Renewable Energy 258 (2026) 124917

Contents lists available at ScienceDirect

Renewable Energy

journal homepage: www.elsevier.com/locate/renene

From ambition to reality: The impact of limited capacity expansion rates on the transformation pathway to a climate-neutral European energy system

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ARTICLE INFO

Keywords:
Energy system modelling
Transformation pathways
Capacity expansion rates
Green hydrogen
Network topology
REMix

ABSTRACT

The rapid expansion of renewable energy technologies is essential for the successful transition to a climate-neutral European energy system. This is particularly important for producing large quantities of green hydrogen to decarbonise hard-to-abate sectors. However, the annual expansion rate of renewable energy technologies could hinder this transformation. These limitations can stem from various sources, including policy incentives that influence investment decisions, import supply chains, and critical materials. To evaluate the potential impact of these limitations on the transformation pathway, we present a model-based scenario analysis with high temporal and subnational spatial resolution, which explicitly considers import corridors for energy carriers. Our results show that, when national limits on expansion rates are considered, hydrogen production shifts from southern Spain to Germany. Furthermore, our results highlight the need to balance green and blue hydrogen production to avoid an escalation in the required scale-up of photovoltaic and wind technologies. Analysing hydrogen import options reveals their significant impact on network topology. Here, the focus should be on connecting regions rich in renewable resources to hydrogen cavern storage sites. Our findings emphasise the need for European coordination to facilitate the development of sufficient energy infrastructure for a successful transformation.

1. Introduction

Achieving climate neutrality in the European energy system by 2050 will require fundamental changes to energy infrastructure and carriers. Green hydrogen is expected to play an important role in hard-to-abate sectors, such as industry and transport [1]. However, given the short timeframe until 2050, one of the biggest risks to successful implementation is the speed at which the energy system can be transformed [2].

The transition to hydrogen must be coordinated across the entire system, from scaling up electrolysers and renewable energy on the supply side, the conversion of infrastructure for hydrogen transport and storage, and the adoption of green energy carriers on the demand side. Aside from the technical implementation, coordination and harmonisation of the different national regulatory and legal frameworks is required. All of these elements are associated with uncertainties, resulting in a wide range of risks that could affect the transformation path and alter how the system might evolve in the short and long term [3]. This challenge is further exacerbated by the large number of different stakeholders involved in the transition towards hydrogen as a key energy carrier [4].

In this paper, we assess the performance of energy transformation pathways towards a climate-neutral energy system in Europe. Specifically, we focus on the techno-economic implementation of hydrogen infrastructure, assessing the impact of varying annual expansion rates for renewable energy technologies and networks. This is achieved by computing the least-cost energy system transformation pathways with high spatial and temporal detail for a variety of scenarios. To take into account various factors influencing the transformation, we consider three clusters of challenges, namely production-side scale-up, system transformation inertia, and long-term strategic uncertainties, as specified in the following.

1.1. Scaling-up capacities

With the increasing deployment of variable renewable energy (VRE) technologies for power generation amounting to a global annual expansion of photovoltaics (PV) capacity by 426 GW and wind turbine capacity by 116 GW in 2023 [5], the vision of a climate-neutral energy system is becoming a reality. However, as renewable energy sources in 2024 still only contributed 31.9% (15% from VRE) to global electricity

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https://doi.org/10.1016/j.renene.2025.124917
Received 24 June 2025; Received in revised form 21 October 2025; Accepted 6 November 2025
Available online 1 December 2025
0960-1481/

List of abbreviations

ATR	Autothermal reforming
BEV	Battery electric vehicles
BECCS	Bioenergy with carbon capture and storage
CDR	Carbon dioxide removal
CCS	Carbon capture and storage
CSP	Concentrated solar power
DAC	Direct air capture
DEA	Danish Energy Agency
CETO	Clean Energy Technology Observatory
EU	European Union
ESOM	Energy system optimisation model
GASP	Global Atlas for Siting Parameters
IEA	International Energy Agency
JRC	Joint Research Centre
LNG	Liquefied natural gas
NECP	National energy and climate plan
NG	Natural gas
PECD	Pan-European Climate Database
PV	Photovoltaics
RFNBO	Renewable fuel of non-biological origin
SAF	Sustainable aviation fuel
SMR	Steam methane reforming
SNG	Synthetic natural gas
UK	United Kingdom
VRE	Variable renewable energy

generation and 41.6% (19.5%) in Europe [6] there is a long way to go, in particular when it comes to the direct and indirect electrification of hard-to-abate sectors. This relates to the fundamental challenge of scaling up investments in and deployment of VRE technologies, as well as electrolysers for green hydrogen production.

The dynamics associated with this scale-up have previously been described for renewable capacities using S-curve approaches to capture logistic-type growth behaviour, reflecting the different formation, growth, and saturation phases based on historical expansion rates [7]. However, particularly for model-based assessments, including upper limits on annual growth rates and generalising to a wide range of model regions remains challenging due to data availability [8]. Furthermore, there is a close interaction between the growth of renewable technologies and the emergence of a hydrogen market. While diminishing revenues from simultaneous feed-in from VRE are discussed as a possible cause of growth saturation [9], demand-side flexibility from electrolysis can mitigate this problem but depends heavily on the dynamics of hydrogen market uptake [10]. This strong interdependence further complicates quantitative assessment and extrapolation for the future.

Furthermore, additional factors can limit this scale-up, such as the availability of energy technologies in the form of PV panels and electrolyser stacks, as well as more indirect factors, such as the availability of skilled workers [11], permitting procedures [5], long-term planning for grid integration [5], and access to critical materials [12]. These factors must be considered for each technology individually. In the case of PV, the main challenge is Europe's high import dependency, accounting for up to 90% of the main components, such as solar cells and electronics for inverters [13]. For wind energy, domestic production of wind turbines accounts for the entire offshore market and 88% of the onshore market, but reliance on a single country for critical raw materials remains a key issue [14]. In 2024, European capacities for domestic electrolyser manufacturing amounted up to 10.2 GW_{H_2}/a with additional 2.7 GW_{H_2}/a under construction [15], still lagging behind the stated goal of an annual electrolyser manufacturing capacity of 17.5 GW_{H_2}/a by 2025.

1.2. Inertia of systems transformation

Infrastructure projects take a long time from planning to completion, and their effects on system design can last for several decades [16], requiring long-term planning. Many uncertainties must be considered during the planning phase, such as the future development of energy carrier demand. This is further complicated in the case of natural gas (NG) and hydrogen (H_2), as they compete with each other for the same pipeline infrastructure. This leads not only to timing and capacity conflicts regarding the repurposing of pipelines, but also to significant challenges with respect to regional gas distribution systems. These systems may become financially unviable or require complete conversion to hydrogen, affecting all end consumers simultaneously. This, in turn, could result in higher overall costs than those associated with electrification or the use of synthetic methane [17].

A large number of European countries provide political targets for the expansion of VRE technologies as part of their national energy and climate plans (NECPs), which are agreements between the European Union (EU) and its member states on the planned development of capacities, the share of renewable energy, and the phasing out of fossil fuels. Therefore, another factor influencing system inertia is the regulatory framework and investment incentives used by countries to meet their targets. Ambitious targets, in turn, require the early and continuous expansion of renewable technologies [18].

Against this background, the modelling of perfect foresight transformation pathways can provide additional insights to distinguish between stranded investments and bridging technologies [19], and ensure that the transformation begins early enough to meet national capacity targets. Additionally, possible end-of-life synergies can be considered during the optimisation. For example, the offshore production of hydrogen could switch from blue to green after gas fields have been depleted, or the economic phase-out is triggered by reduced electrolyser costs and higher carbon prices [20].

1.3. Long-term uncertainties and import strategy

For VRE and electrolysers, future uncertainties primarily concern the potential for increased efficiency and reduced costs through technological development and the use of innovative materials. In contrast, there is greater uncertainty regarding the technological viability of other technologies. These include direct air capture (DAC) [21,22] to enable the production of synthetic fuels, the combination autothermal reforming (ATR) and carbon capture and storage (CCS) for the production of blue hydrogen with a high capture rate [20], and technologies for the long-distance transport of hydrogen, such as liquid hydrogen (LH_2) ships and the corresponding port infrastructure [23]. While prototypes of these technologies exist, their large-scale implementation remains to be proven.

Another highly uncertain and impactful aspect is the uptake of a global hydrogen market [24]. This encompasses not only available volumes and prices at European ports, but also global competition and supply routes. In the short term especially, importing hydrogen via pipelines can be cheaper than ship-based imports. However, pipeline-based imports to Europe are limited to a few countries. Similarly, the required pipeline system, cavern storage, and strategic positioning in relation to domestic production will differ significantly depending on the establishment of a global hydrogen market.

In this case, having prior knowledge of import options during perfect foresight optimisation allows for the consideration of future hydrogen availability. However, this approach provides limited information on how the system can adapt to different scenarios. To estimate the range of possible systems, we consider different extremes, where cost shifts are observable or certain supply technologies are excluded.

1.4. Modelling transformation pathways in high spatial and temporal resolution

Providing insights to inform decisions relating to the scaling up of capacities, systems inertia, and long-term uncertainties can be achieved by computing transformation pathway scenarios using energy system optimisation models (ESOMs). These models have become a widely used method of providing decision-makers with a range of alternatives and important considerations [25]. This extends to a large number of studies showing the viability of climate-neutral systems in 2050 with high VRE shares [26], the future role of hydrogen in the European energy system [3,19,27], and a possible realisation of a global hydrogen trade system [28]. All underlying studies demonstrate the need for a significant increase in VRE capacity, as well as the efficient use of transmission networks and storage systems to balance energy carriers spatially and temporally.

In general, representation of transformation pathways ESOMs falls under three categories: optimisation of target years; transformation pathways with myopic foresight; or transformation pathways with perfect foresight. An additional consideration of high technological, temporal, and spatial detail of the modelled system drives the size of the resulting optimisation problem, often leading to computational challenges. To deal with this challenge, trade-offs between different model dimensions are required [29].

The strength of target year optimisation lies in its high spatial and temporal resolution, which provides insights into long-term static systems. Typically, large contributions from VRE technologies are part of the least-cost solution, and the strong effect of spatial and temporal balancing in the form of power grids, gas pipelines, and energy storage can be observed [30]. This approach is especially useful for assessing the overall design and operation of the energy infrastructure and detailed network topology. However, the single-year nature of the optimisation limits the insights into optimal timing.

Target year models can be extended to a myopic approach across multiple model years, to obtain some information about the transformation pathway. Capacities from a target year optimisation are considered in each of the subsequent years. This rolling horizon approach can include either a single year per iteration, or include one or more years of foresight into the future. However, considering longer periods of foresight, again, leads to larger optimisation problems and greater computational challenges. Conversely, shorter periods of foresight can result in more stranded investments if transformation pathways are optimised without sufficient foresight [31].

In contrast, pathway optimisation models with perfect foresight typically use aggregation methods for the temporal dimension. These methods use representative days or peak hours to model demand peaks [32], thereby managing the computational burden. However, this creates new challenges when it comes to representing long-term energy storage technologies, such as gas caverns, and the intermittent nature of VRE [33]. Conservative estimation of VRE technologies, in particular, leads to a significantly higher utilisation of gas-fired power plants during peak hours compared to hourly resolved models with high spatial resolution, accounting for up to 10% of annual electricity generation in 2050 [34]. Similarly, models that implement endogenous learning require transformation pathways with perfect foresight, but due to the necessity of using mixed integer formulations, they have to accept even stricter limitations in their spatial and temporal resolution [35].

In their recently published work, Fleiter et al. [3] assess a wide range of possible hydrogen demand scenarios for the European energy system until 2050. To achieve this, they employed perfect foresight pathway optimisation with a high temporal resolution. To stay within computational limitations, they opt for a spatial resolution at country level and group smaller countries such as the Baltic States and the Balkans together. However, this approach restricts their ability to provide insights into network requirements and the spatial allocation of energy conversion and storage technologies across Europe.

1.5. Contribution and research questions

Our contribution to the existing literature involves modelling of transformation pathways for the European energy system between 2030 and 2050 at a subnational level and with detailed temporal resolution, focusing specifically on hydrogen supply infrastructure. A key novelty in model design, compared to earlier work, is the explicit modelling of port infrastructure as part of the gas network for energy imports. The application of the model focuses on the often-overlooked issue of limited capacity expansion rates for VRE, which could impede the transformation, particularly with regard to the provision of substantial amounts of domestic hydrogen. Our model-based analysis addresses the following research questions:

- How do the realisable VRE expansion rates and the available CO_2 emissions budgets influence the use of different technologies for providing electricity, hydrogen and methane along the transformation path to 2050?
- Are the national targets for VRE expansion in line with realisable renewable energy expansion rates, and do these targets enable substantial shares of domestic hydrogen production in Europe and individual countries?
- How do delays in the hydrogen network deployment and availability of import options affect the optimal system design, and how do these factors interact with the VRE expansion rates?

To answer these research questions, we systematically analyse a wide range of scenarios using a comprehensive ESOM framework. The scenarios comprise a variety of assumptions regarding national limitations on the expansion rates for VRE technologies, the permitted carbon budget for transformation pathways, different political targets for VRE capacities, short-term network infrastructure delays, and long-term uncertainties associated with hydrogen import.

The remainder of this paper is structured as follows: Section 2 outlines the model formulation and the general input data which are used across all scenarios. Section 3 provides an overview of the scenarios and the assumptions on the annual capacity expansion rates considered in this study. Section 4 presents the results from the model-based assessment and contextualises the findings within the broader scope of similar modelling activities. Section 5 critically reflects on the limitations of the study and outlines possible future research directions to address. Finally, Section 6 summarises the key findings and draws conclusions from them.

2. Model scope and input data

To evaluate the impact of different scenarios on the most cost-effective pathway towards climate neutrality, we employ the open-source energy system modelling framework REMix [36]. This framework is used to create a detailed model of the European energy system and calculate the most cost-effective transformation pathways. These pathways consider the integrated optimisation of capacity expansion and economic dispatch in five-year increments from 2030 to 2050. All considered years are optimised simultaneously using a perfect foresight approach to limit stranded investments and pre-emptive overshoot of the permitted carbon budget. The model covers all EU countries located in continental Europe, as well as Switzerland, Norway, the British Isles, and the EU membership candidate countries in south-east Europe (Fig. 1). The model explicitly considers all infrastructures for producing, storing, and transporting electricity, hydrogen, and methane. Energy demand in the industry, heating, and transport sectors is considered based on their respective energy carriers.

2.1. Pathway methodology

To model the overall system cost along the transformation pathway, REMix uses the logic that all costs are annualised and refinanced over the technical lifetime of the infrastructure, in order to make investments between technologies comparable and to correctly account for the end of the optimisation horizon. Similar to other studies on transformation pathways [37,38], a socioeconomic discount rate of 2% and a cost of capital of 8% are used for the weighting between different technologies and model years. The highly generalised accounting model in REMix enables detailed constraints to be established in a simplified manner by associating indicators with various components of the optimisation model. Several of required modelling features used in this study, such as carbon budgets, limits on annual capacity expansion rates and capacity targets can be derived from it, as described below. For a more detailed nomenclature of the mathematical model description see Appendix.

Eq. (1) provides the generalised accounting form, which comprises contributions from the expansion and decommissioning of energy conversion units, and fixed costs of existing power plants (1a). Similar contributions are considered for network infrastructure (1b). The remaining terms relate to dispatch decisions made during infrastructure operation. It considers contributions from conversion activities, such as power generation (1c), energy transfers between model regions (1d), and imports or exports across the system boundaries (1e).

$$j_i = \sum_{y\in Y} W_{y,i} \cdot \Bigg(\sum_{n\in N,p\in P} J^{\text{build}}_{i,n,y,p} \cdot \Delta x^{+}_{n,y,p} + J^{\text{fix}}_{i,n,y,p} \cdot x_{n,y,p} + J^{\text{decom}}_{i,n,y,p} \cdot \Delta x^{-}_{n,y,p} \tag{1a}$$

$$+ \sum_{l\in L,p\in P_L} J^{\text{build}}_{i,l,y,p} \cdot \Delta x^{+}_{l,y,p} + J^{\text{fix}}_{i,l,y,p} \cdot x_{l,y,p} + J^{\text{decom}}_{i,l,y,p} \cdot \Delta x^{-}_{l,y,p} \tag{1b}$$

$$+ \sum_{t\in T,n\in N,p\in P_C,a\in A} J^{\text{var}}_{i,t,n,y,p,a} \cdot d_{t,n,y,p,a} \tag{1c}$$

$$+ \sum_{t\in T,l\in L,p\in P_L} J^{\text{flow}}_{i,t,l,y,p} \cdot \left(f^{+}_{t,l,y,p,q} + f^{-}_{t,l,y,p,q}\right) \tag{1d}$$

$$+ \sum_{t\in T,n\in N,q\in Q} J^{\text{import}}_{i,t,n,y,q} \cdot g^{+}_{t,n,y,q} + J^{\text{export}}_{i,t,n,y,q} \cdot g^{-}_{t,n,y,q} \Bigg) \tag{1e}$$

$$\forall i \in I$$

To keep track of the total number of installed technologies, Eq. (2) provides a balance of the added and decommissioned capacities throughout the transformation pathway. To ensure that capacities are decommissioned, Eq. (3) sums up both the added and decommissioned capacities up to any given year, offset by the maximum lifetime of the technology in question. This formulation allows capacities to be decommissioned flexibly, while ensuring that plants are decommissioned by the end of their respective lifetimes at the latest.

$$x_{n,y,p} = x_{n,y-1,p} + \Delta x^{+}_{n,y,p} - \Delta x^{-}_{n,y,v} \qquad \forall n \in N, y \in Y, p \in P \tag{2}$$

$$\sum_{y'\le y-\lambda_v} \Delta x^{+}_{n,y',p} \le \sum_{y'\le y} \Delta x^{-}_{n,y',p} \qquad \forall n \in N, y \in Y, p \in P \tag{3}$$

If capacities can only be decommissioned at the end of their lifetime, without repurposing or decommissioning costs being taken into account, Eqs. (2) and (3) can be substituted by Eq. (4), which uses a backward-looking rolling horizon over the lifetime to limit the number of decision variables and reduce the computational burden.

$$x_{n,y,p} = \sum_{y-\lambda_v<y'\le y} \Delta x^{+}_{n,y',p} \qquad \forall n \in N, y \in Y, p \in P \tag{4}$$

The limitations on carbon budgets and the available gas reserves from offshore fields in Eq. (5) can be derived from the generalised accounting by using the relevant factors for carbon-emitting activities and gas extraction. The weighting factor ensures that annual emissions are scaled up to account for a time period of five years.

$$\sum_{y\in Y} W_{y,CO_2} \cdot \Bigg(\sum_{t\in T,n\in N,p\in P_C,a\in A} J^{\text{var}}_{CO_2,t,n,y,p,a} \cdot d_{t,n,y,p,a} + \sum_{t\in T,n\in N,q\in Q} J^{\text{import}}_{CO_2,t,n,y,q} \cdot g^{+}_{t,n,y,q} + J^{\text{export}}_{CO_2,t,n,y,q} \cdot g^{-}_{t,n,y,q} \Bigg) \le J^{CO_2 budget} \tag{5}$$

Similarly, annual capacity expansion rates can be constrained on a per-country and per-year basis by Eq. (6).

$$\Delta x^{+}_{n,y,p} \le X^{max}_{n,y,p} \qquad \forall n \in N, y \in Y, p \in P \tag{6}$$

Likewise, capacity targets can be specified including their corresponding slack variables. The slack variables enable the determination of the capacity gap between stated policy and maximum expansion under limited expansion rates, as shown in Eq. (7)

$$x_{n,y,p} + x^{slack}_{n,y,p} \ge X^{target}_{n,y,p} \qquad \forall n \in N, y \in Y, p \in P \tag{7}$$

2.2. Input data and assumptions

For the annual energy demands we generate a dataset for all European countries based on the *Clean Planet for All* study by the European Commission [39]. Here, we consider a demand-side scenario H_2 which focuses on the increased use of hydrogen, particularly in the industrial and transport sectors and, to a limited extent, in space heating. We treat the demand scenarios as model-exogenous input to derive the required infrastructure transformations for supply, storage, and transmission across the system. The annual demand data is distributed into hourly profiles for electricity, hydrogen, and methane using the extremOS profiles [40] and is aggregated from NUTS3 areas to the model regions used in this study.

The existing network between model regions is derived from the sci2Grid_gas dataset [41] and the ENTSO-E grid map, which was created using an updated version of GridKit [42]. These two high-resolution networks are combined into a single network graph by adding edges between power and gas nodes in close proximity. The network topology is then partitioned using a community-finding algorithm, which is calibrated to identify the most relevant long-distance and large-capacity transfer options for electricity and gas. This ensures the network adequately reflects the pan-European transmission infrastructure, while also enabling national boundaries to be maintained and larger European countries to be divided into multiple regions based on their respective network topology. This preserves both cross-border and internal transmission bottlenecks. The resulting European network comprises 83 regions, including sub-national regions in 16 countries. In addition to these regions, the model explicitly incorporates 28 LNG terminals, four import nodes and two offshore hubs using a reduced set of technologies.

In terms of existing gas infrastructure, the capacities of LNG terminals and cavern storage are based on the sci2grid dataset and are connected to the gas network via their respective pipeline connections. Natural gas cavern storage sites and pipeline infrastructure can be decommissioned before the end of their technical lifetime to enable the model endogenous repurposing towards hydrogen, as described in a previous study [43]. Imports of gases via pipelines from outside the scope of the model are permitted based on realised gas imports in 2024, as provided by the ENTSO-G gas flow dashboard [44]. Imports of natural gas amounted to 107 TWh_{CH_4} from Algeria to Spain, 223 TWh_{CH_4} from Tunisia to Italy, 322 TWh_{CH_4} from Turkey to Greece and Bulgaria, and 169 TWh_{CH_4} from Ukraine to Slovakia. We assume that, by 2030, only 20% of energy imports can come from green hydrogen or synthetic methane, with this volumetric share gradually increasing to 100% by 2045. (0.2, 0.3, 0.5, 1.0, 1.0 for the 5-year intervals between 2030 and 2050). Alternatively, blue hydrogen can be produced from steam methane reforming (SMR) and ATR with CCS and transported through pipelines repurposed for hydrogen.

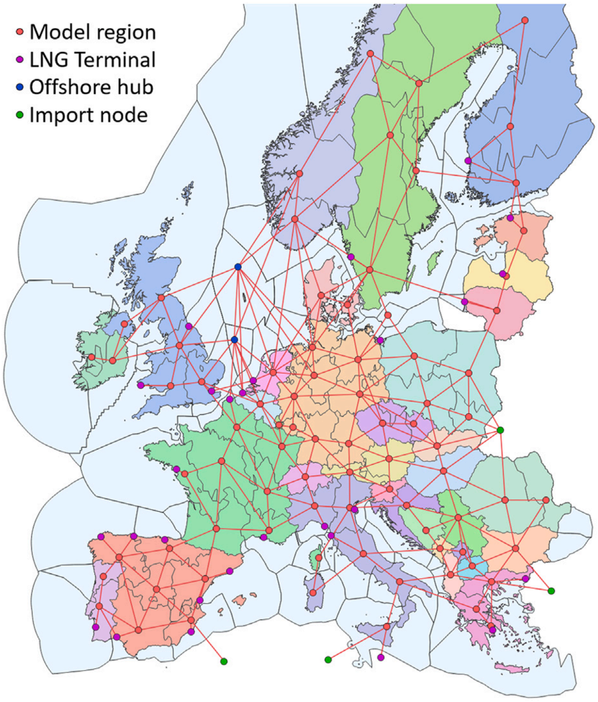

Fig. 1. Geographical scope and network topology of the case study. Model regions (red vertices) contain the full set of technologies for capacity expansion and hourly energy demand. LNG terminals (purple vertices), offshore hubs (blue vertices), and import nodes (green vertices) contain no energy demand and a reduced set of technologies. Network corridors (red edges) represent existing grid and pipeline connections that can be further expanded or, in the case of natural gas pipelines, repurposed for hydrogen use.

Similarly, the extraction and distribution of natural gas from the North Sea via offshore pipelines is based on recent production levels. The maximum permitted extraction of natural gas is based on the 2024 annual production volumes of 192 TWh for the United Kingdom and 1225 TWh for Norway [44], which is mapped to the two offshore hubs in the North Sea. The duration for which the offshore natural gas reserves will last is highly uncertain and depends significantly on additional exploration activities, which in turn depend on future policies and incentives for blue hydrogen. To estimate the overall energy amounts that can be freely allocated along the transformation pathway, we assume remaining extraction times of 5 and 15 years for the gas fields in the UK and Norwegian gas fields, respectively.

In order to enable model-endogenous investment in hydrogen offshore hubs, the North Sea area and the island of Bornholm are included as separate regions. Infrastructure expansion can take the form of either wind farms connected via undersea cables or direct offshore electrolysis with transport via pipeline infrastructure [45]. Additionally, the offshore hubs in the North Sea are used for the domestic extraction of natural gas, which can be converted to grey or blue hydrogen via SMR and ATR. Blue hydrogen can be produced via SMR-CCS with a carbon capture rate of 56% or ATR-CCS with a carbon capture rate of 90%, as detailed in the supplementary information provided by Ueckerdt et al. [20]. To better observe the timing between the technologies, the capacity expansion of ATR-CCS is only permitted from the second modelling year (2035) onwards. While carbon networks are also gaining increasing attention as a potential CCS option in industry [46], this study only considers blue hydrogen production in close proximity to gas extraction sites [47].

The existing capacities of conventional power plants are based on data from the Global Nuclear Power Tracker [48], the Global Oil and Gas Plant Tracker [49], and Beyond Fossil Fuels for coal plants [50]. These capacities are then allocated to subnational clusters using Voronoi polygons derived from the network nodes. Similarly, hydro capacities are derived from the Joint Research Centre (JRC) hydropower dataset [51] using normalised hourly profiles from the Pan-European Climate Database (PECD) [52]. Capacities for existing VRE technologies are taken from Eurostat [53], grouped into five-year intervals for capacity expansion, and allocated to model regions based on spatial distribution factors derived from the region specific maximum permitted installation for PV and wind turbines. The techno-economic assumptions for most technologies are taken from technology catalogues provided by the Danish Energy Agency (DEA) [54]. To ensure security of supply for electricity, for each of the model regions the capacity for firm-capacity power plants, such as gas-fired turbines using either synthetic methane or hydrogen, must be at least as high as the peak hour of the inflexible electricity demand.

Renewable energy power generation profiles are calculated using the COSMO-REA6 weather reanalysis [55] and the CORINE land cover dataset [56], in order to account for suitable and restricted areas for the expansion of renewable energy technologies. For wind turbines, the potential is categorised according to IEC 61400 classes using geospatial information from the Global Atlas for Siting Parameters (GASP) project [57]. The power curves are modelled using data from three different Vestas turbines (V112, V124, V136) with hub heights (91.5 m, 117 m, 155 m) corresponding to turbines with similar power densities. To reflect the wide range of conditions affecting VRE generation profiles, the weather years between 2012 and 2016 from the REA6 reanalysis are mapped, in chronological order, to the model years between 2030 and 2050 along the transformation pathway.

3. Scenario design

To answer the research questions raised in Section 1, we design a multi-layer scenario approach in which the different key parameters influencing the transformation pathways of the European energy system are varied. To identify a wide range of possible pathways towards climate neutrality, we consider the following variations: (1) the available carbon budget for power generation and downstream emissions for industry and heating, (2) the achievable speed for capacity expansion of VRE technologies across Europe, (3) the achievement of policy targets for renewable energy technologies as outlined in European and national policies such as the NECPs and the Ostend Declaration,[1] (4) possible delays in expanding the European network infrastructure, particularly in repurposing existing pipelines for hydrogen, and (5) the available volumes and prices of future pipeline- and port-based hydrogen imports.

These five aspects are grouped into three categories according to the research questions to be answered, and their respective scenario assumptions are specified below. Section 3.1 is dedicated to the interaction between the available CO_2 budget and achievable VRE expansion rates. Section 3.2 builds on this by explaining how the political expansion targets are incorporated into the model. Finally, Section 3.3 provides the assumptions for the delays in developing hydrogen networks and the availability of various import options. The subsequent model results in Section 4 follow the same structure. Fig. 2 summarises this structure and the key variations per scenario dimension.

[1] The Ostend Declaration is an agreement on the joint expansion of offshore wind energy and infrastructure between the European countries bordering the North Sea [58]. These countries include the United Kingdom (UK), Ireland, France, Belgium, the Netherlands, Germany, Denmark, and Norway.

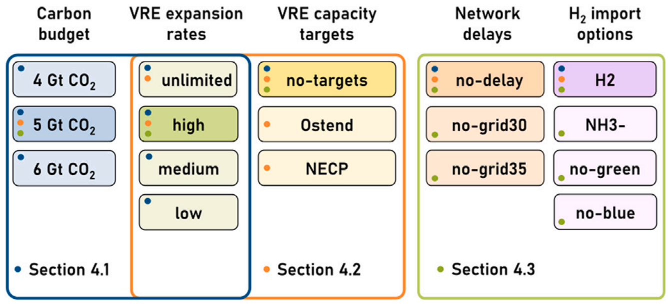

Fig. 2. Overview of the scenario variation combinations in this study. The coloured dots indicate the variations considered in each of the results sections, while the coloured boxes indicate the key variations each section focuses on.

3.1. Carbon budgets and VRE expansion rates

The cumulative carbon emissions in the time frame between 2030 and 2050 are one of the main drivers of the speed of transformation, as achieving a lower cumulative sum requires more ambitious and rapid emissions reductions and faster VRE expansion. Taking into account downstream emissions from the model-exogenous demand for methane, the cumulative baseline for the carbon budget is 5.5 Gt_{CO_2}. If the allowed cumulative carbon budget is higher than this baseline, additional emissions from fossil power plants or the production of grey and blue hydrogen is possible. Conversely, a lower cumulative carbon budget requires additional use of DAC in order to produce synthetic methane and close the carbon cycle. Against this baseline, we consider three different variations of 4, 5, and 6 Gt_{CO_2} as an available cumulative carbon budget across all model years, providing scenarios with different levels of ambition for reducing emissions.

The achievable annual capacity expansion rates are extrapolated based on the International Energy Agency (IEA) report on the expected progress of renewable energy technologies [5]. The study considers various influencing factors, such as historical expansion rates, falling investment costs, policy incentives and manufacturing capacities. While the outlook only provides information on the expected expansion between 2024 and 2030, any progress or delays will affect subsequent decades. Therefore, we use this dataset as a per-country baseline, limiting the expansion of VRE technologies while increasing the capacity expansion rates towards later model years to account for future efforts. Specifically, we derive a *high* expansion scenario based on the accelerated case, using the following factors for the five model years between 2030 and 2050: 1.0, 1.2, 1.5, 2.0, 2.0. For the scenarios *medium* and *low* scenarios, we use the main case as a baseline with the following factors: 1.0, 1.2, 1.5, 2.0 and 2.0, and 0.8, 1.0, 1.2, 1.5 and 2.0, respectively. The resulting annual expansion rates for each model year and country with the highest expected expansion rate for each VRE technology are listed in Table 1. To assess the impact of limited expansion rates, we also consider an *unlimited* scenario, in which annual capacity expansion rates are not constrained.

3.2. Political VRE expansion targets

To consider the stated policy targets for the expansion of VRE in European countries, we utilise the dataset from the EU NECP tracker compiled by Ember [59]. In terms of capacity targets for PV Germany has the most ambitious targets by far, with 215 GW by 2030 and 400 GW by 2040, followed by Spain with 95 GW and Italy with 79 GW, both of which are planned to be reached by 2030. A similar pattern emerges for onshore wind energy: Germany aims to reach 115 GW by 2030 and 160 GW by 2040, followed by France with 37 GW by 2030 and Italy with 26 GW by 2030. While the NECPs outline additional targets, such as the phase-out of fossil power plants and target shares for renewable electricity, we only consider the targets for VRE expansion.

With regard to the joint expansion of offshore wind energy in the North Sea, as set out in the Ostend Declaration [58], equally ambitious targets have been agreed upon. The joint targets to be reached across all participating countries are 120 GW by 2030 and 300 GW by 2050. Country-specific contributions for 2030 are led by the UK with 30 GW, followed by Germany with 26 GW and the Netherlands with 21 GW. By 2050, Germany's target is 66 GW, followed by the Netherlands with 50 GW, Denmark with 35 GW, and Norway with 30 GW.

Although the capacity targets for NECPs and the Ostend Declaration should be considered simultaneously, we are treating them as separate scenarios to better isolate their respective impacts on spatial shifts in domestic hydrogen production. To ensure that capacity targets are met despite delays caused by limited annual capacity expansion rates, slack variables are introduced to penalise any capacity gaps between the total installed capacity and the target capacity. For intermediate years without explicit capacity targets, the most recent active target remains in place.

3.3. Network expansion delays and hydrogen import options

With regard to infrastructure delays, we consider the three variations *no-delay*, *no-grid30*, and *no-grid35*. In the first variation, capacity expansion for power grids and pipelines (including the repurposing of natural gas pipelines for hydrogen) is permitted in all model years. In contrast, the two latter variations prevent the short-term expansion in the model years 2030 and 2030 to 2035, respectively. While the expansion of new hydrogen pipelines along the corridors between model regions is unlimited, repurposing natural gas pipelines for hydrogen use requires the same number of natural gas pipelines to be decommissioned in the same model year and corridor. However, repurposing comes at a significantly lower cost of 1.1 M€/km compared to 3.4 M€/km, when investing into new hydrogen pipelines [60].

In terms of hydrogen import costs, we consider the variations H_2, NH_3-, *no-blue*, and *no-green*. H_2 reflects the baseline assumptions on hydrogen prices, taking into account all available sources. Pipeline-based imports can enter the system via the import nodes, ship-based imports are facilitated in the LNG terminal nodes, and extraction of NG takes place in the offshore hubs.

The large uncertainty surrounding the costs of producing and importing green hydrogen can be seen in previous literature estimates. Weißenburger et al. compare a range of literature values for hydrogen imports to Germany, deriving several price pathways ranging from 80–250 €/MWh_{H_2} in 2030 to 50–165 €/MWh_{H_2} in 2050, with the largest number of literature values for 2050 clustered between 50–90 €/MWh_{H_2} [61]. Similarly, Schmitz et al. provide price pathways ranging from 69–149 €/MWh_{H_2} for hydrogen and 92–186 €/MWh_{CH_4} for synthetic methane in 2030 and respectively 73–98 €/MWh_{H_2} and 95–134 €/MWh_{CH_4} in 2050 [62]. However, it should be noted that in the study by Schmitz et al. only the high-price scenario is based entirely on green hydrogen; the medium-price scenario considers a mix of green and blue hydrogen, and the low-price scenario assumes only blue hydrogen.

The TYDNP 2024 scenarios are significantly more optimistic, assuming that by 2040, the cost of hydrogen will range between 27–73 €/MWh_{H_2} depending on the scenario and country of origin [63]. The dataset also provides long-term import cost estimates for ship-based hydrogen imports using ammonia (NH_3) as a transport vector, derived using a global import assessment tool. This yields reference values for hydrogen imports at European ports of 138, 108, and 87 €/MWh_{H_2} for the years 2030, 2040 and 2050, respectively. Furthermore, the cost range is differentiated between the two scenarios, resulting in a range of hydrogen importing costs between 69–104 €/MWh_{H_2} in 2050.

Table 2 provides an overview of the import costs assumed in this study, which have been derived in part from the above-mentioned

Table 1
Assumptions on the maximum annual expansion rate in GW/a for the scenarios *low* and *high* and the European countries with the highest annual capacity expansion of VRE for each technology.

		Scenario *low*					Scenario *high*				
		2030	2035	2040	2045	2050	2030	2035	2040	2045	2050
PV utility scale	Germany	11.1	13.9	16.6	20.8	27.7	15.8	18.9	23.7	31.6	31.6
	Spain	3.9	4.9	5.8	7.3	9.7	8.5	10.2	12.8	17.0	17.0
	United Kingdom	3.6	4.5	5.4	6.8	9.0	5.8	6.9	8.7	11.6	11.6
	France	2.3	2.9	3.5	4.3	5.8	4.3	5.2	6.5	8.7	8.7
PV distributed	Germany	9.6	12.0	14.4	18.0	24.0	16.3	19.6	24.5	32.6	32.6
	Italy	4.8	6.1	7.3	9.1	12.1	7.3	8.7	10.9	14.5	14.5
	Netherlands	3.6	4.5	5.4	6.8	9.0	5.2	6.2	7.7	10.3	10.3
	France	3.0	3.7	4.4	5.5	7.4	4.2	5.1	6.3	8.4	8.4
Wind onshore	Germany	6.2	7.8	9.3	11.6	15.5	9.8	11.7	14.7	19.6	19.6
	United Kingdom	2.2	2.7	3.2	4.0	5.4	3.3	3.9	4.9	6.5	6.5
	France	2.0	2.4	2.9	3.7	4.9	2.9	3.5	4.3	5.8	5.8
	Italy	1.6	2.1	2.5	3.1	4.1	2.8	3.4	4.2	5.6	5.6
Wind offshore	Germany	2.0	2.6	3.1	3.8	5.1	4.6	5.5	6.8	9.1	9.1
	United Kingdom	3.1	3.8	4.6	5.8	7.7	4.2	5.1	6.4	8.5	8.5
	Netherlands	1.3	1.6	2.0	2.5	3.3	2.0	2.4	3.1	4.1	4.1
	Denmark	1.0	1.2	1.4	1.8	2.4	1.6	1.9	2.4	3.2	3.2

Table 2
Assumptions on import costs for energy carriers and model years for the base scenario H_2, the reduced cost scenario for a global hydrogen market using ammonia as transport vector NH_3- and the scenario without imports of green energy carriers *no-green*. Costs for H_2 and NH_3 are given as €/MWh_{H_2}, while costs for LNG, NG, and SNG are given as €/MWh_{CH_4}. Values for the intermediate years 2035 and 2045 are interpolated using the geometric mean.

Scenario	Import source	2030	2035	2040	2045	2050
H_2	H_2 (pipeline)	94	84	75	67	60
	NH_3 (ship)	138	122	108	97	87
	LNG (ship)	56	56	56	56	56
	NG (extraction)	28	28	28	28	28
	NG (pipeline)	28	28	28	28	28
	SNG (pipeline)	129	119	108	100	93
NH_3-	NH_3 (ship)	97	86	76	68	61
no-green	H_2 (pipeline)	–	–	–	–	–
	NH_3 (ship)	–	–	–	–	–
	SNG (pipeline)	–	–	–	–	–

sources. Additional adjustments have been made to ensure that energy carriers reflect their respective end use in the model, and that no further conversions to other energy carriers are economically viable. The scenario NH_3- assumes the availability of ship-based hydrogen imports, which are cost competitive to pipeline-based imports.

To evaluate the impact of fully domestic production on the transformation pathway, the *no-green* scenario assumes that no green hydrogen or fuels derived from it are imported. Similarly, the *no-blue* scenario evaluates the impact on the transformation pathway if blue hydrogen is not utilised on a large scale.

4. Results and discussion

The structure of this section follows the research questions (Section 1) and scenario design (Section 3). First, we analyse the impact of carbon budgets and VRE expansion rates on the system design (Section 4.1). The results of this section provide insights into how the carbon budget affects the pace of transformation, potentially causing peaks in the required annual capacity expansion rate. Similarly, national limits on annual capacity expansion lead to significant spatial shifts in the siting for VRE and electrolysers. This is then related to the stated political targets for VRE expansion (Section 4.2), where we find that not all national targets can be met at limited expansion rates and observe a similar spatial shift in VRE technologies induced by capacity targets. Finally, we address challenges posed by delayed network expansion and the unavailability of hydrogen supply options (Section 4.3), highlighting the strong influence of import prices on network topology and providing insights into seasonal hydrogen storage patterns for high shares of domestic electrolysis.

4.1. Impact of limited capacity expansion rates and available carbon budget

The most significant systematic changes to the transformation pathways are caused by the permitted cumulative carbon budget. This is the main factor that determines how quickly and ambitiously the system needs to transform. As discussed in Section 2, the exogenously assumed methane demand results in downstream emissions of 5.5 Gt_{CO_2}. If the carbon budget is higher than this threshold, more options for the conversion of natural gas to hydrogen via SMR become available. Conversely, a more restricted carbon budget has the opposite effect by forcing the model to utilise either domestically produced synthetic methane from the Sabatier process or import synthetic or biogenic methane from outside the system boundaries, due to a lack of endogenous carbon dioxide removal (CDR) options within the model.

Fig. 3 shows the system-wide energy balances for the energy carriers methane (top), hydrogen (middle), and electricity (bottom). As expected, stricter limitations on the carbon budget (4-6 Gt_{CO_2} from left to right) require a higher annual expansion rate for electrolysers to provide green hydrogen for increased synthetic methane production. Similarly, a shift in imported fuels from natural gas to green methane via existing pipeline infrastructure can be observed. In the 5 Gt_{CO_2} scenario, the assumed limits on annual green methane imports are almost sufficient to realise the reduction in downstream carbon emissions. For achieving the 4 Gt_{CO_2} budget, domestic production of synthetic methane is required between 2030 and 2040.

Further changes to the system are caused by the different annual capacity expansion limitations. While all scenarios utilise blue hydrogen from ATR-CCS as soon as the technology is available in the model year 2035, only the scenario with a 6 Gt_{CO_2} limit uses SMR-CCS to start producing blue hydrogen in 2030. In the case of the unconstrained annual capacity expansion (*unlimited*), the utilisation of blue hydrogen is generally lower compared to scenarios with restricted expansion of VRE technologies. This is due to the reduced ability to rely on domestic green hydrogen production, which is caused by the lack of electricity from VRE to support this indirect electrification.

However, the overall amount of blue hydrogen produced varies with more restrictive expansion rates of VRE, as does the amount of natural gas reserves utilised in the different model years. With strongly limited VRE expansion (*low*), more offshore gas capacity is reserved for the production of blue hydrogen in later decades. With unconstrained annual capacity expansion (*unlimited*), blue hydrogen is utilised more

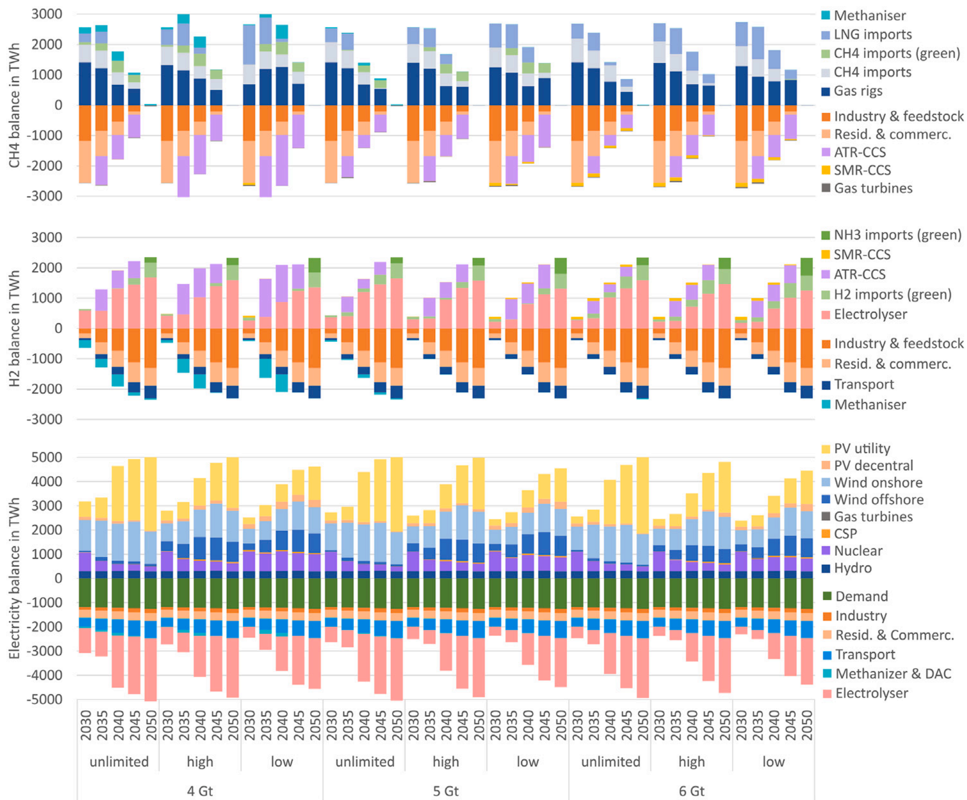

Fig. 3. Energy balances for supply and demand of methane (top), hydrogen (middle), and electricity (bottom) along the transformation pathway for scenarios with different carbon budgets (*4 Gt*, *5 Gt*, and *6 Gt*) and limited annual capacity expansion rates (*unlimited*, *high*, and *low*). Note that the y-axis scaling differs for the different energy carriers.

in the short term (i.e. until 2035) as soon as the technology becomes available. One possible reason for this is the expectation of decreasing investment costs for the electrolyser and VRE technologies in later years. This allocation exacerbates the required rate of capacity expansion rate in 2040 resulting in 55 GW_{H_2}/a for electrolyser plants and 249 GW/a for utility-scale PV.

In general, the reduced expansion of utility-scale PV and onshore wind energy leads to a shift towards other renewable technologies, such as distributed PV and offshore wind. In the case of the scenario *4 Gt low*, where this effect is most pronounced, offshore wind turbines contribute 918 TWh/a to the annual electricity generation, while distributed PV contributes 276 TWh/a. Alongside these shifts in VRE technologies, the main increase in power generation is observed in nuclear power plants, which remain at a similar production level to those seen today. In contrast, with unlimited VRE capacity expansion nuclear power plants are gradually phased out of the system. Despite the additional investments required for reserve capacity, the system-wide utilisation of gas-fired power plants remains below 16 TWh/a in all scenarios, indicating that the flexibility provided by electrolysers, power grids, and electricity storage systems is sufficient to compensate for the intermittency of VRE.

This systematic shift in VRE expansion likewise affects the spatial allocation of investments, as illustrated in Fig. 4. In 2035, an unconstrained expansion of capacity leads to onshore wind energy in the North Sea region, particularly in Scotland, becoming the main contributor to electricity generation, providing 182 TWh/a (compared to a total onshore wind production of 371 TWh/a across the UK and a Europe-wide electricity production from VRE of 2240 TWh/a). For PV, the main contributions come from Spain (149 TWh/a) and Italy (101 TWh/a). However, this concentration of generation in a few resource-rich areas becomes less prevalent when limitations on the capacity expansion are considered. While these regions still account for a large proportion of the overall electricity generation, additional capacity expansion shifts towards Germany, for both onshore wind in the north and PV capacities in the south.

In terms of the spatial distribution of VRE and electrolyser technologies in 2050, the focus shifts heavily towards utility-scale PV due to the low cost of electricity for green hydrogen production. This is particularly evident in regions of Southern Spain, where up to 292 TWh_{H_2}/a of hydrogen are produced per year (out of a total of 432 TWh_{H_2}/a in Spain and 1654 TWh_{H_2}/a across Europe) in the unconstrained case. However, this high spatial concentration decreases significantly under limited capacity expansion rates. This results in an annual hydrogen production across Spain of 249 TWh_{H_2}/a when considering the optimistic capacity (*high*), and 154 TWh_{H_2}/a in the pessimistic case (*low*). Conversely, the *high* limitation leads to an increase in the long-term annual hydrogen production in the UK (297 TWh/a), Germany (287 TWh/a), and France (129 TWh/a).

This suggests that earlier studies may have overestimated the role of individual regions in producing large quantities of hydrogen, given that these studies did not impose limits on the expansion of renewable energy. This can be observed, for example, in the model results of Fleiter et al. [3] who identified a similar pattern involving the production of green hydrogen in the British Isles in 2030 (up to 21 GW_{H_2}) and in the Iberian Peninsula in 2050 (up to 207 GW_{H_2}). In our study, limiting capacity expansion for these regions to the *high* case results in reductions from 42 GW_{H_2} down to 12 GW_{H_2} for the British Isles, and from 158 GW_{H_2} down to 99 GW_{H_2} for the Iberian Peninsula.

Regarding the required increase in electrolyser production, Victoria et al. estimate that 500 TWh of green hydrogen production are required in Europe by 2030 to achieve a carbon budget that would result in a high likelihood of staying within the 1.5 degree target for global warming [2]. Under the assumed limited expansion rates, our results indicate that a domestic production of green hydrogen up to 415 TWh/a is feasible in 2030, in the most optimistic case.

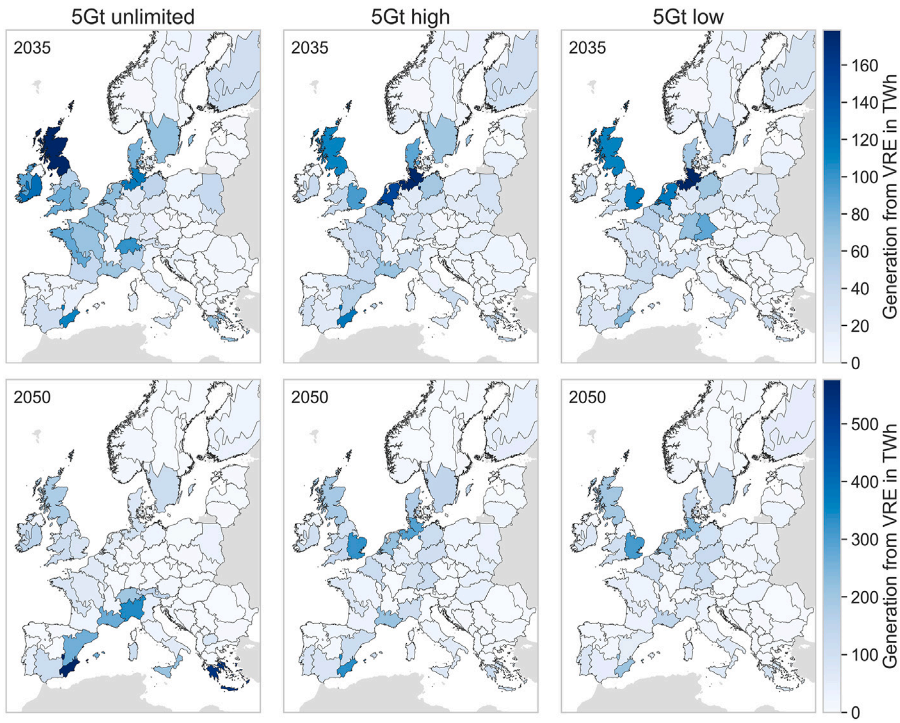

Fig. 4. Spatial distribution of annual VRE generation under different limitations on capacity expansion limitations and a fixed carbon budget for the years 2035 and 2050. In 2035, the system-wide VRE generation totals 2240 TWh/a, 2035 TWh/a, and 1877 TWh/a for the *unlimited*, *high*, *low* scenarios, respectively. In 2050, it totals 4695 TWh/a, 4368 TWh/a, and 3675 TWh/a, respectively.

4.2. Political targets and achievable expansion rates for renewable energy technologies

If the annual expansion rate is limited, a key question is whether the current political VRE capacity targets can still be achieved. Furthermore, a successful implementation of the NECPs and the Ostend Declaration is expected to influence both the timing and spatial distribution of VRE expansion, and therefore also the location of hydrogen production.

Our results show that the long-term NECP capacity targets for 2050 can be met at all limited expansion rates. However, the short- and medium-term targets are at risk of delay in the scenarios involving limited capacity expansion (*medium* and *low*). In the *medium* scenario, the gap between total installations and capacity targets amounts to 40 GW for PV in Spain in 2030, 46 GW for onshore wind in Germany in 2030, and 40 GW for onshore wind in Spain in 2035. Stronger limitations on the annual expansion of VRE capacities (*low*) would delay the achievement of the NECP targets until the year 2045.

The *Ostend* scenario reveals a significant discrepancy between the capacity expansion achieved in the past and the ambitious goals set for 2030 and beyond. In Norway, 3 GW and 30 GW of offshore wind are targeted for the years 2030 and 2050, respectively. The first floating offshore wind farm, with an 88 MW capacity, began operating in 2023. However, as the reference dataset for annual capacity does not anticipate any offshore installations in Norway, the capacity gap remains across all scenarios and model years. For the UK, the Netherlands, and Ireland the capacity gap between stated policy and model results begins in 2030 at 28 GW, 8.2 GW, and 3.7 GW, respectively, even in the *high* scenario. While the UK and the Netherlands close the gap in 2040 and 2035, respectively, Ireland's capacity gap remains throughout all model years and ultimately reaches 13 GW due to higher targets in 2050.

Fig. 5 shows how different capacity targets impact the spatial distribution of annual domestic hydrogen production. Compared to the *high* scenario, the scenarios with an unconstrained annual capacity expansion show a significantly greater difference to their respective *no-targets* baseline. This suggests that the reference solution already involves a high spatial concentration of electrolyser technologies and that limiting annual capacity expansion rates and modelling capacity targets both have a systemic effect on the spatial distribution of electrolysers.

In both the *NECP* and *Ostend* scenarios, increasing electricity production in specific geographic regions affects the location of electrolysers. This is most evident in northern Germany in both 2035 and 2050, where there is a significant increase in hydrogen electrolysis. Similarly, the capacity targets reduce the hydrogen production in southern Spain in 2050, although Spain remains the country with the highest production in all scenarios. Unlike the *NECP* scenario, the *Ostend* scenario includes a greater contribution to the domestic hydrogen supply from the UK in both 2035 and 2050.

In the *Ostend* scenario, the model allocates some electrolyser capacity to offshore regions. However, with an annual production of just 35–43 TWh/a in 2050, offshore hydrogen production is quite limited compared to the total hydrogen production of 1776 TWh/a and 1628 TWh/a for the *5 Gt unlimited Ostend* and *5 Gt high Ostend* scenarios. This is consistent with the findings of Gea-Bermúdez et al. [64], who found that electrolyser capacities are predominantly installed onshore before 2050.

4.3. Impact of hydrogen import strategy and network delays

While the network delays up to 2030 (nogrid30) have only a minor impact on the system, network delays for hydrogen pipelines until 2035 (*nogrid35*) prevent access to green and blue hydrogen from the North Sea and import nodes. Fig. 6 shows the more widespread distribution of electrolysers across regions, facilitating production close to demand sites. Consequently, the spatial distribution of VRE technologies is also influenced, utilising resource-rich regions close to demand sites and the existing electricity grid. As spatial balancing between model regions via hydrogen networks is not possible in this scenario, the required electrolyser capacity increases significantly in 2030 from 64 GW_{H_2} to 92 GW_{H_2} if hydrogen infrastructure is slightly delayed (*nogrid30*) and

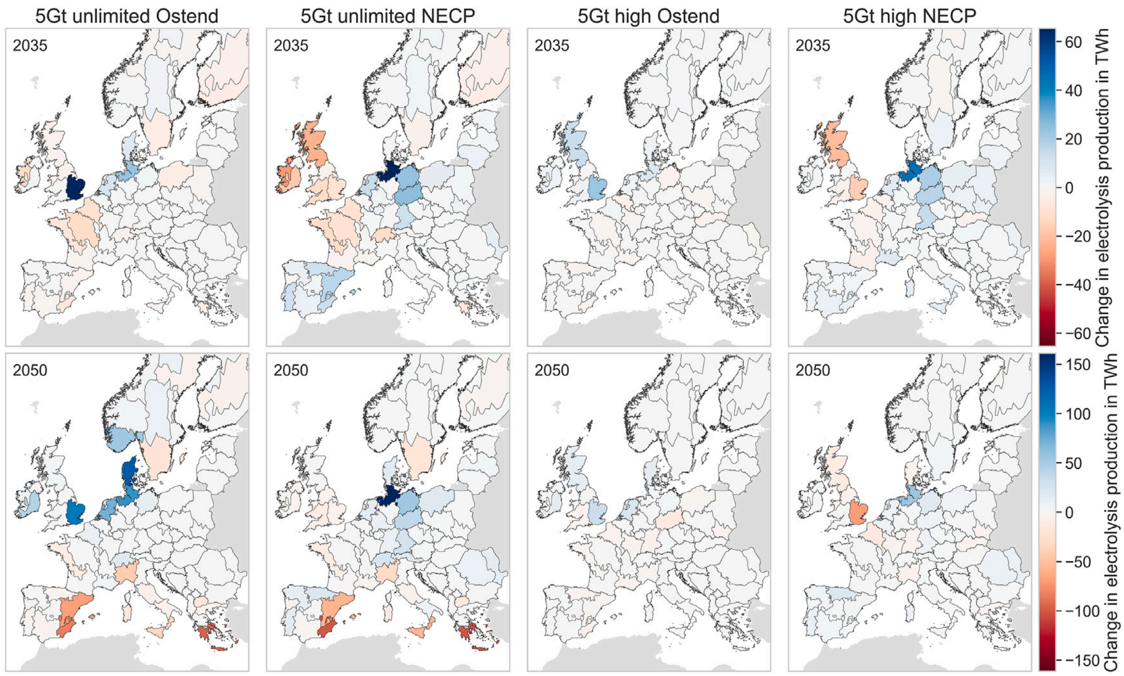

Fig. 5. Impact of *NECP* and *Ostend* capacity targets for a 5 Gt_{CO_2} carbon budget and considering the *unlimited* (left figures) and *high* scenarios (right figures) compared to their respective *no-targets* counterparts. Annual domestic hydrogen production in 2035 for the *no-targets* reference amounts to 377 TWh in the *unlimited* scenario and 248 TWh in the *high* scenario. For 2050 the reference values amount to 1620 TWh and 1381 TWh, respectively.

to 167 GW_{H_2} if network delays are expected to continue until 2035 (*nogrid35*).

A similar shift in the siting of hydrogen production can be observed in the scenario *no-blue*, in which greater emphasis is given to onshore wind in the North Sea area to compensate for the offshore production of blue hydrogen. However, hydrogen production is also set to increase significantly across various regions in France, reaching up to 130 TWh_{H_2}/a in 2035. In the NH_3- and *no-green* scenarios, the short-term impact compared to the H_2 scenario is limited, as the affected hydrogen import options are not yet cost-competitive with domestic production.

The largest reduction in domestic production in 2050 is seen in the scenario where the cost of port-based hydrogen imports is similar to that of pipeline-based imports (NH_3-). Shorter transport routes for hydrogen imports reduce domestic hydrogen production, particularly in regions close to LNG terminals. While the significant overlap between regions with good VRE potential and regions in close proximity to LNG terminals poses challenges for the economic efficiency of domestic production, it also offers synergies in terms of infrastructure.

Conversely, in a scenario where the import of green hydrogen or hydrogen derivatives is prohibited (*no-green*), we observe the repurposing of blue hydrogen offshore infrastructure to green hydrogen production by 2050. The existing offshore infrastructure can facilitate up to 94 TWh_{H_2}/a electrolysis from offshore wind energy and supply neighbouring countries via pipelines. Similarly, to compensate for the lack of green hydrogen imports from Turkey and Tunisia, there is an increase in domestic hydrogen production in Greece and Sardinia.

With a carbon budget of 5 Gt_{CO_2} and limited expansion rates (*high*), the results further show that providing sufficient domestic green hydrogen can be challenging. In both scenarios, in which green imports or blue hydrogen production are prevented, the slack variable for the carbon budget is utilised to a small degree. This suggests that, given the assumed speed of transformation in hydrogen demand, some additional green imports or blue hydrogen production is necessary, even if VRE expansion is limited to the optimistic scenario.

Similar to the changes in the spatial distribution of electrolyser production, the import strategy and hydrogen prices influence the topology of the network needed for hydrogen transfer, as shown in Fig. 7. In 2035, the topology is primarily determined by the option of utilising blue hydrogen production in the North Sea. Additionally, capacities for hydrogen transfer along the import corridors from Algeria, Tunisia, and Turkey are established early on.

In 2050, significant variations in topology are evident, primarily centred on import corridors (H_2 and *no-blue*), connections between LNG terminals (NH_3-), and inter-European hydrogen transfer (*no-green*). A common feature of the scenarios is the hydrogen transfer route between Southern Spain and demand centres in the North Sea area. To a lesser extent, this also includes corridors along Italy and the route connecting Greece to Central Europe.

The choice of hydrogen strategy and import routes significantly impacts the interaction between domestic hydrogen production and storage utilisation. Fig. 8 shows this interaction on an hourly basis, comparing domestic production, imports, and storage levels in caverns and pressurised tanks. Given that the model framework has perfect foresight for each hour of every year, the total storage capacity reflects only the volume of storage necessary for effectively balancing the supply and demand of hydrogen over the course of a year. This results in storage being completely full at the end of summer and completely empty at the end of winter, as no uncertainties on the demand or supply side are considered. In reality, however, additional strategic reserve capacities are required to account for uncertainties in demand, extreme weather events, delays in hydrogen imports and other supply chain disruptions.

As expected, there is a clear correlation between the overall share of domestic production and the required seasonal storage. When green hydrogen imports are avoided (*no-green*, right figures), the storage must be able to provide the full seasonal shift, relying on a more consistent balance between solar PV and wind energy as electricity sources. Conversely, when cheap hydrogen imports are available (NH_3-, left figures), domestic hydrogen production mainly utilises the best solar potential, reducing reliance on imports during the summer months.

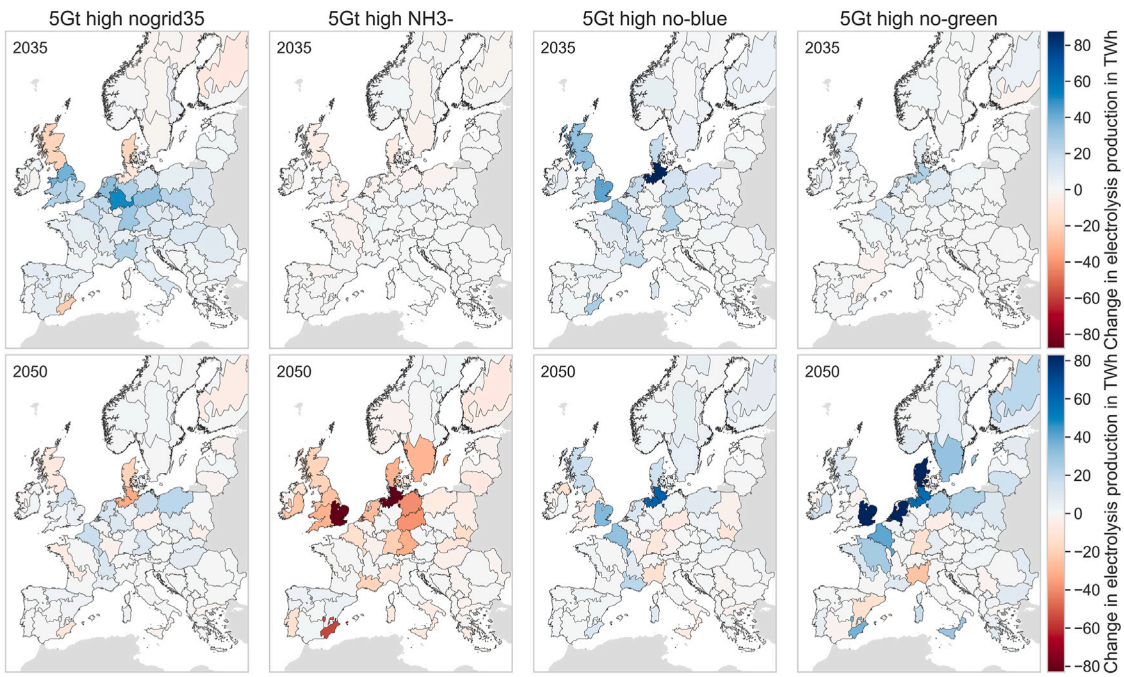

Fig. 6. Impact of the network delays scenario (*no-grid35*) and hydrogen import scenarios (NH_3-, *no-blue*, and *no-green*) compared to their respective H_2 reference for limited annual expansion rates (*high*) and a 5 Gt_{CO_2} carbon budget. Annual domestic hydrogen production in 2035 for the *5 Gt H2 high* reference scenario amounts to 332 TWh in 2035 and 1579 TWh in 2050.

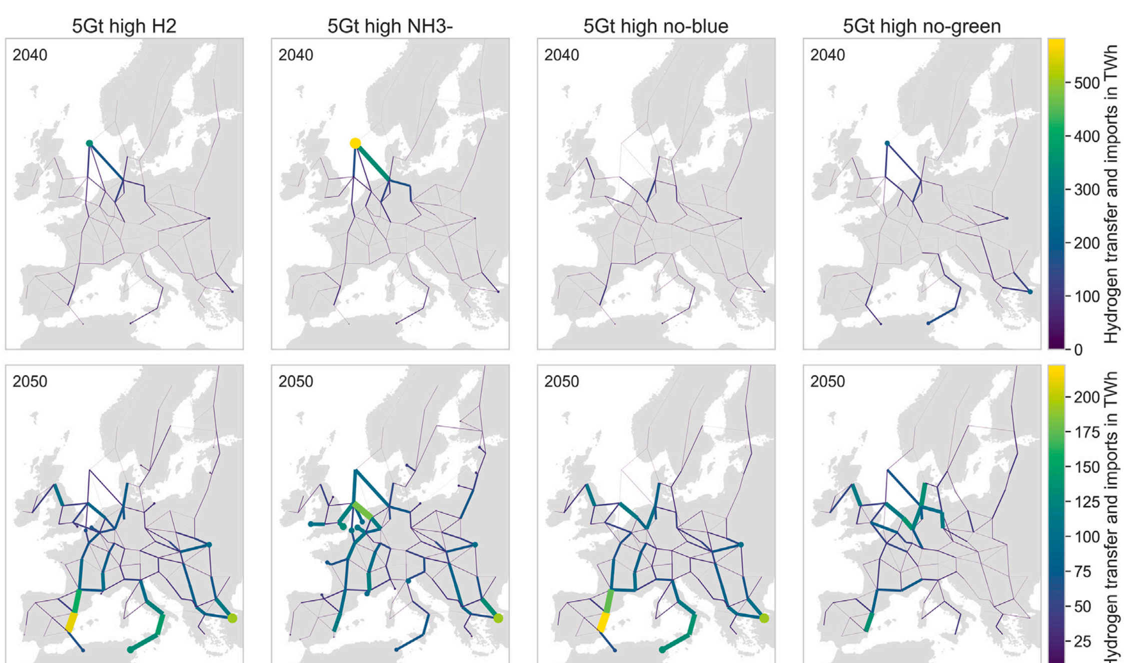

Fig. 7. Annual hydrogen network flows and imports from outside the system boundaries across different import scenarios. Note, that the import sources depicted as coloured circles can be either blue hydrogen from ATR-CCS or green hydrogen from electrolysis, or a combination of the two, depending on the conditions of the scenario. In 2040, the annual hydrogen transport throughout the system accounts for 2793 TWh/a, 3330 TWh/a, 2141 TWh/a, and 3002 TWh the scenarios H_2, NH_3-, *no-blue*, and *no-green*, respectively. For 2050, the annual hydrogen transport totals 4690 TWh/a, 5554 TWh/a, 4562 TWh/a, and 3308 TWh/a, respectively.

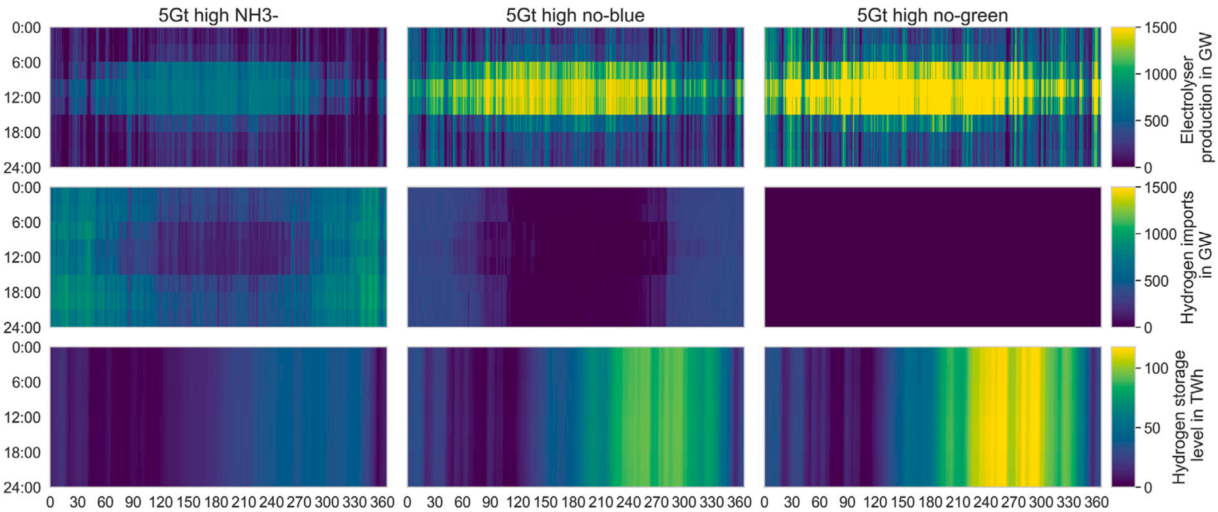

Fig. 8. Hourly utilisation of domestic electrolysers (top row), hydrogen imports (middle row), and seasonal storage level of for hydrogen caverns and pressurised hydrogen tanks (bottom row) across three different hydrogen import scenarios NH_3- (left column), *no-blue* (middle column), and *no-green* (right column). Note the difference in axis scaling between the domestic hydrogen production and hydrogen import (GW_{H_2}) and the storage level (TWh_{H_2}).

This scenario also results in lower storage requirements for seasonal balancing, but shifts the risk to import availability and potential price spikes.

The base scenario and the scenario without blue hydrogen (*no-blue*, middle figures) combine aspects of the two extreme cases previously discussed. Domestic hydrogen electrolysis in summer enables full domestic production for half the year, while seasonal hydrogen imports in winter reduce Europe's overall peak hydrogen storage requirement. For countries aiming to export hydrogen, this seasonal behaviour could favour imports from the Southern Hemisphere – for example Chile, South Africa and Australia.

The required hydrogen storage capacity of up to 160 TWh is similar in magnitude compared to the findings of Fleiter et al. [3], who observed a maximum hydrogen storage capacity of 215–300 TWh with the same one-cycle seasonal operational pattern. This large storage volume also enables a better integration of VRE by providing short-term flexibility in the power sector via electrolysers.

5. Limitations and outlook

There are various aspects outside the scope of this study that may influence the overall findings of the model-based analysis. While input data, such as future technology costs and overall demand trends, are always subject to large uncertainties, this section discusses the study's specific limitations. These limitations can be grouped into three categories: sectoral scope, technological scope, and fundamental modelling approach.

A major limitation of the study is that it did not consider the possibility of large-scale domestic hydrogen production for renewable fuels of non-biological origin (RFNBOs). These are expected to play a crucial role in decarbonising aviation and shipping. However, large uncertainties remain regarding market competition between different carriers, particularly with regard to bio-jet, as well as aspects of the regulatory framework. While the EU currently mandates a 70% share for sustainable aviation fuels (SAFs) of and a 35% share for RFNBOs for the aviation sector in 2050 [65], the national implementation of these targets and the possibility of importing these fuels remains uncertain. Significant RFNBO production in Europe would necessitate accelerated VRE expansion. Follow-up assessments should address the uncertainty surrounding the additional demand for hydrogen in the context of limited capacity expansion rates. Similarly, a better understanding and alignment of the dynamics between the potential re-acceleration of VRE expansion [7] and the scale-up of the hydrogen market [10] is required.

In terms of the technological scope of the study, aside from indirect electrification via hydrogen, there is a lack of detailed endogenous sector coupling options. This leads to an underestimation of flexibility options. In the power system, electrolysis, power grids, and battery storage systems offer the greatest flexibility. However, given the increasing market penetration of battery electric vehicless (BEVs), electric heat pumps, and smart meters, overall demand-side flexibility is expected to grow substantially. While the chosen model resolution is sufficient for addressing questions related to the deployment of large infrastructures, future model-based assessments need to consider demand-side flexibility in more detail.

While the technologies included in the model allow for the production of synthetic methane, there are no explicit CDR options, such as bioenergy with carbon capture and storage (BECCS) [66] or the utilisation of carbon as feedstock for the chemical industry [67]. Including these technologies, as well as carbon emission reduction strategies in other sectors, would enable a more comprehensive consideration of the overall carbon budget and cross-sectoral effects. Similarly, including pipelines for transporting and storing CO_2 could alter the overall emission trajectory. Extending the modelling period to 2070, while allowing for temporary overshooting to be compensated for later, would provide further insight into the allocation of the carbon budget across different sectors, particularly those not considered in this study.

The annual capacity expansion rates assumed in this study likewise are subject to limitations that must be considered when interpreting the model results. As the increase is only extrapolated based on an estimated short-term expansion rate, the analysis does not consider the dynamic effects of scaling up between different technologies or countries. This was demonstrated in the model results with regard to the expansion of offshore wind technologies in the North Sea. To provide a clearer picture of the solution space, more in-depth research is required into the limiting factors on a per-country and per-technology basis. These factors include the future availability of skilled workers, import dependence for technologies, components and raw materials, market incentives and societal impact, as outlined in the Clean Energy Technology Observatory (CETO) reports [13,14,68].

In terms of the modelling approach, the uncertainty surrounding the hydrogen strategy and imports is only considered through deterministic scenarios. Stochastic or robust optimisation could provide additional insights, for example, into a more robust and adaptable topology for the hydrogen pipeline network, and into hedging strategies against high import prices. Similarly, selecting only five different weather years and mapping them across the transformation pathway may introduce bias into the spatial allocation of investment between solar and wind technologies [69].

More generally, system-wide least-cost optimisation lacks the multitude of perspectives from individual actors and their investment incentives. At a system level, this can result in an overestimation of VRE sites with high capacity factors and long-distance transmission throughout the system. In contrast, regional actors will always invest in VRE and electrolyser technologies if doing so benefits them in their market situation. Although the model results suggest clear co-location of electrolyser capacities and VRE sources, future studies need to further investigate the integration of these technologies at the level of regional energy systems, taking into account the perspectives of local actors.

To allow for the wide range of scenarios, the temporal dimension is downsampled to a 3-hourly resolution, which leads to a significant reduction in solution time from 170 h down to 20 h per scenario. Previous studies have shown that a downsampling to 3-hourly resolution is still suitable for energy system models, as it adequately captures the intermittency of high shares of VRE [70]. To assess the impact of the temporal downsampling, a 1-hourly resolution run is conducted for the *5 Gt high no-targets no-delay* H_2 scenario as reference. For the year 2050, the key differences between the two runs confirm that the main differences lie in flexibility options, with a system-wide increase in battery converter capacities of 18 GW (17.4% increase) and utilisation of 34 TWh (19.4% increase). Similarly, the capacity of hydrogen buffer storage units in Southern Europe increases by 37 GW (11.8% increase) and their utilisation increases by 8.6 TWh (13.7% increase). Furthermore, reductions are observable in the annual electricity supply from concentrated solar power (CSP) by 15 TWh (6.2% decrease) and PV by 18 TWh (1% decrease), while offshore wind energy increases by 7 TWh (18.5% increase). Taking into account the differences in required short-term flexibility options, this suggests that the downsampling results are reasonable compared to the overall uncertainties in the input data.

6. Conclusions

First and foremost, the findings of this study highlight the crucial role of achieving high annual VRE capacity expansion rates in the successful transformation towards a climate-neutral energy system. While modelling transformation pathways with high spatial and temporal resolution and perfect foresight can ensure that sufficient capacities are reached through early investment, it also reveals the systematic impact of national limits on annual expansion rates. Therefore, energy system modellers must carefully consider limitations on annual expansion rates and associated uncertainties, not only when modelling transformation pathways, but also when modelling target years. This also requires more in-depth investigations into the interplay between the various factors that can potentially limit future annual expansion rates, enabling the move away from pure extrapolation and adopting a stronger, scenario-based approach with a solid foundation of data.

Regarding the stated policies, we can observe that some targets, such as the NECP targets for onshore wind energy and PV in Spain and Germany, require a significant acceleration in the annual capacity expansion compared to the *high* baseline. While there is a risk of missing these particular targets, the overarching goal of achieving a climate-neutral energy system by 2050 remains feasible, if capacity expansion is distributed across more European countries. In order to achieve this, a clear European strategy is required to incentivise more countries to contribute to VRE capacity expansion. This would mitigate the risk of individual countries lagging behind and ensure a sufficient European hydrogen network to enable spatial balancing across borders. The expansion of VRE and networks must be closely coordinated and monitored to ensure electrolysers can be deployed on a regional level providing demand-side flexibility, while the hydrogen network enables access to hydrogen cavern storage sites for seasonal balancing.

The co-location of VRE capacities and electrolysers throughout all scenario variations also demonstrates the value that hydrogen can offer in terms of system integration. Flexible operation of systems comprising a renewable electricity source, buffer storage, and an electrolyser reduces reliance on the power grid and contributes to overall system stability. Given both the co-location and matching operational patterns of VRE technologies and electrolysers, we can also conclude that policies, such as the RFNBO classification, in terms of temporal and geographical matching, can be seen as being in line with the operational patterns required to integrate large shares of VRE into the system.

Regarding the use of blue hydrogen, we conclude that a strong reliance in the short term poses a significant risk to achieving the carbon budget. This is because it delays the required expansion of VRE and electrolyser capacities to later years, based on the expectation of lower future investment costs. Consequently, this delay necessitates a faster rate of annual capacity expansion for the transition to green hydrogen in 2040. Similarly, over-reliance on blue hydrogen can induce an increased dependency on energy imports in the long term if it results in reduced investment in domestic electrolyser capacities.

Therefore, incentives for hydrogen production and demand should focus solely on green hydrogen, as this indirectly facilitates the rapid expansion of VRE. Although blue hydrogen could substantially increase hydrogen usage in industry by 2035, this would only be possible without affecting the carbon budget if sufficiently high capture rates for ATR-CCS can be achieved. When considering the trade-off between blue and green hydrogen, competition for investment funds must be taken into account. Similarly, if the provision of blue hydrogen relies on repurposing existing pipelines, this could delay the installation and network connection of green hydrogen production facilities, leading to a medium-term dependency on fossil fuels and exacerbating the need to expand VRE capacities.

Based on the model results, ensuring a long-term, fully domestic supply of green hydrogen requires a significant increase in annual capacity expansion to 51 GW/a for PV and 49 GW/a for onshore wind energy across Europe. Until 2050, the annual expansion rate for PV needs to almost triple to 139 GW/a, while the level of around 50 GW/a for onshore wind needs to be consistently maintained throughout this period. However, the exact peak of the maximum capacity expansion rate varies depending on the scenario and could happen earlier if CCS with high capture rates is not technically or economically viable.

In terms of hydrogen network infrastructure, the clear impact of the relative costs of import sources on the overall network topology is evident. This suggests that the expected costs and volumes require further investigation. However, assuming high levels of domestic hydrogen production, a common pattern emerges across the topologies: connecting large hydrogen supply regions to cavern storage systems along the route from southern Spain to the North Sea area appears to be a viable option and would allow existing LNG terminals to be connected along this corridor. Additionally, smaller sized hydrogen network capacities are required to connect spatially distributed electrolysers to seasonal hydrogen storage sites.

In summary, VRE capacity expansion rates and the reasons for their limitations are one of the crucial determining factors for a successful energy transition and must be adequately considered in modelling activities. This is particularly relevant if the aim is to produce large quantities of green hydrogen domestically, as failing to achieve the required expansion rates would result in a reliance on imports of hydrogen or the long-term use of blue hydrogen derived from fossil fuels. Adequate measures must be implemented to ensure that the burden of rapid VRE expansion is shared across a large number of European countries, and that sufficient hydrogen network capacity is in place to enable access to seasonal hydrogen storage sites. Going forward, additional effort is needed to better understand the reasons and conditions that could prevent the rapid expansion of VRE, and to adequately and proactively address the associated risks.

CRediT authorship contribution statement

Manuel Wetzel: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Hans Christian Gils:** Writing – review & editing, Writing – original draft, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Valentin Bertsch:** Writing – review & editing, Supervision, Investigation, Formal analysis.

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 reported in this paper.

Acknowledgements

The research for this paper was partly conducted in the context of the project 'HINT', which is supported by the German Federal Ministry of Research, Technology and Space under grant number 03SF0690, and the project 'ARTESIS', which is supported by the German Federal Ministry of Economic Affairs and Energy under grant number 03EI1067A.

The authors thank Stefan Kronshage for his contributions to the demand scenario data, Jens Schmugge and Hedda Gardian for their support in the data collection and modelling activities, and all current and former members of the Energy Systems Modelling group of DLR for their continuous contribution to the input data and model framework.

Furthermore, the authors gratefully acknowledge the scientific support and HPC resources provided by the German Aerospace Center (DLR). The HPC system CARO is partially funded by the "Ministry of Science and Culture of Lower Saxony" and the "German Federal Ministry for Economic Affairs and Energy".

Appendix. Model nomenclature

Model dimensions

$t \in T$	time steps
$y \in Y$	year intervals
$n \in N$	model nodes
$l \in L$	transfer links
$q \in Q$	energy carriers
$a \in A$	converter activities
$p \in P$	technologies
$i \in I$	system indicators

Model variables

$x \geq 0$	number of available units/links
$\Delta x^+ \geq 0$	number of commissioned units/links
$\Delta x^- \geq 0$	number of decommissioned units/links
$d \geq 0$	utilisation of converter activities
$f^+ \geq 0$	flow along transfer link
$f^- \geq 0$	flow against transfer link
$g^+ \geq 0$	import of energy carriers
$g^- \geq 0$	export of energy carriers
j	accounting indicator variable

Model parameters

J	indicator coefficient matrix
W	weighting factor between year intervals
X	number of target units/links
λ	technical lifetime

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