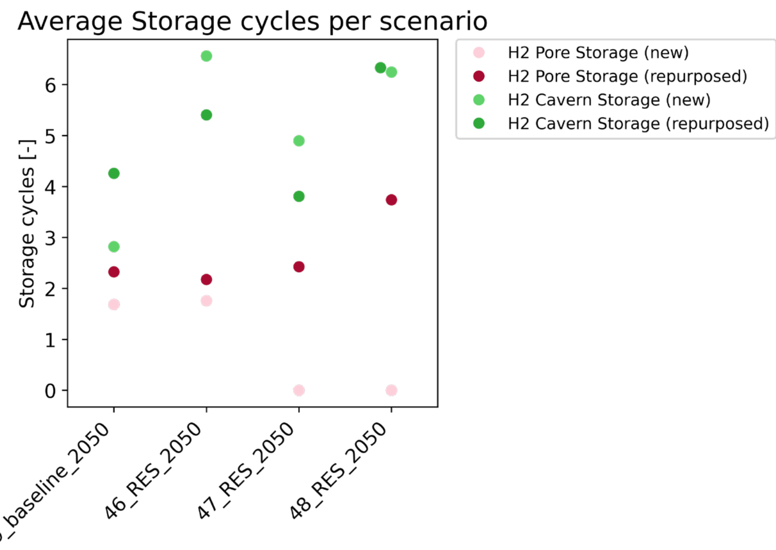

Figure 5-40. Average storage cycles for the UHS technologies in the weather sensitivity scenarios in 2050. For information on scenario descriptions see Table 1.

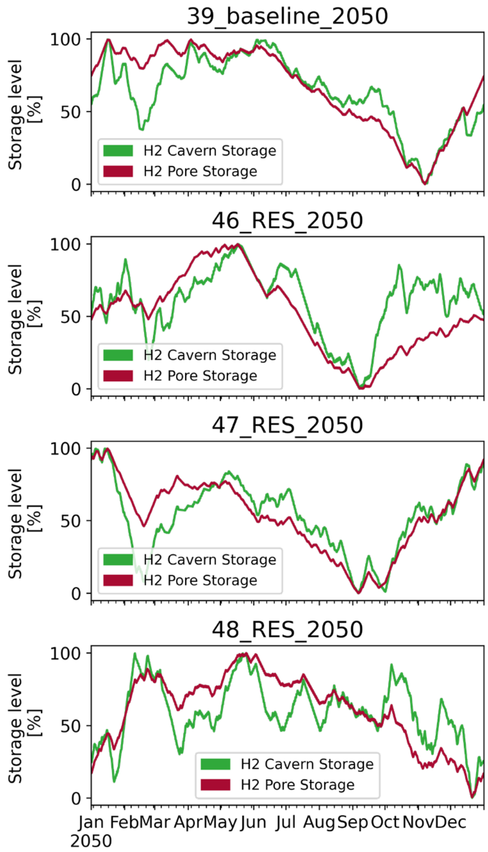

Figure 5-41. Aggregated storage levels in % throughout the year for pore and cavern storage in the weather sensitivity scenarios in 2050. For information on scenario descriptions see Table 1.

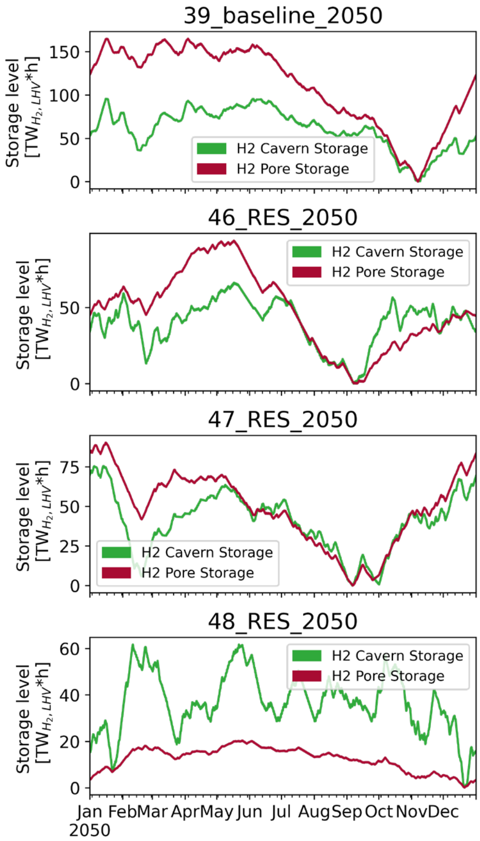

Figure 5-42. Aggregated absolute storage levels throughout the year for pore and cavern storage in the weather sensitivity scenarios in 2050. For information on scenario descriptions see Table 1.

In summary, the results emphasize the critical impact of weather conditions on optimal UHS capacities. Storage capacity requirements are chiefly dictated by the balance of surplus or deficit residual electricity for hydrogen production. Although storage capacity determines the volume of energy that can be stored, annual discharge and storage cycles are also influenced by intra-seasonal fluctuations in production.

5.2.5 Impact of import restrictions

The results for prohibiting or forcing hydrogen imports are shown in the following. Figure 5-43 displays the resulting storage capacities for the sensitivity scenarios for the target year of 2050. As the baseline scenario for 2050 exhibited hydrogen imports amounting to around 400 TWh, prohibiting them leads to a slight increase in optimal storage capacity from 260 TWh to 270 TWh. To balance the missing hydrogen import, slightly more generation capacity is needed within Europe. The overall impact on the energy system is negligible.
Nevertheless, prohibiting imports slightly increases the required storage capacity. This effect is more pronounced in the 2040 scenario where the baseline scenario foresees higher amounts of imports. Here, optimal storage capacity increases from 160 TWh to 210 TWh when imports are prohibited.
Enforcing imports to 30% of the annual demand (*44_2050_REPowerEU*) leads to reduced storage capacities. Here, the required storage capacity is reduced to 230 TWh.

In contrast to all other scenarios, the *seasImportsREPowerEU* and *seasImports* scenarios do not assume constant hydrogen imports but use the generation profile from the exporting country since it is assumed that produced hydrogen is directly transported to Europe without any storage. Both scenarios result in higher amounts of hydrogen imports (1200 TWh in 2050) compared to the baseline scenario. This is due to lower hydrogen import costs for pipeline imports, as the export profile follows hydrogen production in the exporting country rather than a flat export profile. However, the seasonality of the imports does not lead to a significant change in overall optimal storage capacity. The optimal hydrogen storage capacity slightly decreases as shown in Figure 5-43. With seasonal imports, more hydrogen storage capacity is needed near the point of import in Italy which is shown for the target year 2040 in Figure 9-45 in appendix. Storage levels throughout the year do not significantly change. Notably, 42 TWh of hydrogen re-electrification can be observed in both the 2050 *seasImportsREPowerEU* and *seasImports* scenarios in Germany, Italy, and the Czech Republic during a period of low renewable generation in February and March as well as in December.

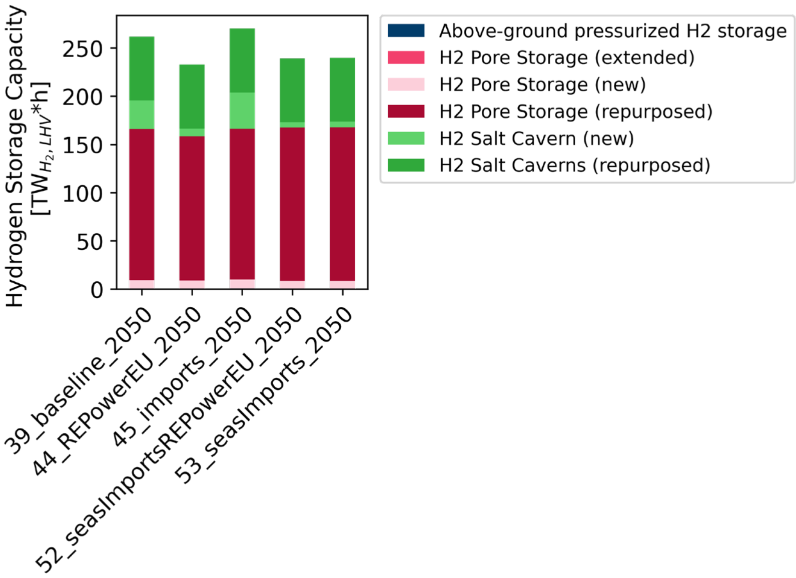

Figure 5-43 Hydrogen storage capacity in the imports sensitivity scenarios. For information on scenario descriptions see Table 1.

5.2.6 Impact of additional restrictions

Further scenarios were calculated to investigate the impact of grid limitations (*limitGridreg*) in which the expansion of the electricity and hydrogen grid is limited, forcing or restricting the expansion of renewables per country (*resTargets)* and the impact of a 4-day Dunkelflaute with RES production reduced to 30% during the beginning of January in Northwestern Europe (*dunkelflaute*). Furthermore, a combined scenario with the aforementioned scenarios and the *seasImportsREPowerEU* scenario was calculated (combi).

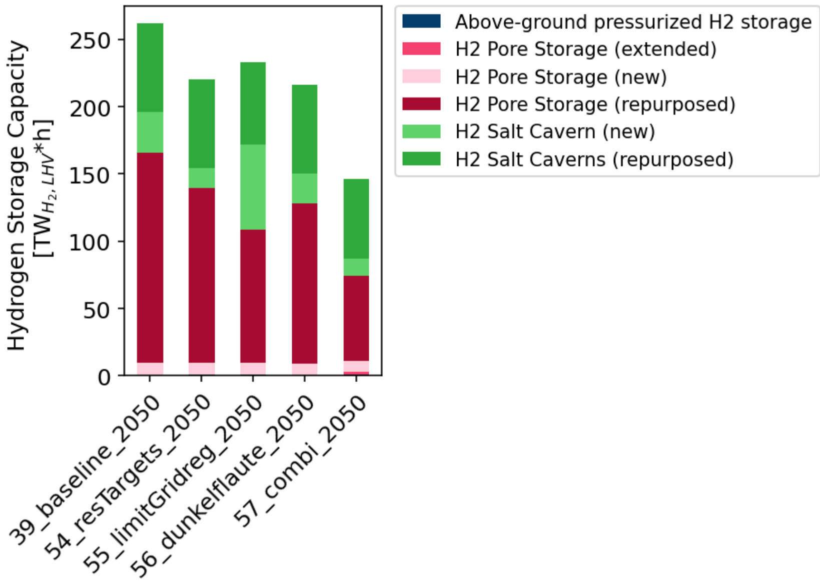

Figure 5-44. Optimal hydrogen storage capacity for the additional restriction scenarios in 2050. For information on scenario descriptions see Table 1.

In the *resTargets* scenario, forcing the expansion of renewable according to announced capacity targets in 2030 outlined in Chapter 3.2.5 leads to a shift of hydrogen production location from the UK, Denmark and Norway to Germany as shown in Figure 5-46. This is due to the fact that Germany is building much more renewable capacity than it needs, which leads to the utilization of the remaining renewable capacity for hydrogen production. Having more renewable capacity than necessary in the system leads to a decrease in hydrogen storage capacity from around 52 TWh to 33 TWh as hydrogen can be produced on demand. Limiting the expansion of renewables per country in 2040 and 2050 results in increased amounts of hydrogen imports as shown in Figure 5-45 and, thus, in a reduction of optimal storage capacity from 161 to 113 TWh in 2040 and from 260 to 220 TWh in 2050. Furthermore, in 2050, 107 GW more wind offshore capacity is being built to compensate for the expansion restrictions of the other renewable energy sources, which represents an increase of 50% compared to the baseline scenario.

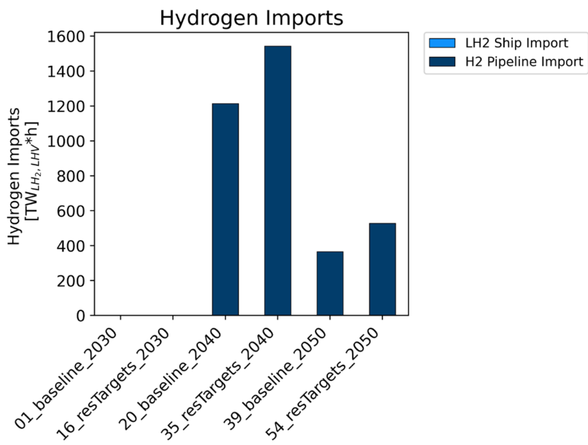

Figure 5-45. Extra-European hydrogen imports in the resTargets scenarios and baseline scenarios in 2030, 2040 and 2050. For information on scenario descriptions see Table 1.

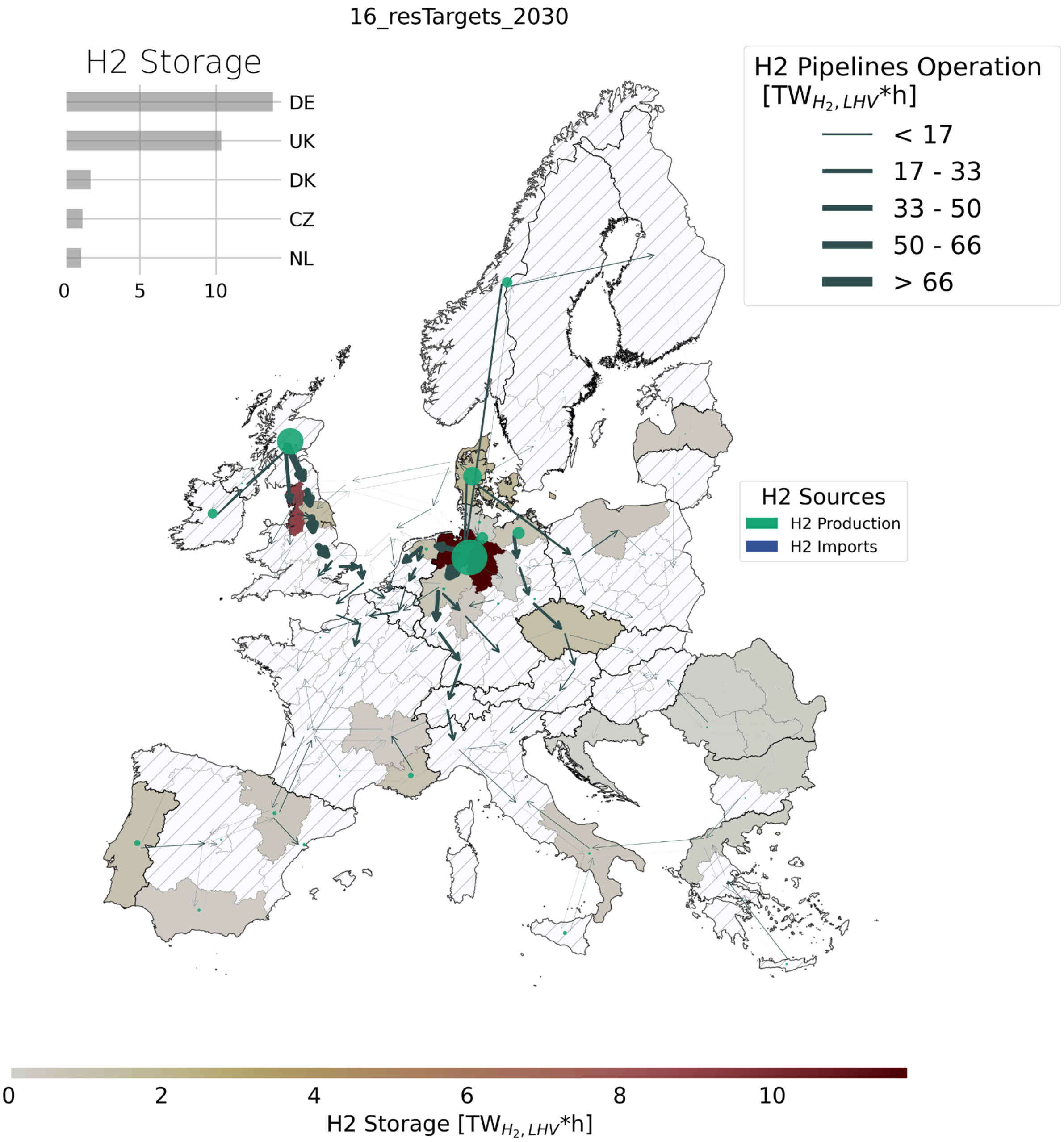

Figure 5-46 Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in 2030 in scenario *17_resTargets_2030*. For information on scenario descriptions see Table 1.

Although the share of offshore wind turbines increases compared to the baseline scenarios, the allocation of hydrogen production sites and pipeline routing do not show significant changes for the target years 2040 and 2050.

In the *dunkelflaute* scenario, during a 4-day Dunkelflaute in 2030 and 2040 in Northwestern Europe conventional power plants (gas and coal) are used as backup to cover the electricity deficit as shown in Figure 5-47. At the same time, the hydrogen production throughout all of Europe is reduced to almost zero during that period. Due to the larger share of conventional power plants, the optimal hydrogen storage capacities are reduced from 51 to 44 TWh in 2030 and from 161 to 135 TWh in 2040 compared to the baseline scenario. This effect was already observed in Section 5.2.2.

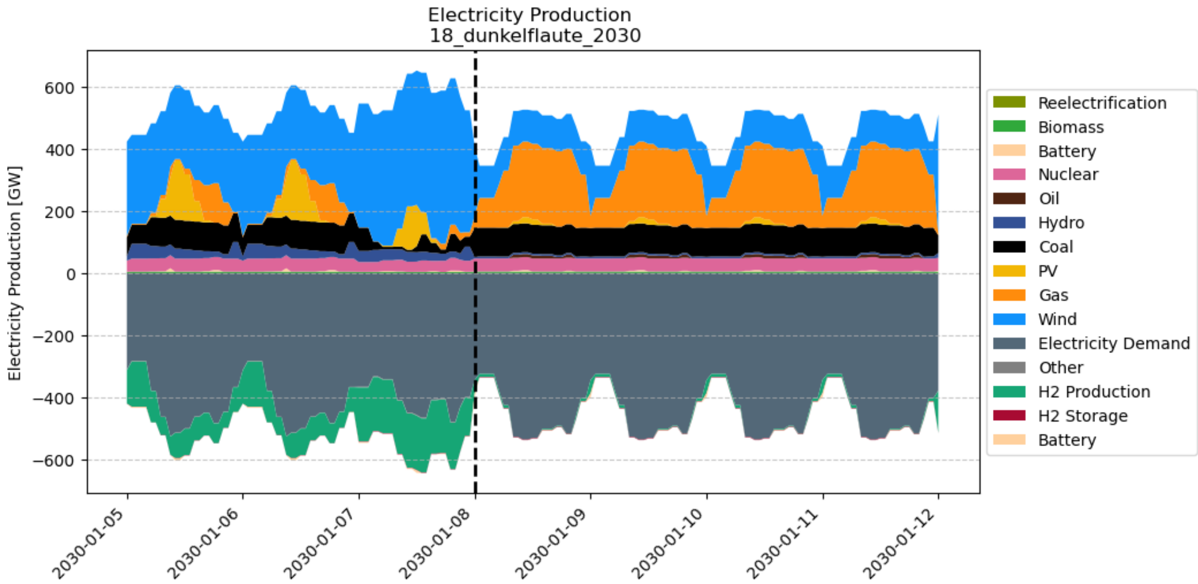

Figure 5-47 Electricity balance in Europe during a Dunkelflaute in 2030 in scenario *18_dunkelflaute_2030*. For information on scenario descriptions see Table 1.

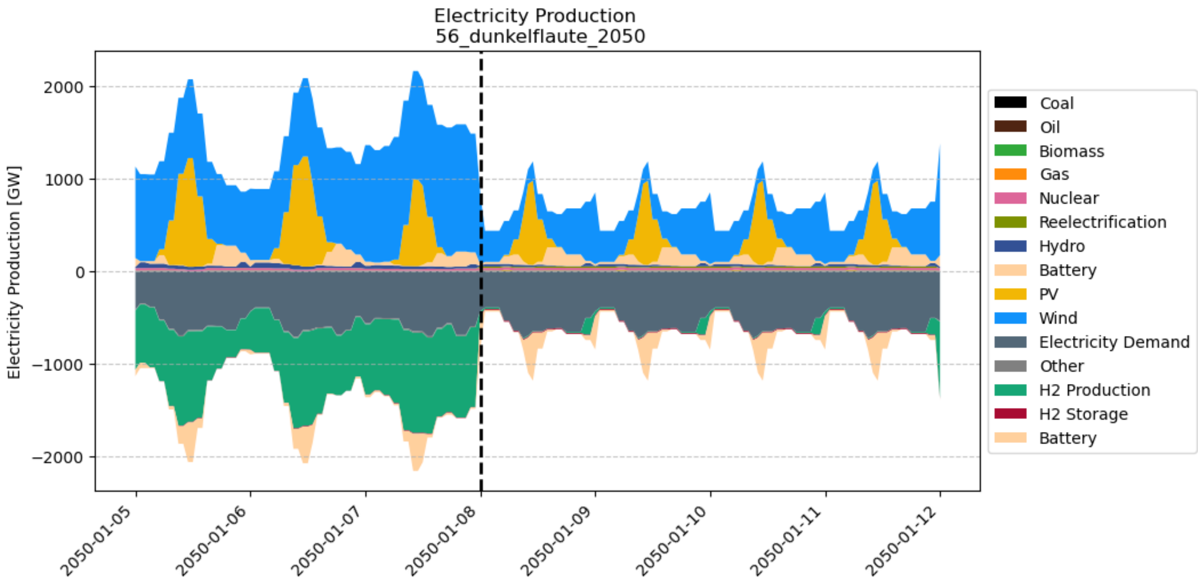

Figure 5-48 Electricity balance in Europe during a Dunkelflaute in 2050 in scenario *56_dunkelflaute_2050*. For information on scenario descriptions see Table 1.

As in 2050 gas and coal power plants are not available due to the emission restrictions, the electricity deficit is covered by slightly shifting renewable energy capacities to regions outside affected regions. As a result, renewable capacities in Poland, Italy, Greece, and Southern France increase. This results in a slight increase in PV capacity (+85 GW) and in an increase in battery storage capacity from 1.2 TWh to 1.6 TWh. Figure 5-48 depicts the electricity balance in Europe during the modeled Dunkelflaute in 2050, whereby only the hydrogen production was discontinued.
The optimal storage capacity in 2050 is reduced from 260 TWh to 216 TWh while the average storage cycles of repurposed pore storage and new cavern storage are increased (see Figure 9-7 (Appendix)), resulting in similar annual discharge as in the baseline scenario.

In the *limitGridreg* scenario, drastically limiting both the expansion of a new hydrogen grid and a repurposed hydrogen grid between regions to 0.2 GW per year leads to a more decentralized hydrogen production. Limiting the grids expansion prevents large amounts of hydrogen imports from North-Africa or production in the UK as transport routes are limited by the maximum capacity expansion. As a result, in 2040 a sharp decrease in hydrogen imports from North Africa can be observed. In the case of the intra-European hydrogen production in the UK, the model tries to circumvent the grid restriction by building a more branched out hydrogen network utilizing offshore transmission routes. This allows the model to still transport large amounts of hydrogen to central Europe. To compensate for the missing hydrogen imports from North Africa, more hydrogen is produced domestically e.g. in France, Germany, or the Netherlands.
Consequently, the hydrogen grid appears much more homogenously developed throughout Europe as hydrogen is produced more decentralized as shown in Figure 5-49. In 2050, several hydrogen corridors can be observed that transport hydrogen from Europe´s peripheral areas to central Europe. However, it should be noted that these corridors were already present in the baseline scenario and rather the prominent corridors from the baseline scenario are reduced. Notably, the average storage cycles of pore storage sites significantly increase in 2050 compared to the baseline scenario indicating that due to the grid restrictions pore storages have to be utilized increasingly to also cover short term fluctuations.

In the combined scenario, the aforementioned restrictive scenarios are combined, and the model is additionally forced to import 33% of its annual hydrogen demand in 2040 and 2050. Due to the grid limitations, the pipeline imports from North Africa are not able to cover this requirement entirely. As a result, liquefied hydrogen is imported by ship in Belgium due to its proximity to hydrogen demand centers as shown in Figure 5-50. Notably, the UK and Ireland do not export significant amounts of hydrogen to central Europe anymore.
As the liquefied hydrogen imports and the hydrogen demands in the model are assumed to be constant, the optimal storage capacity is reduced from 260TWh to 146TWh, while at the same time, the storage cycles slightly increase (see Figure 9-7 and Figure 9-4(Appendix)). Furthermore, notable differences in the storage levels throughout the year can be observed. The combined scenario in 2050 sees an additional large discharge in the beginning of the year from January to February as well as more constant storage levels from May to September. This can be attributed to the more decentralized hydrogen production where the hydrogen surplus is less dominated by the weather conditions in the UK anymore.

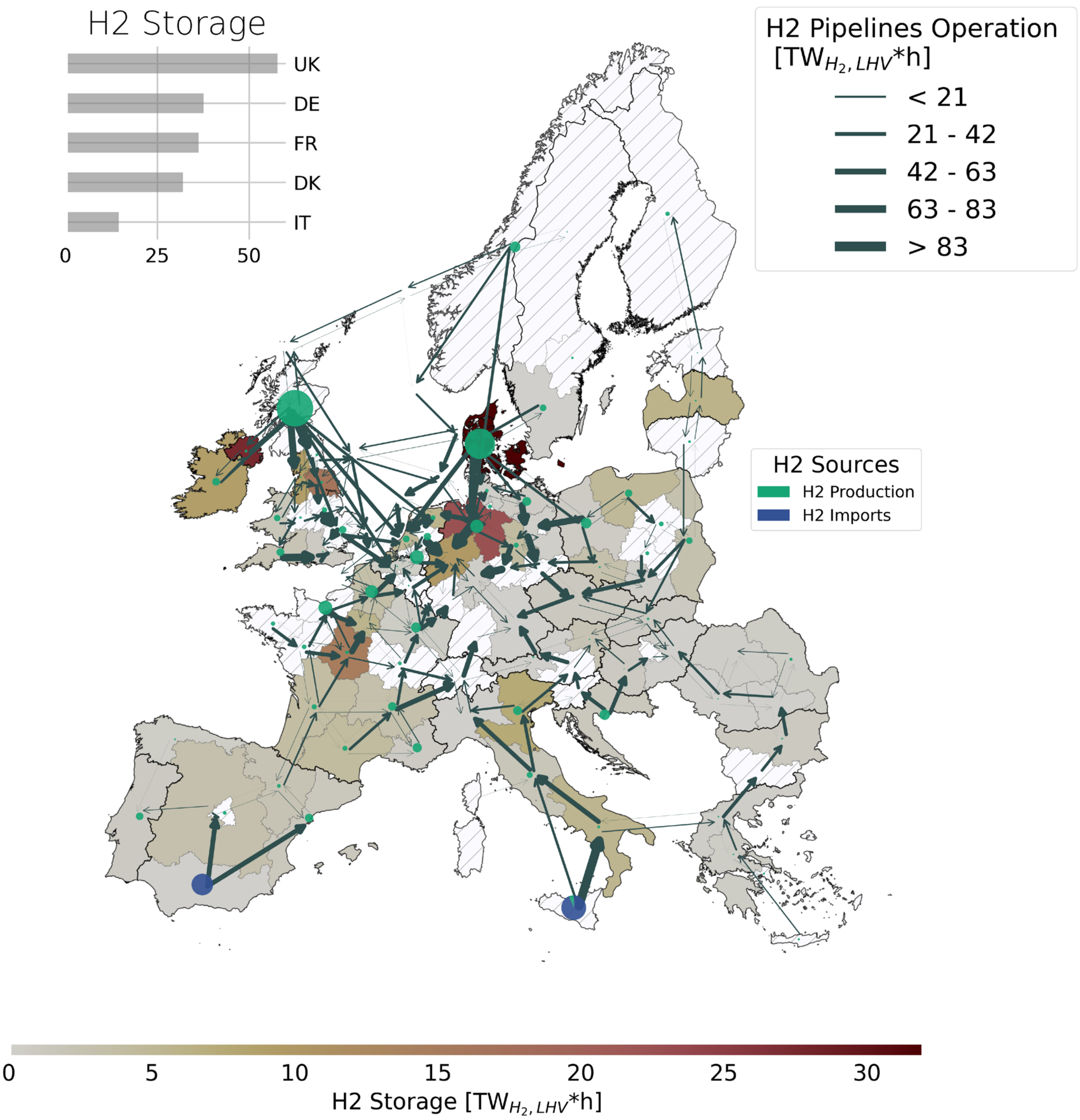

Figure 5-49 Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in 2050 in scenario *55_limitGridreg_2050*. For information on scenario descriptions see Table 1.

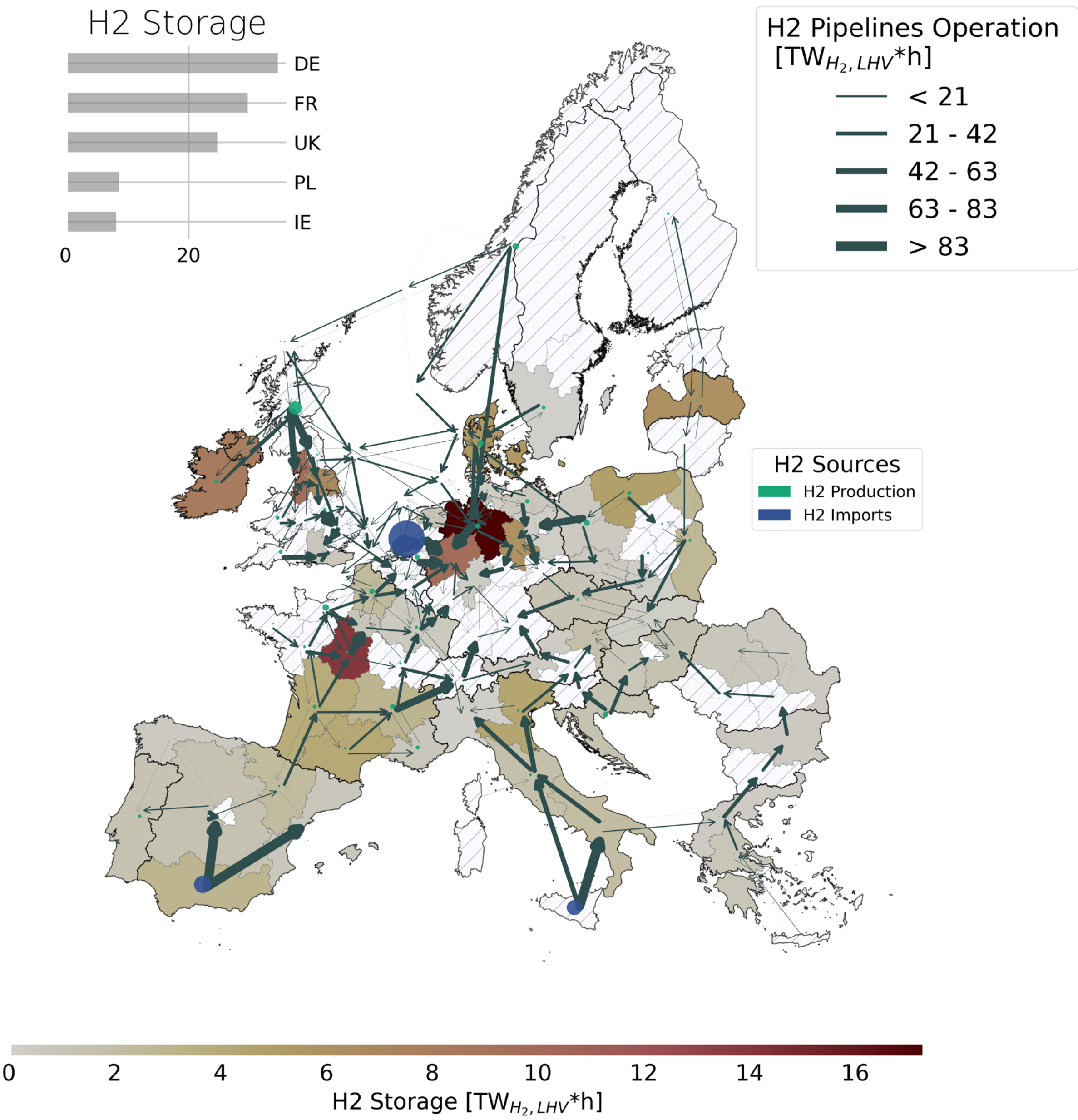

Figure 5-50 Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in 2050 in scenario *57_combi_2050*. For information on scenario descriptions see Table 1.

In conclusion, limiting the expansion of the electricity and hydrogen grid has the largest impact on the energy system as it limits hydrogen from previous origins such as hydrogen pipeline imports from North Africa and the UK. When more imports are enforced as is done in the combined scenario, hydrogen ship imports can become necessary due to grid limitations. The absence of the UK as provider of additional hydrogen for central Europe has a notable impact on the storage levels throughout the year.

5.3 Resulting LCOH

The expected average LCOHs are presented in Figure 5-51 with a mean LCOH of 89 €/MWh (2.96€ /kg) across all 2050 scenarios. As expected, the highest impact on LCOH can be observed for varying cost assumptions, which result in LCOHs ranging from 60 €/MWh (2.0 €/kg) in the "optimistic" cost scenario to 122 €/MWh (4.1 €/kg) in the "pessimistic" one. Furthermore, higher demand leads to higher LCOHs and vice versa, resulting in an increase from 86 €/MWh (2.88 €/kg) in the reduced scenario to 91 €/MWh (2.0 €/kg) in the elevated demand one. Notably, the assumed weather year also shows a relevant impact on the LCOH, which can increase to 94 €/MWh (3.1 €/kg). Furthermore, limiting the transmission grid expansion, which leads to a more decentralized hydrogen production, only slightly increases the mean LCOH by 0.03 €/MWh.

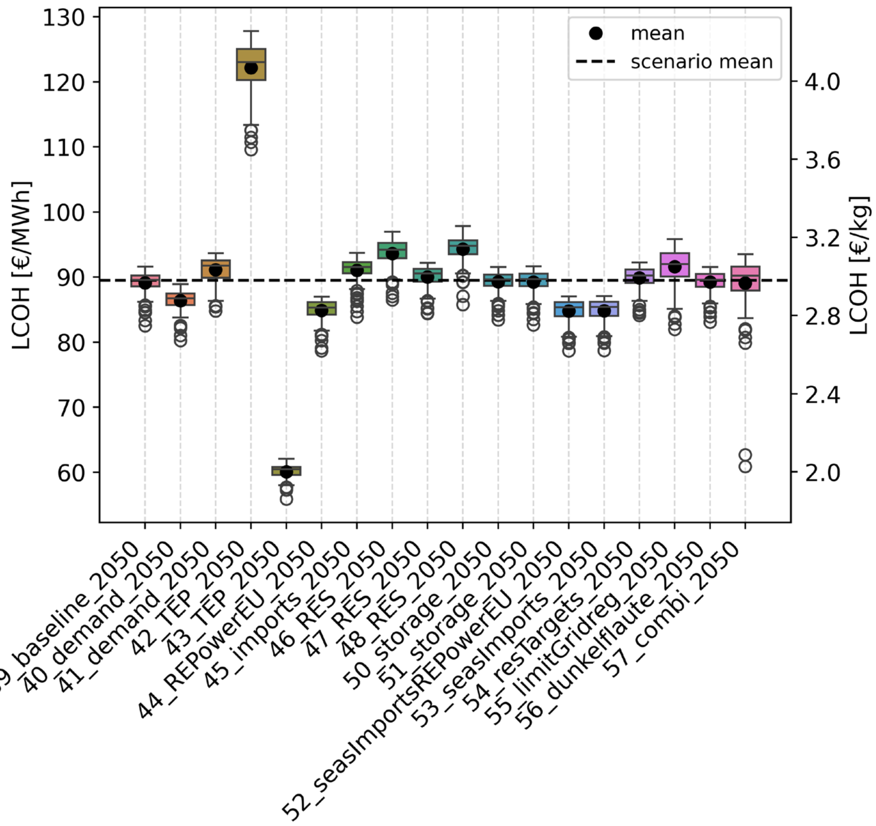

Figure 5-51 LCOH in 2050 sensitivity scenarios; mean across all considered scenarios is 89 €/MWh (2.96 €/kg). For information on scenario descriptions see Table 1.

6 Discussion

The results presented in this report reveal the importance of UHS in the future European energy system. In the baseline scenario for the three modeled target years, most of the hydrogen demand will be sourced from within Europe, with limited imports from North Africa to close the gap. Electrolyzers for green hydrogen production will mainly be fed with wind power from turbines strategically located in Northern Europe, particularly in the UK and Denmark, taking advantage of favorable wind conditions there. The baseline scenario foresees storage capacities of 50 TWh in 2030 extending to 260 TWh in 2050, and discharging over 20% (750 TWh, 2050) of the annual hydrogen demand throughout the year. In terms of surface components, the results show a total injection capacity for cavern storage of 195 GW and total withdrawal capacity of 250 GW. At the same time, the injection capacity for pore storage is notably lower with 138 GW and the withdrawal capacity is 120 GW. Notably, cavern storage sees higher withdrawal capacities while pore storage sees higher injection capacities, reflecting the role of cavern storages as medium- and short-term buffer for hydrogen and the role of pore storage as seasonal storage.
In general, the UHS turns out to be instrumental as a cost-efficient technology for securing the hydrogen supply across seasons, while accounting for only 2.4% of the resulting total annual system costs. Assuming average storage site capacities of 3.14 TWh (pore storage) and 1.13 TWh (cavern storage), this would require about 90 (100 TWh) cavern storage sites with approximately 5 to 10 caverns per site and about 50 (160 TWh) pore storage sites in 2050. The average capacities were calculated using data provided in work package 1 of the HyUSPRe project (Cavanagh et al. 2022).

The results further show that hydrogen storage will be operated differently to today's natural gas storage. Natural gas has a relatively consistent supply throughout the year, but demand fluctuates, being higher in winter and lower in summer. To balance this fluctuation, natural gas storage is utilized. Storage facilities are filled during the summer and emptied during the heating period. The results show that, under the assumption of constant hydrogen demand, hydrogen storage will be utilized to primarily cover fluctuations in production stemming from weather-dependent renewable supply.
This means that for natural gas storage, demand defines the storage operation, whereas for hydrogen storage supply will define the storage operation.

This chapter is structured as follows: Section 6.1 clearly outlines the assumed boundary conditions of the model and their impacts, which is crucial to fully understand the results. In Section 6.2, the results are contextualized in relation to other studies, emphasizing both similarities and differences in their findings.

6.1 System-changing boundary conditions

Some boundary conditions should be considered when interpreting the presented results. The following subsections describe the assumptions of the model and how changes in these assumptions would affect the resulting system configuration, in particular the design and operation of hydrogen storage systems.

6.1.1 National trends and targets

The presented results do not follow national trends and country-specific energy-related targets described in national energy and climate policies, e.g. in terms of PV or wind power capacity expansion, as the model finds overall cost-optimal system configurations based on the assumed cost projections. Considering specific capacity targets could significantly impact the results, as they strongly influence the electricity mix of each country as explored in the sensitivity scenario *resTargets.* This, in turn, would affect both the total required hydrogen

storage capacity and the hydrogen storage capacities in each country as the hydrogen production is directly connected to the amount of electricity generated.
Similarly, capacity targets for nuclear power are not set in the model, while the planned phase-out in countries such as Germany is considered. Due to high assumed costs and assumed decommissioning of nuclear power plants, the model results show a decrease in nuclear power capacity. These assumptions do not reflect the current targets of various European countries, e.g. France, who plan to expand their nuclear capacity. With higher nuclear capacity in the model, a higher baseload electricity supply would be available. Consequently, less renewable energy sources and less electricity storage will be needed. This might also decrease the need for re-electrification plants in periods of low renewable energy generation, and therefore the need for UHS could be lower.
Same is true for bioenergy. Bioenergy plays only a marginal role in the resulting electricity supply due to the assumed high costs. However, bioenergy could offer similar flexibilities as today´s natural gas power plants. In general, with an increased share of bioenergy in the electricity generation, less re-electrification for flexible electricity supply and lower PV and wind capacities could be observed. Which, in turn, would impact the optimal hydrogen storage capacity.

Furthermore, the holding of geostrategic reserves has not been taken into account in the scenarios described in the Chapters 4 and 5. Storage restrictions could recreate today's storage situation for natural gas in which almost all European countries have their own underground gas storages. This constraint would increase the need for underground gas storage significantly as it is the option with the lowest costs to match gaseous hydrogen demand compared to other storage options for hydrogen and its derivatives. If each country needs storage capacity for at least 30% of its annual hydrogen demand, this would require about four times the storage capacity described in the results for the baseline scenarios. As a result of the required high storage capacity, both repurposed pore and repurposed cavern storage would be almost fully utilized throughout Europe.

6.1.2 Assumptions for cost projections

Whereas our findings reveal the crucial role of UHS, they also reveal the uncertainty related to optimal future hydrogen storage capacity. As the model minimizes the total annual costs, the results are very sensitive to the assumed cost projections leading to different system configurations. The resulting energy systems show a high dependency on onshore wind power, which is accounting for more than 61% of total electricity generation in 2050 in the baseline scenario, whereas PV only holds a share of 23%. This can be explained by the fact that the PV cost projections are very conservative, assuming less cost reduction than the cost projections of other studies (see de Maigret and Viesi, 2023). Figure 6-1 provides an overview of the assumptions made by various projects for installation cost projections of renewable energy sources, including PV, onshore wind, and offshore wind (de Maigret and Viesi, 2023; Michalski, 2022; ENTSO-G and ENTSO-E, 2021). In particular, the assumed costs for PV installation in the average and pessimistic cost scenarios of our studies are higher than in the compared recent studies. Even though the assumed costs for PV are about half as high as those for onshore wind, onshore wind turbines have a clear cost advantage over PV due to their higher generation potential. The model implements more onshore wind than other renewable energy sources because there are no fixed assumptions regarding the future electricity mix or expansion rates.

The results could differ further in case of different cost structures as the model aims to minimize the total annual costs. Cheaper PV costs could lead to a shift towards a more decentralized hydrogen production where a larger share of hydrogen is produced from PV. This would impact both hydrogen transport infrastructure and optimal storage locations. Hydrogen supply corridors could change, and hydrogen storage locations could shift e.g. towards the Central

EU. Furthermore, hydrogen imports could become more cost competitive in case of lower hydrogen production costs in the exporting countries.

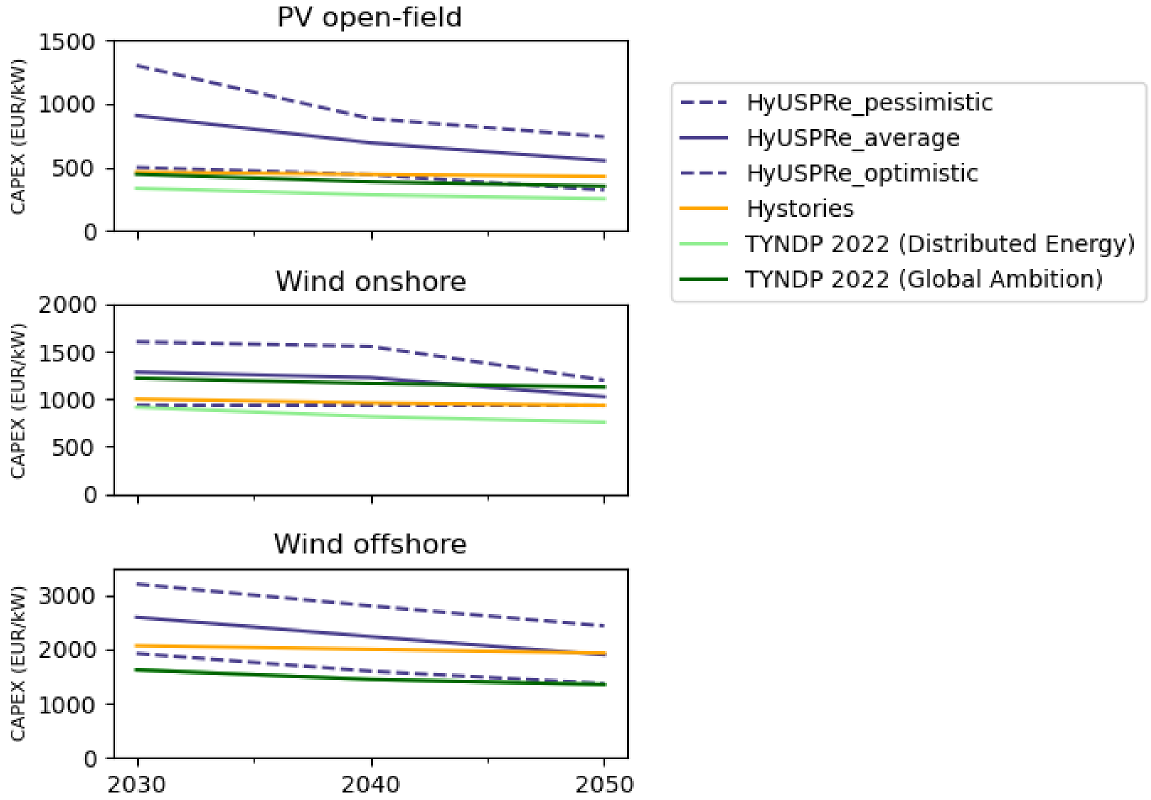

Figure 6-1. Comparison of cost projections in different projects. The comparison is done for the cost assumptions of HyUSPRe (de Maigret and Viesi, 2023), Hystories (Michalski, 2022), and the Ten Year Network Development Plan (TYNDP) 2022 (ENTSO-G and ENTSO-E, 2021).

This behavior can be observed in the "optimistic" costs scenarios. In scenario *43_2050_TEP*, solar PV account for around two thirds of the installed electricity generation capacity and generate around half of the electricity produced which is significantly higher compared to the baseline scenario. As a result of the higher PV share in the system, a more decentralized hydrogen production can be observed with additional production facilities in countries such as Spain, Italy, and Greece (see Figure 5-33). Hydrogen production in 2050 also takes place in southern Europe leading to similar hydrogen transport routes as outlined by the European Hydrogen Backbone (van Rossum et al., 2022). Consequently, hydrogen storage is located closer to the mainland of Europe due to observed siting of storage close to production sites and along hydrogen transport routes. Compared to the baseline scenario (260 TWh), overall lower hydrogen storage capacity of 166 TWh is found. This might be the result of a complementary effect of PV and wind generation. These findings again highlight the sensitivity of the results to the assumed costs which should be considered when interpreting the model results.

6.1.3 Unforeseen weather conditions

The observed optimal storage capacities in the model are lower bounds as the design of the energy system is based on minimum costs. However, with almost 100% RES electricity generation in the future, reserves for unforeseen weather conditions, e.g., prolonged periods with cloudy skies and low to no wind (Dunkelflaute) and extreme hot or cold weather, will be necessary. Therefore, future European hydrogen storage capacity should be implemented with sufficient reserves to ensure security of hydrogen supply. Future studies ought to explore how the variability in renewable electricity generation, influenced by weather conditions, affects the

required storage capacity, aiming to obtain more resilient and accurate assessments. Their findings might also highlight the potential benefits of utilizing hydrogen in power sector through re-electrification plants which do not play a significant role in the scenario results of this study. Hydrogen in combination with hydrogen storage can be a reliable source of power during periods of Dunkelflauten. This has been demonstrated in several studies (e.g., Stolten et al., 2022; 2023).
The strong impact of the assumed weather conditions on the optimal storage capacity was already observed in the sensitivity scenarios (see Section 5.2.4 and 5.2.6). Longer periods of Dunkelflaute might have a more significant impact on the electricity balance than shown. Additionally, the optimized system configurations could be further explored assuming different weather conditions to evaluate the need for back-up capacities and their impact on the optimal storage capacity. Furthermore, the impact of climate change and disruptive events and the role of hydrogen storage for a resilient energy system should be explored.

6.1.4 Future hydrogen demand and hydrogen imports

The future hydrogen demand in the scenarios, given exogenously, remains constant throughout the year, and it is only considered for end consumers in the industrial and transport sectors, and not for residential heating. Constant demand could lead to an underestimation of required storage capacity. If instead fluctuating hydrogen demand is assumed, optimized storage capacity might be higher as additional hydrogen storage will be needed for times of high demand. For example, if hydrogen is used for heating purposes in future, the demand curve for hydrogen will peak in winter, and storage operations will be similar to those for natural gas today. This effect have been observed in Hystories project´s results (Michalski and Kutz, 2022).
The future hydrogen demands are not optimized due to complexity restrictions. Optimizing demands within an integrated model could lead to different final demands and energy system configurations. Furthermore, the assumed amount of hydrogen demand in this study is on a high level compared to other studies. Discussion on this can be found in Groß et al., 2022.

The results for the scenario with hydrogen imports into Europe could be different as well. Here, the imports resulted in a notable reduction in the required hydrogen storage capacity due to the constant supply and assumed constant demand. If instead fluctuating hydrogen demands are assumed, optimized storage capacity would also be higher in this scenario. Similar effect was also observed in the sensitivity scenarios with seasonal imports (c.f. Section 5.2.5). Furthermore, considering additional import routes, e.g., hydrogen imports from Ukraine, would affect the spatial distribution of required storage capacities.

6.1.5 Blue hydrogen

The modeled energy systems do not currently incorporate blue hydrogen. This is due to the fact that the model does not consider carbon capture, usage, and storage (CCUS) as option for decarbonization. Blue hydrogen production could enable the ramp-up of a hydrogen economy and necessary infrastructure development in the transition period in which the growing share of electricity from renewables can still be absorbed by demand and electricity storage at affordable price levels, leaving too little for green hydrogen production to be competitive. In this situation, blue hydrogen could be the solution to decarbonize current grey hydrogen used at a competitive price to grey hydrogen, subject to the cost of CO2 emission (ETS).

Employing blue hydrogen and substituting some amount of green hydrogen with blue hydrogen generated from, e.g., steam methane reforming (SRM), could lead to multiple impacts on the resulting energy system. As SMR is not impacted by weather conditions, consistent hydrogen production profiles become possible. Blue hydrogen could be produced at the locations where hydrogen is needed, which could lead to less hydrogen having to be transported via the hydrogen pipeline network. The extended use of natural gas storage could potentially decrease the necessity for seasonal hydrogen storage, and the natural gas infrastructure could see a prolonged lifetime. However, if blue hydrogen was produced within natural gas producing countries (e.g. Norway) and transported within the same hydrogen pipeline grid, this could benefit the ramp up of a hydrogen transmission infrastructure. The utilization of blue hydrogen has the potential to facilitate the implementation of hydrogen technologies, while also posing a potential obstacle to the advancement of a hydrogen infrastructure.

6.1.6 Blending of hydrogen

Current regulatory limits on hydrogen blending are diverse in Europe ranging from 0.1% to 10% (Erdener et al., 2023). Nevertheless, the model does not consider any blending of hydrogen into the natural gas grid as this would significantly increase the complexity of the model. The potential impacts of blending on the results are briefly discussed: Blending could help the ramp-up of hydrogen supply. If green hydrogen were used for blending, hydrogen demand would increase. As a result, hydrogen production and renewable capacities could see an increased growth especially during the ramp up of a hydrogen economy. Emissions of current natural gas power plants and sectors which use natural gas for heat supply would be reduced. On the other hand, blending could prolong the lifetime of the natural gas grid as well as natural gas storage sites, and consequently slow down the emergence of a hydrogen transmission and storage infrastructure as the repurposing potential would remain limited. In case blending was considered in the model, the results could show more newly built hydrogen transmission and storage infrastructure once demand for green hydrogen emerges.
However, assessing the impact of blending on the European energy system and its transition towards GHG-neutrality are beyond the scope of the project.

6.1.7 Hydrogen derivatives and further storage options

Further, it should be noted that alternatives for large scale UHS might become a viable option in the future. As the results have shown, alternatives to UHS such as LOHC, methanol, and ammonia tank storage are not cost-competitive without a direct demand for that energy carrier due to the high associated additional energy conversion losses. Especially a reconversion to hydrogen will therefore be unlikely.
However, these storage options could become viable if value chains and end-use demand for hydrogen derivatives and chemicals, e.g., ammonia, methanol, and Fischer-Tropsch fuels, arise. In this case, hydrogen could be converted to the required product that can be stored more space efficient in, e.g., large tanks. Due to the high volumetric density, alternative transport options such as trailer or shipping might become cost competitive.
In that case, the resulting energy system and required UHS capacity could be different. In general, the required UHS storage capacity would be lower because some amount would be substituted with a hydrogen derivative storage technology. As the exact implementation of aforementioned value chains for hydrogen derivatives is yet unclear, so are the potential impacts on UHS. Two scenarios could be envisioned:
Firstly, hydrogen derivatives could be produced from hydrogen at the location of demand. Secondly, hydrogen derivative production could be realized at the electrolyzer location resulting in the emergence of a separate transport infrastructure (ship, trailer, etc.). In the first case, the hydrogen transport infrastructure would be similar to the results shown in this report. Required UHS would be lower as the final products could be stored directly. UHS would still be required to absorb the fluctuating production of green hydrogen from renewable energies.
In the second case, the impact on the required UHS capacity could be significantly higher. Separate and parallel transport and storage infrastructure would arise where the demand for the transport sector as well as ammonia, methanol and Fischer-Tropsch fuels in the industry would be covered by independent value chains. As a result, the demand for gaseous hydrogen to be transported and stored would decrease significantly, as it is mainly hydrogen that is used for high-temperature process heat. However, it remains unclear if any of the mentioned

scenarios or value chains are realistic and cost competitive. Future research should investigate this.

6.2 Scenario results in comparison to literature

In the following, the results are contextualized in relation to other studies, emphasizing both similarities and differences in their findings. The subsections compare the results to existing scenarios and roadmaps described in Chapter 2, present a detailed comparison with the results of the Hystories projects, and place the results in the context of the European Hydrogen Backbone.

6.2.1 Comparison to existing scenarios and roadmaps

In Chapter 2 several energy systems modelling scenarios with a European focus were described. Most of the scenarios reported hydrogen storage capacities of less than 200TWh if UHS is considered as option (see Figure 2-1). The range of optimal hydrogen storage capacities observed in the literature highlights the sensitivity to contextual factors, which include among others the considered weather conditions, the underlying hydrogen demand and cost assumptions. Comparing the results from different existing scenarios[6], the storage capacity required for hydrogen storage increases if hydrogen demand is not constant in time, e.g., by using hydrogen for heat production (Göke et al., 2023) or for re-electrification (Caglayan et al., 2021b). In particular, hydrogen re-electrification comes into play if the expansion of the electricity grid is restricted or battery storage is not considered as available option (Neumann et al., 2023; Caglayan et al., 2021b; Gawlick and Hamacher, 2023). In these cases, hydrogen transport, storage and re-electrification is used to replace electricity transmission and storage. As electricity grid expansion and battery storages are not entirely excluded in any modeled scenario in this report, significant re-electrification cannot be observed in our findings to overcome these issues. However, several sensitivity scenarios show re-electrification in the range of 10 to 132 TWh. The studies also support that hydrogen production in regions with high renewable energy generation is preferred to electricity transmissions and electrolysis close to demand centers (Wetzel et al, 2023). This aspect can also be seen in our results as hydrogen production and UHS are more often located close to regions with high renewable energy supply to reduce more expansions of the electricity grid. In addition, the results described are consistent with the recent study of Artelys and frontier economics (2024) which is used by the EU-wide alliance H2eart for Europe (Peterse et al., 2024). The observed deviations in hydrogen storage capacity and injection capacity are only around 10%, both in 2030 and 2050.
As far as mentioned in the studies, the existing scenarios indicate a significantly lower demand for hydrogen in 2050 compared to our projected demand. This could directly impact the required hydrogen storage capacity. Additionally, it should be noted that, with exception of the Hystories project scenarios and the scenarios in the study of Artelys and frontier economics (2024), the described scenarios have limited access to UHS as only salt caverns with a limited spatial distribution across Europe are considered as available option. This might also affect the need for hydrogen storage as it is only available for a limited number of regions. Furthermore, the studies do not focus on resilient energy systems designs which could require more flexibilities in form of dispatchable power supply in times of low renewable feed-in. This is also true for the scenario calculations done within this project.
Stakeholders should therefore collaboratively devise cohesive strategies, considering factors like grid expansion, renewable energy integration, security of energy supply, and evolving hydrogen demand patterns.

[6] The comparison with Hystories results is done in Subsection 6.2.1.

6.2.2 Hystories project

When contrasting our findings with those of the Hystories project (Michalski and Kutz, 2022), several noteworthy observations emerge. Hystories identifies optimal hydrogen storage capacities of approximately 50 TWh in 2030, 150 TWh in 2040, and 300 TWh in 2050. These values align closely with our results. Similarly, Hystories notes an optimal storage throughput of around 25-30% of the annual demand in 2050, a trend consistent with our own outcomes. Parallel to our report, Hystories indicates limited pore storage capacity in 2030, with a subsequent increase to approximately 50% for pore and cavern storage by 2050. Our results show slightly higher shares of pore storage capacity in 2050.

In terms of storage cycles, Hystories reports that after 2040, both cavern and pore storage operate on a seasonal basis resulting in storage cycles of 1.4-1.9 (cavern) and 1.1 (pore storage). Our results deviate significantly, indicating higher storage cycles for both options, 2.0-4.3 for cavern storage and 1.5-2.2 for pore storage. Moreover, distinct filling level profiles throughout the year are observed. While Hystories identifies country-specific profiles, our study observes a more uniform European-wide storage profile due to the balancing effect of the hydrogen and electricity grid. Differences in the modeling approach, specifically the "three-step" methodology employed by Hystories, may account for these deviations. The reduced storage capacity needs in 2040 in the Hystories project can be attributed to the differences in assumed demand. Both studies identify the UK, Sweden, and Ireland as net exporters and Germany, the Netherlands, and Belgium as net importers of hydrogen. Additionally, both projects foresee wind turbines dominating electricity generation by 2050.

Resulting hydrogen costs are in a comparable range. While Hystories finds hydrogen costs to be around 2-2.5 €/kg (60-75 €/MWh) in 2050, we observe higher costs of around 89 €/MWh on average across the scenarios. This could be due to differences in the techno-economic parameters as well as the higher hydrogen demand in our scenario assumptions.

In summary, our results align closely with Hystories concerning optimal storage capacities, but notable distinctions arise in optimal storage operation. These variations may be attributed to differences in modeling assumptions and methodologies.

6.2.3 European Hydrogen Backbone

Within Europe, distinct hydrogen importing and exporting countries will emerge, with hydrogen demand centers as primary importers. In the baseline results, an emerging north–south corridor is observed that will connect hydrogen production centers in the northern UK, Denmark, and Sweden to diverse demand centers across Europe by 2030. It should be noted that the hydrogen infrastructure roadmap of the European Hydrogen Backbone (EHB, 2023) is not considered as given in the model. The described hydrogen grid is part of the optimization results and optimized in alignment with the cost-optimal placement of hydrogen producers and storage facilities.
The European Hydrogen Backbone presents the vision of several European network operators. It is based on national analyses of the availability of existing natural gas infrastructure, and the future developments of the natural gas market and the hydrogen market.
Thereby, the European Hydrogen Backbone (EHB, 2022) foresees the establishment of five different pan-European supply and import corridors that can already emerge by 2030 to deliver the hydrogen demand targets set by the REPowerEU plan (European Commission, 2022).
In comparison with the results of this study, it can be seen that the described corridor C of the European Hydrogen Backbone, connecting the North Sea area with the mainland, is also part of the described scenario results (EHB, 2023). This corridor is described to include hydrogen supply from offshore wind, blue hydrogen, and large-scale integrated hydrogen projects in the North Sea to meet the demand in the UK, the Netherlands, Belgium, and Germany (EHB, 2022). The described corridor A of the European Hydrogen Backbone (EHB, 2023), connecting

North Africa and southern Europe, can be observed with increasing extra-European hydrogen imports as observed e.g. in the 2040 baseline scenario. Corridor B can be observed in several sensitivity scenarios, e.g., in the optimistic cost scenario, different weather year scenarios, or the seasonal imports scenario. The other corridors of the European Hydrogen Backbone cannot be observed, or they exhibit opposite flow directions.
While each country produces hydrogen to a certain extend domestically to cover its own demand, additionally required hydrogen is mainly sourced from wind energy and is therefore mainly provided in northern Europe or by extra-European imports. As described in Section 6.1.2, a more diversified energy mix would lead to a more decentralized allocation of hydrogen production, requiring additional infrastructure for hydrogen transmission. Several scenarios such as the ones described in Section 5.2.6 and 5.2.2 show the impact of a change in hydrogen production locations.

Nevertheless, the results of this report support the message that cross-border pipeline corridors are needed as connections between hydrogen supply and demand centers to achieve the goals of energy transition. The results also show a high level of reuse of the existing gas infrastructure for hydrogen transport, as it is also described by the European Hydrogen Backbone (EHB, 2023).

7 Conclusions

The results presented in this report reveal the increasing importance of UHS in the future European energy system. In the baseline scenarios of the three target years, the majority of hydrogen production occurs within Europe, with additional pipeline imports from North Africa. Several countries produce a share of their hydrogen demand domestically. Hydrogen transported through Europe to supply regions with high demand is predominantly sourced from wind turbines. These are strategically located in northern Europe, particularly in the UK and Denmark, and capitalize on favorable wind conditions. Within Europe, distinct hydrogen-importing and -exporting countries emerge, with countries having large hydrogen demand centers as primary importers. An emerging north–south corridor is observed to connect green hydrogen production centers in the northern UK, Denmark, and Sweden to diverse demand centers across Europe by 2030. UHS plays a pivotal role in bridging seasonal fluctuations in green hydrogen production and is further utilized to balance demand and supply on smaller timescales, i.e., weekly to daily fluctuations. The optimal spatial distribution of storage locations strategically aligns with hydrogen transit routes, ensuring efficient transport from production centers to demand hubs.

The baseline scenarios foresee storage capacities of 50 TWh in 2030, extending to 260 TWh in 2050, discharging over 22% (700 TWh, 2050) of the annual hydrogen demand throughout the year. In terms of surface components, the results show a total injection capacity for cavern storage of 195 GW and total withdrawal capacity of 250 GW. At the same time, the injection capacity for pore storage is notably lower with 138 GW and the withdrawal capacity is 120 GW. In general, the UHS stands out to be instrumental as a cost-efficient technology for securing the hydrogen supply, accounting for only 2.4% of the total annual system costs.

Further aspects of UHS are explored in sensitivity scenarios. A comparison of all scenario results on required hydrogen storage capacities for the three target years are presented in Figure 9-2, Figure 9-3, and Figure 9-4 in the appendix. The sensitivity scenarios reveal a linear relationship between hydrogen demand and optimal UHS capacity. If pipeline capacities are not a bottleneck, it does not significantly affect the costs whether a storage facility is installed near production, near consumption, or in between, and the placement will therefore depend more on availability.
Differing technology cost assumptions (see “optimistic” or “pessimistic” cost scenarios from de Maigret and Viesi, (2023)) can impact the optimal electricity mix and therefore the location of hydrogen production, hydrogen corridors and hydrogen storage. Both increased conventional power generation and increased PV have been shown to significantly change the optimal storage operation, capacity, and location, and resulting hydrogen corridors.
Different weather conditions, which were modeled by assuming different weather years, have a strong impact on the resulting optimal storage capacities ranging from 83 to 260 TWh for the target year of 2050. The storage capacity requirements are chiefly dictated by the balance of surplus or deficit residual electricity available for hydrogen production. Furthermore, due to changes in weather conditions in exporting extra-European countries hydrogen imports can become more favorable.
The assumption of constant hydrogen imports can lead to lower hydrogen storage capacity with increasing annual import amounts, an effect that is not observable if seasonal hydrogen imports are assumed. Having significantly more renewable capacity in the system than necessary leads to reduced hydrogen storage capacities from 52 to 33 TWh in 2030, as periods of deficit supply are less frequent. Conversely, limiting renewable expansion increases reliance on external hydrogen sources, lowering optimal storage capacities from 260 TWh to 220 TWh by 2040, due to constant import assumptions. Imposing limitations on grid expansion has shown to restrict certain hydrogen corridors leading to a more centralized hydrogen production and the need for liquefied hydrogen imports. Notably, grid restrictions lead to higher storage cycles for pore storages which must be utilized more frequently to also cover short

term fluctuations. Furthermore, the absence of the UK as provider of additional hydrogen for central Europe has a notable impact on the storage levels throughout the year.

To summarize, the results have shown that optimal UHS capacity is dictated by multifaceted interplay of determinants. These determinants encompass various factors, notably including: the quantity, geographical distribution, and temporal availability of hydrogen imports; the hydrogen demand which demonstrates a linear correlation with the required storage capacity; the electricity mix of the energy system from which hydrogen is produced which impacts daily and seasonal hydrogen production patterns and favorable hydrogen production locations; the prevailing meteorological conditions which dictate the amount of residual electricity and consequently significantly impact the amount of hydrogen that is stored or discharged and potential system restrictions which potentially limit the availability of hydrogen transport.

From a cost perspective, it appears that pore storage capacities are not indispensable for the future European energy system, yielding total annual cost improvements of approximately 0.4% (€2 billion euro/year) if a pronounced hydrogen grid developed. However, implementing pore storage capacities enables a more decentralized approach to UHS across Europe. This enhances resilience and accessibility within the hydrogen infrastructure while reducing the need for the implementation of new salt caverns as hydrogen storage.

The findings indicate that UHS will be crucial in the future European energy system due to the increasing prominence of hydrogen in the energy transition. This highlights the importance of strategic planning for storage infrastructure. Stakeholders should collaboratively devise cohesive strategies, considering factors like grid expansion, renewable energy integration, and evolving hydrogen demand patterns. The cultivation of a comprehensive perspective in planning is imperative, as it renders the integration of UHS a cohesive element within a resilient, sustainable, and adaptive future energy system. Decisions related to site-specific realizations and capacities must be made individually for each site, taking into account the specific restrictions and requirements of that location. Continued investment in research and development is crucial to refine storage technologies and address safety concerns.

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9 Appendix

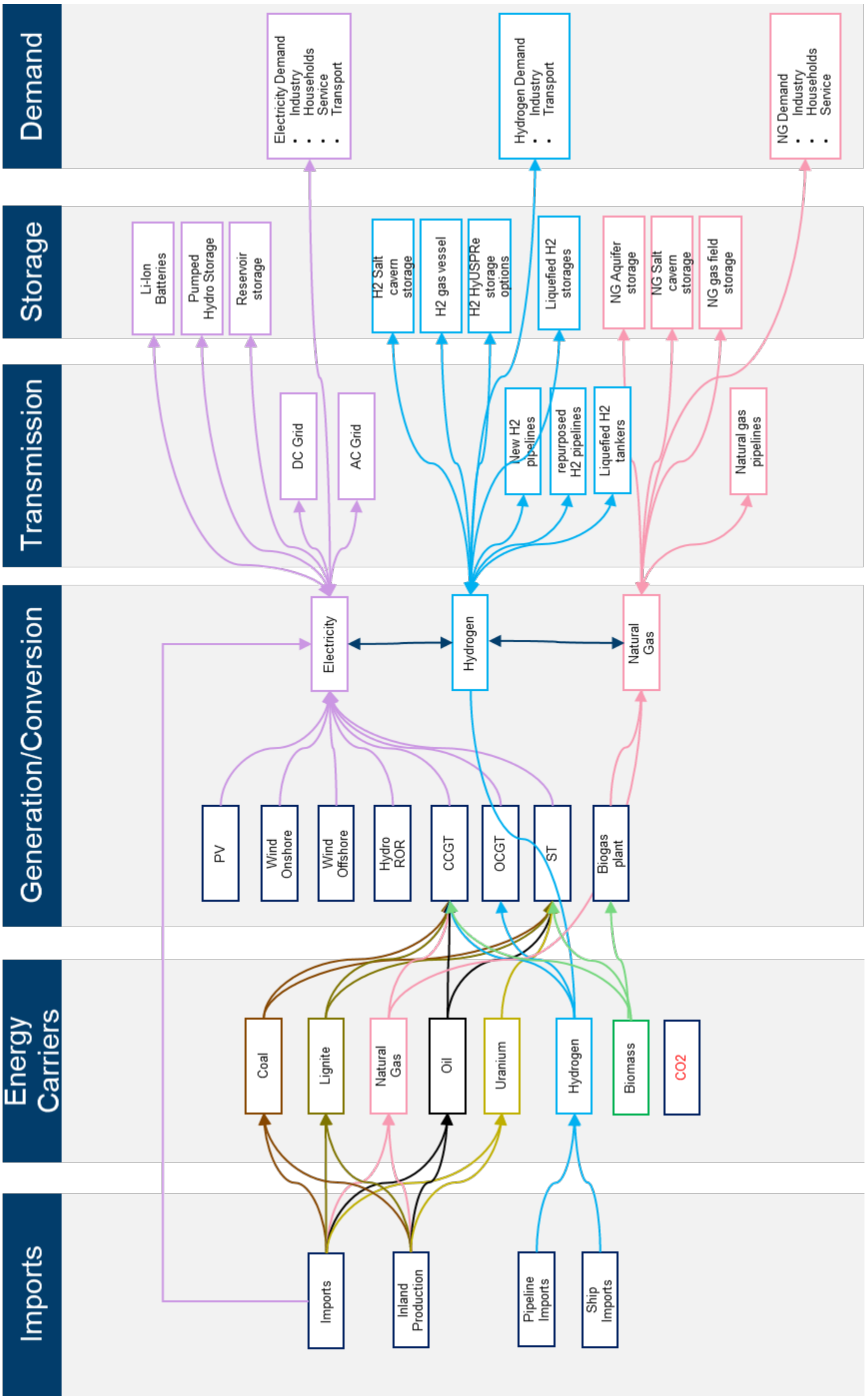

Figure 9-1. Overview of the European energy system model: modeled components and interconnections between them.

Table 2. Assumed commodity prices in €/MWh based on [(Breyer et al. 2022; Erichsen et al. 2019; IEA 2022; ENTSO-S 2022)].

	2030			2040			2050		
commodity	pessimistic	average	optimistic	pessimistic	average	optimistic	pessimistic	average	optimistic
Oil	48.8	44.4	37.7	43.5	43.5	43.5	50.9	49.4	29.1
Natural gas	29.7	31.1	28.6	40.2	40.2	40.2	36.3	33.6	28.9
Hard coal	17.5	12.8	8.7	11.1	11.1	11.1	18.6	12.0	7.5
Uranium	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Lignite	11.3	10.1	9.1	8.6	7.0	5.3	6.0	4.0	1.5

Table 3. Assumed techno-economic parameters for fossil power plants based on [(The World Bank 2021; Lopion 2020; Breyer et al 2022)].

		2030			2040			2050		
technology	variable	optimistic	average	pessimistic	optimistic	average	pessimistic	optimistic	average	pessimistic
Hard Coal Power Plant	economicLifetime	42.500	42.500	42.500	42.500	42.500	42.500	42.500	42.500	42.500
	investPerCapacity	2.100	2.461	2.822	2.100	2.461	2.822	2.100	2.461	2.822
	opexPerCapacity	0.041	0.047	0.052	0.041	0.047	0.052	0.041	0.047	0.052
Nuclear Power Plant	economicLifetime	40.000	45.000	40.000	40.000	45.000	40.000	40.000	45.000	40.000
	investPerCapacity	5.621	6.212	7.911	5.621	6.005	7.911	5.621	5.970	7.911
	opexPerCapacity	0.107	0.113	0.150	0.107	0.106	0.150	0.107	0.104	0.150
NG CCGT	economicLifetime	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000
	investPerCapacity	0.834	0.997	1.161	0.834	0.997	1.161	0.834	0.997	1.161
	opexPerCapacity	0.014	0.017	0.020	0.014	0.017	0.020	0.014	0.017	0.020
NG OCGT	economicLifetime	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000
	investPerCapacity	0.721	0.810	0.900	0.721	0.810	0.900	0.721	0.810	0.900
	opexPerCapacity	0.014	0.015	0.017	0.014	0.015	0.017	0.014	0.015	0.017
Lignite Power Plant	economicLifetime	45.000	45.000	45.000	45.000	45.000	45.000	45.000	45.000	45.000
	investPerCapacity	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500	1.500
	opexPerCapacity	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045
Oil Power Plant	economicLifetime	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000	25.000
	investPerCapacity	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900
	opexPerCapacity	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.117

Table 4. Assumed techno-economic parameters for missing transmission technologies based on [(European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014; Reuß et al 2019)].

		2030			2040			2050		
technology	variable	pessimistic	average	optimistic	pessimistic	average	optimistic	pessimistic	average	optimistic
HVDC	Technical lifetime	60	60	60	60	60	60	60	60	60
	investPerCapacity	0.00112	0.00102	0.00092	0.0011	0.00096	0.0008	0.00108	0.0009	0.0007
	opexPerCapacity	0.0000392	0.0000357	0.0000322	0.0000385	0.0000336	0.000028	0.0000378	0.0000315	0.0000245
	losses	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001
H2 compressor station	Technical lifetime	15	15	15	15	15	15	15	15	15
	investPerCapacity	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042
	opexPerCapacity	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04

Table 5. Assumed techno-economic parameters for missing storage technologies [(Stolten et al., 2022)].

technology	variable	unit	2,030	2,040	2,050
battery_LIIon	economicLifetime	[a]	15	15	15
	investPerCapacity	[1e9$/GW_el]	0.18	0.15	0.13
	opexPerCapacity	[1e9$/GW_el/a]	0	0	0
	chargeEfficiency	[%]	0.99	0.99	0.99
	dischargeEfficiency	[%]	0.99	0.99	0.99
	cyclicLifetime	[h]	10,000	10,000	10,000
	chargeRate	[1/h]	1	1	1
	dischargeRate	[1/h]	1	1	1
	selfDischarge	[1/h]	0.000042	0.000042	0.000042

Table 6. Assumed techno-economic parameters for additional biomass components [(Danish Energy Agency, 2022a; 2022b)].

	variable	unit	2030	2040	2050
09a Wood Chips, Large 50 degree	Efficiency	[]	0.269909	0.26754	0.265171
	Technical lifetime	[a]	25	25	25
	investPerCapacity	[1e9€/GW_e]	3.35	3.255	3.16
	opexPerCapacity	[1e9€/GW_e/a]	0.096	0.093	0.09
08 WtE CHP, Large, 50 degree	Efficiency	[]	0.208126	0.2123315	0.216537
	Technical lifetime	[a]	25	25	25
	investPerCapacity	[1e9€/GW_e]	8.11	7.59	7.07
	opexPerCapacity	[1e9€/GW_e/a]	0.191	0.1765	0.162
81 Biogas Plant, Basic conf.	Efficiency	[]	1	1	1
	Technical lifetime	[a]	20	20	20
	investPerCapacity	[1e9€/GW_e]	1.54	1.465	1.39
	opexPerCapacity	[1e9€/GW_e/a]	0.197702	0.196712	0.195722
82 Biogas, upgrading	Efficiency	[]	1	1	1
	Technical lifetime	[a]	15	15	15
	investPerCapacity	[1e9€/GW_biogas]	0.381	0.362	0.343
	opexPerCapacity	[1e9€/GW_biogas/a]	0.0095	0.00905	0.0086

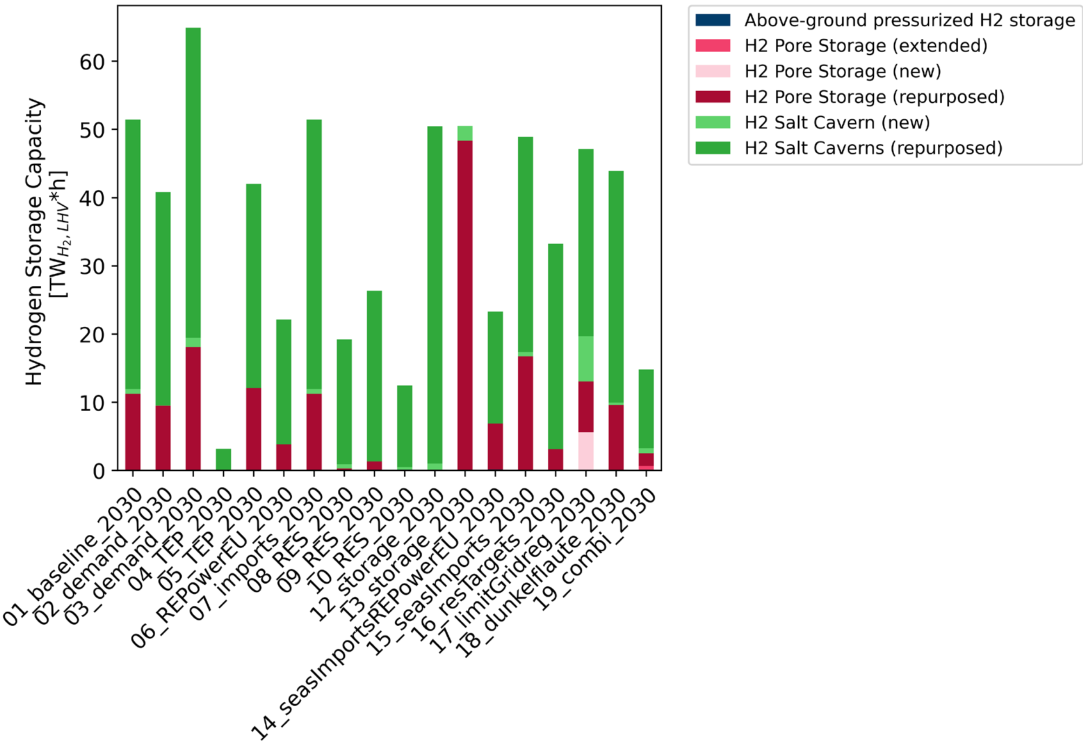

Figure 9-2. Optimal hydrogen storage capacities in all scenarios for 2030. For information on scenario descriptions see Table 1.

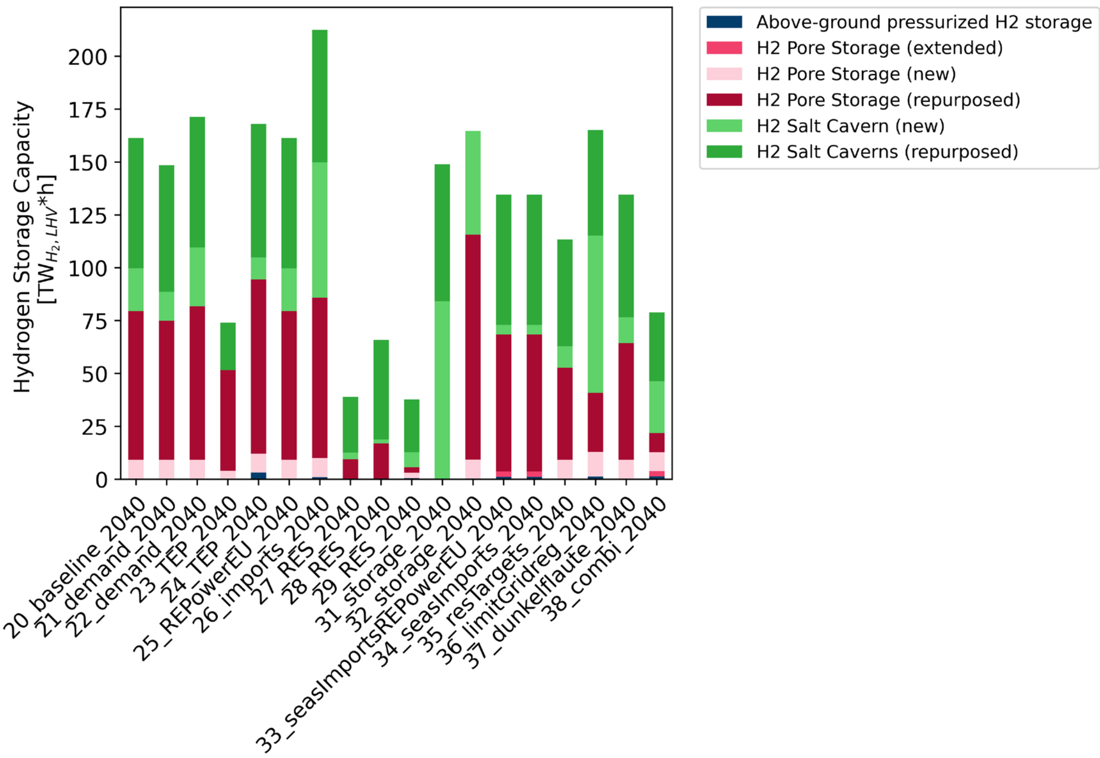

Figure 9-3. Optimal hydrogen storage capacities in all scenarios for 2040. For information on scenario descriptions see Table 1.

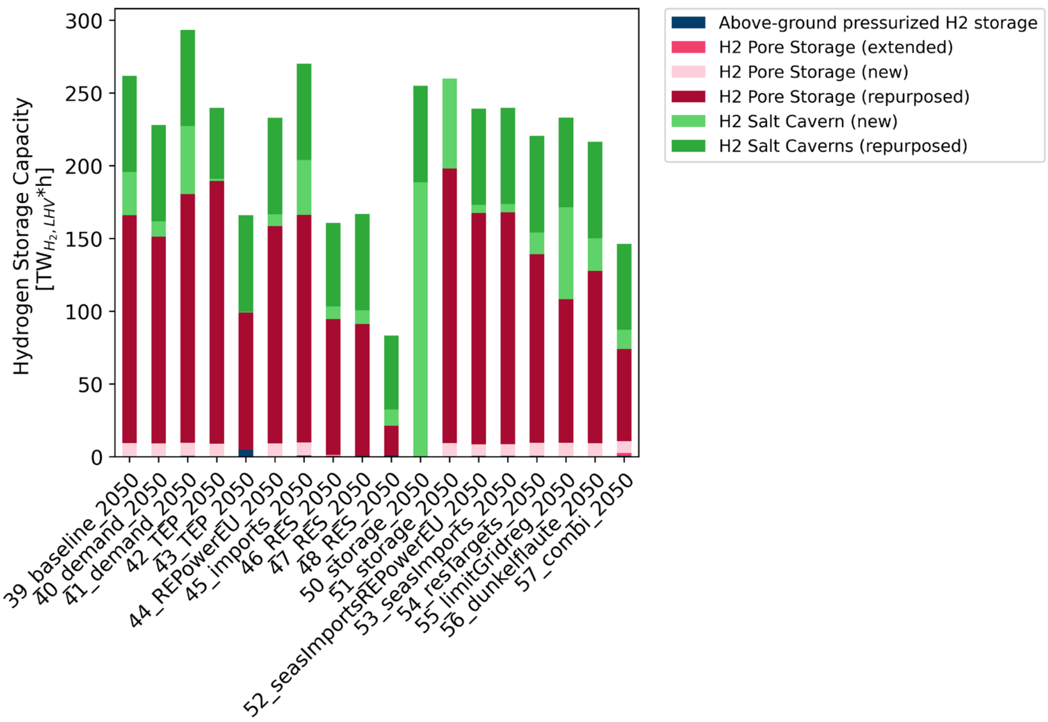

Figure 9-4. Optimal hydrogen storage capacities in all scenarios in 2050. For information on scenario descriptions see Table 1.

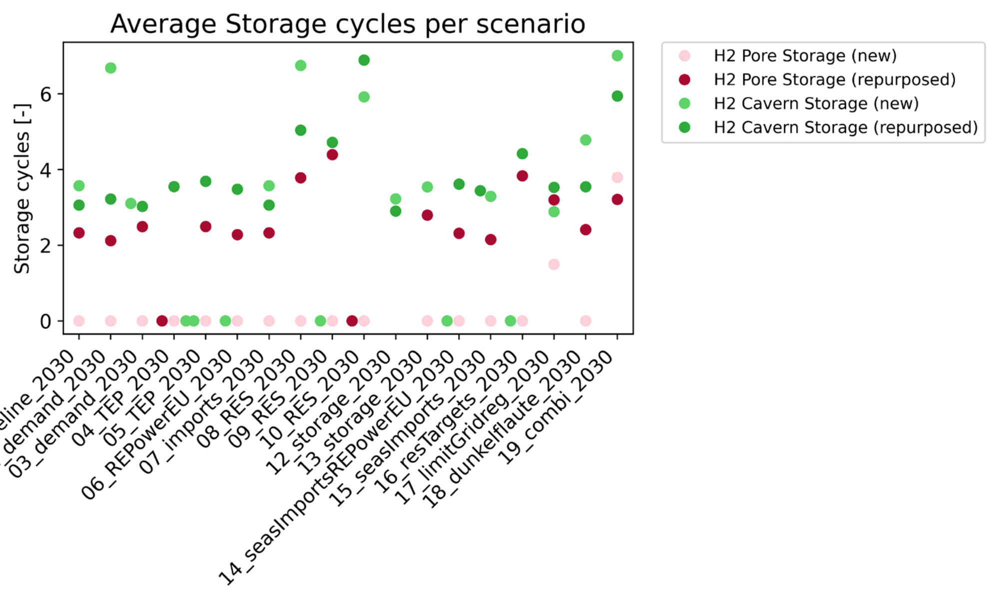

Figure 9-5 Optimal hydrogen storage cycles in all scenarios for 2030. For information on scenario descriptions see Table 1.

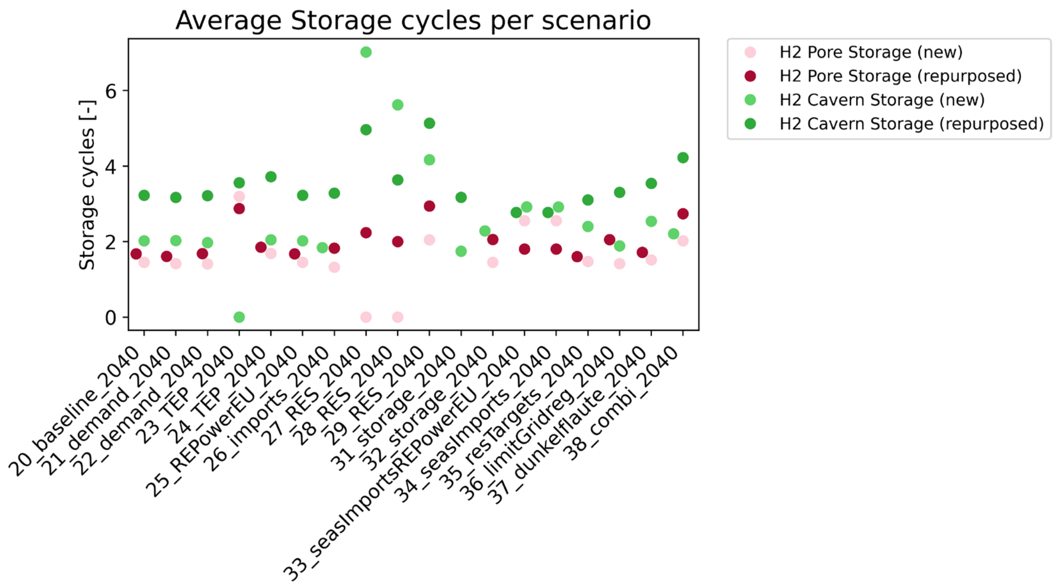

Figure 9-6 Optimal hydrogen storage cycles in all scenarios for 2040. For information on scenario descriptions see Table 1.

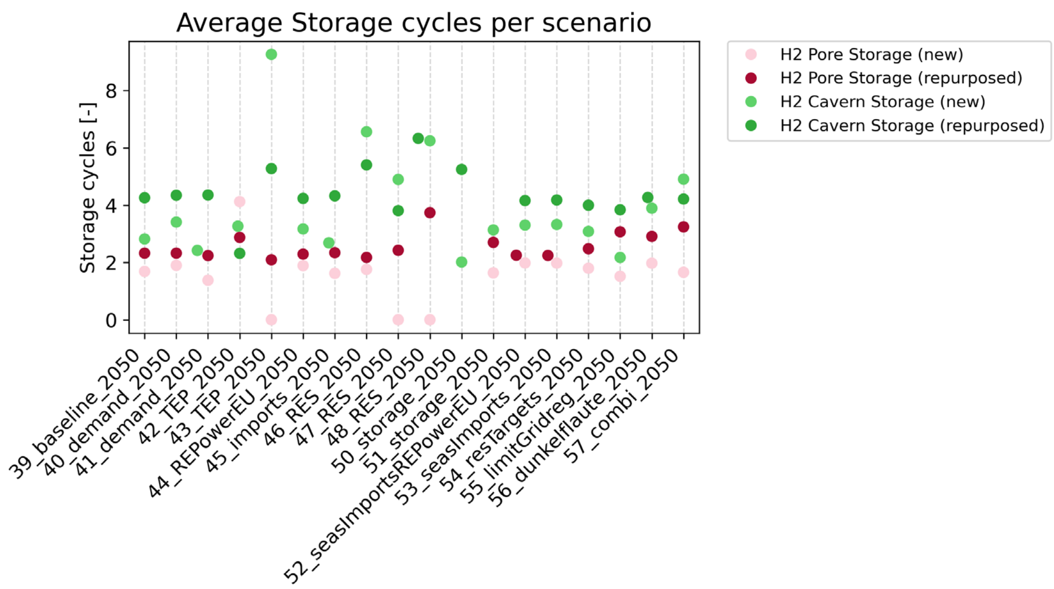

Figure 9-7 Optimal hydrogen storage cycles in all scenarios for 2050. For information on scenario descriptions see Table 1.

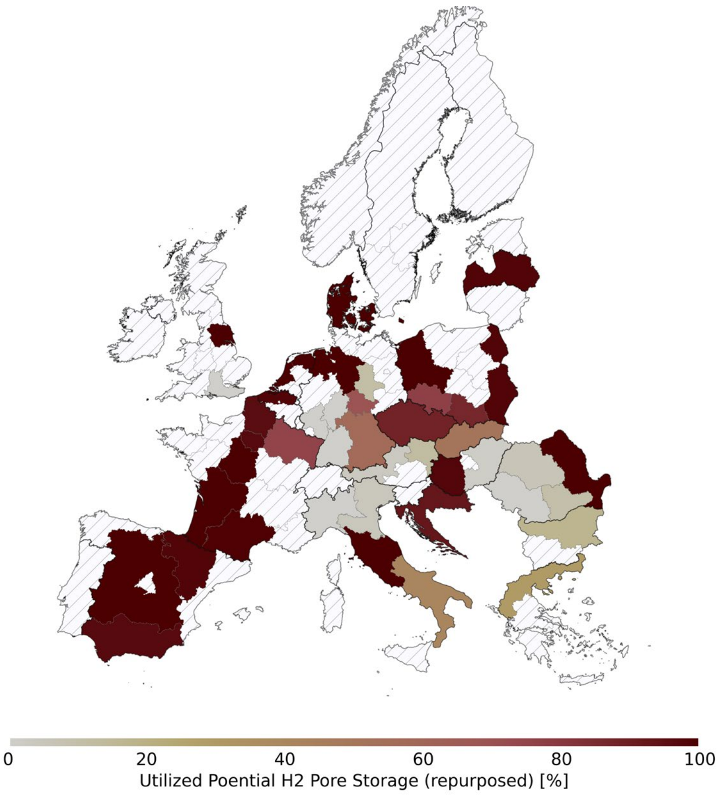

Figure 9-8. Potential utilization (map) of repurposed pore storage in the baseline scenario for 2050.

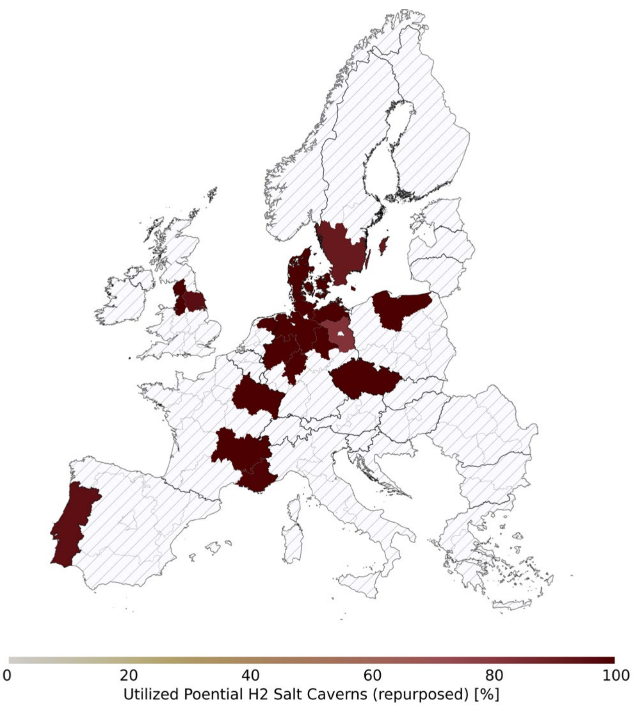

Figure 9-9. Potential utilization (map) of repurposed salt cavern storage in the baseline scenario for 2050.

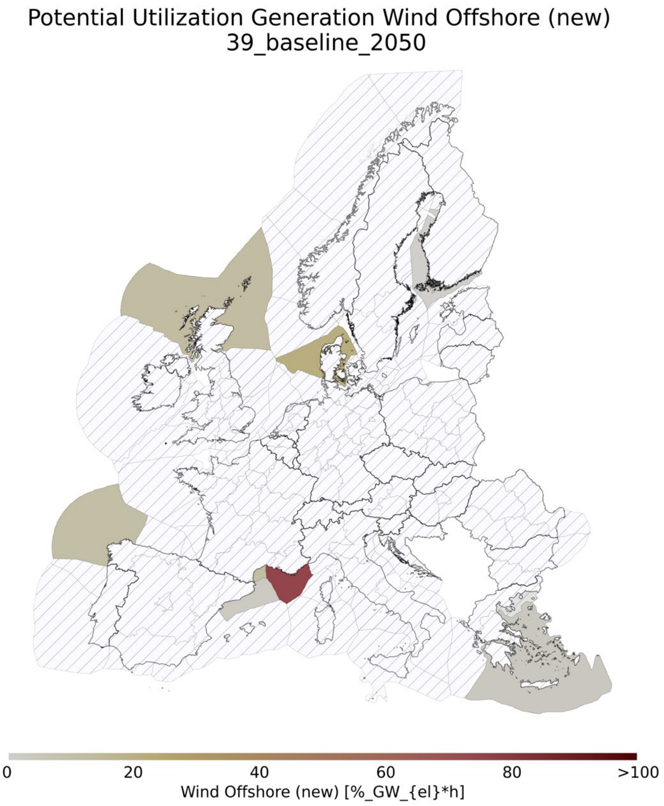

Figure 9-10. Potential utilization (map) of wind offshore capacity in the baseline scenario for 2050.

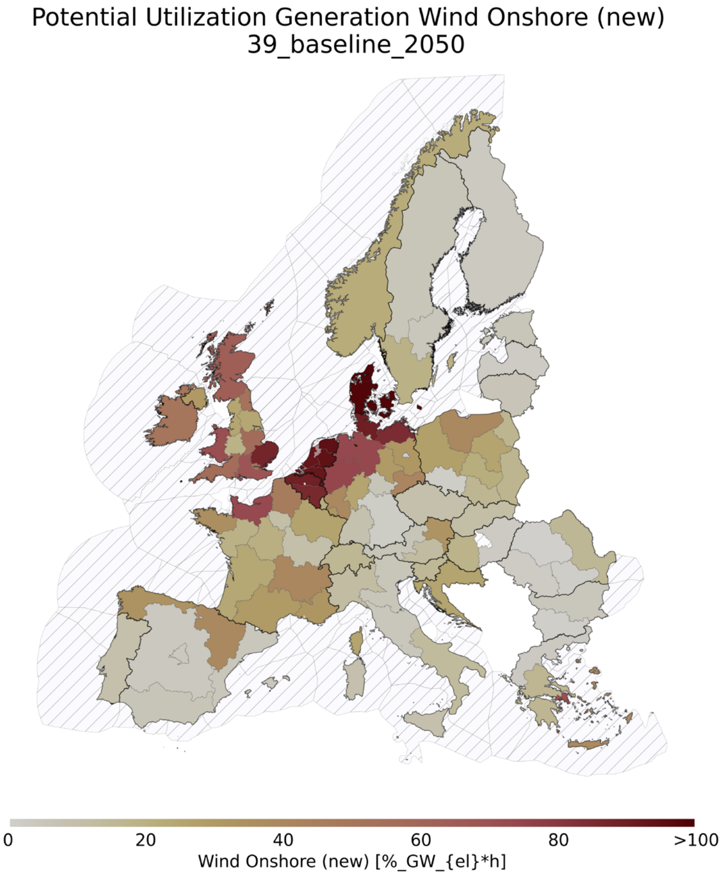

Figure 9-11. Potential utilization (map) of wind onshore capacity in the baseline scenario for 2050.

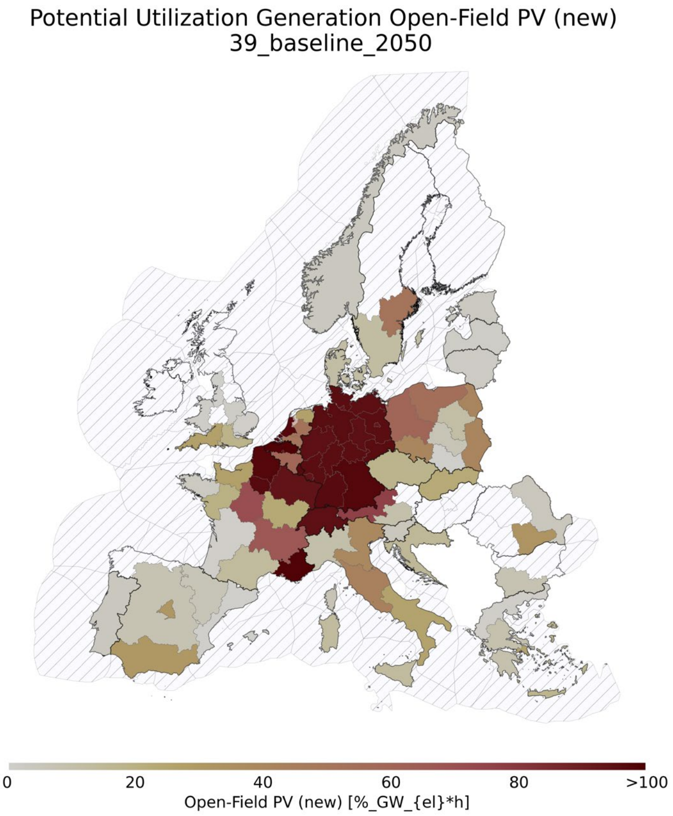

Figure 9-12. Potential utilization (map) of OFPV capacity in the baseline scenario for 2050.

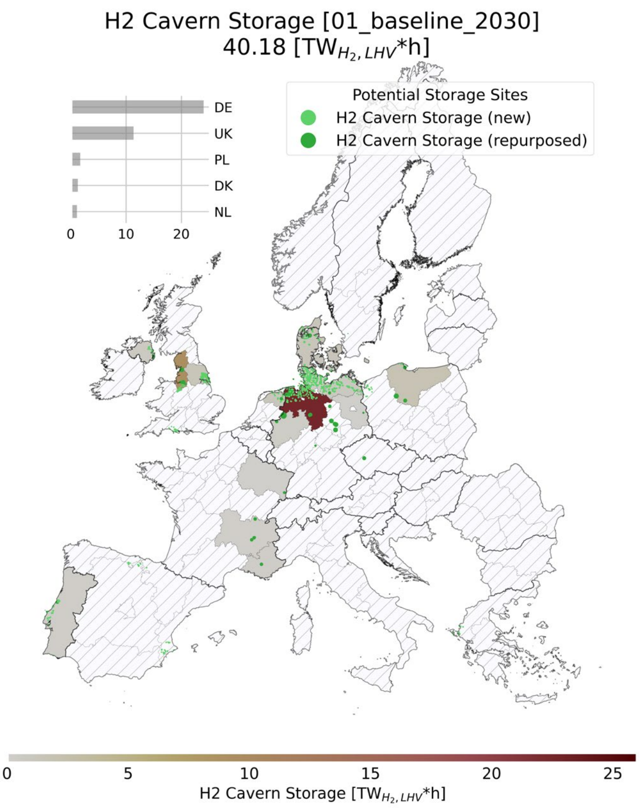

Figure 9-13. Hydrogen cavern storage capacity map for the baseline scenario for 2030.

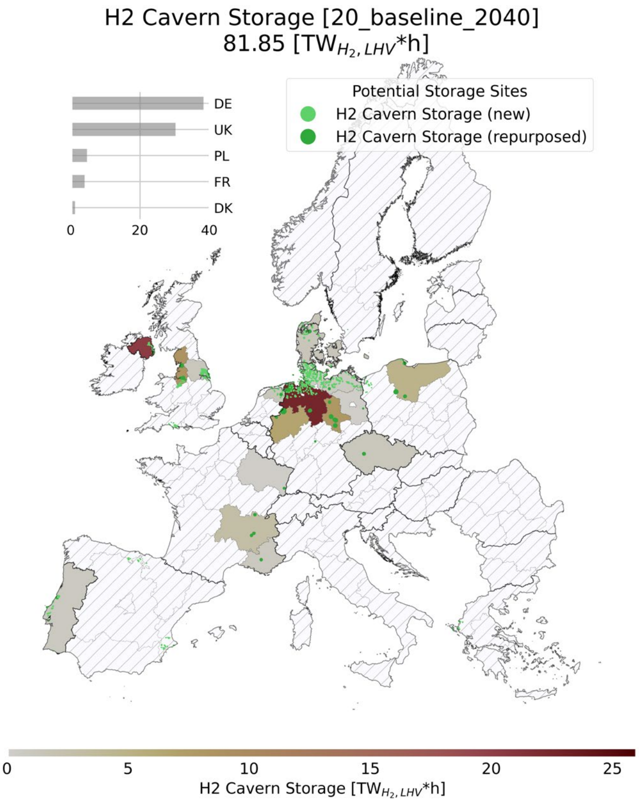

Figure 9-14. Hydrogen cavern storage capacity map for the baseline scenario for 2040.

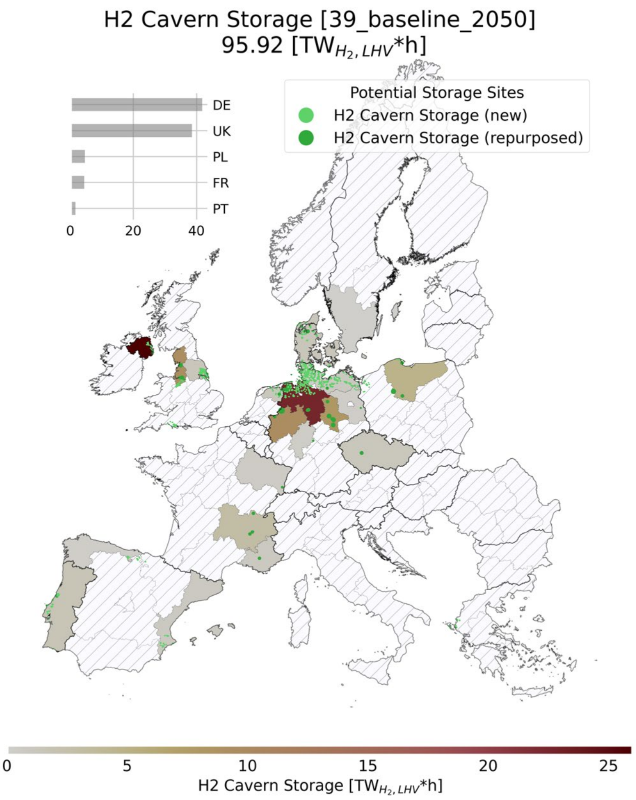

Figure 9-15. Hydrogen cavern storage capacity map for the baseline scenario for 2050.

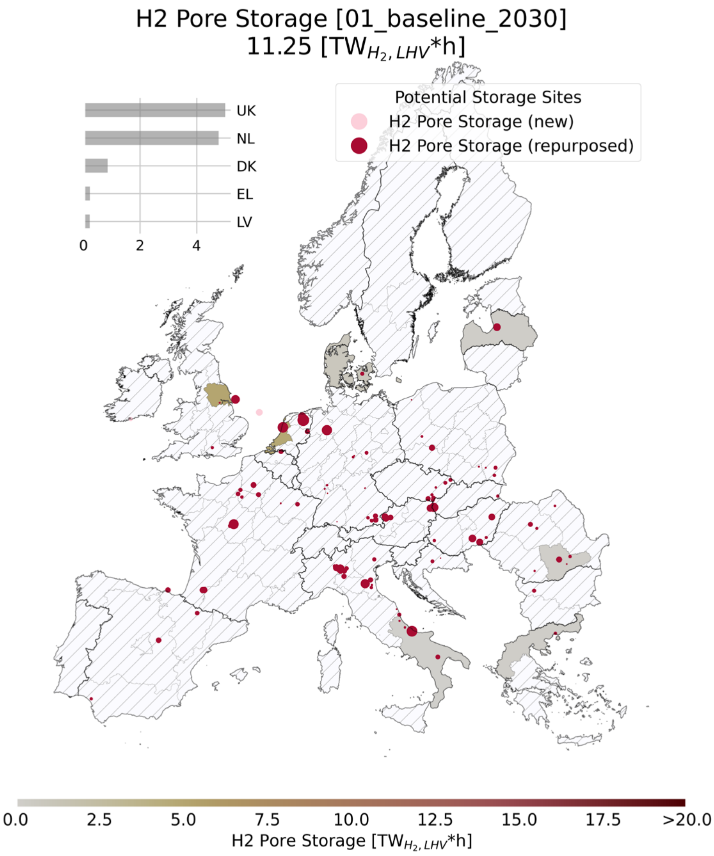

Figure 9-16. Hydrogen pore storage capacity map for the baseline scenario for 2030.

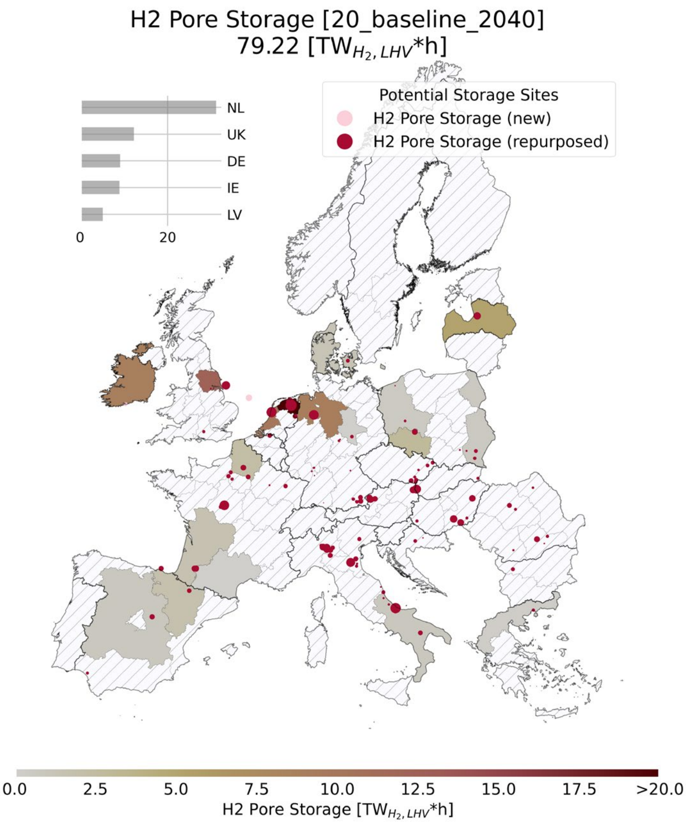

Figure 9-17. Hydrogen pore storage capacity map for the baseline scenario for 2040.

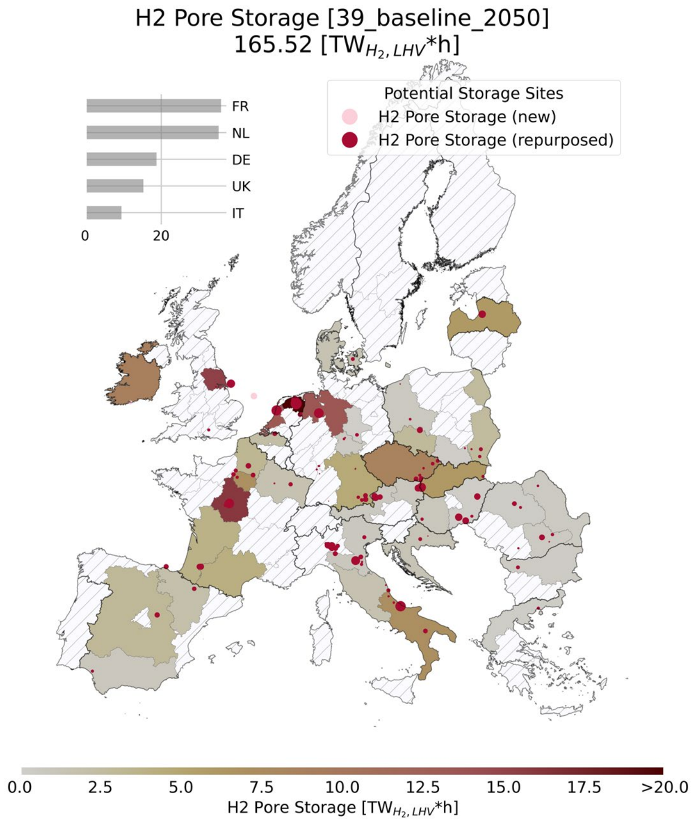

Figure 9-18. Hydrogen pore storage capacity map for the baseline scenario for 2050.

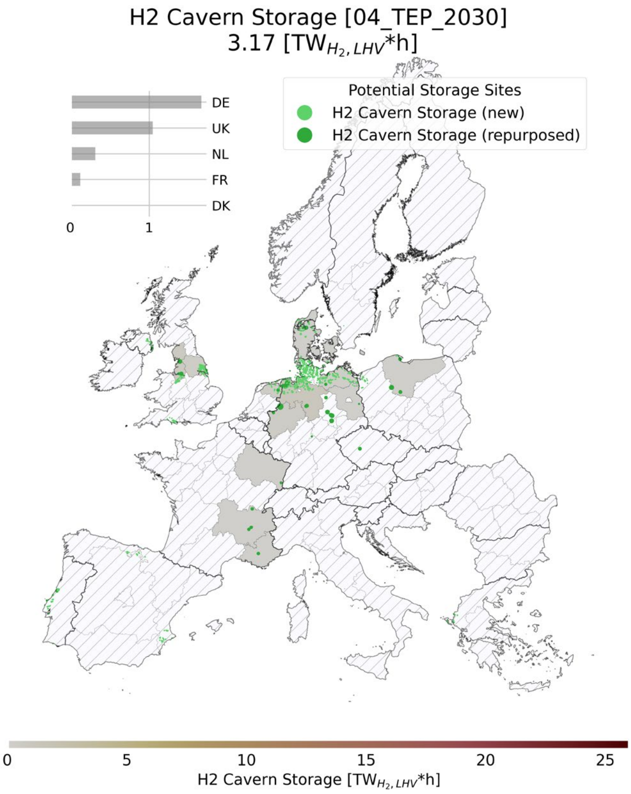

Figure 9-19. Hydrogen cavern storage capacity map for the *pessimistic* costs scenario in 2030.

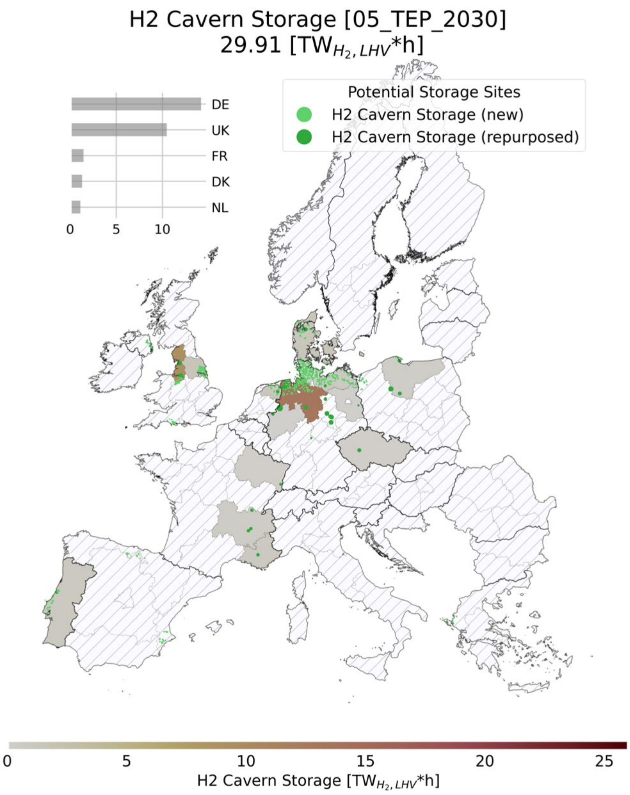

Figure 9-20. Hydrogen cavern storage capacity map for the *optimistic* costs scenario in 2030.

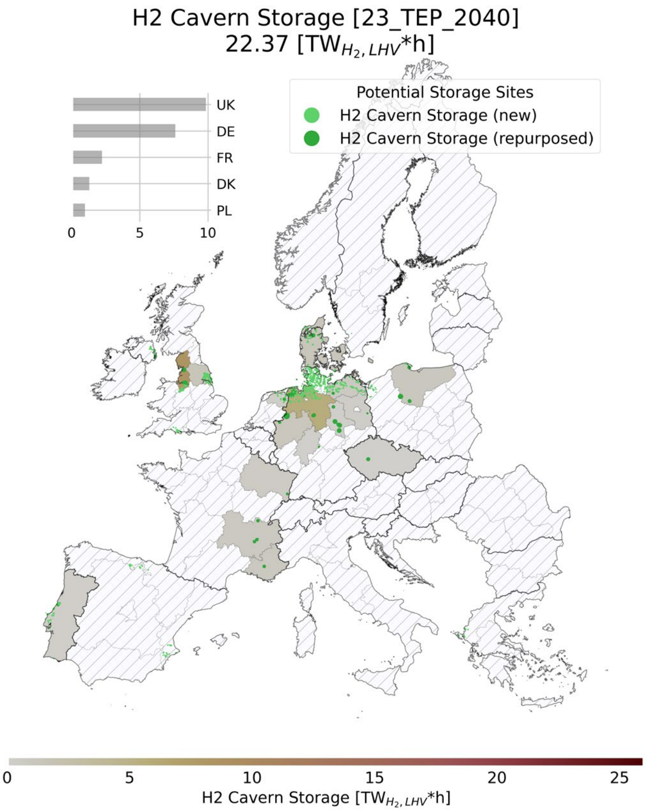

Figure 9-21. Hydrogen cavern storage capacity map for the pessimistic costs scenario in 2040.

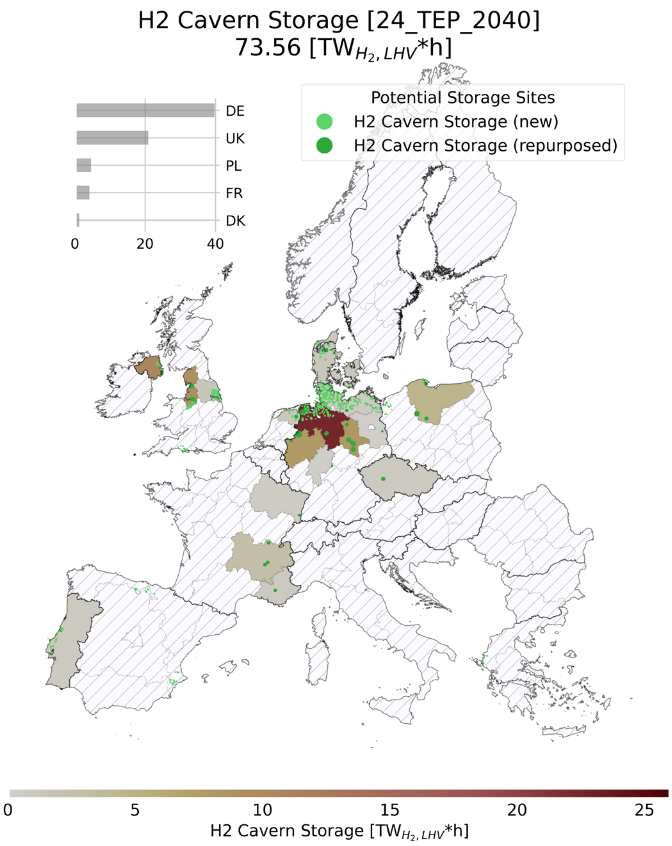

Figure 9-22. Hydrogen cavern storage capacity map for the optimistic costs scenario in 2040.

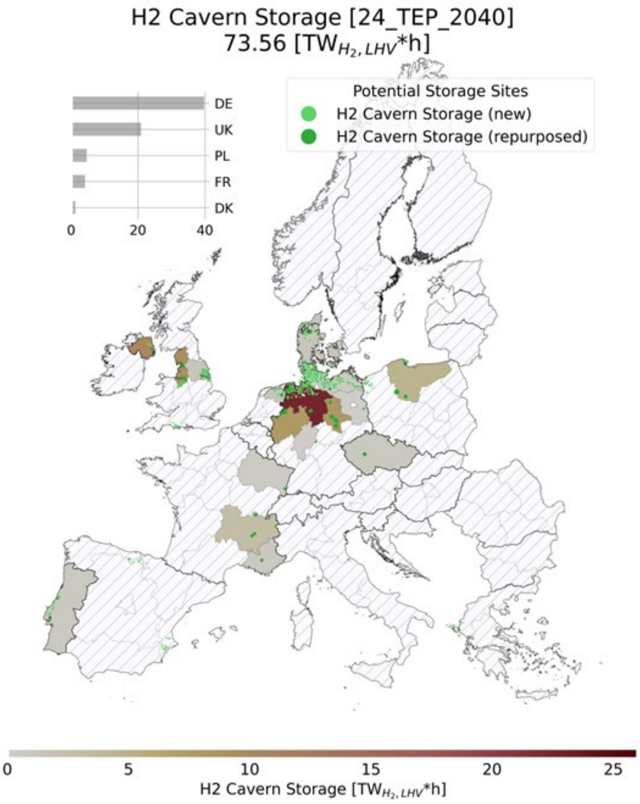

Figure 9-23. Hydrogen cavern storage capacity map for the pessimistic costs scenario in 2050.

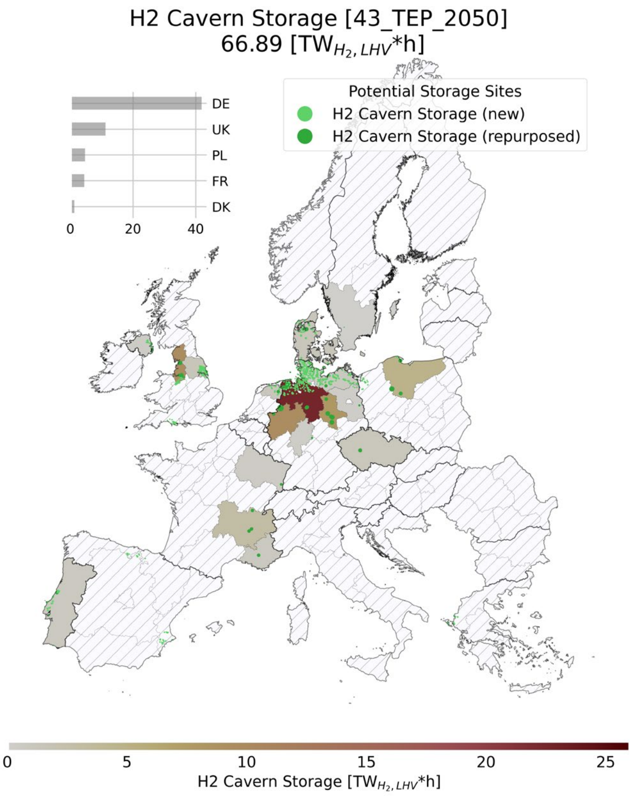

Figure 9-24. Hydrogen cavern storage capacity map for the optimistic costs scenario in 2050.

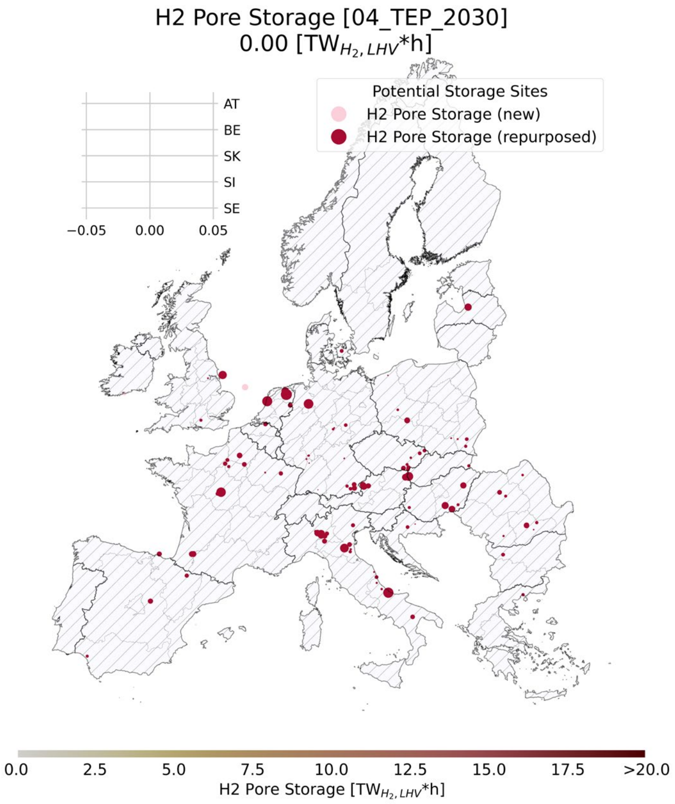

Figure 9-25. Hydrogen pore storage capacity map for pessimistic costs scenario in 2030.

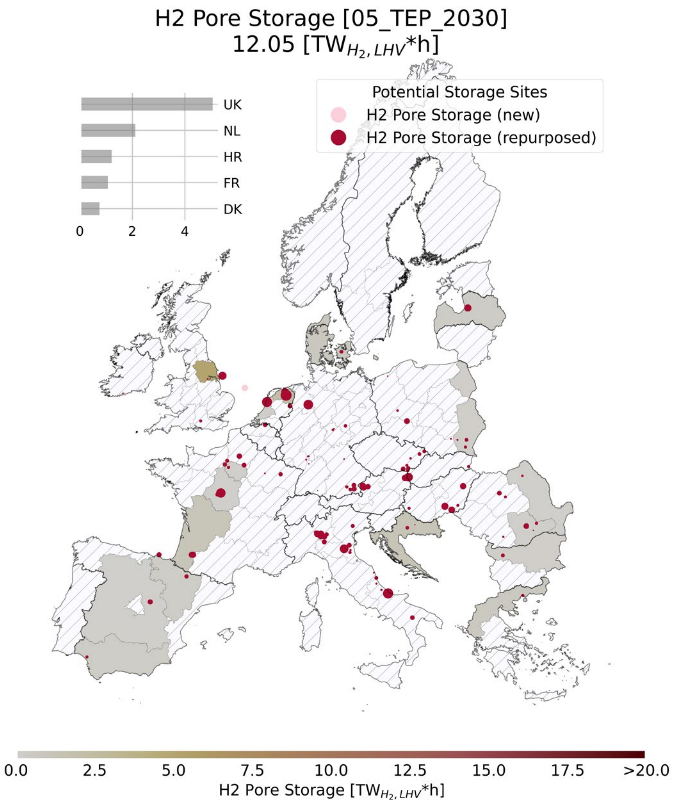

Figure 9-26. Hydrogen pore storage capacity map for the optimistic costs scenario in 2030.

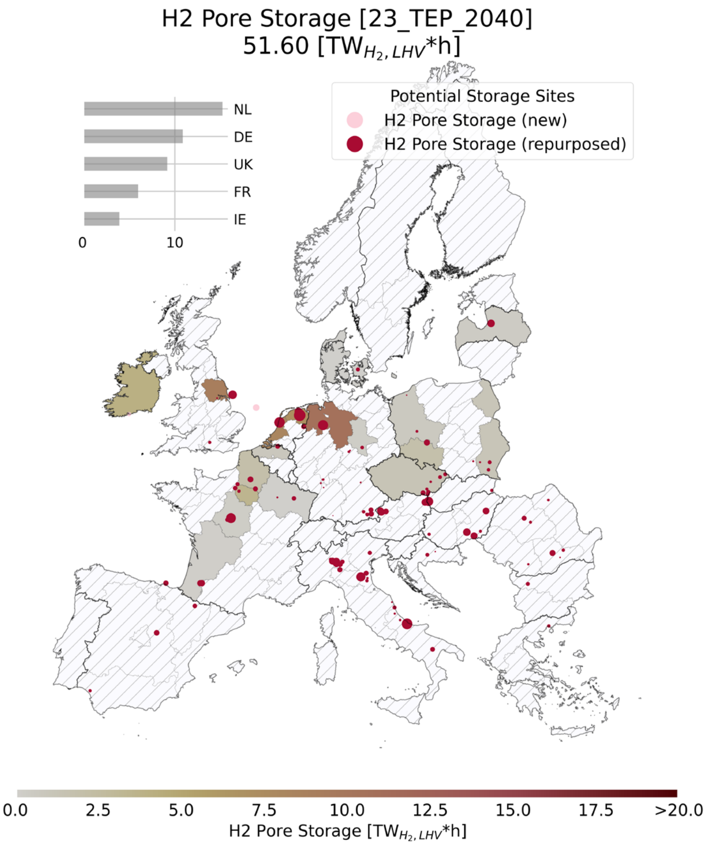

Figure 9-27. Hydrogen pore storage capacity map for the pessimistic costs scenario in 2040.

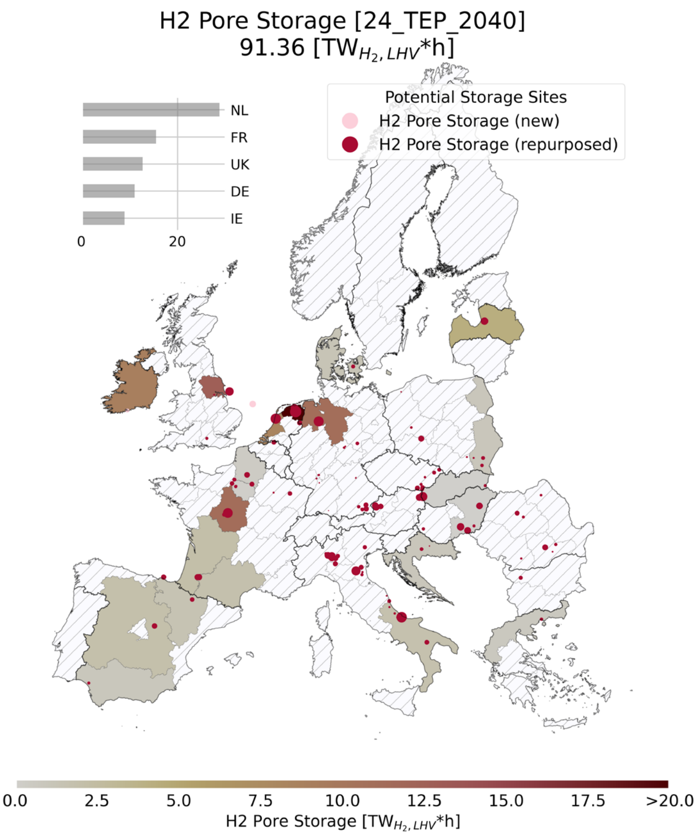

Figure 9-28. Hydrogen pore storage capacity map for the optimistic costs scenario in 2040.

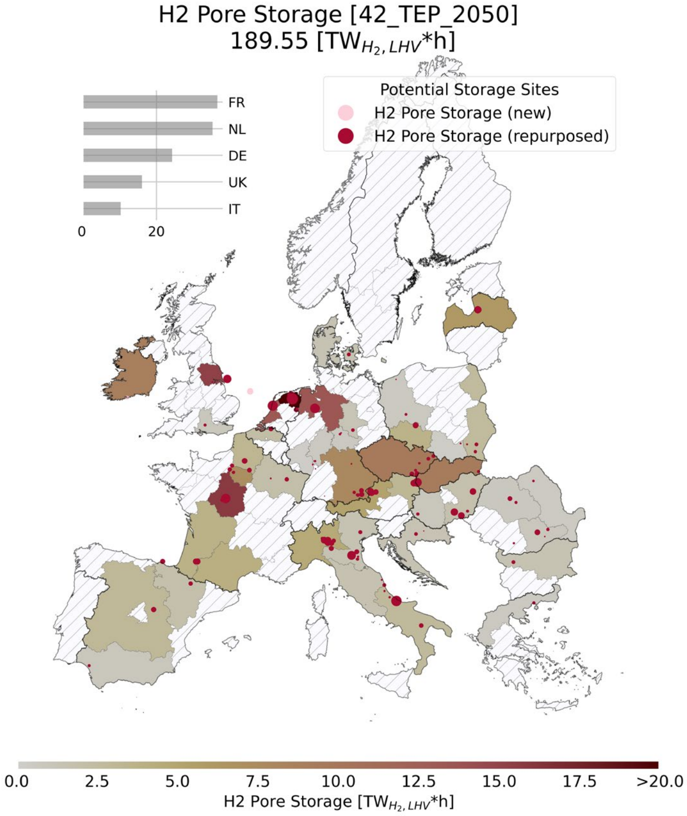

Figure 9-29. Hydrogen pore storage capacity map for the pessimistic costs scenario in 2050.

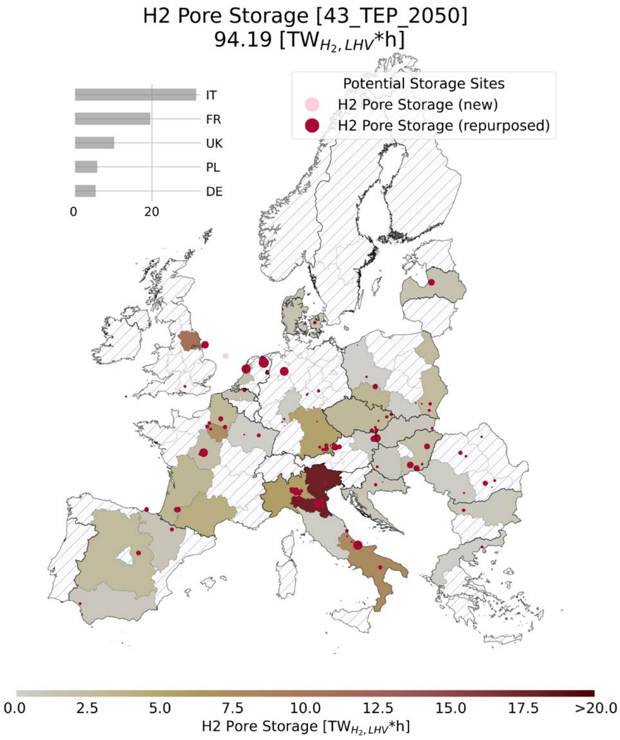

Figure 9-30. Hydrogen pore storage capacity map for the optimistic costs scenario in 2050.

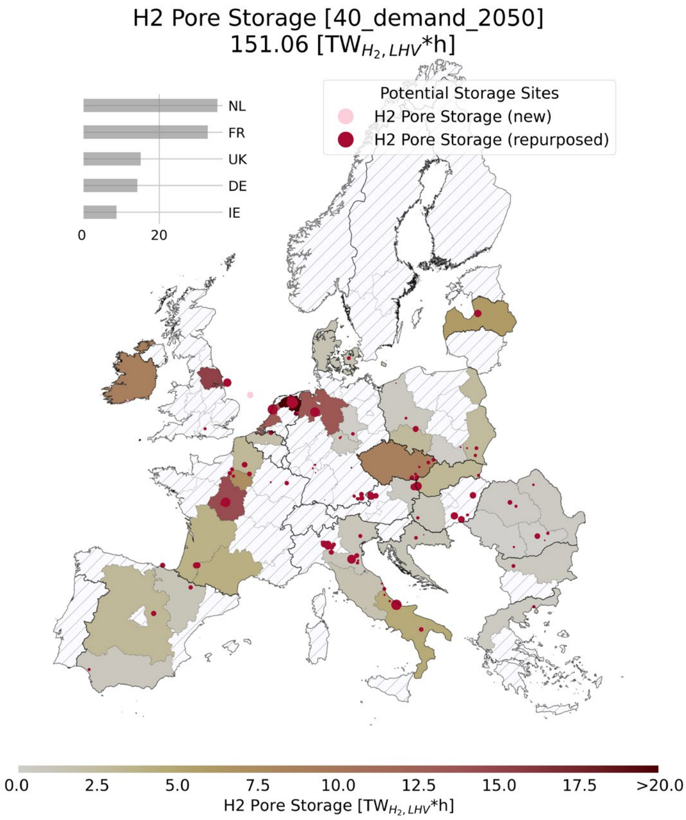

Figure 9-31. Hydrogen pore storage capacity map for the reduced demand scenario in 2050.

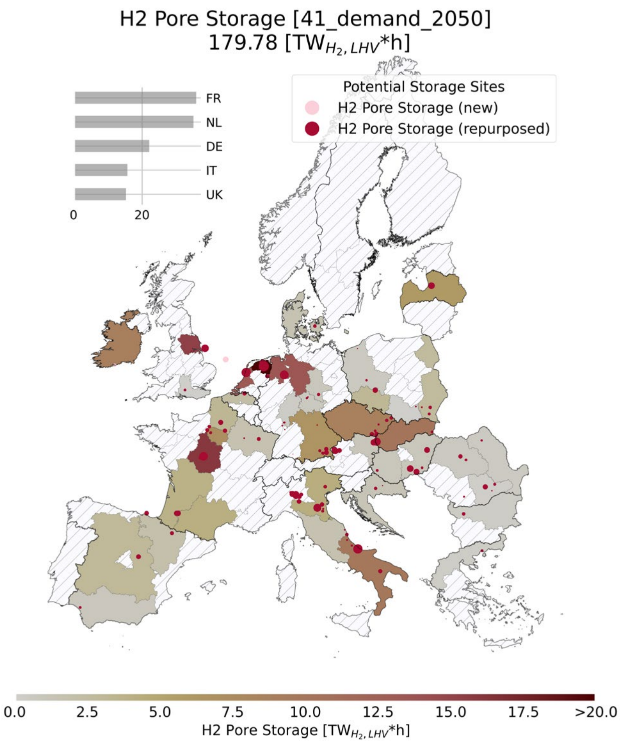

Figure 9-32. Hydrogen pore storage capacity map for the ambitious demand scenario in 2050.

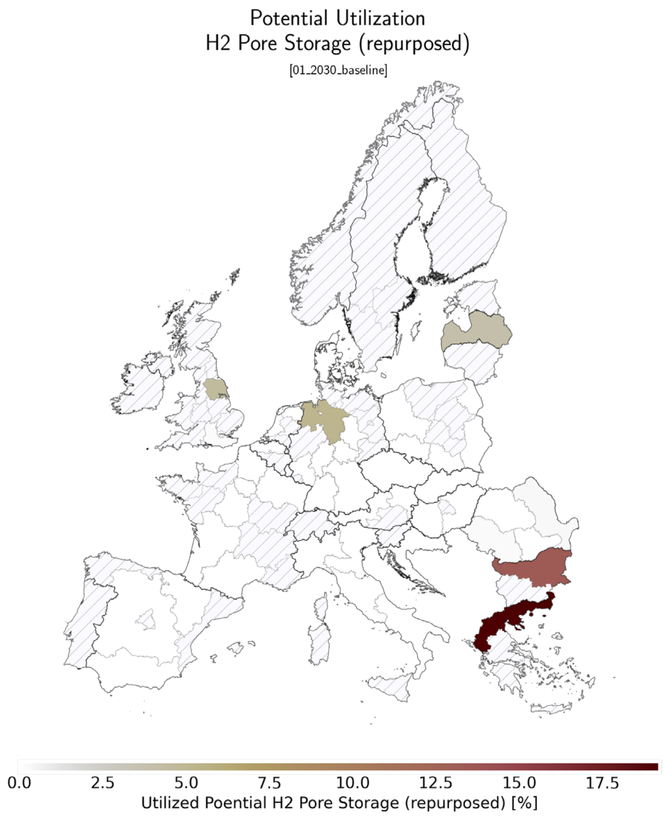

Figure 9-33. Utilization of repurposed pore storage potential (map) in the baseline scenario for 2030.

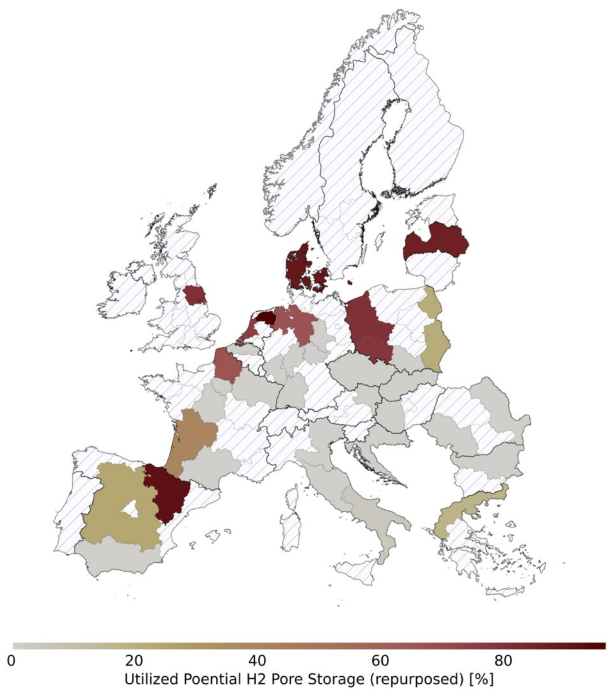

Figure 9-34. Utilization of repurposed pore storage potential (map) in the baseline scenario for 2040.

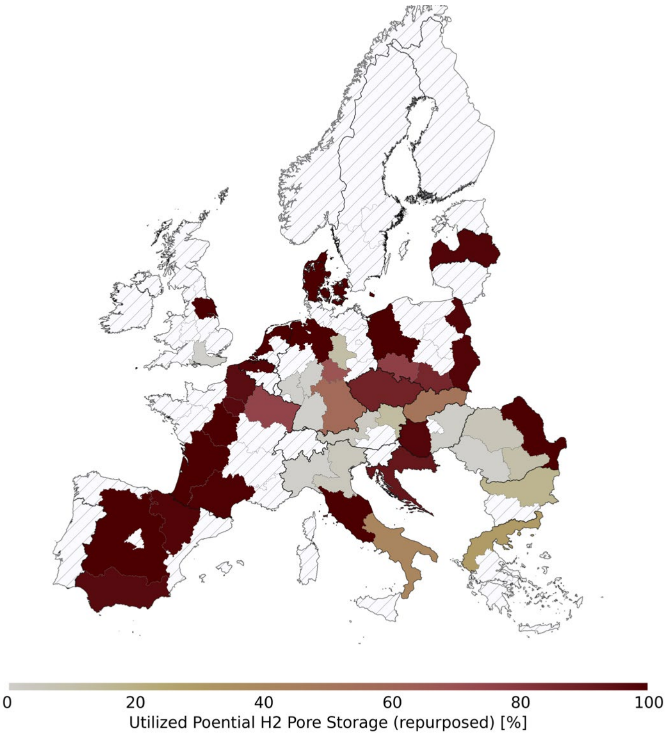

Figure 9-35. Utilization of repurposed pore storage potential (map) in the baseline scenario for 2050.

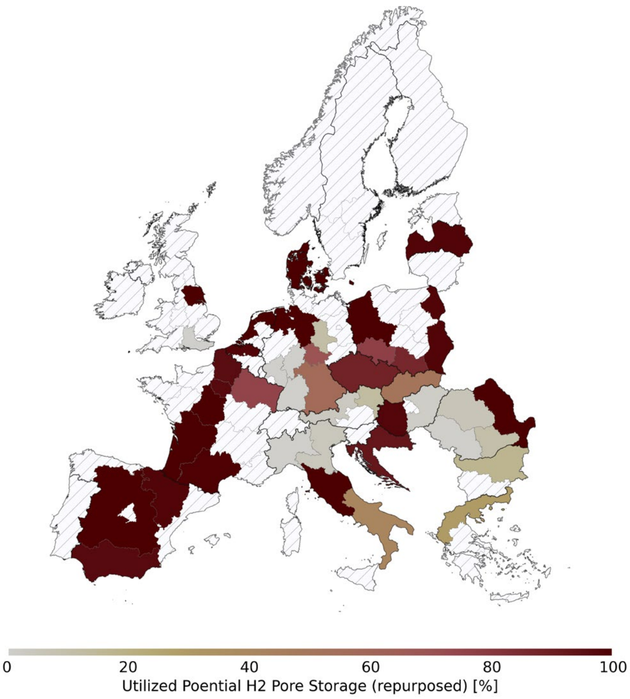

Figure 9-36. Utilization of repurposed cavern storage potential (map) in the baseline scenario for 2030.

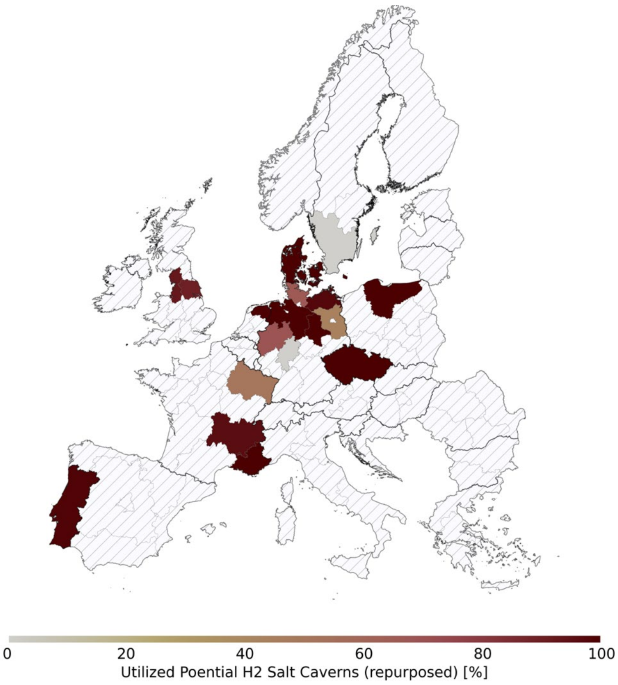

Figure 9-37. Utilization of repurposed cavern storage potential (map) in the baseline scenario for 2040.

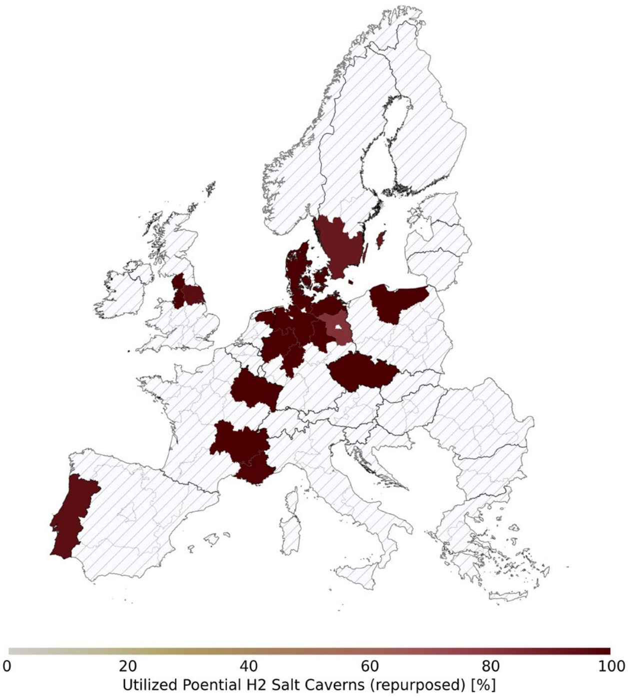

Figure 9-38. Utilization of repurposed cavern storage potential (map) in the baseline scenario for 2050.

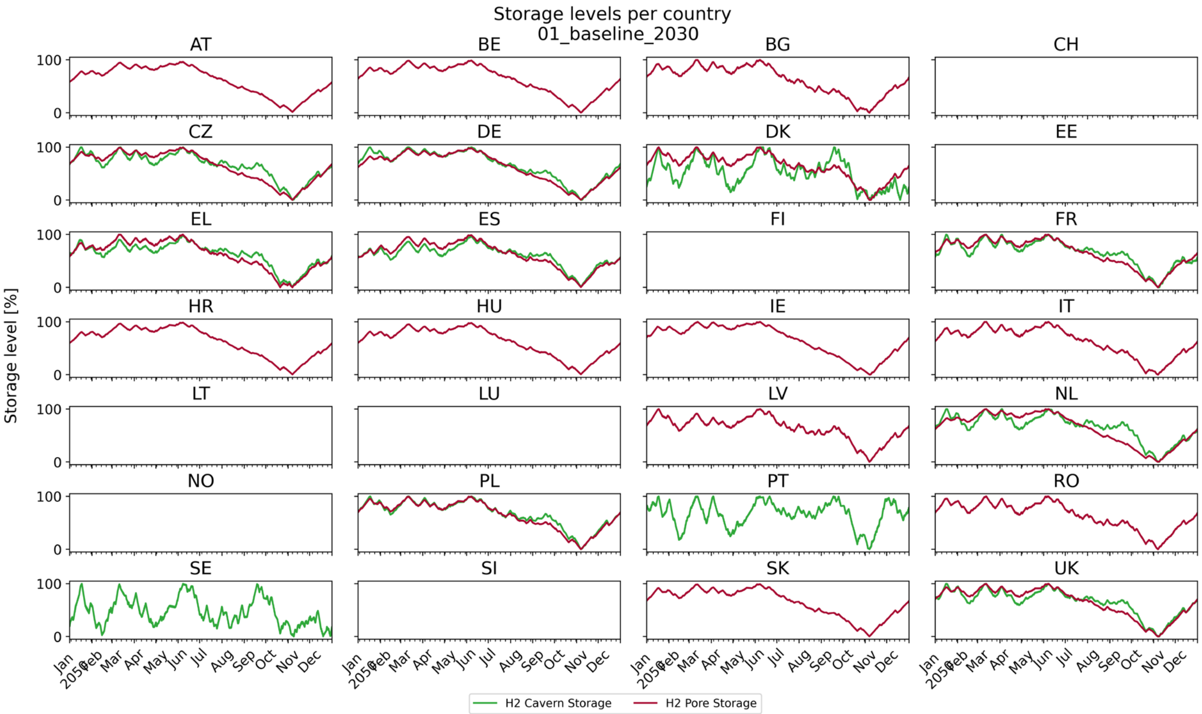

Figure 9-39. Storage levels of cavern and pore storage per country for the baseline scenario for 2030.

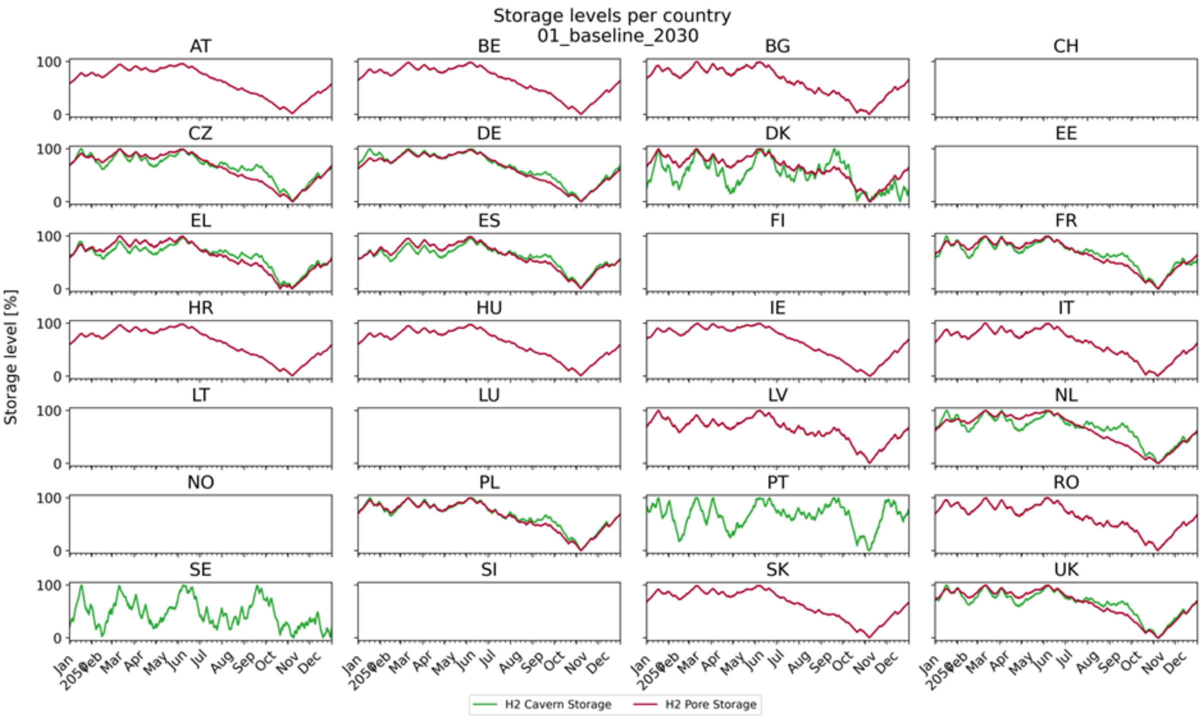

Figure 9-40. Storage levels of cavern and pore storage per country for the baseline scenario for 2040.

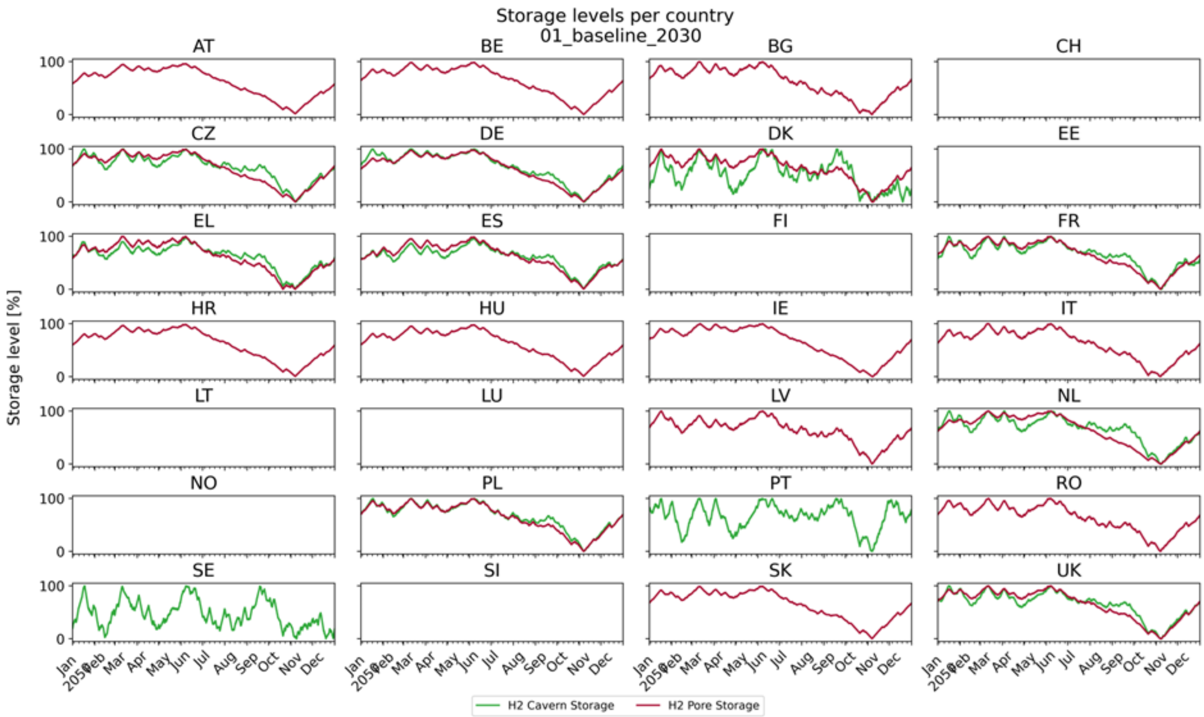

Figure 9-41. Storage levels of cavern and pore storage per country for the baseline scenario for 2050.

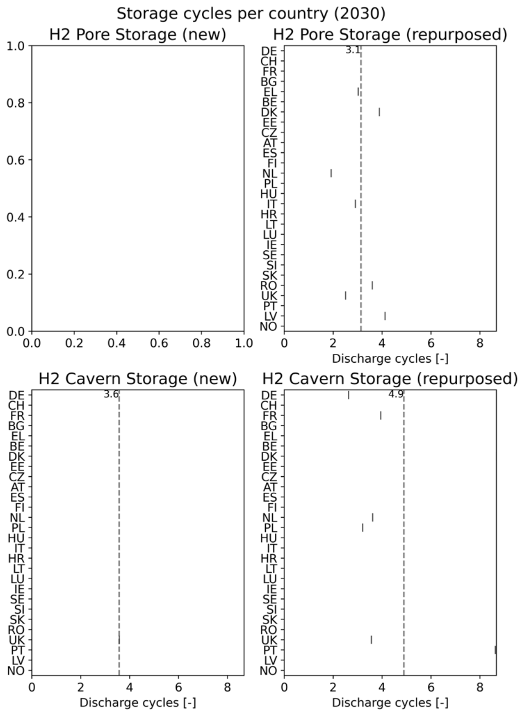

Figure 9-42. Storage cycles per country for the baseline scenario for 2030.

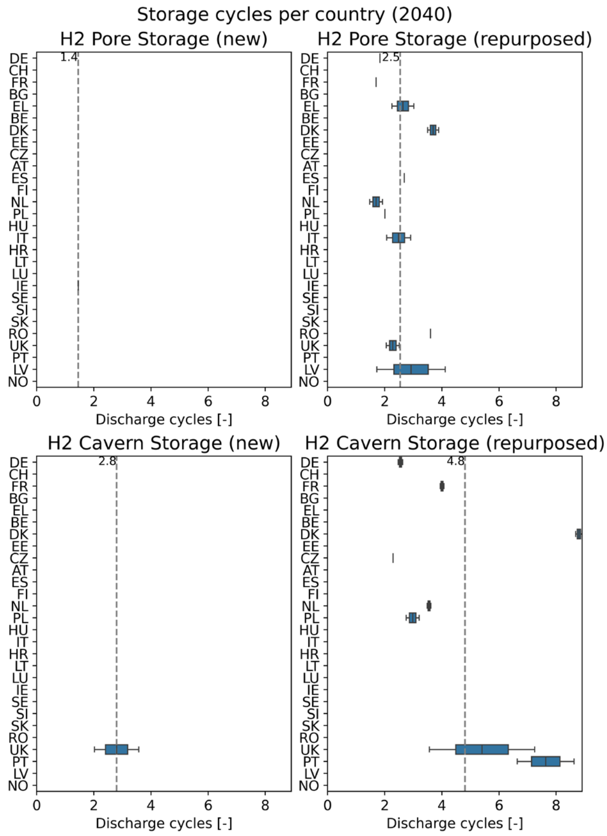

Figure 9-43. Storage cycles per country for the baseline scenario for 2040.

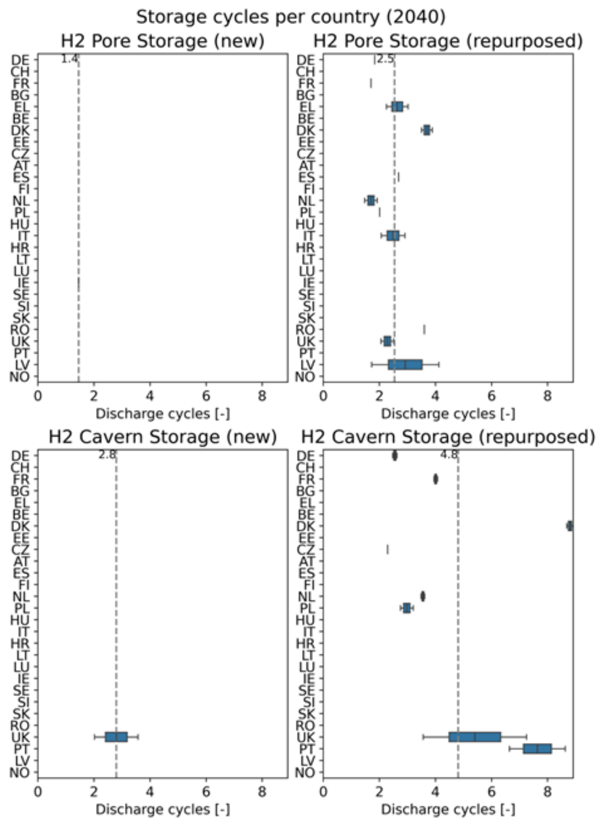

Figure 9-44. Storage cycles per country for the baseline scenario for 2050.

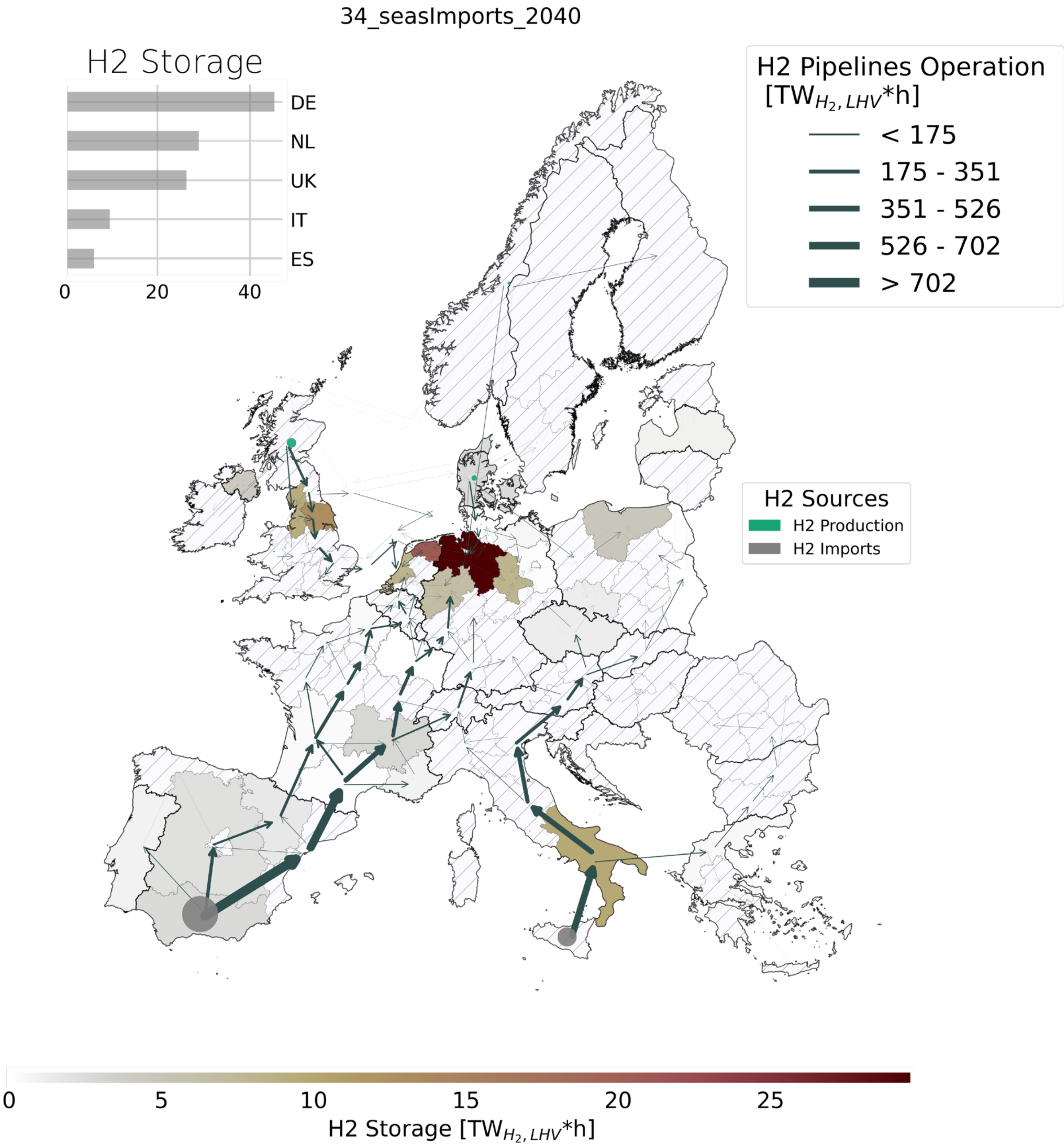

Figure 9-45. Hydrogen transmission (arrows), hydrogen storage capacity (areas), and hydrogen production (filled circles without quantities) in 2040 in scenario *34_seasImports_2040*. For information on scenario descriptions see Table 1.