

Determining priorities for hydrogen infrastructure projects in Europe based on total system costs

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ABSTRACT

Hydrogen production can provide important flexibility in a carbon-neutral European energy system, but its value depends on where and how pipeline and storage infrastructure are deployed. This study assesses the system benefits of hydrogen flexibility using REMix-Eur, a linear optimisation model of the European energy system with hourly resolution, 57 model regions and a technological scope of more than 100 technologies. We optimise a carbon-neutral 2050 target system and compare it with 24 scenarios in which hydrogen transfer and storage capacities are restricted relative to the cost-minimal case. The evaluation takes total system costs, investments, levelised cost of hydrogen, electrolyser operation, and regional infrastructure priorities for hydrogen technologies into account. Our results show that for the chosen scenario setup an inflexible hydrogen system increases annual system costs by 36 billion€ or about 10 % compared to the cost-optimal case. Most of this penalty comes from restricting network rather than storage expansion. In the optimal case, Europe builds around 120 TWh of hydrogen cavern storage, with 57 % of it repurposed from previous natural gas utilisation. Electrolyser capacity ranges from around 330 GW to more than 500 GW across scenarios, and infrastructure enabling flexibility reduces the model-implied levelised cost of hydrogen from 64 €/MWh in the inflexible case to 51 €/MWh for the optimum. Our findings suggest that early hydrogen planning should prioritise cross-border pipeline corridors and the retrofitting of existing storage sites, especially in the North Sea region.

1. Introduction

The transition of the European energy system toward climate neutrality by 2050 represents a paradigm shift from localised fossil-fuel generation to an interconnected, weather-dependent network. While the rapid expansion of variable renewable energy sources (VRES) forms the backbone of this transition, it challenges the temporal and spatial stability of the energy supply. To bridge these gaps, hydrogen (H₂) produced via water electrolysis has emerged as a crucial vector for system-wide flexibility [1,2]. Thanks to its storage characteristics, this molecule can be deployed across multiple demand sectors, serving either as an energy carrier or as a chemical feedstock to drive decarbonisation in hard-to-abate processes.

However, achieving system flexibility through H₂ requires a continental-scale transport and storage network to decouple production from final demand. This infrastructure framework introduces two complementary dimensions: temporal flexibility, which encompasses both the flexible operation of electrolysers and geological storage, and spatial flexibility, enabled by pipeline networks. The term “H₂

flexibility” refers precisely to this integrated system where electrolysers are operated dynamically alongside transfer and storage assets which are also referred to as “H₂ flexibility infrastructure” throughout this paper. By temporally and spatially disentangling H₂ production from end-use demand, this configuration allows the system to maximise renewable generation while significantly reducing curtailment [3,4]. At the spatial level, optimal planning suggests locating electrolysers close to favourable wind and solar sites, utilising (existing) pipeline networks to transport energy more cost-effectively than expanding electricity transmission grids [5,6]. Temporally, large-scale geological storage, particularly in salt caverns, offers the seasonal flexibility needed to shift massive renewable energy generation from spring and autumn to winter peak demand periods. Studies indicate that optimal cavern sizing in countries like Germany could reach 104 TWh, enhancing the economic efficiency of electrolyser fleets [7,8]. Additionally, underground storage costs depend heavily on how often they are used, with salt caverns becoming much more cost-effective under frequent cycling [9]. Beyond these operational dynamics, evaluating energy transitions under broad

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Acronyms

AEL	Alkaline electrolysis
CAPEX	Capital expenditures
CO ₂	Carbon dioxide
EU	European Union
H ₂	Hydrogen
LCOH	Levelised cost of hydrogen
LH ₂	Liquified hydrogen
OPEX	Operational expenditures
PV	Solar photovoltaics
REMix	Energy system optimisation framework
REMix-Eur	European energy system model built in REMix
SMR	Steam methane reforming
UK	United Kingdom
VRES	Variable renewable energy sources

market uncertainties highlights an urgent need to construct massive new pipeline corridors and seasonal facilities [10].

The deployment of H₂ storage and transmission infrastructure should be assessed within a sector-integrated framework, as the optimal mix of balancing and storage options depends on interactions across energy sectors [11]. In the case of H₂, this involves trade-offs between the capital costs of storage and transmission assets and the systemic benefits derived from their flexibility. In this context, Kiviluoma et al. [12] demonstrate that cross-sectoral coupling and transmission expansion provide higher systemic benefits than electricity storage. Similarly, McPherson et al. show that failing to reduce H₂ and storage costs significantly increases the total economic burden of low-carbon transitions [13]. In a comprehensive European study with a focus on H₂ networks, Neumann et al. [14] quantify their potential economic value for the energy system with up to 3.4% of total system costs. Expanding on this grid perspective at a continental scale, Kountouris et al. [1] analyse the architecture of a European H₂ network, focusing on the trade-offs between domestic infrastructure and international imports. Specifically, they identify potential lock-in risks of blue H₂ and quantify the cost penalties associated with forcing strict green H₂ self-sufficiency instead of enabling H₂ import. Also at the European level, Gawlick et al. investigate the flexibility provision due to the coupling of the electricity and H₂ sectors in a zero-emission European energy system in 2050 using a cost-optimisation model [15]. By successively adding flexibility options, including pipeline and salt cavern scenarios leading to a totally flexible configuration, they find that sector coupling can reduce total system costs by up to 14%. However, their analysis relies on a highly aggregated country-level spatial representation where only inter-nodal transmission lines are considered, explicitly stating that future work should focus on a higher spatial resolution. For a decarbonised German energy system and assuming a low H₂ demand, Guerra and Hartmann [16] find that the spatial flexibility which the planned so-called Hydrogen Backbone is to provide only slightly reduces total system costs. Li et al. argue from a market participants' perspective that the benefits of Power-to-Gas (PtG) flexibility are even lower than its costs [17]. Using a stylised model of the Dutch energy system, they conclude that PtG is not a profitable solution from a social-welfare perspective to provide flexibility to electricity systems with high shares of renewables, unless the carbon break-even price reaches 750 €/t in their reference scenario. H₂ flexibility's cost-effectiveness remains heavily linked to regional competitiveness, given that underlying electricity prices inherently dominate the levelised cost of hydrogen (LCOH) across various system configurations [18]. Prianto et al. [19] evaluate that with a regional energy system of West Sweden, for which

they find that H₂ flexibility becomes cost-effective with high shares of renewables.

Despite the benefits of H₂ flexibility, the allocation of infrastructure costs and the distribution of economic welfare remain an important challenge. The literature highlights an “arbitrage paradox”: as H₂ deployment increases, it flattens the electricity price-duration curve, thereby eroding the arbitrage revenues that operators rely on to recover their investments [20]. Addressing this cannibalisation effect, Ruhnau [21] shows that flexible H₂ electrolyzers establish a price-responsive demand during low-price hours, creating a price floor that prevents the decline of wind and solar market values. Consequently, while renewable integration improves social welfare, it triggers a redistribution of surplus that shifts value away from electricity consumers toward renewable producers and storage operators [22]. These effects also create a misalignment of incentives. Roach and Meeus [20] state that the socially optimal level of H₂ capacity can actually result in financial losses for private investors, providing an economic rationale for targeted subsidies to support flexible electrolyser deployment. Investments in H₂ infrastructure are also threatened by direct technology competition: Blanchard and Megy [23] highlight that batteries and H₂ aggressively contend for the same flexibility value streams, squeezing H₂'s economic viability. These investment challenges are also exacerbated by regulatory design. Ruhnau and Schiele [24] argue that enforcing strict hourly simultaneity between generation and production forces an inefficient oversizing of infrastructure, whereas a flexible annual matching policy drastically improves project economics without necessarily increasing emissions. Schöb et al. [25] demonstrate that restricting electrolyser flexibility, for instance by imposing high full-load hour requirements, can double renewable electricity curtailment and increase total system costs by up to 10.5% for continuous electrolyser operation, showing that flexibility is essential for managing both “harvesting peaks” and “dark lulls”. Similarly, Geis et al. [26] show that restricting flexibility options severely penalises energy systems, leading to higher electricity prices and a significant reliance on imports. They also show that H₂ tends to provide medium- (weekly) to long-term (annual) flexibility compared to the short-term balancing nature of batteries.

Compared to the existing literature, this paper expands the analysis both geographically and technologically through highly-resolved spatial modelling of a future European multi-energy system. Adopting a system-optimal perspective, we assess the total system cost penalties incurred when H₂ flexibility is restricted, focusing specifically on constrained long-distance pipelines and large-scale underground storage.

Our analysis relies on a technology-rich multi-energy system optimisation model featuring hourly temporal and sub-national spatial detail. This model is applied to a 2050 target system with relevant usage of H₂ in industry and the transport sector. We construct a parametric study spanning 25 distinct scenarios that systematically vary the capacities of H₂ storage and pipeline deployment, using the cost-optimal layout and a completely inflexible configuration as key benchmarks. It allows us to derive explicit priorities for the deployment of storage facilities and pipelines, and to determine the gradients of the considered system indicators. The focus of this study is to answer the following research questions:

1. What is the system value of H₂ transmission and storage infrastructure in a carbon-neutral European energy system?
2. How do different levels of H₂ network and storage deployment affect system costs, H₂ supply costs, and the spatial allocation of electrolysis?
3. Which H₂ storage sites and pipeline corridors provide the highest system benefits?
4. What are the system effects of enforcing a higher, operator-profit maximising electrolyser capacity factor compared with system-friendly flexible operation?

To answer these questions, we evaluate total system costs, H₂ production costs and model-endogenous investments in H₂ infrastructure. On this basis, we derive trends and priorities in establishing flexible H₂ production. The results of our analysis strengthen the understanding of the effect of specific infrastructure decisions concerning both the dimensioning and location of H₂ electrolyzers, storage and pipelines. This is equally helpful for policy makers and system planners aiming for a high benefit of large-scale energy infrastructure.

The paper is divided into four main parts. Section 2 sets out the methodology and the underlying data of the multi-energy system model and the parametric study performed. Based on this, Section 3 presents the modelling results and their analysis. This is discussed in Section 4, while Section 5 derives the main conclusions and possibilities for future research.

2. Methods

We build our flexibility study around a scenario design focused on the variation of H₂ flexibility infrastructure (i.e., cavern storage and pipelines) presented in Section 2.1. To calculate results, we apply a linear optimisation approach using the REMix framework (Section 2.2) and the REMix-Eur optimisation model and data collection and assumptions as described in Section 2.3. We evaluate our results based on the output indicators introduced in Section 2.4.

2.1. Scenario design

The approach followed within this study is to solve the REMix-Eur model once to find the optimal energy system expansion and dispatch. Based on this optimal run, 24 further scenario runs are performed, in which the capacities of H₂ flexibility infrastructure (i.e. H₂ cavern storage and H₂ pipelines) are altered by enforcing limits on them which are formulated as shares relative to the optimal case. The optimal case is the scenario with 100 % share of H₂ network and 100 % share of H₂ storage infrastructure, or, in short, scenario 100/100. The mentioned limits are set in 50 % steps starting from zero H₂ transfer and zero H₂ storage infrastructure up to an overbuilding of factor 2 (scenario 200/200). Eight additional runs are performed with a 20 % deviation from the optimum to be able to gain deeper insights on system-cost benefits compared to near-optimal solutions. This results in a scenario matrix of 25 runs as shown in Fig. 1, which highlights also the quadrants of over- and under-investment in H₂ flexibility infrastructure as well as the two quadrants from which we can derive the cost of wrong prioritisation of either H₂ network or storage infrastructure. By systematically examining a wide range of scenarios, gradients and tipping points in the evaluated system, indicators can be identified more effectively than if the analysis was limited to just a few scenarios.

The mentioned limits (=shares relative to the optimal case) are not strictly applied, but set with a 2.5 % range around the respective values to improve numeric stability (and thus solvability) of the resulting optimisation problems. The “network/storage” share nomenclature introduced above and shown in Fig. 1 as well as the figure itself serve as reference to the respective scenarios¹ in the remainder of this article.

Besides these scenarios as described above, we calculate a single additional one in which we enforce an electrolyser capacity factor of around 83 % to compare system benefits with a single-operator profit maximisation.

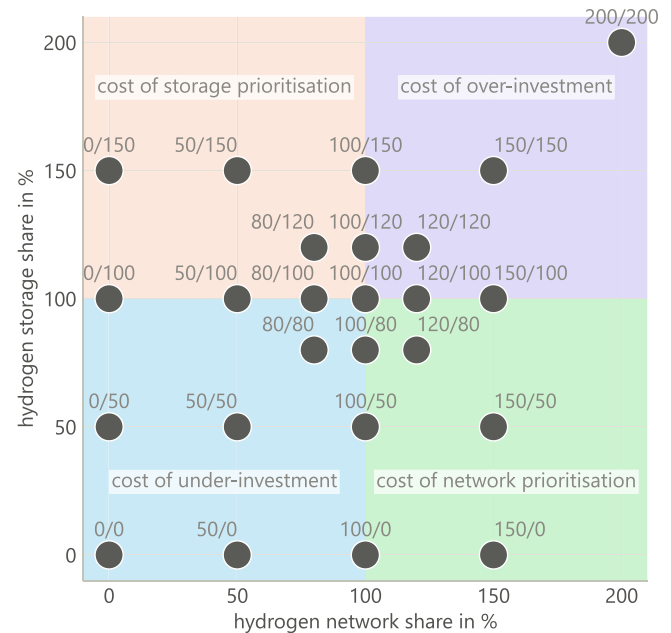


Fig. 1. Overview of the scenario runs performed for this study. We use the shown “network/storage” share abbreviation to refer to each respective scenario throughout the article.

2.2. REMix: an energy system modelling framework

REMIX is an open-source energy system modelling framework developed at the German Aerospace Center since 2006 that has been used in many studies to date [27]. It provides the possibility to build (mixed-integer) linear programmes and puts special attention to providing capabilities for modelling especially large-scale systems. The optimisation provides optimal (usually cost-minimal) results from a central-planner’s perspective for infrastructure expansion as well as (hourly) dispatch.

2.3. REMix-Eur: a European energy system optimisation model

In the following paragraphs, we give a description of the REMix-Eur model scope, the underlying data and assumptions and, as the H₂ infrastructure is at the core of this study, outline the H₂ import costs and its availability in the model.

2.3.1. Geographical, technological and temporal scope

The REMix-Eur model is set up with 70 nodes and laid out and solved for an hourly temporal resolution. Its general data availability is for all years between 2020 and 2050 in 5-year steps. For this study, however, we only perform target-year optimisations for 2050 for all scenarios (see Section 2.1), since this is the year in which we expect most H₂ penetration in the energy system. As an earlier pre-screening of results showed that it is possible to represent relevant potential bottlenecks in the gas and electricity transmission networks with less nodes, and to speed up result generation, only an aggregation to 57 nodes is used for the present study. Transfer of commodities within a single model region is not modelled and possible without limitations. All nodes are an aggregation of NUTS regions according to the 2016 version of this classification system. The visualisations and texts in the remainder of this article use the designations introduced in Fig. A.1 for the respective nodes. A double underscore (“_”) between two nodes symbolises an inter-regional transfer link of the specified kind (electricity or gas).

It is important to mention that although three different electrolysis technologies and their respective learning curves are in the data scope

¹ The words *case* and *scenario* are used interchangeably throughout this article.

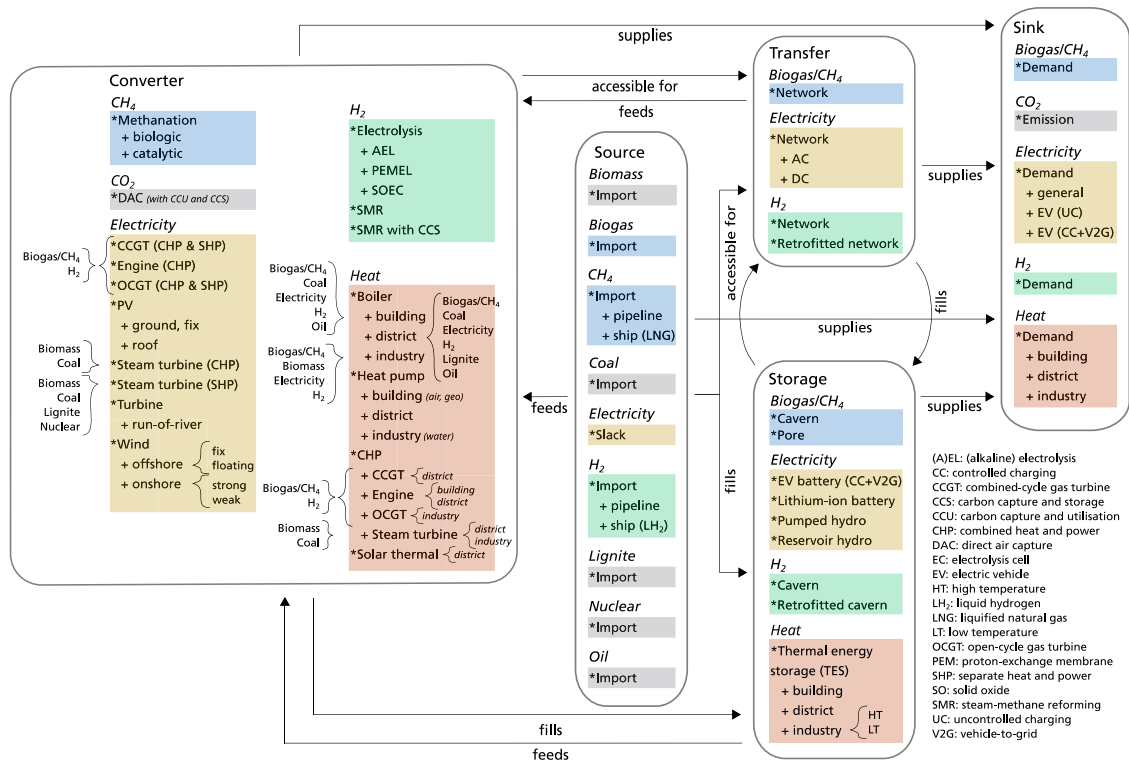


Fig. 2. Technological scope of the REMix-Eur instance used. It comprises more than 100 different technologies, over half of them in the heat sector.

(alkaline electrolysis (AEL), proton-exchange membrane (PEMEL), and solid-oxide electrolysis (SOEC)), for the final runs presented within this study we only left AEL in the model scope, because the optimisation never chose the other two in previous runs.

2.3.2. Data and assumptions

The target year 2050 is optimised with the boundary condition of a carbon dioxide (CO₂)-emission balance of zero without explicit CO₂ penalty. All costs in the model are converted to the price year 2015 and have a discount rate of 8%. As input data we use the REMix-Eur data collection, which combines energy system modelling data from a large range of publicly available sources with some own assumptions [28]. It is important to note that in case of duplicates for specific data points across different input files, always the manually collected data in the files containing the word "INPUTDATA" takes precedence. The electric-vehicle profiles are the only data points that are not included in that data collection; they were created with the open-source software venco.py [29] using the assumptions as documented in Table A.2.

As the assumption for an exogenous H₂ demand of 2199 TWh is of special interest regarding the research aims of this study, it is visualised in Fig. A.2 in its distribution across the model regions. It corresponds to the "H2" scenario in Wulff et al. [2] and ranges at the higher end of future H₂ demand projections.

2.3.3. Hydrogen import cost and availability

If not via domestic production through electrolysis or steam methane reforming (SMR), H₂ is available to the system via pipeline-based or ship (liquified hydrogen (LH₂)) imports. The possible import locations and associated minimal costs for H₂ imports from outside the geographical model scope (see Fig. A.1) via pipeline and ship are illustrated in Fig. 3 respectively.

2.4. Output indicators

The indicators to be analysed mostly stem directly from the REMix output and comprise installed capacities of H₂ production, H₂ storage

and transmission infrastructure, the amount of H₂ imports, as well as the electrical grid. One additionally derived indicator is the capacity factor of the electrolyzers.

Furthermore, we calculate the (model-implied) levelised cost of hydrogen (LCOH) and the spread between said LCOH and the average marginal cost as described in the following. The conventional LCOH is generally calculated by dividing the discounted lifetime costs of a H₂ production asset by its discounted lifetime H₂ output. In this study, we derive a model-implied LCOH from the production-weighted shadow value of H₂. This methodological choice reflects the capacity-expansion formulation of REMix-Eur, in which investment and hourly dispatch decisions are jointly optimised. The dual variable associated with the H₂-balance constraint in each node measures the change in the total optimised system cost resulting from supplying one additional unit of H₂ at a given node and time step. Unlike in a dispatch-only model, this shadow value may therefore reflect not only operating costs, but also the investment in capacities required to supply H₂. Under the model's optimality conditions, for continuous and endogenously invested capacities that are not constrained by binding exogenous bounds, the H₂ shadow price ensures the recovery of annualised investment and fixed costs. The indicator therefore has a long-term cost-recovery interpretation related to the conventional LCOH, although it is not the same cash-flow calculation.

For a set of model nodes R the model-implied LCOH is calculated as the hydrogen-production-weighted average of the hourly and nodal H₂ shadow values:

$$\text{LCOH}_R^{\text{model}} = \frac{\sum_{n \in R} \sum_t c_{t,n}^{\text{H}_2} q_{t,n}^{\text{H}_2}}{\sum_{n \in R} \sum_t q_{t,n}^{\text{H}_2}}, \quad (1)$$

where $c_{t,n}^{\text{H}_2}$ is the nodal H₂ shadow value, interpreted as the marginal cost of supplying H₂ at time step t and node n and $q_{t,n}^{\text{H}_2}$ is the H₂ production from electrolysis.

We analyse the LCOH values for the 2050 target year across various H₂ infrastructure dimensioning scenarios (see Section 2.1). Furthermore, we evaluate the spread between the model-implied LCOH from

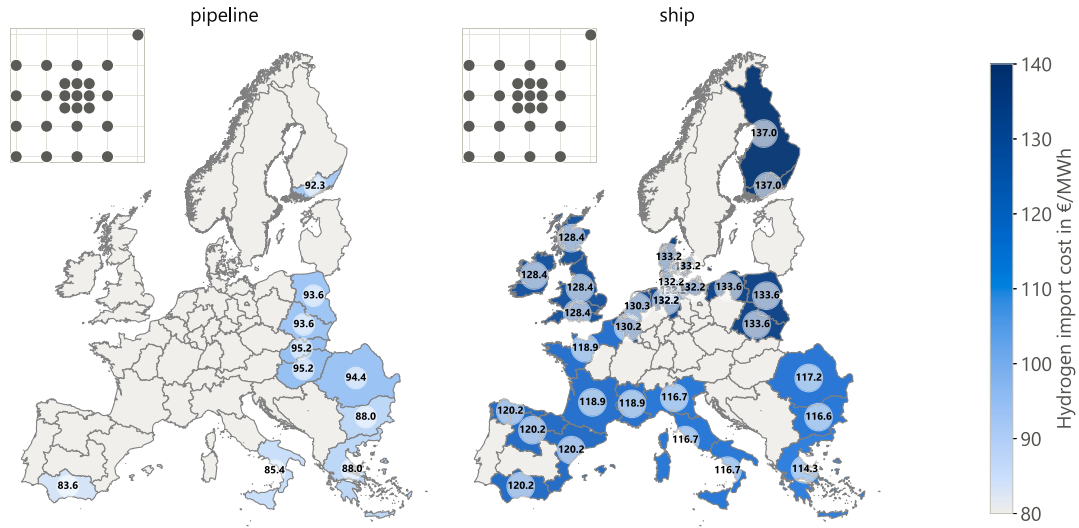


Fig. 3. Possible hydrogen import locations and costs for gaseous imports via pipeline (left) and liquified hydrogen imports via ship (right) from outside the geographical model scope for all scenarios (derived from [30]). Only the respective minimum import cost for each region is shown as only the least-cost import option is relevant when hydrogen import volumes are not restricted by origin.

Eq. (1) and the annual average marginal cost (including expansion costs) as shown in Eq. (2).

$$\text{LCOH spread}_R = \sum_{n \in R} (\text{LCOH}_n^{\text{model}} - \bar{c}_n^{\text{H}_2}) \quad (2)$$

$\bar{c}_n^{\text{H}_2}$ is the annual time-average H_2 marginal cost at node n , and $\text{LCOH}_n^{\text{model}}$ corresponds to Eq. (1) evaluated for $R = \{n\}$.

Since the LCOH functions as a quantity-weighted average of the marginal cost, the spread serves as an indicator of systemic flexibility: a negative spread implies that the energy system capitalises on low marginal costs for production, whereas a positive spread indicates that the system is forced to produce even when marginal costs, particularly those driven by electricity prices, are high.

3. Results

The analysis of results ranges from an evaluation of installed capacities for H_2 production, transmission and storage to a detailed cost analysis of capital expenditures (CAPEX) and LCOH. An overview of optimisation parameters (Appendix B), the evaluation of the impact of changes in the H_2 infrastructure on H_2 imports (Appendix C) and the electricity system (Appendix D) can be found in the Appendix.

3.1. Hydrogen production

The optimal electrolyser capacity across Europe ranges from a good 330 GW to over 500 GW (Fig. 4). These large differences result from the plant utilisation rates achieved and the quantities of imported H_2 . It might seem counter-intuitive on first sight that the aggregated electrolyser capacities in the optimised case and the inflexible case are very similar. Although not cost-efficient, electrolyser expansion is enforced in the inflexible case because the H_2 demand has to be met, but imports are not available for most regions. As also import quantities are comparable in the optimised and inflexible case (see Appendix C), similar capacity factors result. If we move along the axis of a synchronised expansion of H_2 grids and storage, we initially observe a significant decrease in electrolyser capacity. However, this is due to the facilitation of imports (see Fig. C.1). This effect is even more pronounced if only grids but no storage is added. The opposite effect of particularly high electrolyser capacities can be seen if only storage and no grids are added. In this case, storage can be used to concentrate H_2 production on hours with high renewable electricity

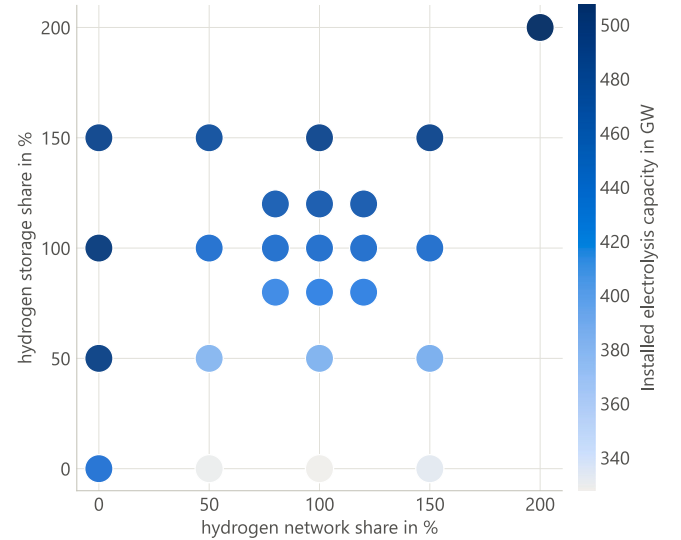


Fig. 4. Overall installed capacities for hydrogen production (alkaline electrolysis) for all analysed scenarios.

generation, but at the expense of higher electrolyser capacities. If grids can also be built, a shift to locations with higher VRES full-load hours is possible, accompanied by lower electrolyser capacities. It is striking that near the optimal case only changes in overall storage capacity have an impact on the electrolyser capacity, whereas a variation of the network capacity has little effect. Although the option of SMR does exist in the technological scope (see Section 2.3.1), all H_2 production capacities stem from the AEL technology.

If we switch to an analysis of individual model regions, we see significantly larger ranges in the respective optimum electrolyser capacity (Fig. 5). Regional H_2 demand and renewable energy potentials drive substantial differences in the corresponding electrolyser capacities. Despite the broad ranges driven by the availability of H_2 storage and network, some clear trends can be observed. Many regions including those on the British Isles, the Netherlands, the Baltic countries, northern Germany, South and East Spain, North and Southeast France are prominent electrolyser locations across most or even all scenarios yet with

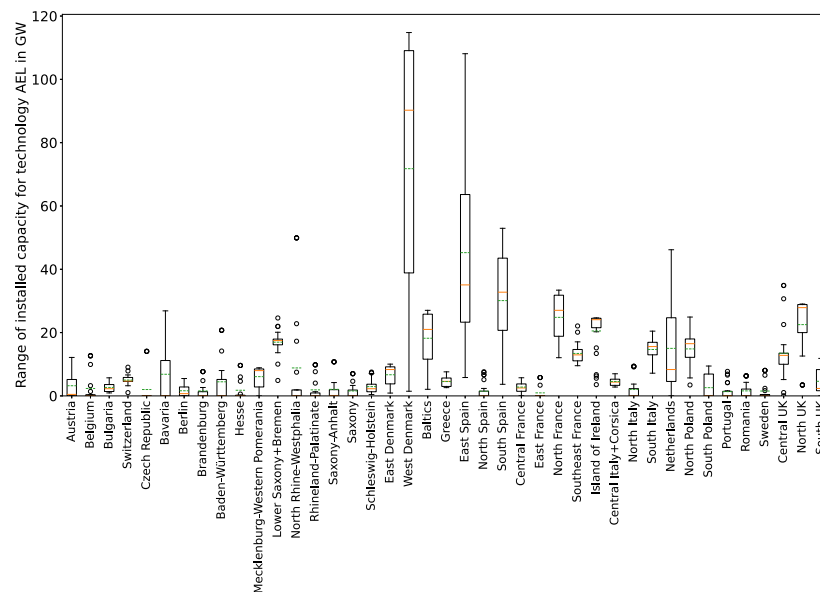


Fig. 5. Range of installed hydrogen production (alkaline electrolysis) capacities above 5 GW per model region for all calculated scenarios. The orange line indicates the median for each region, whereas the green dashed line stands for the mean installed capacity. The whiskers are placed at the farthest point within the 1.5x inter-quartile range respectively.

broad ranges. On the contrary, H_2 production is strongly reduced or even eliminated by networks and storage in many other regions across the continent such as Sweden, Belgium or North Rhine-Westphalia in Germany.

Enabling H_2 storage and pipelines results in significant changes in the spatial distribution of electrolyser in Europe (Fig. 6). Without grids and storage, the locations essentially correspond to the regional H_2 demand (see Fig. A.2), affected only by imports by ship and pipeline (see Appendix C), as well as differences in the capacity factors. In the system of optimised H_2 networks and storage, the number of regions with their own generation shrinks by more than half to just 26, which represent the best locations for the use of wind and solar energy. Further expansion of the grids and storage facilities does not reduce the number of locations any further, but will lead to some redistribution. If storage and grid expansion is reduced to half of the optimum, the spatial concentration of H_2 production is less pronounced. However, even in this case, some regions remain without their own H_2 production. Regional grid clusters are formed, which ensure that England is supplied from Scotland and Ireland, western and southern Germany from northern Germany, Denmark and the Netherlands or North Italy from South Italy.

To realise this concentration, the interplay of H_2 networks and storage is required. If networks can be expanded only to 50% of the optimum and no storage can be built, substantial differences appear, especially for Germany. Instead of a dominance of imports from the Netherlands and Denmark, almost all regions, including those in western and southern Germany, will remain as distinct electrolyser locations. However, in the event of greater network expansion (100/0), there will again be a switch to imports, particularly from Denmark and countries outside the model scope. If, on the other hand, grid expansion lags behind storage expansion, regions with large storage facilities can benefit in particular and also become electrolysis locations. East Spain, northern Germany, southern France and the Netherlands benefit in particular, at the expense of Denmark and the Baltic states. If grid expansion reaches the optimum level and storage goes beyond (100/120, 100/150), East Spain in particular can benefit as an electrolysis location, while imports from North Africa decline (see Appendix C).

The geographical concentration of H_2 production in some regions leads to great imbalances in the regional self-supply shares (Fig. H.1).

While some regions depend completely on imports, others produce much more than they consume. In the case of optimal H_2 storage and networks, West Denmark stands out with a production of more than 40 times its demand. East Denmark, the Baltic states, Scotland, Ireland and South Spain also produce around 5 to 8 times their demand. A further increase in storage and grid expansion leads to some regional shifts without fundamentally changing the trend.

The annual capacity utilisation described by the capacity factor is of great importance for the economic efficiency of electrolyser operation. Without storage and grids, the capacity factor results directly from the H_2 demand profile. As this varies from region to region, the values range from a good 30% to over 70%. In most cases, the expansion of H_2 storage and networks and the relocation of electrolysis to regions with higher VRES availability are accompanied by a decrease in the capacity factor. The exception is Norway, where values of over 80% are achieved due to the high availability of storage hydropower. In the other production regions, the optimised case results in values between 40% in South Italy and just under 60% in West Denmark. In the case of a reduced expansion (50/50), the values are significantly higher, particularly in southern Europe, whereas in the case of an increased expansion (150/150), lower utilisation rates are accepted as a result of foregoing other flexibility options (particularly electrical grids, less so battery storage). If only storage and no grids are expanded (0/100), this essentially means that significantly lower utilisation rates of 35% to 50% are realised in the regions with storage potential, with significantly higher values in the regions without storage. The opposite case of pure grid expansion (100/0), on the other hand, is characterised by very high utilisation rates in the main production regions.

3.2. Hydrogen pipelines

The resulting H_2 network capacities show broad variations both between the individual connections and the scenarios (Fig. F.1). It becomes obvious that many connections are of limited relevance in all cases, with values very close to zero. On the contrary, some main corridors can be identified, including a connection from Scotland and the island of Ireland to England as well as from Spain through France and Germany. High connection capacities can also be identified for the eastern North Sea regions (Denmark, Netherlands, northern and western Germany). However, they show very broad distributions on

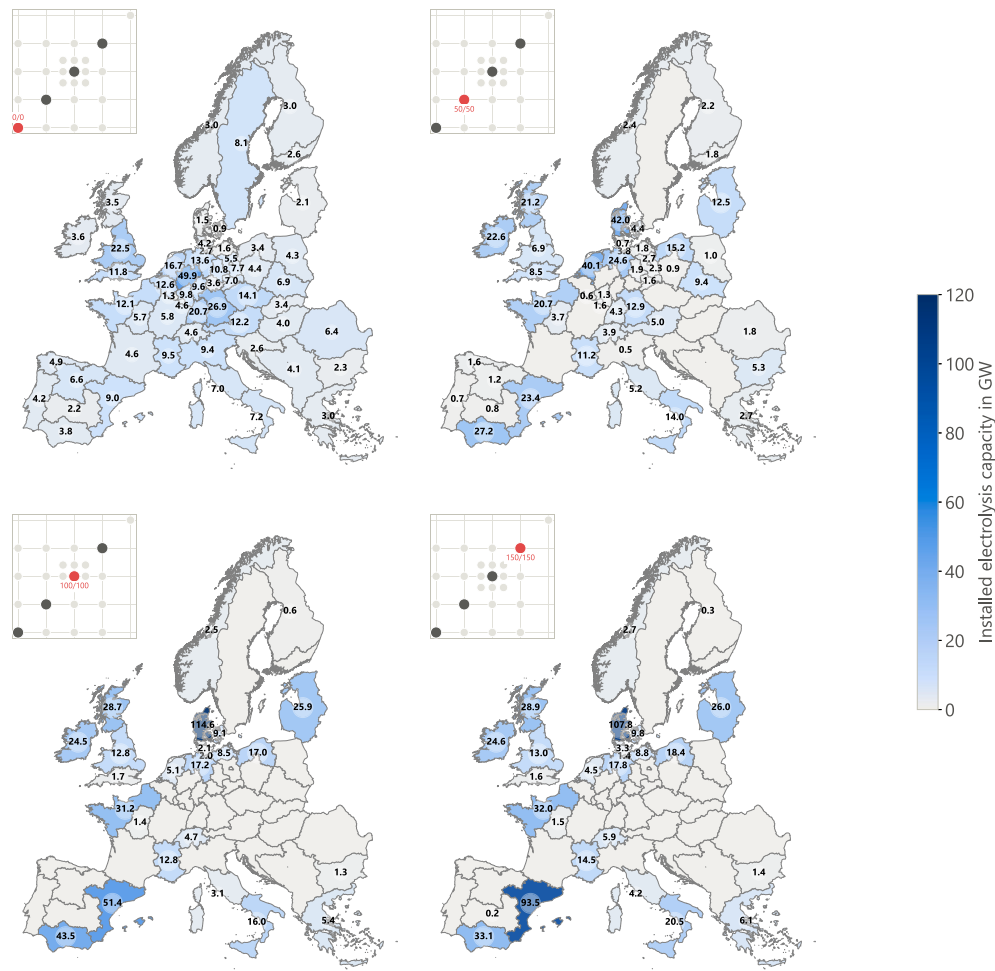


Fig. 6. Installed capacities for hydrogen production (alkaline electrolysis) for the 0/0, 50/50, 100/100, and 150/150 scenarios as highlighted by the red dot in the mini scenario plot in the upper left corner respectively.

the level of individual lines (see, e.g., Schleswig-Holstein to West Denmark). This is being explored further by looking into the individual scenarios.

Comparing the scenarios allows us to establish priorities for the development of a European pipeline network. As storage facilities and networks are scaled up simultaneously from zero (50/50), the focus shifts to enabling imports from outside Europe. To this end, existing gas pipelines from Algeria to North Italy, from Morocco to Spain and on to France and Germany, as well as from Ukraine to Poland, the Czech Republic and Germany, are repurposed. To meet the high demand in England and western Germany cost-effectively, wind-rich electrolysis sites in Scotland, Ireland and Denmark are also connected. H₂ production in Denmark takes a detour via the Netherlands, where the focus is on expanding storage capacity (see Section 3.3). Enabling further network and storage expansion leads to the extension of the aforementioned corridors, as well as the construction of new ones. These run from North France through Belgium to Germany, and from Denmark across the Baltic Sea to eastern Germany. However, the dominant development is the construction of a direct pipeline from Denmark to northern Germany and on to western Germany. Beyond these central corridors, a network is emerging between almost all modelled regions of Europe.

Reducing the available aggregated network capacity to 80 % of the optimal value does not result in any significant changes to the topology. This applies equally to storage expansion of 100 % and 120 % of the optimal value. However, if grid capacity is reduced further to 50 %

of the optimal value, a drastic change can be observed in the North Sea region as shown in Fig. 8. Instead of building pipelines for direct export to the various regions of northern Germany, REMix favours the construction of a high-capacity pipeline to the Netherlands, the region with the largest storage facilities (see Section 3.3). From there, in turn, pipelines are being built on a large scale towards Germany.

If grid expansion can be achieved to the extent of the optimal total value, but storage expansion is limited, no significant changes to the grid topology are initially observed (80 % of storage capacity). If storage capacity is further reduced (to 50 %), this results in a strengthening of the line from the UK to the Netherlands, as well as along the import corridors from South Spain and South Italy towards France and Austria. If no expansion of H₂ storage can be realised at all, the grid topology differs significantly. Whilst pipeline capacity between the North Sea coastal states, particularly between Denmark and Germany, decreases markedly, the import corridors from eastern and southern Europe towards the industrial centres in Germany, France and Italy gain in importance. This reflects the observed higher proportion of imported H₂ (see Appendix C). Continued high production in Ireland and Scotland can nevertheless be transported to England and France, whilst pipelines to Sweden and the Netherlands are being built to export H₂ produced in Denmark. The characteristics described can be observed regardless of whether only 50 % or 100 % of the optimal H₂ network capacity can be realised. Conversely, if H₂ storage capacity is expanded beyond the optimal level, this has the opposite effect of weakening the import corridors from South Italy and South Spain. The

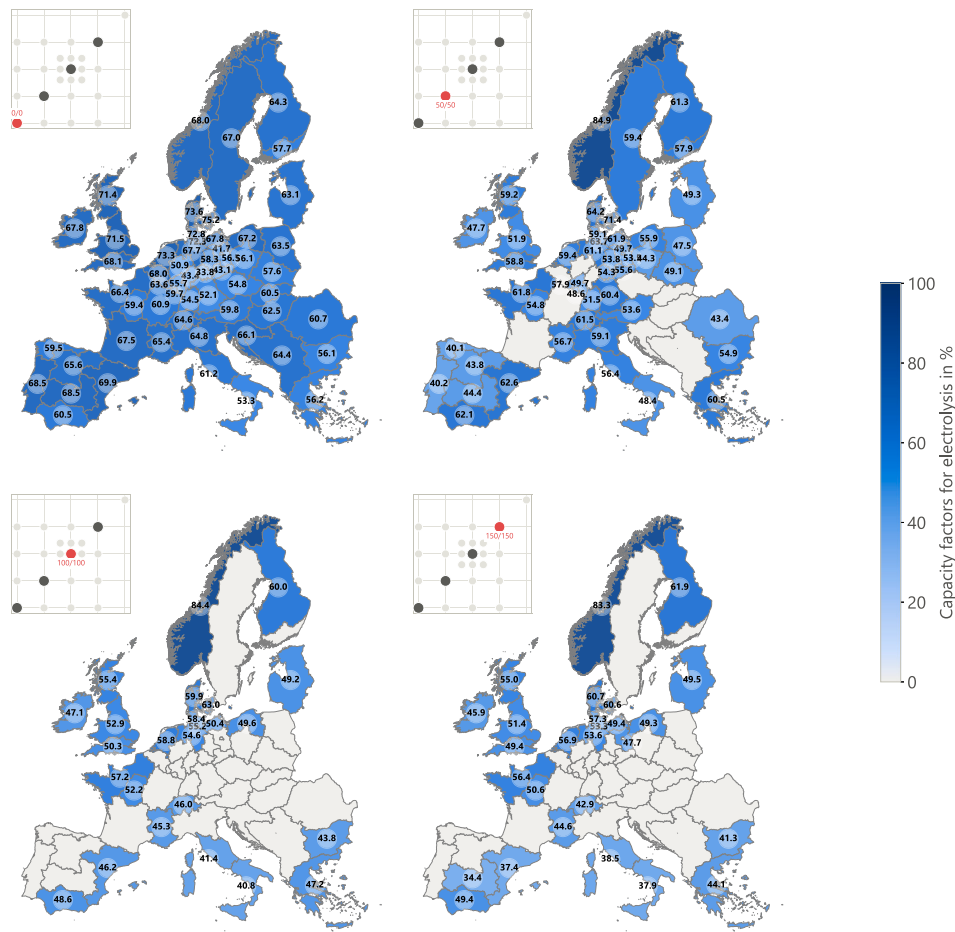


Fig. 7. Capacity factors of (alkaline) electrolysis for the 0/0, 50/50, 100/100, and 150/150 scenarios.

increase in H_2 production in Denmark and Spain made possible by the additional storage capacities (see Section 3.1), on the other hand, is transported via larger pipelines to the demand and storage regions.

An enforced grid expansion beyond the optimal level mostly leads to an increase in the capacity of the shortest link, thus lowering the related investment costs. From this follows that only very limited economic benefit can be created through further grid expansion (see Appendix F).

3.3. Hydrogen storage caverns

In the optimal scenario, around 120 TWh of H_2 storage capacity are established across Europe. Of this capacity, around 57% are converted natural gas storage facilities, whilst new salt caverns are developed for the remainder (Fig. 9). The geographical focus is on northern Germany and the Netherlands followed at a considerable distance by Denmark, Spain and the United Kingdom (UK). If grid and storage expansion is limited to half of the optimal level (50/50), the H_2 storage deployment priority lies with the Netherlands, which acts as a storage hub between Denmark, Germany and the British Isles. In addition, storage capacity is expanded in regions with high H_2 production using wind power, specifically in north-west Germany, the UK and Ireland (see Fig. 6). With lower overall storage capacity, the overall share of converted natural gas storage increases to 88% of the total H_2 cavern capacity leaving only 12% to new construction. If the storage can only be expanded to half of the optimum, but the grid can be expanded beyond this (100/50, 150/50), there is almost no change compared to the optimal case. Slightly larger storage facilities in Spain and France are offset by smaller ones in Denmark and Poland. In the case that grid and storage

expansion is possible to 80% of the optimum, additional storage sites in northern Germany, the UK and Denmark are developed. Only then do the aforementioned sites in Poland and Spain, as well as in Southeast France, follow. The latter see further expansion in the event that greater storage and grid capacities are enforced (120/120). If grids can be expanded to 80% and storage to 120% of the optimum, storage facilities in France, Spain and Poland stand to benefit most. If we consider the opposite scenario of reduced storage expansion alongside increased grid expansion (120/80), this is particularly at the expense of newly built caverns, whereas converted storage facilities maintain their volume. Consequently, Spain, Poland, the UK, and Denmark are particularly affected by reductions. With an even greater reduction in storage to half the optimal level and grid expansion in line with the optimum (100/50), results are very similar to the 50/50 case. If no H_2 network is built (0/50, 0/100), H_2 storage facilities are being established in all regions with a potential, to an extent related to the regional demand. This makes Denmark and Poland less attractive compared to the cases with a network, while more storage is being built in Spain and France.

A detailed look at the regional range of installed storage capacities essentially confirms the picture described above (Fig. 10). The refurbishment of existing storage facilities, particularly in Lower Saxony and the Netherlands, is very constant apart from the outliers to the left caused by the cases with very low storage expansion. Significantly broader distributions result in the other regions where there is little or no potential for the refurbishment of existing storage facilities. The outliers to the right, as well as the broad bands in North Poland, East Spain, West Denmark and Mecklenburg-Western Pomerania, result from the forced over-installation of storage facilities.

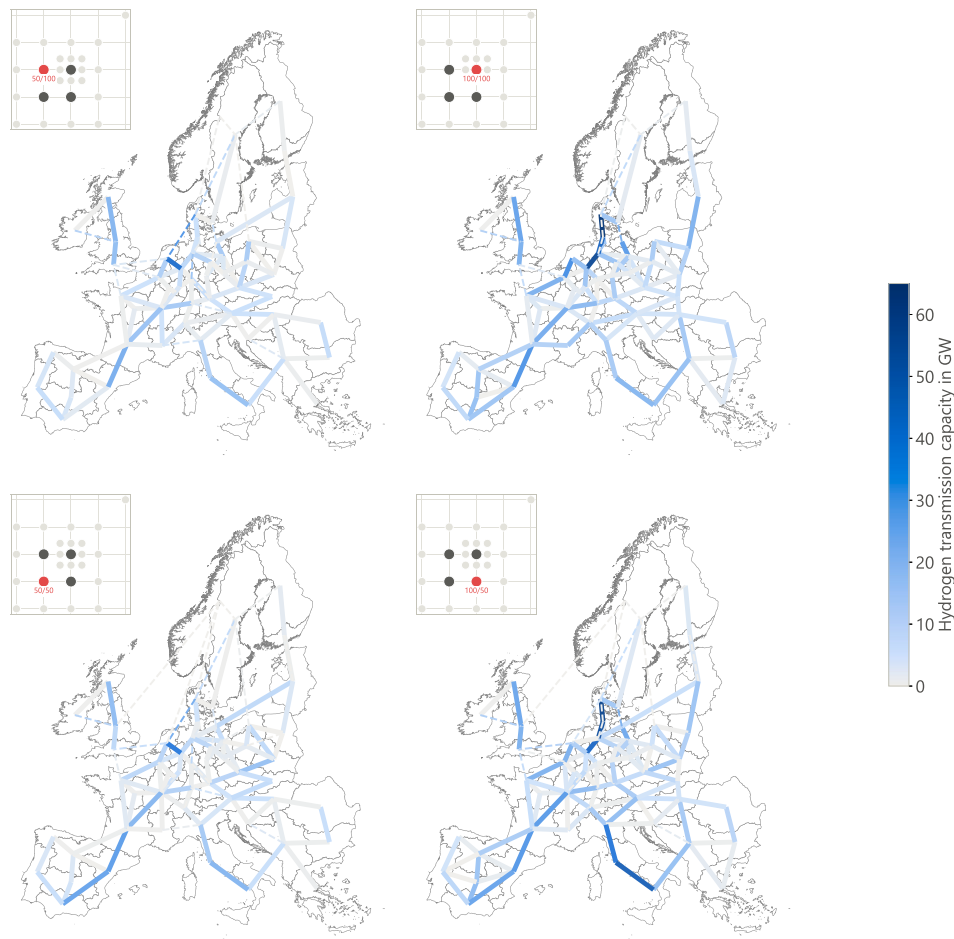


Fig. 8. Hydrogen transmission capacity for the 50/100, 100/100, 50/50, and 100/50 scenarios. The thick lines show retrofitted pipeline capacities, whereas the thin dashed lines on top of them stand for capacities of newly built pipelines. Only capacities equal or greater than 100 MW are shown.

In terms of H₂ storage potential, only the central European regions Schleswig-Holstein and Mecklenburg-Western Pomerania reach their natural limits for some higher-flexibility scenarios, while for West Denmark only a small buffer remains. All other regions with salt cavern potentials, however, are far away from the need of being fully exploited in the calculated scenarios.

In summary, the analysis shows that the priority for expanding H₂ storage capacity should be given to the retrofitting of existing caverns, and that sites in the North Sea region should be given preference.

3.4. Cost indicators

In the following paragraphs, we analyse and compare the overall system costs, the changes in CAPEX for relevant technologies, and the LCOH metrics between all calculated scenarios.

3.4.1. Overall system costs

Fig. 11 visualises the economic value of electrolyser flexibility from the perspective of the energy system. The maximum absolute annualised savings for the energy system occur in comparison with the completely inflexible 0/0 case and lie around 36 billion €, which translates to relative savings of almost 10 %.

The overview shows that the flexibility provided by the H₂ transmission network is significantly more valuable for the energy system than the flexibility provided by H₂ storage caverns when only one of both options is available (x/0 and 0/x cases). This, however, is not surprising, since H₂ storage caverns are locally very restricted in

their availability (see, e.g., **Fig. 9**). So, if no transmission network is available, only these 10 regions can profit from higher storage capacities, whereas every modelled region can immediately profit from the transmission network.

On the other extreme, it is striking that differences in overall system costs are below 1 % for all but one case with at least 50 % of the optimal installed capacities for H₂ network and storage. However, the 50/50 case with 1.25 % higher cost is still close to that margin, whereas for all cases to the left and bottom of it jumps in value become more pronounced. Consequently, the cost of over-investment into H₂ flexibility infrastructure is less than the cost of under-investment.²

3.4.2. Capital expenditures

Firstly, we analyse the results of the different scenarios based on the investment in capacities resulting from the REMix optimisations for the target year 2050. The findings demonstrate that the absence of dedicated H₂ transmission and storage infrastructure as modelled in the 0/0 scenario imposes a significant rise in investment resulting in an almost 8 % increase in total investment costs relative to the optimal case. This triggers a reallocation of capital, characterised by a 37 % contraction in offshore wind investment and a 37 % expansion in utility-scale solar photovoltaics (PV), alongside a more than twofold surge in

² This statement, however, needs to be taken with caution regarding the specificity of the optimiser's treatment of transmission over-capacities further described in **Appendix F**.

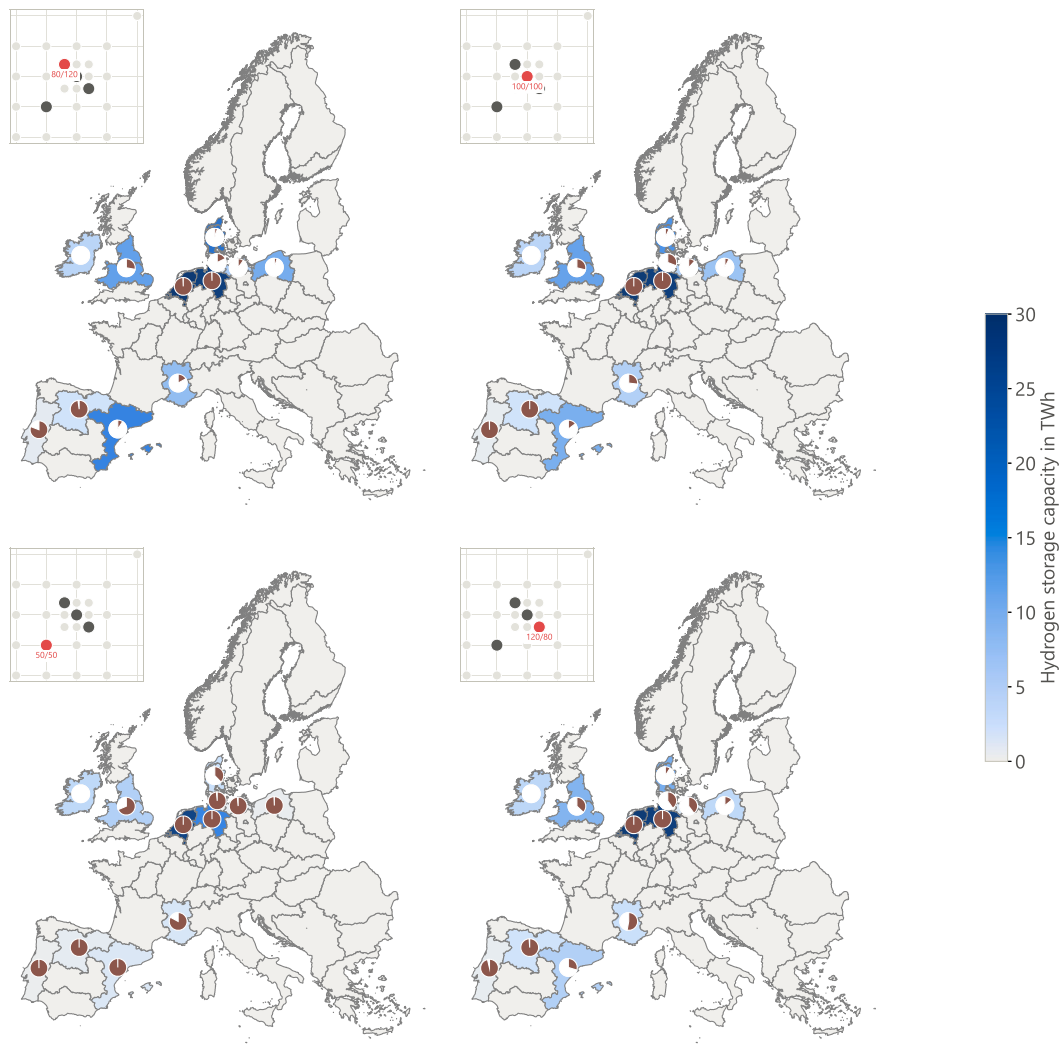


Fig. 9. Hydrogen storage capacity for the 80/120, 100/100, 50/50, and 120/80 scenarios. The pie charts show the share of newly built salt caverns (white) versus repurposed ones from previous natural-gas usage (brown) respectively.

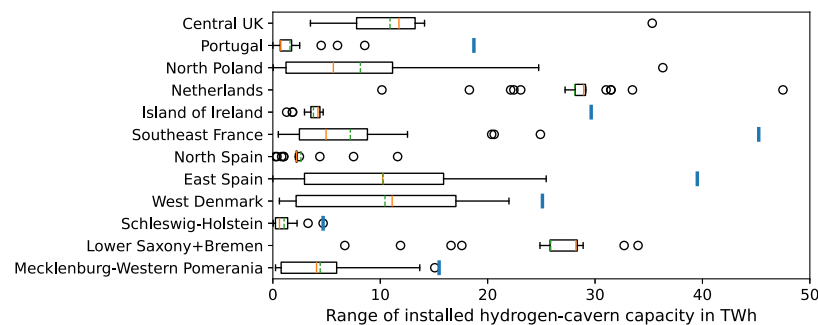


Fig. 10. Range of installed storage capacities per model region for hydrogen caverns (newly built and retrofitted combined) for all calculated scenarios. The orange line indicates the median for each region, the green dashed line the mean installed capacity, and the thicker blue line the maximum installable storage capacity for the respective region (if no blue line is visible for a region, this means that the potential is (far) higher than the 50 TWh axis limit). The whiskers are placed at the farthest point within the 1.5× inter-quartile range respectively.

spending on Li-ion battery deployment (+103 %) to provide short-term localised flexibility.

The absence of a H_2 network and storage caverns results in a massive concentration of investment in Germany (+60 %) and France (+18 %), where capital is reallocated toward PV and onshore wind to satisfy domestic H_2 demand. In contrast, the investment attractiveness

of the Danish energy system collapses by 73 % under identical constraints, driven by the stranded value of its offshore wind potential with an investment allocation drop by 87 %. Spain demonstrates a specific sensitivity to infrastructure expansion, with investment increasing by almost 16 % in the 200/200 scenario, fuelled by accelerated spending on PV.

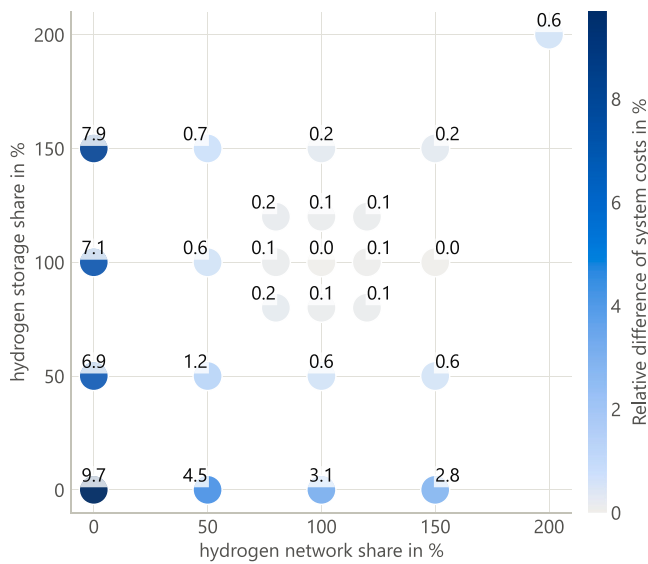


Fig. 11. Difference in overall system costs relative to the optimal case across all considered scenarios.

Finally, the regional allocation of AEL investment in 2050 demonstrates that while total European CAPEX remains stable at approximately 21 billion € between the reference and inflexible scenario, its spatial distribution is very sensitive to infrastructure. In the absence of a H₂ grid and storage infrastructure, investment collapses in export hubs such as Denmark, falling from 5.916 billion € to 114 million €, while capital is reallocated to industrial centres like Germany, where spending reaches 8.523 billion € from 1.427 billion €, alongside significant increases in the Czech Republic and Austria. Conversely, the 200/200 scenario facilitates a significant expansion of the AEL sector, with total European investment rising by 14 %. This enables a reallocation of AEL investment toward regions with superior renewable yields. Spain exemplifies this trend, as its AEL investment of 4.550 billion € in the optimal case increases substantially to 7.176 billion € under the situation of over-investment in H₂ infrastructure.

3.4.3. Model-implied levelised cost of hydrogen (LCOH)

To measure the economic competitiveness of H_2 , the LCOH (see Eq. (1)) and the spread between the LCOH and the annual average marginal cost (see Eq. (2)) are evaluated and illustrated in Fig. 12. All values reported in this subsection refer to the model-implied LCOH as defined in Eq. (1). They represent the long-term H_2 supply cost consistent with the optimised capacities and dispatch.

We observe a notably high LCOH around 63.7 €/MWh without H₂ storage and transmission infrastructure, representing a significant 26 % increase compared to the reference case with 50.6 €/MWh. The spread between the LCOH and the average marginal cost is positive in the 0/0 case, reaching +3.7 €/MWh. This indicates that H₂ production is largely inflexible and occurs even during periods of high electricity prices. In the scenario without H₂ infrastructure, Germany, which is the largest H₂ producer in that case, produces at a very high cost (74.9 €/MWh compared to 52.2 €/MWh in the optimal case), with a national spread that is even more pronounced at 9.8 €/MWh. Consequently, while a scenario without storage may attract more localised investments in H₂ production near high-demand centres, the final production cost and overall competitiveness of H₂ are highly penalised by this lack of flexibility.

Conversely, scenarios involving over-investment in H₂ infrastructure result in a lower LCOH than the optimal case, reaching a low at almost 49.4€/MWh for the 200/200 case (a 2.4 % decrease). In this scenario, where Spain is the second-largest H₂ producer in Europe,

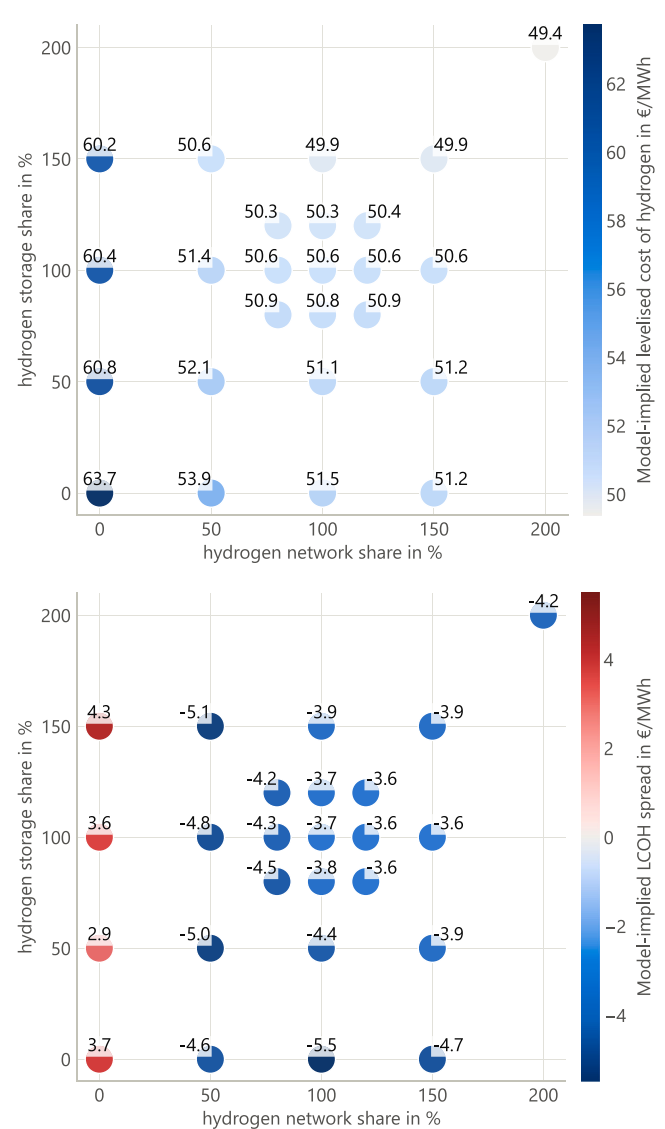


Fig. 12. Model-implied levelised cost of hydrogen (LCOH) (top) and spread between model-implied LCOH and average marginal cost of hydrogen (bottom) across all considered scenarios. The darker blue the dot, the more profitable it is on average to produce hydrogen in the respective scenario.

the country achieves a very low LCOH of 44.6€/MWh. It benefits significantly from flexibility options, as evidenced by a substantial negative spread of -7.2€/MWh between the LCOH and the average marginal cost. Nevertheless, at the European level we observe that this negative spread does not continue to widen as infrastructure increases beyond a certain point, primarily because average marginal costs also decrease significantly due to the overall rise in system flexibility.

3.5. Impact of a high electrolyser capacity factor

An additional model run evaluates the impact of enforcing a binding capacity factor constraint of around 83 % for all electrolyzers without applying any bounds to H₂ network and storage. The REMix results show a decrease in both electrolyzer and H₂ storage capacity to about 60 % of the value in the optimised case without minimum capacity factor (100/100). The reduction in H₂ production is not equally distributed across Europe. Most regions with high hydro and solar power generation can maintain or even increase their capacity, whereas wind-dominated regions produce much less H₂ (Fig. E.1, top). H₂ production

is almost completely eliminated in Germany, Italy and the Netherlands and substantially reduced in Denmark, Poland and the British Isles. The change in Italy must be seen in the context of H_2 imports. These increase from 9 % to 14 % of demand, and almost completely enter Europe through South Italy. The reduction in H_2 storage capacity only affects newly built caverns, which heavily concentrates the remaining capacity in the regions with retrofit options especially in Germany and the Netherlands. In contrast to electrolyzers and storage, the overall H_2 network capacity is not affected by the additional constraints. However, the network structure changes substantially (Fig. E.1, bottom). Corridors from Spain and Italy towards central Europe result to have the highest capacities, at the expense of a decrease in the North Sea region. These substantial changes in the H_2 supply infrastructure come with an increase in system costs by almost 6 % compared to the optimal case, which lies in the range of up to 10.5 % for continuous electrolyser operation previously established in the literature [25].

4. Discussion

4.1. System value and robustness of hydrogen infrastructure

The cost-optimal configuration highlights a structural mismatch between where H_2 can be produced cheaply, where it can be stored, and where it is ultimately consumed. Production tends to concentrate in regions with favourable renewable resources, import access or network connections, while large-scale storage is limited by geological potential and by the possibility to retrofit existing gas storage sites. Demand, by contrast, remains largely driven by industrial and sectoral needs. The role of infrastructure is therefore to connect these different geographies. Pipelines allow regional production advantages to be used at the European scale, while storage provides temporal flexibility in the subset of locations where it is technically and economically available. This distinction is useful for interpreting the model results: transmission and storage are complementary, but they do not address the same constraint. H_2 storage should therefore be assessed as a component of a broader sector-integrated flexibility portfolio. Its economic value depends on its interaction with network infrastructure and on the spatial availability of suitable storage sites.

This spatial mismatch is reflected in the relative value of network and storage expansion. Removing all H_2 flexibility increases total system costs by 9.68 %, but most of this penalty comes from restricting the network rather than storage.² Scenarios without H_2 network expansion increase costs by around 7 % to 8 %, whereas scenarios without storage expansion remain closer to the optimum, with cost increases around 2.5 % to 4.5 % (see Fig. 11). Storage is therefore valuable, especially where existing gas storage can be repurposed, but it mostly provides local and temporal flexibility. The network has a broader role: it gives demand regions access to cheaper production, imports and renewable resources elsewhere. From a policy perspective, this supports early coordination of cross-border corridors and market rules, in line with the 2024 EU Gas and Hydrogen Decarbonisation Package [31], while storage planning should remain more targeted to locations with clear geological or retrofitting value.

Finally, the results suggest that infrastructure planning should account for an uncertain future H_2 demand. The model shows a strong penalty for under-investment, but only a limited cost impact from moderate over-investment. Most scenarios with at least half of the optimal network and storage capacities remain close to the cost optimum, while additional infrastructure can even slightly reduce the LCOH by improving access to low-cost supply. This matters because future H_2 demand remains uncertain not only in its location, but also in its overall scale. The role of H_2 in industry, heavy transport, synthetic fuels or balancing will depend on its competition with alternatives such as direct electrification, carbon capture, or changes in industrial processes. If these options develop faster or prove cheaper than expected, H_2 demand may remain limited; otherwise, it could increase substantially.

This makes infrastructure planning difficult, since pipelines and storage assets are long-lived and capital-intensive.

The assumptions on H_2 demand we use in this case study lie in the upper range [2]. However, it has been shown previously for Germany that H_2 transmission infrastructure becomes cost-optimal already at rather low H_2 demands [32]. Previous evaluations with our European model and lower future H_2 demand showcase the tendency of a more decentralised H_2 production and less long-distance network infrastructure with similarities to what we show for less H_2 flexibility infrastructure in the present case study (see Fig. 8). Bearing this in mind, system planning around low demand risks creating bottlenecks if H_2 use expands, whereas moderate over-investment appears less costly in the model results. This asymmetry supports a more ambitious approach to infrastructure planning rather than narrowly matching uncertain demand forecasts.

4.2. Cross-border infrastructure cost sharing

The deployment of H_2 infrastructure introduces significant challenges regarding the sharing of investment costs. In the cost-optimal scenario, strong geographic asymmetries emerge: for instance, West Denmark is projected to produce up to 40 times its domestic demand. In this configuration, producing countries bear substantial hosting costs, including high capital expenditures and negative externalities associated to environmental and land-use costs of electrolyzers and other necessary infrastructure. Meanwhile, countries with high demand but less favourable conditions to produce H_2 can use H_2 imports from regions with more favourable conditions for H_2 production for their domestic demand at a significantly lower LCOH. This imbalance suggests that a part of the benefits is captured by importing nations while their investment in H_2 infrastructure stays small if it is limited to a national scope. This could create a free-rider effect, which discourages host countries from investing at the socially optimal level for the European energy system.

To address these imbalances, the European Union provides a framework known as the Cross-Border Cost Allocation (CBCA). This mechanism is designed to distribute the investment costs of Project of Common Interests (PCIs) among countries in proportion to the benefits they receive. Its primary objective is to unlock projects that are socially beneficial at the EU level but might be unattractive for a single hosting country. H_2 projects have only become eligible for PCI status since the end of 2023, and formal CBCA decisions for this sector are expected in the coming years. Nevertheless, costs in most CBCA projects often remain national, as member states typically agree to cover their own shares. Financing an asymmetric H_2 infrastructure could remain a persistent challenge at the European level.

To give an indication of investment asymmetries, we can quantify the economic rationale for European cooperation by evaluating the LCOH spread between scenarios. We do this for the example of Germany, the projected major future H_2 consumer in our studied region. In the absence of a H_2 network and storage infrastructure, the country faces a high domestic LCOH of 74.9 €/MWh, which drops to 52.2 €/MWh in the cost-optimal configuration. Since the H_2 marginal costs reflect its equilibrium production price, this domestic LCOH acts as a proxy for the regional market price where local production and imports converge. The model-implied LCOH used in this study represents the long-term regional H_2 supply cost consistent with the optimised system configuration, rather than a directly observable market price. The 22.7 €/MWh difference provides an upper-bound estimate of Germany's system-cost benefit from cross-border infrastructure. Multiplying this value by Germany's total H_2 demand establishes a theoretical financial ceiling for potential CBCA transfers from Germany to support European H_2 infrastructure, which—for the assumptions underlying this study—lies at a maximum amount of just under 4.4 billion € equalling around 12 % of total system cost benefits.

This is only an estimate based on the benefits related to H_2 demand. Other factors may generate positive externalities for producing countries, such as job creation, industrial attractiveness, and trade balance. These externalities may lower the threshold at which producing countries agree to build the necessary H_2 infrastructures. Alternatively, cooperative game theory, specifically the Shapley value method, could offer a relevant framework to design cross-border cost-allocation mechanisms for H_2 infrastructure expansion [33].

4.3. Cost sharing among economic agents

Another issue related to cost-sharing emerges among the various economic agents involved in the H_2 ecosystem. Research suggests that electrolyser operators must run their assets at a rather high percentage of time for them to become an economically viable investment [34,35]. In our optimal scenario, however, electrolysers operate at capacity factors ranging from only approximately 40 % to 60 % with only Norway as an exception to that at almost 85 % (see Fig. 7). It is therefore possible that the economic choices of electrolyser operators make it impossible to achieve the cost-optimal European system setup without financial transfers in their favour.

To quantify this gap, we estimate the transfer payment necessary to incentivise operators to accept flexible operation. This can be estimated by comparing the total system costs of the optimal system with a scenario where electrolysers are required to run at a higher capacity factor. We choose an electrolyser capacity factor of around 83 % to do this assuming that operators reach profitability at around this threshold. The resulting difference in total system costs reflects the value of flexible H_2 generation for the energy system. By dividing this total cost difference by the total H_2 demand, we derive a proxy for the maximum subsidy per unit of H_2 that could be redistributed to electrolyser operators. Overall, we find a total cost difference of a little over 21 billion € for said case, representing a cost per unit of H_2 in the system of around 9.5 €/MWh. We assume that this represents the maximum socially acceptable amount that could be distributed to H_2 operators to incentivise flexible operation. If flexible operation remains unprofitable for operators despite this subsidy, then it is preferable from a cost perspective for the electrolysers to operate with a capacity factor that ensures unsubsidised profitability.

This subsidy could be funded through a transfer from the economic agents who benefit from the flexible operation of the electrolysers. On one hand, H_2 demand sectors are beneficiaries, as flexibility allows for a significantly lower LCOH. On the other hand, renewable energy producers benefit from flexible electrolysis, which establishes a price-responsive demand during low-price hours. This creates a price floor that prevents the collapse of wind and solar market values, thereby increasing the market value of VRES. It must be emphasised that our calculation provides only a rough estimate of the necessary subsidies. REMix does not explicitly model the strategic behaviour of individual economic agents. To refine these findings, multi-agent models capable of simulating profit maximisation would allow for a more precise determination of the transfer mechanisms required between producers, consumers, and grid operators in the H_2 ecosystem.

4.4. Critical reflection

Our analysis relies on 2012 as the single weather year, which affects the robustness of cost-optimal energy system designs as has been shown in previous research [36]. Especially short-term extreme events establish and raise the need for flexible dispatch, although also long-term events like dark lulls are putting stress onto the energy system. As our chosen weather year is not extreme in that sense, the optimisation with more extreme weather years will alter the optimal power-plant park in a way that more dispatchable generation is available, which, depending on the event, can come from, e.g., gas turbines or storage technologies. As a consequence, this could influence the expansion of

H_2 turbines, raising the H_2 demand exogenously, and thus potentially increase the need for H_2 flexibility infrastructure. Our current results, however, show the tendency that rather gas turbines operated with biogas are favoured for the peak events in a cost-optimal system, which seems to make the potential influence of a different weather year on our assessment rather minor.

As can be seen in our study, different availability of H_2 flexibility infrastructure has a huge impact on the LCOH. Vice versa, it can be expected that future sector-integrated energy systems are quite sensitive to the cost of H_2 . This study only takes one H_2 import cost scenario as a basis which is situated somehow in the middle of future cost assumptions leading to overall import shares in a range of 7 % to 21 % for the performed optimisations (see Appendix C).

Lower H_2 import costs will raise the overall H_2 import share, although most H_2 supply will still come from domestic production as previous work has shown. Furthermore, lower H_2 import costs will change the cost-optimal transmission infrastructure such that demand centres in Europe are connected to the cheapest import location. Depending on where this location will be, this could make any of the Spain–France–Germany, UK or Italy links more pronounced. In the case of cheaper H_2 imports from Eastern Europe — which were not included in the present case study — the aforementioned links will lose importance in favour of a new H_2 transmission link connecting the Baltic states with central Europe. This so-called penny-switching effect is a general issue of linear optimisation models. From our input assumptions, however, results a rather diversified H_2 supply situation with possible advantages in terms of resilience, although an assessment of this is not in the scope of this study. These considerations can be projected on changing electrolyser CAPEX, as lower electrolyser costs will also make H_2 imports cheaper and raise demand, whereas higher electrolyser costs will lead to the opposite trend, which raises the question on the effect of H_2 demand on results.

This is a key limitation of this study as we are applying a fixed and price-inelastic H_2 demand scenario. In the H_2 market, if the system cannot achieve a sufficiently low LCOH due to high production costs, H_2 demand would likely be price-elastic. High costs could force end-use sectors to substitute H_2 with alternative technologies or reduce their overall consumption. Because any shift in total demand would fundamentally alter the optimal sizing and location of pipelines and storage, this missing general economic equilibrium effect remains a limitation of our assessment.

The specific implications of this are further discussed in Section 4.1.

The model-implied LCOH should be interpreted with caution, as it may differ from a conventional accounting LCOH when investment bounds are binding, capacities are exogenously imposed, or infrastructure constraints generate scarcity effects. Nevertheless, the use of nodal shadow values as long-term marginal supply-cost signals is well established in linear capacity-expansion modelling.

This study has a focus on the use of H_2 in a future climate-neutral European energy system, which is why herein only the economic value of flexibility from H_2 technologies is assessed and evaluated. This, however, is by no means to imply that H_2 is the only flexibility or decarbonisation option for the future energy system. On the contrary, there are other decarbonisation approaches with high or even higher potential economic value compared to H_2 , such as direct electrification, district heating, or bioenergy. These are also included in our model (see Fig. 2), although without assessing their respective economic value as part of the presented analysis.

5. Conclusions

Using a large-scale energy system model in hourly resolution encompassing 57 model nodes and more than 100 different technology options, we show the impact of hydrogen (H_2) flexibility on and its economic value in a 2050 sector-integrated, decarbonised European energy system. We perform a parameter study of 25 scenarios in which

we change the availability of H₂ storage and transmission infrastructure relative to the optimal case and analyse the impacts on economic efficiency and infrastructure development. Our findings indicate that H₂ flexibility should be understood as a means for system integration of H₂ infrastructure rather than as an isolated option for electrolyser operation. In a carbon-neutral European energy system, pipelines and large-scale storage have a major influence on where H₂ is produced, how electrolysers are operated, and which regions can access low-cost renewable resources. The central result is therefore not only that H₂ flexibility infrastructure reduces system costs, but that its spatial allocation matters.

We find a maximum system value of almost 10 % that the availability of H₂ flexibility infrastructure provides compared with its complete inexistence regarding overall system costs. Across all analysed scenarios, the major H₂ cavern storage locations appear to be the Netherlands and Lower Saxony/Northern Germany which are both developed exclusively through retrofitting gas caverns. Also, three H₂ pipeline routes appear consistently, which is connecting (1) northern Spain through south and east France with Germany, (2) the wind-potential rich Scotland with the south of the British Isles, and (3) the south with the north of Italy, although the latter is more sensitive to the chosen scenario. A fourth route connecting Denmark with Lower Saxony in Germany only becomes viable when H₂ network infrastructure of more than 50 % of the optimum is allowed to be built. An additional scenario enforcing electrolyser operation with a capacity factor of around 83 % further supports these findings. It also uncovers a potential of almost 6 % of optimal system costs that could be used by policy makers to encourage system-friendly behaviour of electrolyser operators, which means keeping their capacity factors between 40 % to 60 % in most regions (Norway being the notable exception).

Our cost analysis indicates an asymmetric investment planning risk. Under-investing in H₂ infrastructure creates bottlenecks and forces more expensive local production, whereas over-investment has a significantly reduced impact on total system costs well below 1 % whenever either over-expanded H₂ storage or transmission infrastructure is accompanied by at least some flexibility from the respective complementary technology. H₂ transmission infrastructure seems to provide a larger system benefit than large-scale H₂ storage infrastructure that plays a complementary role in the studied area because of its spatially limited geological potential. Our findings support a proactive planning approach in which early infrastructure deployment is guided by European system benefits rather than by national demand alone. Future work could analyse the impact of different future H₂ demands on infrastructure locations and levelised cost of hydrogen and thus further test the robustness of our results. Moreover, beyond cost-optimal infrastructure sizing the institutional question of how the described system benefits from H₂ flexibility can be allocated between producing regions, importing regions, network operators, and H₂ producers is an area to be further addressed.

CRedit authorship contribution statement

Jens Schmugge: Writing – original draft, Visualization, Validation, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Writing – review & editing. **Hans Christian Gils:** Writing – original draft, Visualization, Validation, Supervision, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization, Writing – review & editing. **Albin Kasser:** Writing – original draft, Formal analysis, Writing – review & editing. **Cyril Bourasseau:** Project administration, Formal analysis, Conceptualization.

Declaration of AI-assistance in the writing process

During the preparation of this work the authors used DeepL and Gemini in order to enhance the comprehensibility of their respective texts. After using these tools, the authors reviewed and edited the content as needed and take full responsibility for the published article.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work on or the content of this article.

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Appendix A. Model setup

In the following paragraphs we show conventions and input data that are central for setting the shown results into perspective.

A.1. Geographical resolution

Fig. A.1 shows the regionalisation and nomenclature of the 57 model nodes used within this study except Germany. With the exception of Lower Saxony and Bremen, which are combined into a single model node, Germany is depicted on federal-state level with the respective names.

A.2. Hydrogen demand per node

The cumulative exogenous H₂ demand of 2199 TWh in the REMix-Eur model which the present study is based on is shown in Fig. A.2 in its distribution to the 57 model nodes.

A.3. Techno-economic data for hydrogen storage caverns

The techno-economic assumptions for H₂ technologies as used in the model are shown in Table A.1.

A.4. Assumptions for battery-electric vehicles

The assumptions as shown in Table A.2 are taken for modelling the battery-electric vehicle fleet in the model used for this case study.



Fig. A.1. Geographical scope of the REMix-Eur instance used, comprising 57 model nodes. Names of nodes in Germany are not depicted, they are equal to those of the federal states. Lower Saxony and Bremen are combined into a single node. Map lines delineate study areas and do not necessarily depict accepted national boundaries.

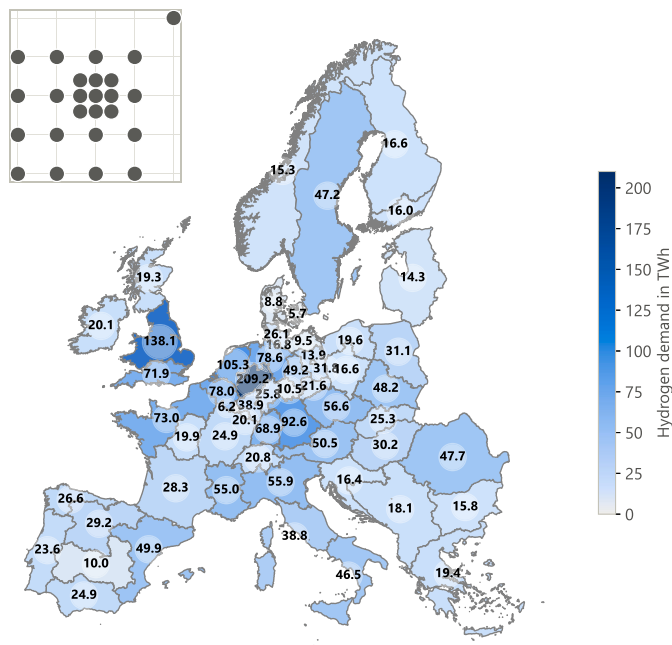


Fig. A.2. Hydrogen demand per model node in all scenarios [2].

Table A.1

Techno-economic assumptions for hydrogen technologies. [28] All costs given for target year 2050 on the basis of price year 2015. OPEX and efficiency of storage cavern from compressor. Pipeline units: k€/ (MW 1000 km) (CAPEX), k€/ (MW a 1000 km) (OPEX), %/1000 km (efficiency). Pipeline CAPEX and OPEX given for (land)/(sea) respectively.

	CAPEX	OPEX	Efficiency	Lifetime
Electrolysis (AEL)	429.3 k€/MW	13.53 k€/MW/a	84.1 %	25 a
H ₂ cavern (new)	175.5 €/MWh	51.1 k€/MW/a	94 %	50 a
H ₂ cavern (retrofit)	66.1 €/MWh	51.1 k€/MW/a	94 %	50 a
H ₂ pipeline (new)	223.2/379.4	2.2/3.8	99.9928	50 a
H ₂ pipeline (retrofit)	31.5/53.6	2.2/3.8	99.9928	50 a

Table A.2

Assumptions for the modelling of battery-electric vehicles in the model that served as input to the `venco.py` software. [29] Values are shown for target year 2050 for an average vehicle fleet. (EV: electric vehicle; UC: uncontrolled charging; V2G: vehicle-to-grid; CI: charging infrastructure share).

EV share	UC: 40; V2G: 60
Battery size	75 kWh/vehicle
Specific consumption	16.9 kWh/100 km
CI home	0 kW; 0.2; 3.7 kW; 0.6; 11 kW; 0.2
CI work	0 kW; 0.6; 3.7 kW; 0.2; 11 kW; 0.2
CI other	0 kW; 0.5; 3.7 kW; 0.3; 11 kW; 0.1; 22 kW; 0.1

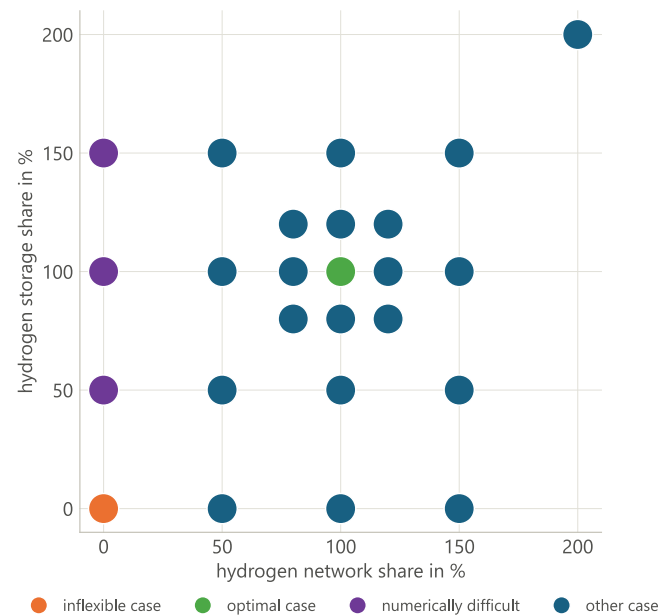


Fig. B.1. Overview of the scenario runs performed for this study. The inflexible case (0/0) is marked in orange, whereas the optimal case (100/100) is marked by the green dot in the middle of the graph. The especially numerically-difficult cases marked in purple were solved using the MOSEK solver (version 11.0.10), all others (blue, green, and orange) were solved with Gurobi 12.0.1.

Appendix B. Optimisation parameters

A summary of the analysed scenario runs is shown in [Fig. B.1](#). All scenarios were solved using a development version of energy system optimisation framework (REMix) 0.14.0 (tag “h2flexflex”) in conjunction with GAMS 49.4.0 using the non-default arguments “accuracy = 0.0001”, “aggfill = 0”, “densecol = 200”, “pathopt = target”, “roundcoefs = 1”, and “threads = 16”, and, where necessary to reach a solution, “barhomogeneous = 1” and “numericfocus = 1”.

For the majority of scenarios Gurobi 12.0.1 was used as solver. Only those scenarios coloured in purple in Fig. B.1 were solved using

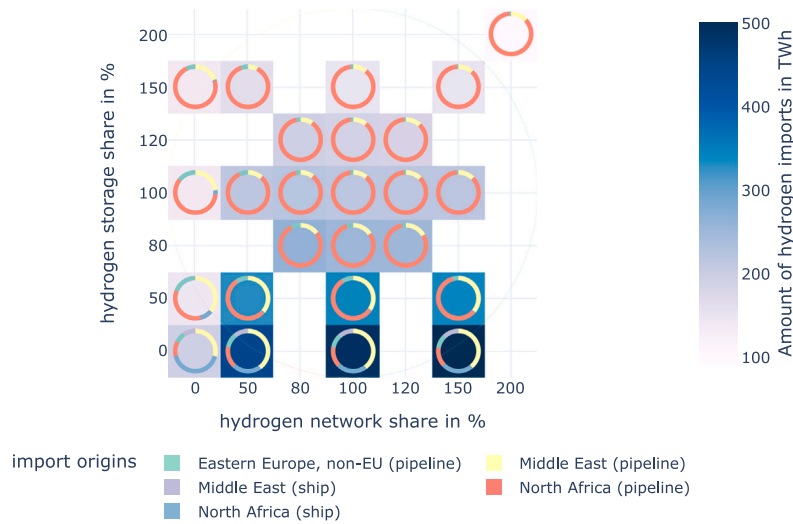


Fig. C.1. Amount of hydrogen imports per scenario. The doughnut charts show the share each origin contributes.

MOSEK 11.0.10 as in these five cases Gurobi reported numerical trouble and stopped optimisation after around 20 iterations.³

The matrix size per model run is around 134 million equations, 132 million columns and 444 million non-zeros (before presolve). The elapsed time per model run ranges from approximately 8 to 14 hours with a maximum RAM usage of around 288 GB with Gurobi and 550 GB to 650 GB with MOSEK on an AMD EPYC 9555 64-Core processor with AVX-512.

Appendix C. Hydrogen imports

The development of a H₂ network is the key enabler for substantial cost-effective H₂ imports from outside Europe. In contrast, the expansion of storage facilities leads to a reduction in imports, as the domestic potential of flexible electrolysis can be better utilised (Fig. C.1). It is interesting to note that the total volume of imports is at a very similar level of 9 % in the inflexible case and 10 % in the optimal case. If we move along the axis of a simultaneous expansion of grids and storage facilities, we see a significant increase in imports to about 15 % of demand at an early stage (50/50). This share only decreases significantly beyond 50 % of the optimum of network and storage. In the event of further expansion to 150 % of the optimum, the initial level is reached again. If grids are expanded more than storage facilities, this leads to higher imports of up to 21 % in 100/0, and in the opposite case to lower imports.

There are significant differences in the realisation of H₂ imports not only in terms of quantity, but also in terms of infrastructure, regions of origin and destination countries (Fig. C.2). For the shown cases 0/0, 50/50, 100/100, and 150/150, this stands in relation to cumulative imports from all available sources of around 192 TWh/9 %, 331 TWh/15 %, 216 TWh/10 %, and 149 TWh/7 % respectively. In the inflexible case, they are divided equally between pipeline-based imports and ship-based imports. Pipeline-based imports can only be used in regions in direct neighbourhood of export regions. They are realised mostly in South Italy and East Poland, which are importing from Algeria and Ukraine, respectively. Instead, ship-based imports are possible for all countries with ports and arrive mostly but not exclusively in the United Kingdom (UK), France, Italy, and Germany. In contrast to that, the role of ship-based imports is marginal in all other cases, and zero if

more than 50 % of optimal grid and storage capacities can be realised (see Fig. C.1). The main entry points of pipeline imports relate to the possible network expansion. At lower overall network capacities, imports from Eastern Europe (excluding EU states) and the Middle East to all accessible regions in EU-Eastern Europe are being favoured, whereas at higher network capacities South Spain, South Italy and Bulgaria become main entry points. Main export region in that case is northern Africa.

Appendix D. Electricity supply and grids

The underlying H₂ demand scenario and the high share of European production make electrolysis a major contributor to total power demand, with a share accounting for up to 36 %. From this follows that the observed re-location of electrolysis capacity enabled by H₂ networks and storage comes along with similar changes in the distribution of variable renewable energy sources (VRES) capacities making better use of good resources. Regions and countries appearing as H₂ importers are mostly also electricity importers. Solar photovoltaics (PV) is concentrated particularly in South and East Spain, whilst declining in central Europe with rising energy system flexibility. The expansion of H₂ networks and storage leads to greater use of wind power in only a few locations, particularly in Denmark, Ireland and the Baltic states. Contrary to that, a decline is observed for some locations in central Europe, including East Poland and East France.

The power grid sees some substantial expansion across all scenarios, mostly strengthening the connection to import regions such as North Spain, North-Rhine Westphalia, Southwest France, England or Bavaria. This includes both national and international connections, mostly following the corridors observed for H₂ networks. Battery storage is used in all scenarios, but reduced with more H₂ networks and storage. The effects of difference flexibility provision by the H₂ infrastructure have an equivalent effect on the marginal cost of electricity as they have on the levelised cost of hydrogen (LCOH) (see Fig. 12), albeit dampened.

Appendix E. Impact of a forced high electrolyser capacity factor

Section 3.5 shows the changes in installed alkaline electrolysis (AEL) capacities per region compared to the optimal case and the resulting H₂ transmission network for the case where a capacity factor minimum of around 83 % is enforced. Both plots are referred to in Section 3.5.

³ Also the additional usage of the parameters “barhomogeneous” and “numericfocus” did not lead to a solution for Gurobi in the cases marked in purple.

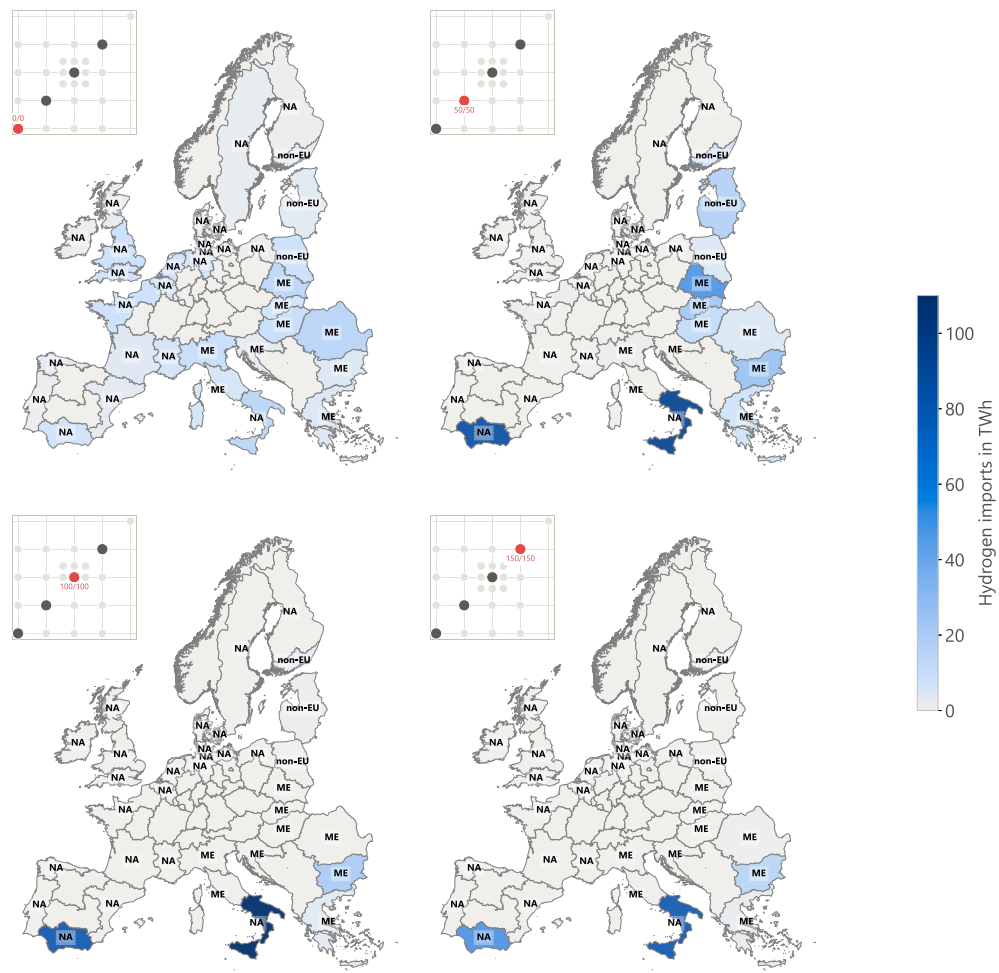


Fig. C.2. Hydrogen imports and origins for the scenarios 0/0, 50/50, 100/100, and 150/150 (ME: Middle East, NA: North Africa, non-EU: Eastern Europe (non-EU)).

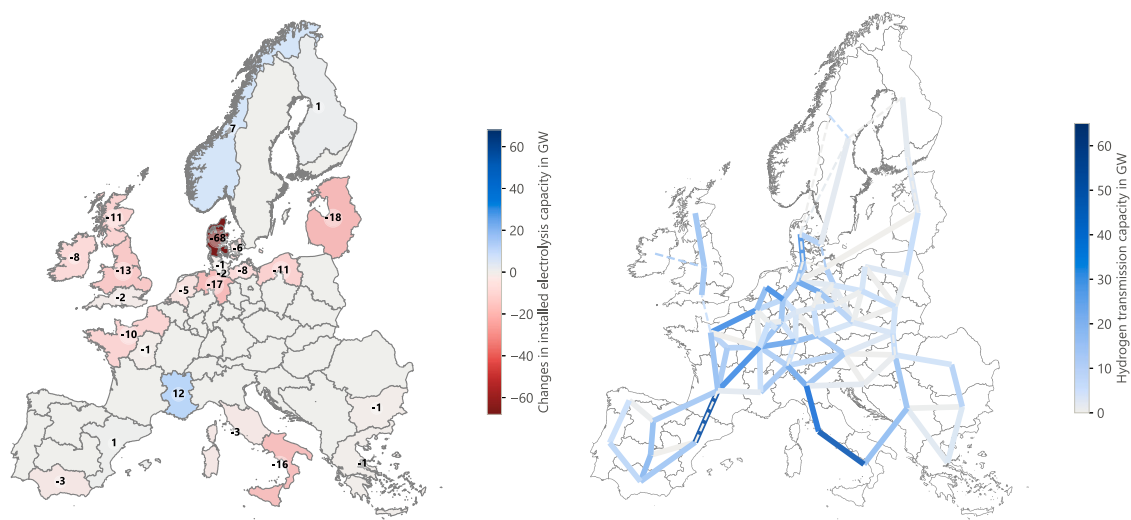


Fig. E.1. Changes in installed (alkaline) electrolysis capacities compared to the optimum (left, red indicating a decrease compared to the optimum), and resulting hydrogen transmission network (right) for the case where a capacity factor minimum of around 83 % is enforced.

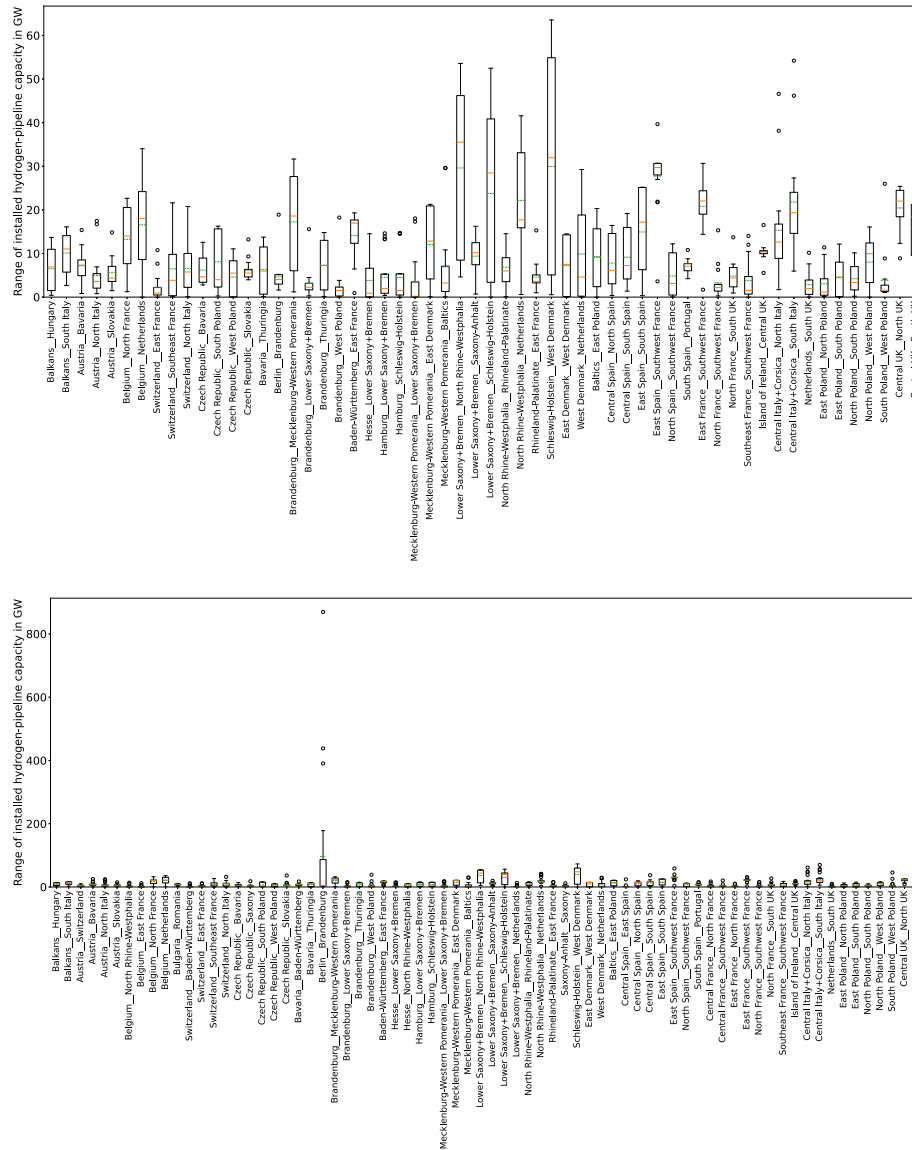


Fig. F.1. Range of installed hydrogen pipeline capacities per model link for the scenarios up to 100 % hydrogen network compared to the optimal case (top), and for all calculated scenarios (bottom). Only links with 10GW capacity or more in any considered scenario are shown (which is the reason more links appear in the plot on the bottom). The orange line indicates the median for each link, whereas the green dashed line stands for the mean installed transmission capacity. The whiskers are placed at the farthest point within the 1.5 $\times$ inter-quartile range respectively.

Appendix F. Distribution of hydrogen pipelines and dumping of over-capacities

The comparison of the upper and lower box plot in Fig. F.1 very well exhibits the effect that a forced over-expansion of H_2 transmission capacities has on the overall system in our linear optimisation model. The operations and maintenance costs of the pipelines seem to be higher than their contribution to an already optimised energy system. As a result, the solver decides to dump most to all forced over-expansion on the shortest link in the model, which is the one between the two German states of Berlin and Brandenburg. This effect can be observed for all cases with a higher-than-optimal share of H_2 infrastructure. The Berlin-Brandenburg link has an H_2 transmission capacity of just under 5.2GW in the optimal case, which corresponds to a share of under 0.6 % for the entire geographical model scope. For the 120/80, 120/100, and 120/120 cases, these values rise to 74.6GW, 123GW, and 148GW with respective share of the Berlin-Brandenburg link of

7 %, 11.6 %, and 13.9 %, before culminating in the 200/200 case where almost all additionally enforced H_2 transmission capacity is dumped on said shortest link in the model with 870GW and 49 % of total share.

Appendix G. Storage capacities

Fig. G.1 shows the H_2 cavern capacities for the 50/100, 80/80, 100/50, and 120/120 scenarios as described in Section 3.3.

Appendix H. Hydrogen self-supply per region

Fig. H.1 shows the share of self-supply per region, which contains additional data to support the descriptions in Section 3.1.

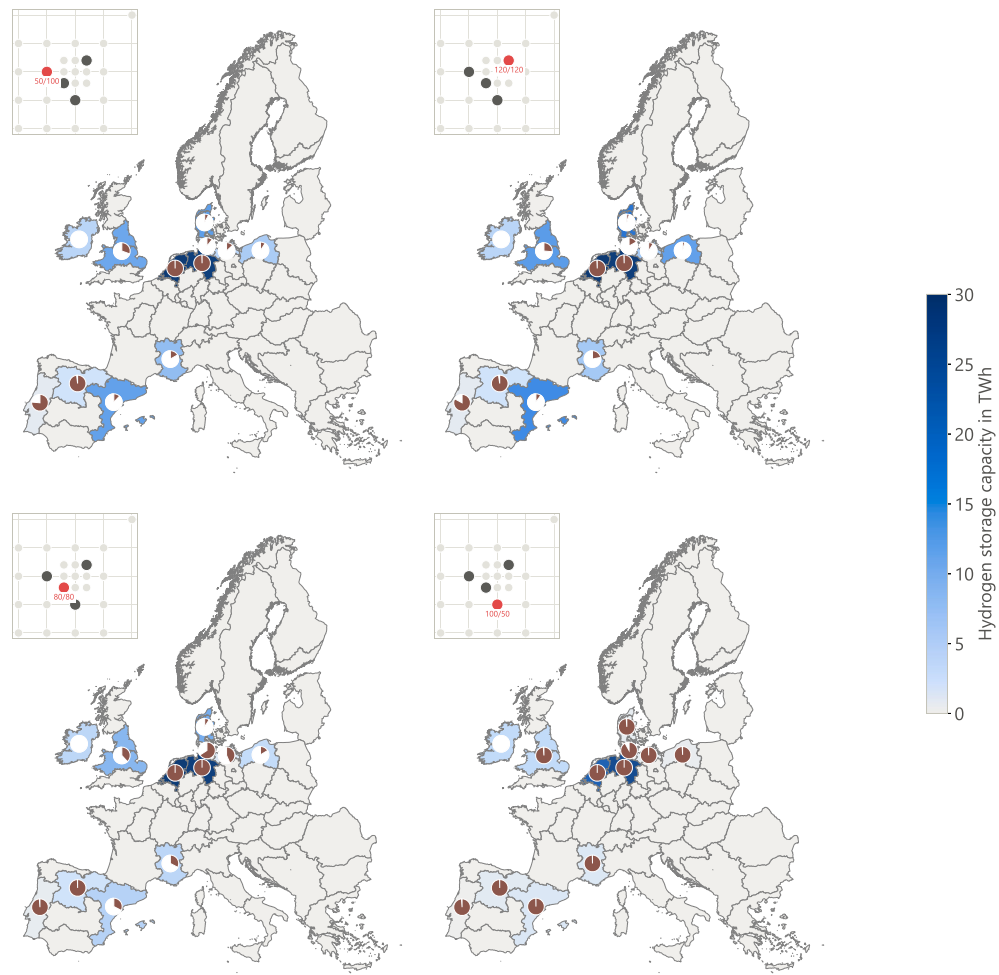


Fig. G.1. Hydrogen storage capacity for the 50/100, 120/120, 80/80, and 100/50 scenarios. The pie charts show the share of newly built salt caverns (white) versus repurposed ones from previous natural-gas usage (brown) respectively.

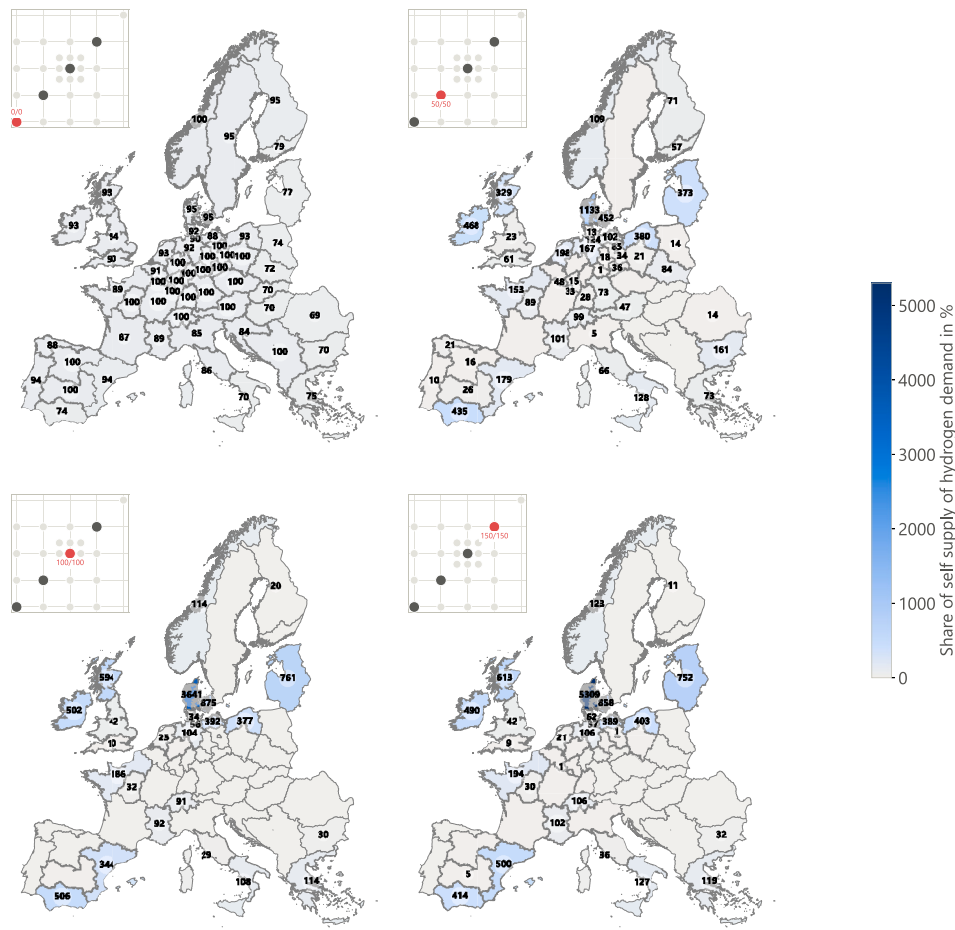


Fig. H.1. Share of hydrogen supply via intra-regional production compared to supply via inter-regional transfer and/or imports from outside the model scope (possible via pipeline and ship) for the scenarios 0/0, 50/50, 100/100 and 150/150. In the scenarios with more flexibility, West Denmark is distorting the scale.

Data availability

The model used in this study is built upon the REMix-Eur data collection [28]. The missing electric-vehicle profiles therein are about to be published and can be made available on request in the meantime.

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