Green energy carriers and energy sovereignty in a climate neutral European energy system

A Preprint

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Abstract

Meeting the goals of the Paris Agreement poses significant challenges to provide renewable energy for the power, heating, transport, and industrial sector. Both green hydrogen and methane are considered key energy carriers for reaching these climate targets. However, future needs for an effective infrastructure deployment are highly uncertain, particularly concerning the timely and substantial expansion of renewable electricity generation in Europe. To better understand the trade-offs between domestic production and large-scale energy imports and the corresponding infrastructures needs, we use the energy system optimisation model REMix. We consider different strategic European story lines and constraints on expansion of pipelines and power grids. The results indicate that European energy sovereignty is feasible but comes at a 2.8% higher cost compared to stronger cooperation with resource-rich areas such as the British Isles or the Maghreb region. In contrast, preventing any network expansion lead to an increase of up to 15.2%. Especially limited network expansion in conjunction with energy sovereignty makes controversial technologies such as nuclear energy necessary. With regard to the extensive adaptations of energy infrastructures required to achieve the emission reduction goal, the timely and substantial expansion of electricity generation from renewable sources in particular is to be regarded as crucial.

Keywords energy system modelling · renewable energy · sector integration · green energy carriers · climate neutrality · REMix

Highlights

- European energy sovereignty comes at higher cost compared to international cooperation
- Strategic narratives have high impact on national and European infrastructure needs
- Repurposing natural gas pipelines enables large-scale transport of green hydrogen
- Production of green hydrogen sited in areas rich in renewable energy
- Combining concentrated solar power and photovoltaics supports the production of low-cost green methane

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List of abbreviations

BEV battery electric vehicles
BECCS Bioenergy with Carbon Capture and Storage
CCS carbon capture and sequestration
CCU carbon capture and utilisation
CHP combined heat and power
CSP concentrated solar power
DAC direct air capture
E2P energy to power
EC European Commission
EU European Union
GHG green house gas
HP heat pump
HVAC high voltage alternating current
HVDC high voltage direct current
LP linear programming
LNG liquefied natural gas
LH2 liquid hydrogen
LOHC liquid organic hydrogen carriers
MILP mixed-integer linear programming
NA North Africa
NTC net transfer capacity
PV photovoltaics
RE renewable energy
RES renewable energy sources
TES thermal energy storage
TYNDP Ten-Year Network Development Plan
VRE variable renewable energy

1 Introduction

Achieving a climate neutral energy system depends on several key drivers to ensure a successful transition from today's system. The most important drivers include political targets to encourage long-term investments, the technical and economic feasibility of the overall system, and low-cost technologies to convert, transport, and store energy. Furthermore, societal aspects such as public acceptance of energy infrastructures and geostrategic aspects such as the diversity of sources for energy imports have to be considered. Therefore, this study focuses on the technical feasibility of a future European energy system in line with the Paris Agreement while assessing a wide scope of different political constraints and degrees of network expansion for energy transport.

Political commitments towards achieving a climate neutral energy system by 2050 are gaining traction both at the European and national levels. The requirement for a full decarbonisation across all sectors and the technical infeasibility of direct electrification of some energy consumers have recently brought hydrogen and green fuels into focus. To this end both the European Commission (EC) and several European countries have announced strategies dedicated to hydrogen. The strategy of the European Union (EU) puts a strong emphasis on hydrogen as a supporting technology in a system with high shares of renewable electricity and envisions an increase in the total share of hydrogen to 13 - 14% in the European energy mix by 2050 [1]. The corresponding Clean Planet study commissioned by the EC emphasises lower than expected costs for renewable energy sources and challenges with respect to carbon capture and sequestration (CCS) technologies as a main driver for low carbon energy carriers such as hydrogen and electrofuels and outlines their respective role in 2050 in line with the emission target according to the Paris Agreement [2].

The study Clean Energy for all Europeans puts further emphasis on strengthening energy sovereignty of the EU [3]. While no clear definition is made, the term is used in the context of reducing imports of fossil fuels, decreasing dependence on external energy suppliers, increasing energy efficiency and positioning the EU as a leader in both development and deployment of renewable energy sources (RES). Westphal [4] further distinguishes between energy sovereignty and security of supply. While a technical robust and resilient system is a prerequisite for both, energy sovereignty is predominantly defined by flexibility, the ability to choose from many options, and reducing dependencies where vulnerabilities can arise. Westphal additionally stresses the difference from energy autarky, as energy partnerships can broaden the scope of options. Similarly, Scholten and Bosman [5] argue that a shift towards renewable energy sources will reduce the overall dependence on energy imports and allow for opportunities for domestic sourcing and cross-border trade for balancing. Tröndle et al. [6] assess the possibly of autarky in the European power system on different spatial scales and conclude that especially on sub-national levels significant barriers remain. On the topic of long term energy imports, Hauser [7] compares different approaches towards a diversification of the European gas supply and identify pipelines to suppliers in North Africa (NA) as a no-regret option and the EU-Russian relationship as a main driver or inhibitor of diversification efforts. Frischmuth and Härtel [8] assess potential hydrogen imports and sourcing strategies in the European context and find a high share of 80% of domestic production of hydrogen even at low import costs. Similar findings are presented by Gils et al. [9] for Germany and neighbouring countries.

In the scientific literature there have been model-based assessments of the EU energy system to demonstrate the technical and economic feasibility of carbon neutral power systems. For example, Child et al. [10] analyse an energy system based on 100% RES in the power sector for the European continent by 2050 in line with the Paris Agreement. They underline the role of interconnection capacities in the electrical grid which can lead to overall reduced system cost. This reduction however comes at the cost of increased system-wide interconnection capacity from 63 GW to 262 GW with the largest expansion between France and the British Isles from 2 GW to 45 GW. The study of Hanley et al. [11] focuses on the emergence of hydrogen as part of energy systems on a global, multi-regional and national level highlighting the role hydrogen can play as a key energy carrier across multiple sectors. They identify deep decarbonisation targets, high shares of renewable energy technologies and a lack of development of CCS technologies as key drivers for the market integration of hydrogen. Deane et al. [12] highlight the close dependency between power grids and gas networks and assess the impact of interruptions in gas supply. On a more limited spatial scope Devlin et al. [13] model a joint optimisation of electricity and gas infrastructure for the British Isles and assessing system robustness against possible extreme weather events.

Several key drivers are enabling this push towards green energy carriers such as progressing technological development of photovoltaics (PV) and water electrolysis which allow for low-cost sustainable production of electricity and hydrogen. While the electrification of demand technologies such as switching to heat pumps and adoption of battery electric vehicles (BEV) offers a rapid way to decarbonise some sectors, other sectors such as the production of steel and concrete and the chemical industry remain more challenging and may rely on hydrogen and methane from sustainable sources [14]. Both hydrogen and methane offer the possibility of storing and transporting large amounts of energy while at the same time enabling higher shares of variable renewable energy (VRE) in the power sector by providing demand side flexibility. This flexibility, however, comes at the additional cost of lower overall efficiencies due to additional conversion steps. Similar effects can also be achieved via other energy carriers such as methanol and ammonia, which are out of the scope of this paper.

Both green hydrogen and green methane provide the opportunity of utilising the existing gas infrastructure of pipelines, storage and liquefied natural gas (LNG) terminals by means of infrastructure repurposing. While historically the sourcing of natural gas depended on oil and gas producing countries, water electrolysis and further methanation via the Sabatier reaction allow for more small-scale regional strategies depending only on low-cost electricity and sufficient water resources. Gorre et al. [15] analyse the technological configuration of such systems in detail and report estimates for techno-economic data in the years 2030 and 2050. Similarly Di Salvo and Wei [16] assess synthetic natural gas production in California highlighting the opportunity of utilising biomass rather than electrolysis. Utilising biomass as resource however is limited in potential. Combining low cost RES, electrolysis and methanation allows countries along historical natural gas corridors and with excellent wind or solar resources to establish themselves as large-scale producers and exporters for green energy carriers. Regions fulfilling both criteria are the British Isles with the largest offshore wind potentials in Europe as well as the Iberian peninsula and the Maghreb region in North Africa where large potentials of direct irradiation can be utilised via concentrated solar power (CSP) and PV. Benasla et al. [17] address this opportunity for the Maghreb region to become an energy exporter for countries in Europe in more detail, showing that high voltage direct current (HVDC) lines to enable imports renewable solar can play a significant role as a spatial flexibility option especially for demand centres in and close to Northern Italy.

Against the background of increasingly inexpensive renewable energy (RE) power generation and the good infrastructural conditions for the use of green gases generated from it, this study is dedicated to the required future energy infrastructure and operation patterns in a climate neutral energy system. In doing so, we analyse two overarching strategies regarding energy import. The first strategy focuses on domestic production and trading in the highly meshed grid in continental Europe (CE), whereas the second puts emphasis on energy partnerships (EP) with neighbouring regions rich in RES. For a more differentiated view on those two worlds we introduce additional story lines on import and export strategies. Another key dimension for the assessment of future energy systems is the assumed technical feasibility of repurposing existing pipeline for hydrogen as well as restrictions on the allowed degree of network expansion and reinforcement. To this end we employ the energy system optimisation model REMix [18] for a case study to answer the following research questions, that have not been addressed by the existing research described above:

- What is the least-cost spatial distribution of green hydrogen and methane production facilities in an integrated, zero-emission European energy system?
- What investments into RE capacities and energy transport infrastructure are robust across a broad scope of different sovereignty strategies and limitations on grid expansion?
- What are the optimal energy carriers and main routes for energy transport across the European continent if energy partnerships with the Maghreb region and the British Isles are either promoted or avoided?
- What are typical daily and seasonal operation patterns of electrolysis, methanation, and other sector integration technologies when mostly supplied with electricity from VRE?

This paper is structured as follows: Section 2 outlines the general workflow applied for the analysis and gives an overview of the scope of the system as well as the required input data and techno-economic datasets, motivates the considered story lines for the case study, and specifies the model formulation. The results Section 3 is structured in a high level comparison of optimisation results for the different story lines, a more in depth analysis of geographical distribution of technologies, assessment of required network expansion decisions, and hourly operation strategies for the supply and storage technologies. Section 4 puts the research into context of other publications and takes a critical look on limitations which could not be addressed in the scope of this study while Section 5 summarises the key findings and gives an outlook on possible follow-up studies.

2 Methods

2.1 Model scope and input data

The system examined here includes all member states of the European Union, plus Great Britain, Norway, Switzerland, the candidate and potential candidate states in South-eastern Europe, and the Maghreb states of Morocco, Algeria and Tunisia. The British Isles and the Maghreb states are connected to the European mainland via existing power lines and pipelines. The extent to which a net import of energy from these countries is possible is defined via the scenarios (Section 2.2). To limit the size of the mathematical problem to be solved, the countries in the study area are partially aggregated to 21 model regions (Figure 7). For these regions, the design of a climate neutral energy supply in 2050 is analysed. The selected scenario year affects the assumptions for energy demand and the techno-economic parameters of the technologies.

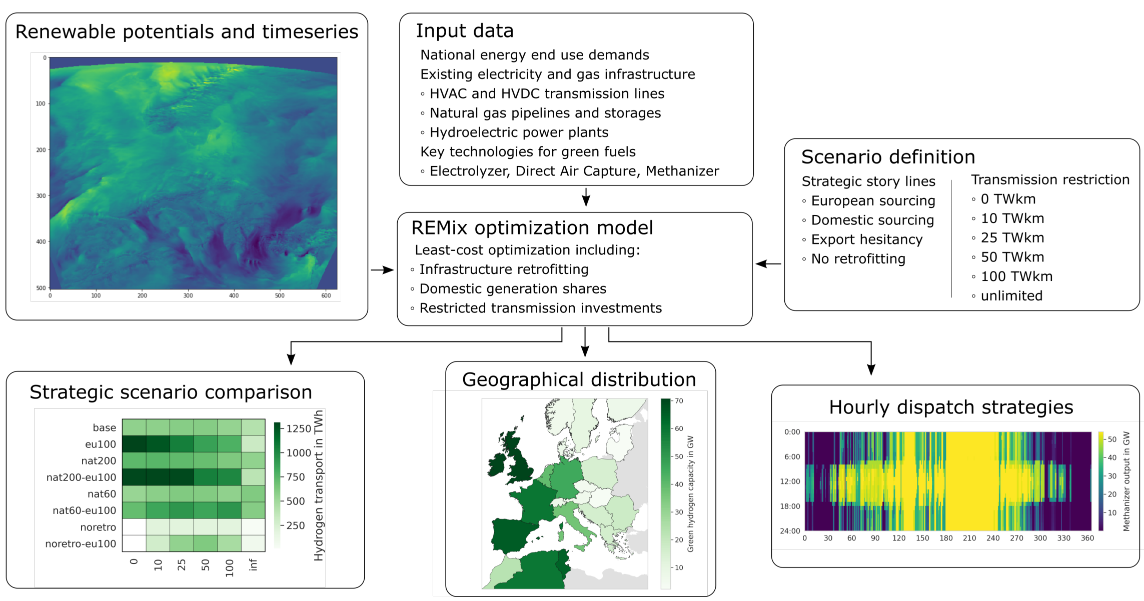

Figure 1: Overview of the methodological approach

In the modelled system, the energy carrier-specific demand is partly specified exogenously and partly a component of the results (Figure 2). In the heating sector, for example, the demand for useful energy is specified exogenously, divided into the consumer classes industry, large heating networks, small heating networks and buildings. The technologies used to meet this demand are determined endogenously. Depending on the consumer class, different types of combined heat and power (CHP) plants, electric boilers, fuel boilers, and heat pumps (HP) can be considered. A further flexibilisation of the operation of these plants can be realised by endogenous investment in thermal energy storage (TES).

Furthermore, the demand for methane and hydrogen for the transport sector and non-energy use is specified exogenously. It is derived from the *TECH1.5* scenario presented in the Clean Planet study [2]. This demand can increase endogenously through fuel use in the power and heat sectors. For countries which are not included in the original data source we estimate future demand for hydrogen and methane based on a mean value of current and future demand in line with demand projections from the e-Highway 2050 study [19]. From the system perspective, all exogenously given demand for methane is accounted with downstream green house gas (GHG) emissions due to usage in decentral heating systems where CCS and carbon capture and utilisation (CCU) are not economically viable or emissions during the ammonia production for fertilisers. This implies that all methane has to be either sourced from biogas, produced as green methane and from renewable electricity, or imported from a world market for green fuels. We model the synthesis of green methane based on direct air capture (DAC) technologies in order to close the carbon cycle of decentralised emissions in the heating sector. Techno-economic data for DAC technologies is taken from Fasihi et al. [20].

The electricity demand that is not related to flexible sector coupling technologies, i.e. is not used for electric heating, electric driving or hydrogen production, is also specified exogenously. Here, we rely on data from [19]. On the electricity supply side, infrastructures are mainly determined endogenously, but existing hydro power plants are considered (Figure 2) based on datasets generated by the tool power plant matching [21]. Further modifications of the dataset have been done based on the power plant dataset published by the German Bundesnetzagentur [22]. These include run-of-river, reservoir and pumped storage hydro plants.

For the power transmission grid, the existing lines and the planned expansion measures until 2030 are exogenously incorporated as stated in the Ten-Year Network Development Plan (TYNDP) [23]. These can be expanded further endogenously within the allowed boundaries of network expansion (Section 2.2).

In the gas system, existing underground storage facilities are considered according to [24] as well as existing transport pipelines based on data from [25]. An expansion of gas storage is not possible for methane but for hydrogen within the limits specified in [26]. Existing gas pipelines can be repurposed for hydrogen transport, new pipelines can be built either for hydrogen or methane. The assumed cost for pipeline repurposing is taken from [27]. Admixtures of hydrogen and methane are not considered in this analysis.

In addition to increasing capacities of existing connections we also allow new connections between neighbouring countries either via pipeline, overhead landlines or sea cables. The demand and capacity assumptions are supplemented by the techno-economic characteristics of the modelled technologies. These are considered according to [26].

An import of renewable gases can be realised through the utilisation of existing LNG terminals which allow model regions to purchase green gases from the world market at a fixed price of 80 €/MWh for hydrogen and 120 €/MWh for methane (for all energy accounting of hydrogen and methane the lower heating value is used consistently). This demand for methane can also be met by using biogas from agricultural waste. The quality of this gas is assumed to be adequate, but the potential is limited for each model region according to [26].

While electricity and heat supply, including buildings and industry, are fully included in the model, this does not apply to the transport sector. There, only ground-based transport is considered, whereas shipping and air traffic are outside the modelled system.

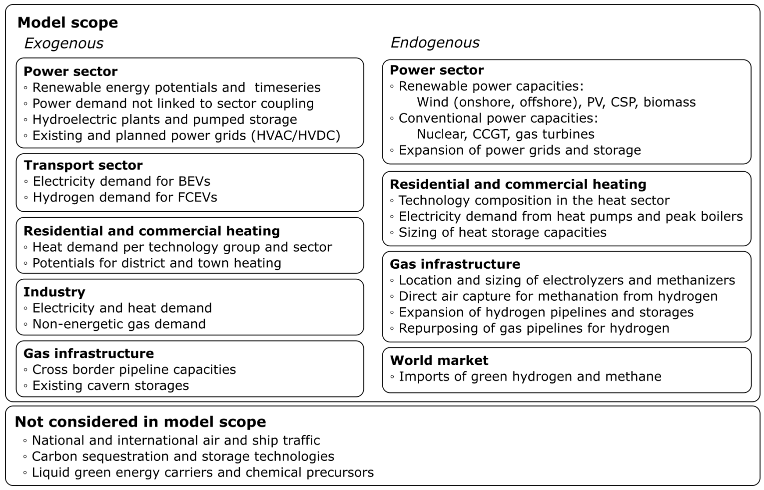

Figure 2: Outline of the model scope grouped by sectors

2.2 Scenario variations

To analyse the impact of different decisions towards energy sovereignty on both the national and European energy systems we utilise the share of domestically sourced energy relative to the regional demand as a key driver. This share is applied to all considered energy carriers individually. Sasanpour et al. [28] present a similar approach in varying self-sufficiency rates, secured capacities and diversity indicators to show a broad range of possible systems. In this analysis, we impose either a lower or an upper limit of domestic supply. While the lower limits ensure a national security of supply for the energy carriers and national contribution towards the mitigation of climate change, the upper limits represent concerns about land use or resource consumption. However, an upper limit can also prevent individual countries from taking up a role as large-scale energy exporter. All limits are based on the annual supply and demand for energy carriers. Therefore, sub-annual exchange between different model regions is still allowed. Furthermore, to ensure the technical feasibility of the system, imports of hydrogen and methane from a world market are allowed in all scenarios but cause additional penalty costs in the objective function of the optimisation if this leads to violations of the domestic generation shares. All scenario story-lines listed in Figure 3 are taken into account during the analysis.

In addition to the story-line component on energy sovereignty, a second key driver for the overall energy system design in Europe is the expansion of existing energy transport networks. Schlachtberger et al. [29] present a methodology to evaluate different large-scale network configurations by limiting the overall investment. Due to the methodology of taking the net transfer capacities (NTC) for both the electrical network based on the e-Highway Scenario and for the gas networks based on the ENTSO-G reported values as well as distances between the population-weighted centroids of each model region, we obtain different values compared to the physical network capacities and distances. Based on the modelled infrastructure, existing capacities for natural gas pipelines of 970.3 TWkm, high voltage alternating current (HVAC) grid of 78.5 TWkm and HVDC lines of 27.2 TWkm are exogenously considered as existing infrastructure. The application of NTC reduces the overall considered power network in comparison to other datasets which also account for lines inside national boundaries (e.g. 345.7 TWkm for the HVAC grid as specified in [30]). This also implies an underestimation of the overall investment requirements into grid infrastructure in comparison to studies with a higher spatial resolution. In this analysis, additional expansion of network infrastructure is limited to 0, 10, 25, 50, 100 TWkm per energy carrier in addition to the unrestricted network expansion. This yields 6 different limits on expansion and in conjunction with the eight scenario story-lines (Figure 3), a total of 48 different scenarios are analysed.

2.3 Model formulation

The energy system optimisation model REMix [18] used in this study allows for finding possible least-cost systems under additional constraints. The overall system costs described in equation 1 are composed of the annualised investment cost C_{inv}, fixed and variable operation cost C_{fix} and C_{var} as well as the costs for fuel imports into the model regions C_{fuel}. While the model also supports a formulation as mixed-integer linear programming (MILP), the analysis in this

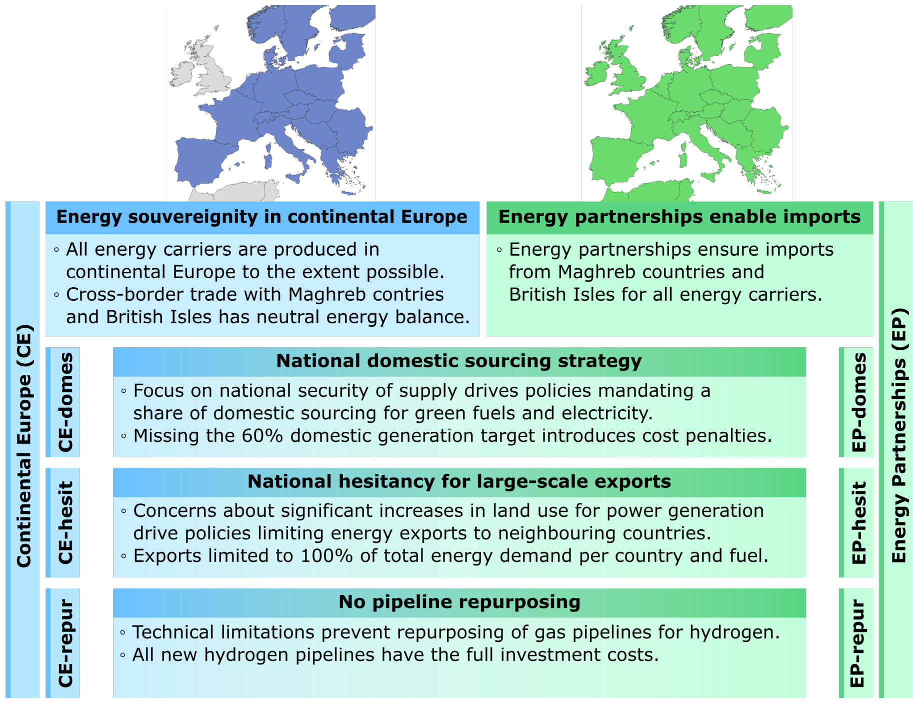

Figure 3: Considered scenarios derived from the two main story lines on energy sovereignty in continental Europe (CE) and energy partnerships (EP) and 3 sub story lines on export hesitancy (-hesit), domestic sourcing (-domes), and limitations on repurposing (-repur)

paper is limited to a linear programming (LP) formulation due to the size of the individual optimisation problems and the number of scenarios considered.

$$\begin{aligned} &\min C_{total} \\ &C_{total} = \sum_{r,p,c} C_{inv,r,p} + C_{fix,r,p} + C_{var,r,p} + C_{fuel,r,c} \\ &\qquad \forall\, r \in regions, p \in techs, c \in energycarriers \end{aligned} \tag{1}$$

In contrast to previous model applications which consider fully separated infrastructures for natural gas and hydrogen [9], we explicitly include the repurposing of natural gas pipelines towards hydrogen as an endogenous model decision. This can be achieved by restricting the investments into repurposed hydrogen pipelines $l_{build,H2repurpose}$ and limiting this variable by the total number of decommissioned natural gas pipelines $l_{decom,CH4}$ on any given pipeline corridor between the model regions r and r' as shown in equation 2.

$$\begin{aligned} &l_{build,r,r',H2repurpose} \leq l_{decom,r,r',CH4} \\ &\qquad \forall\, r, r' \in regions \end{aligned} \tag{2}$$

Equation 3 shows the formulation for considering the domestic generation shares per energy carrier. This equation is only applied to scenarios which consider either upper or lower constraints on the domestic generation dgs_{upper} and dgs_{lower}. We account for the overall generation gen and demand dem of each energy carrier c and technology p without temporal and spatial flexibility options in the form of storage, pipelines and power grids. To ensure feasibility of the optimisation problem, we introduce an additional slack variable for the domestic generation. This slack variable comes with additional penalty costs which prioritise domestic generation of electricity before hydrogen and hydrogen before methane. The prioritisation is motivated firstly by the need to keep electricity demand and supply continuously balanced and secondly due to the increasing electricity demand for water electrolysis and hydrogen demand for the methanation making the achievement of domestic generation targets more challenging with each additional conversion step.

$$dgs_{lower,r,c} \cdot \sum_{p} dem_{r,p,c} \leq \sum_{t,p} gen_{t,r,p,c}$$
$$\sum_{p} gen_{r,p,c} \leq dgs_{upper,r,c} \cdot \sum_{t,p} dem_{t,r,p,c} \tag{3}$$
$$\forall\, r \in regions, p \in techs, t \in timesteps, c \in energycarriers$$

For the analysis of the energy transport infrastructure requirements, we limit the number of newly constructed power lines and gas pipelines to a given value as shown in equation 4. This limit is given individually per energy carrier c and consists of the product of new lines l_{build}, the rated transfer capacity p_{rated}, and the distance between model regions $dist_{r,r'}$.

$$\sum_{r,r',p} l_{build,r,r',p} \cdot p_{rated,p,c} \cdot dist_{r,r'} \leq exp\_limit_c$$
$$\forall\, r, r' \in regions, p \in techs, c \in energycarriers \tag{4}$$

3 Results and discussion

The evaluation of the cost-minimal solution for 48 scenarios yields a wide range of different systems to explore. While the overall system costs do not significantly vary, the main deviations are attributed to a few technologies (Figure 4. The system costs are consistently lower for the energy partnership (EP) story-lines than for the continental Europe (CE) sovereignty story lines, on average by 2.8%. The complete omission of network expansion leads to a cost increase by 15.7% in the EP story-line and goes along with the substitution of HVDC lines and CSP plants especially by world market imports and offshore wind power. In the CE story-line, instead, costs increase by 13.5% if no network expansion is allowed, which is mostly related to higher world market imports and VRE capacities, as well as the usage of nuclear power. The maximum network expansion is significantly higher at 740 TWkm in the EP story line compared to the 510 TWkm in the CE story line.

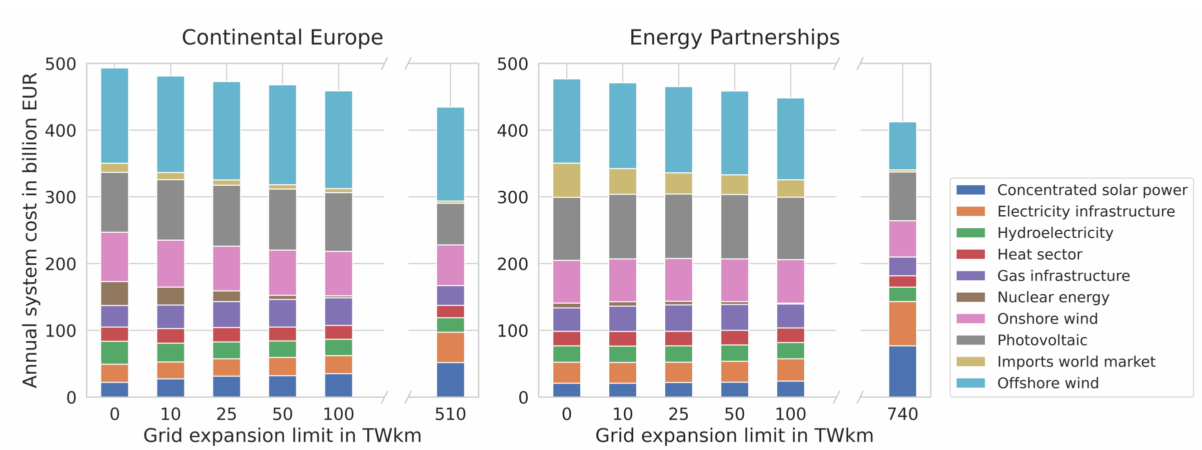

Figure 4: Overall system costs in billion EUR (y-axis) for the two main story-lines energy sovereignty in continental Europe (left) and energy partnerships (right) along the allowed degree of network expansion (x-axis). The value of the highest degree of network expansion corresponds to the scenario in which network expansion is unlimited.

A closer look into the technology specific share of total system costs depicted in Figure 5 indicates a large variation for a small set of technologies. With green hydrogen mainly produced via water electrolysis and green methane produced via hydrogen and DAC, the main source of all energy carriers is electricity produced from RE technologies. This fundamental role can be seen in the large investments in both onshore and offshore wind energy and PV closely followed by CSP. The costs for hydroelectricity consist of maintenance costs for existing pumped storage and reservoir plants as well as investment costs into new run-of-river plants. The large variation regarding the required capacities of offshore wind energy indicates a high dependence on different scenario narratives and the corresponding policy-driven constraints. Similarly for CSP, we can observe a significantly wider range of investment costs across all scenarios. Notably, also the imports from the world market as well as the utilisation of nuclear energy are subject to a large variation. Furthermore we find that the assumed costs for imports of green energy carriers from a world market are cost competitive towards the techno-economical assumptions for RES and electrolysis for domestic production and pipeline-based imports.

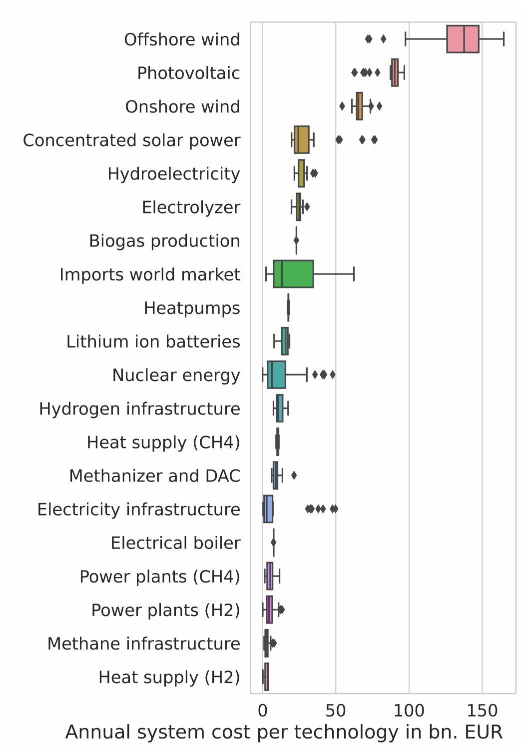

Figure 5: Contribution of different technology groups (y-axis) to the overall system costs (x-axis) across all 48 combinations of story lines and network restrictions. Higher variations in the box plots indicate more different systems in a subset of all considered scenarios.

3.1 Implications of strategic decisions

To further analyse the implications of the story-lines and network expansion limitations, we take a closer look at the use of the technologies with the largest variations between the scenarios. This particularly concerns the annual power generation by offshore wind, CSP, and nuclear power as well as the dependence on world market imports (Figure 6).

Offshore wind turbines significantly contribute to the overall electricity generation in most of the scenarios. This is notably reduced by unconstrained network expansion, which favours a higher usage of CSP. Furthermore, there is a preference for offshore wind in the energy sovereignty story-lines as long as a moderate grid expansion is still possible. The strong dependence of CSP usage on grid expansion can be explained by the resource availability of this technology limited to regions in Southern Europe and the Maghreb states. Limiting the overall grid expansions restricts the total share the technology can achieve and shifts the utilisation of CSP towards providing flexible electricity generation on a regional scale with a minimum generation level of around 500 TWh per year. In case of the story-lines including a European energy sovereignty, we observe a slight preference for CSP technologies compared to the non-constrained scenario counterparts.

Substantial investments into nuclear power plants can be observed only in scenarios which combine the European sovereignty story-lines with strong limitations of capacity expansion of networks. This implies that the limited transport range of low-cost VRE electricity promotes the use of nuclear power plants especially in regions in Eastern Europe.

At the assumed prices, the maximum imports of green hydrogen and green methane to continental Europe reach up to 890 TWh and 240 TWh, respectively. In the energy partnership story lines (EP-) the hydrogen imported to

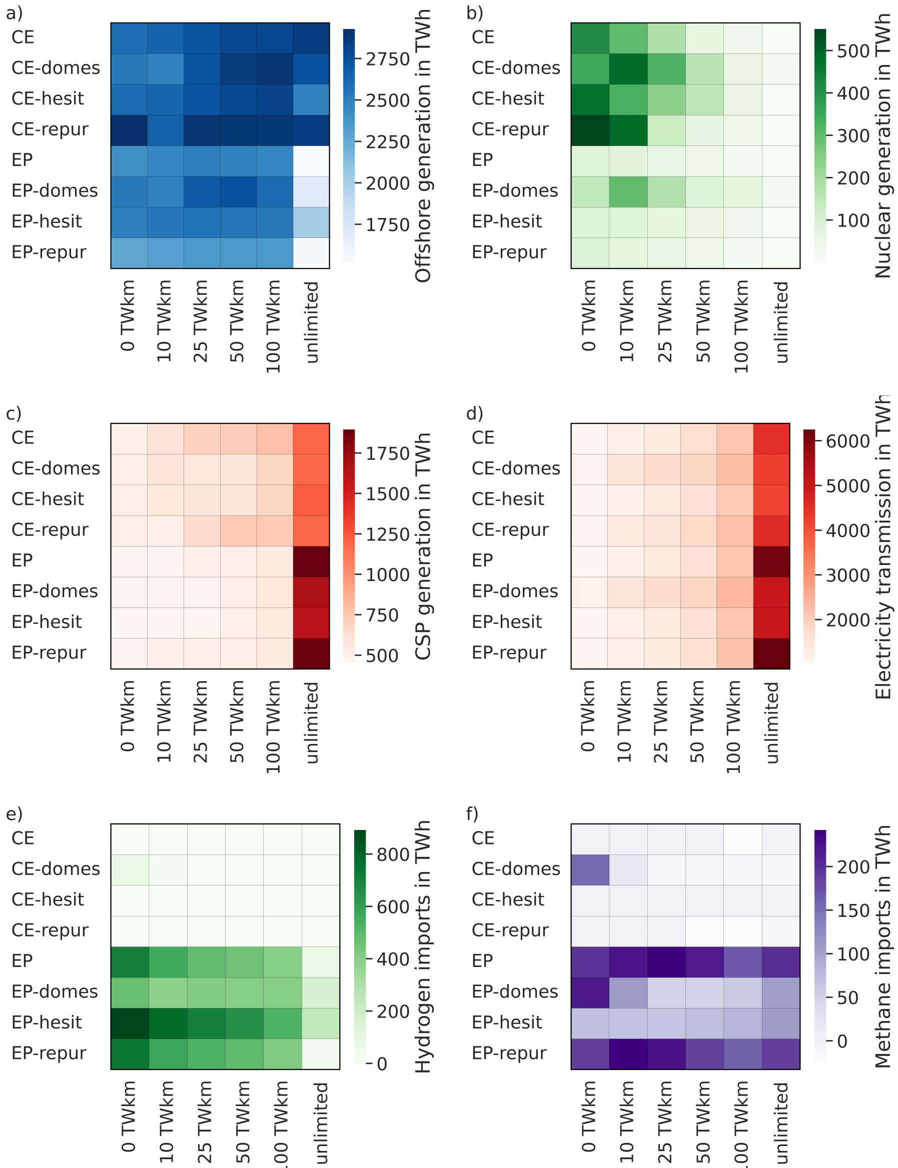

Figure 6: Evaluation of the selected indicators across the different story-lines (y-axis) and degrees of network expansion (x-axis). The intensity of the heat map (z-axis) corresponds to the level of the indicator. Each heat map has a different scale with some minimum values higher than zero. The individual figures show the annual power generation of offshore wind (a), nuclear power (b) and CSP (c), as well as the annual power transmission (d) and world market imports of hydrogen (e) and methane (f).

continental Europe equals 43% of the overall demand in continental Europe of which 20% can be attributed to energy partnerships and 80% to the world market. Methane imports to continental Europe equals to 53% of the corresponding overall demand, of which the imports are attributed almost completely to energy partnerships with imports from the world market contributing only about 1%. In contrast the story-line focusing on continental Europe (CE-) enforces the complete removal of imports from the system except for the imports required in the case of constraint violations. Furthermore, the increase in hydrogen imports by a factor of two in the story-line with national hesitancy towards large-scale exports indicates an increased reliance on a global hydrogen market. Both the share of energy imports via energy partnerships as well as the ratio between hydrogen and methane are highly dependent on the exogenously assumed prices.

The analysis of aggregate technology use yields three main findings. First, resource-rich areas such as the Maghreb region and the British Isles can offer lower cost production of green energy carriers compared to imports from a global market. This comes back to the additional transport and infrastructure costs for ship-based transports in contrast to existing pipelines and power grids. However, to fully utilise such energy partnerships, large-scale investments into either pipelines or power lines are a prerequisite. Second, prices on a world market exceeding the exogenously assumed prices for the study can increase the shift to regional sourcing of renewable energies and therefore provide incentives for strong European collaboration and investment into transport infrastructure. Third, focusing on European energy sovereignty while at the same time preventing sufficient expansion of transport networks can favour nuclear energy. However, this can counteract the independence from energy imports by causing new dependencies on uranium imports for the production of fuel rods. This shift is especially prevalent if national policies prevent the emergence of large-scale energy exports or limited expansion of hydrogen networks.

3.2 Spatial distribution of power and fuel generation

The spatial distribution of power and fuel generation facilities is closely linked to the scenario assumptions. However, minimum capacity values can be derived across the majority of 90% of the scenarios providing a robust lower value for the spatial distribution of different technologies (Figure 7). The spatial distribution of RE power generation is clearly correlated to the available resource potentials. Offshore wind energy is especially prevalent in the British Isles and shores of the North Sea and Atlantic Ocean, whereas it plays only a marginal role in Northern Europe and the Mediterranean. Hydroelectricity and onshore wind energy are dominant in the Northern countries and a combination of PV and CSP in the Southern countries. There, the low cost VRE power supply from PV is supplemented by thermal energy storage integrated into the CSP power plants. Both PV and onshore wind energy can be found in most model regions, with a slight preference for PV towards the South and wind onshore towards the North. Electrolysers and methanation plants are located close to the electricity sources indicating a preference for transporting gaseous energy carriers across the system while using the electricity grid for spatial balancing of supply and demand according to the overall weather situation across Europe. This assumption is further underlined by the broad distribution of onshore wind and PV across the model regions.

For the VRE capacities, using the 10^{th} percentile method we obtain system wide robust investments of 1.63 TW for PV (compared to 2.44 TW in the scenario with the highest PV capacity), 492 GW for onshore wind energy (compared to 693 GW in the scenario with the highest capacity), and 569 GW for offshore wind energy (compared to 870 GW in the scenario with the highest capacity). As these capacities represent the lower bound for 90 % of all considered scenarios, they can be seen as no-regret investment options for the underlying techno-economical assumptions. For electrolysers the spatial distribution of capacities has a larger variance, but around 469 GW are considered robust investments (compared to 860 GW in the scenario with the highest electrolyser capacities). Investments into CSP plants and methanation plants show the highest variance across scenarios. Robust investments amount only to 23.2 GW for methanation and 69.9 GW for CSP plants (compared to a maximum of 169 GW for methanation and 293 GW for CSP in their respective scenarios with the highest capacities).

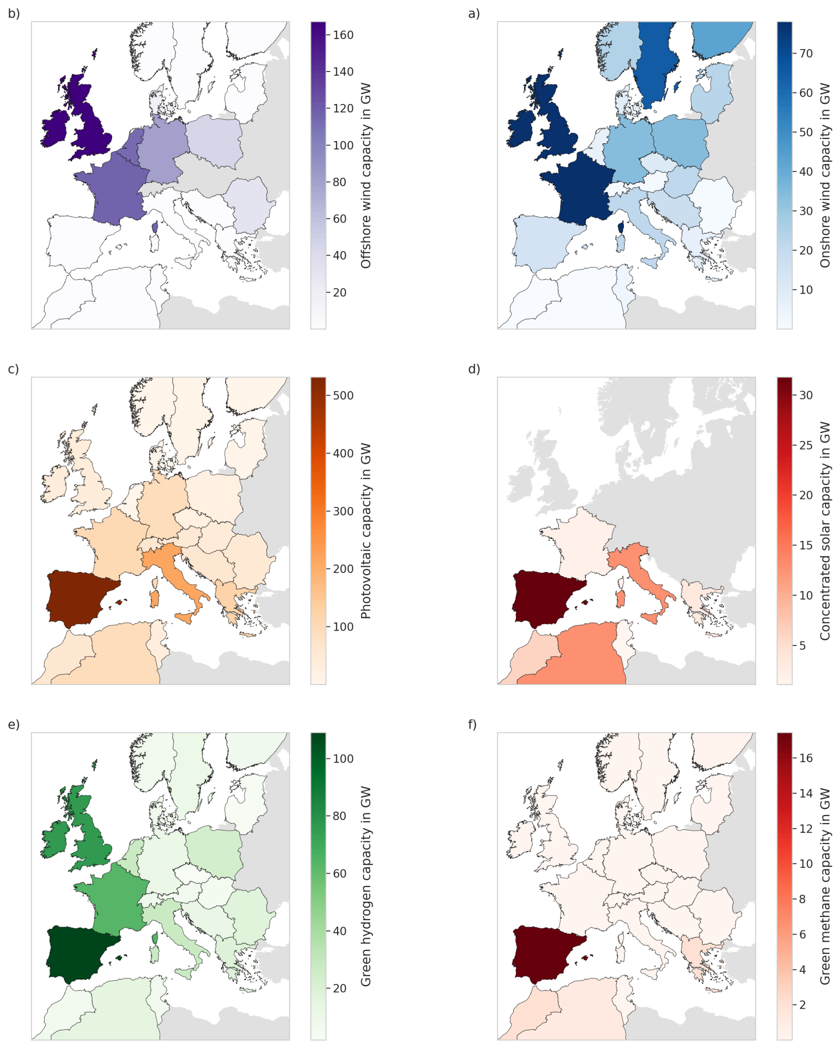

Figure 7: Regional distribution of robust technology capacities for offshore wind (a), onshore wind (b), PV (c), CSP (d), electrolysers (e) and methanation (f). Robust capacities are calculated via the 10^{th} percentile per region. This means at least the same amount or more capacities are build in 90% of all analysed scenarios across all scenarios and degrees of network expansion. Regions in grey are either outside the model scope or do not have any potential for the corresponding technology.

3.3 Trade-offs for storage and grid expansion

The possibility to repurpose natural gas networks adds an additional layer of complexity when deciding how the future infrastructure should look like, but can at the same time enable new options potentially limiting public resistance against such infrastructure projects. Figure 8 shows the comparison of overall storage capacities and new as well as repurposed pipeline capacities for both hydrogen and methane.

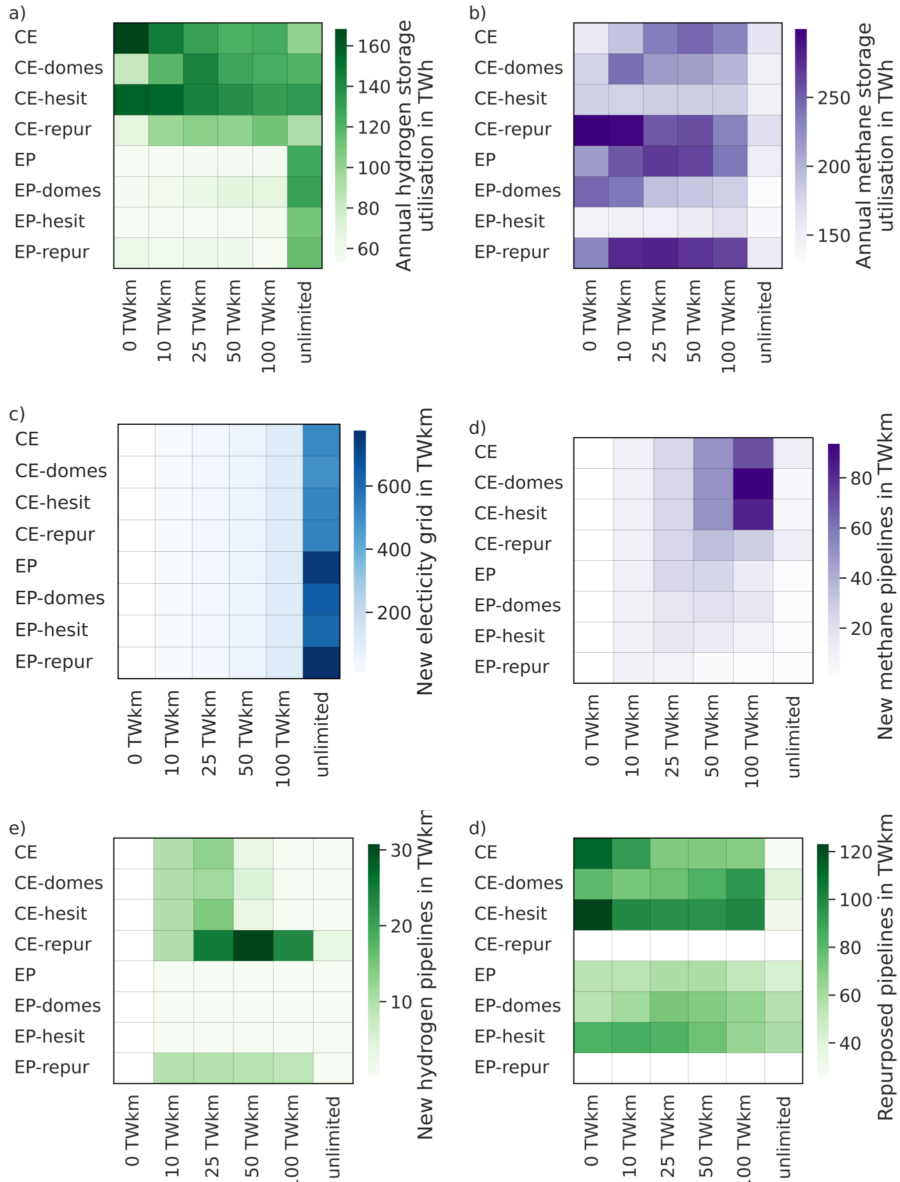

Figure 8: Comparison of annually used storage volumes and pipeline capacities for hydrogen and methane across the different story-lines (y-axis) and degrees of network expansion (x-axis). The intensity of the heat map (z-axis) corresponds to the level of the indicator. The sub-figures show the storage usage for hydrogen (a) and methane (b), as well as the capacities of new power lines (c), new hydrogen pipelines (d), new methane pipelines (e) and repurposed pipelines (f). Each heat map has a different scale with some minimum values higher than zero.

The assumption of European energy sovereignty clearly drives investments into hydrogen storage even if repurposing is not possible (top left, CE-repur). At the same time, technical challenges in repurposing lead to an increasing importance of large methane storage facilities (top right, -repur) and decrease in importance if countries tend towards avoiding large-scale exports (top right, -hesit). New methane pipelines are installed especially in the European sovereignty story-lines. This is linked to the partial reliance on imports from a world market which require increased pipeline capacities for methane from the Iberian peninsula towards France. Furthermore, we observe a clear order of preferences in the expansion of the energy networks. Expansion of the electricity grid is always the preferred option reaching the imposed limitation across all scenarios (middle left). As the capacity expansion of power grids becomes increasingly restricted, further investments into methane pipelines are chosen by the model. Again the limit is reached, but only in the story-lines focusing on continental Europe (middle right, CE-), where no natural gas networks are being repurposed.

As last option we see additional investments into new hydrogen pipelines starting at a network expansion constraint of 25 TWkm for each network. New hydrogen pipelines however are relatively small compared due to the option of repurposing from natural gas to hydrogen, which is chosen in all scenarios where it is allowed but plays the largest role when combining the story-lines on sovereignty and national export hesitancy (bottom right, CE-hesit). This combination prevents concentrated regions for production and has a strong reliance on a widespread hydrogen network.

For the analysis of energy flows, we split the scenarios into the group focused on European energy sovereignty and the remaining scenarios. Figure 9 shows the 67th percentile for the energy flows along each line for each scenario group. The arrows provide the minimum flows observed in one third of the corresponding scenarios. For the European sovereignty case (Figure 9, left side), we identify two main supply regions. Denmark and Belgium provide both electricity and hydrogen especially to Germany, whereas the Iberian peninsula becomes a main provider for green methane. Due to the large scale production of hydrogen necessary to provide methane to other European countries we can additionally observe hydrogen transport from the Iberian peninsula towards Morocco to better utilise the infrastructure investments. In contrast, in the energy partnership story-line (Figure 9, right side), we can identify an increased role of the Maghreb region in providing electricity, hydrogen, and methane to Europe via Italy. This energy transport route almost fully substitutes the corridor from Spain to France and continued distribution to countries in Central Europe. For hydrogen, the imports to Germany from neighbouring countries such as Denmark, the Netherlands and Belgium are replaced by imports from the British Isles. Germany, however, still remains dependent on electricity imports from Denmark, although to a lesser extent. In summary, in both scenario groups Germany and Italy are the main energy import countries due to their high energy demand compared to the available area for RES. For Germany, both PV and wind capacities reach their assumed techno-economic limits of 143 GW and 113 GW, respectively, across all scenarios. For Italy the maximum PV capacity of 215 GW is reached in all scenarios and the maximum wind power capacity of 158 GW in almost all scenarios with a continental Europe energy sovereignty focus.

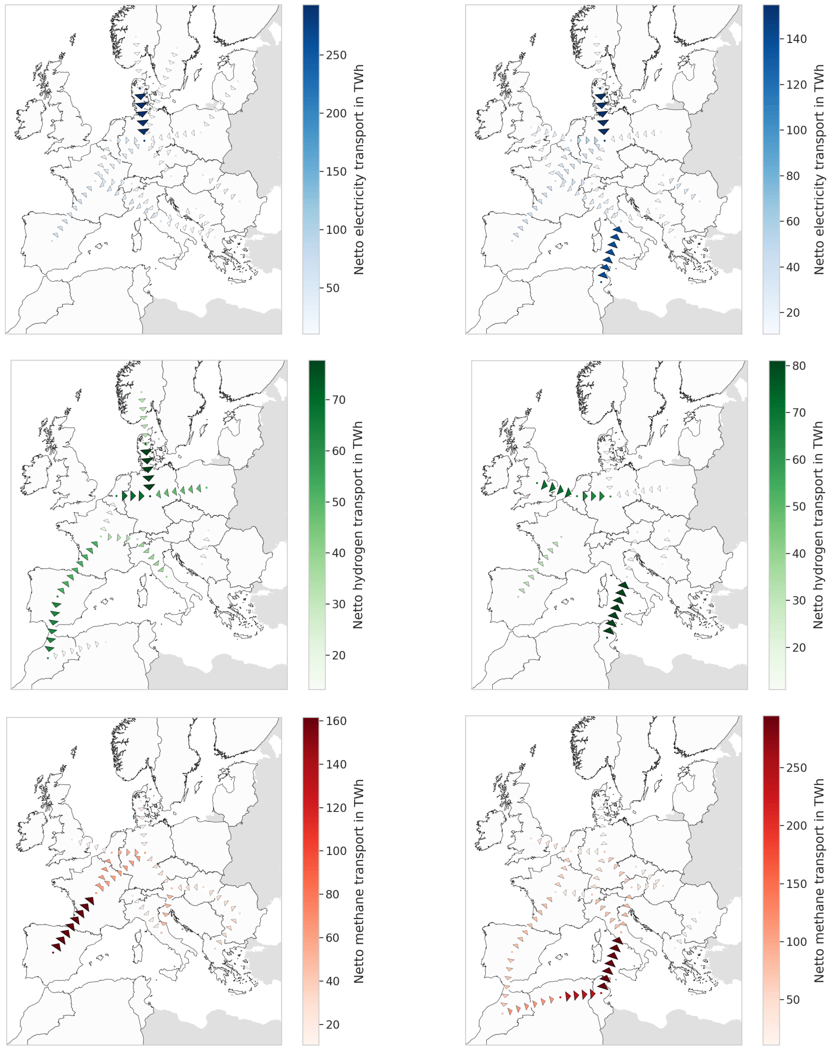

Figure 9: Regional distribution of robust energy flows across 80% of scenarios for story lines focused on energy sovereignty in continental Europe (left, CE) and predominant focus on energy partnerships (right, EP). Compared are the flows of electricity (top), hydrogen (middle) and methane (bottom).

3.4 Hourly system operation and storage utilisation

The production of heat, hydrogen and methane is, on a temporal scale, closely correlated with the VRE power generation (Figure 10). Specifically, we observe a clear correlation between the electricity supply from PV and the utilisation of electrolysers. The operation of electrolysers additionally reflects some elements from the feed-in profile of wind energy. This can be explained by the spatial allocation of electrolysers to regions with either high solar or high wind resources. One of the main challenges of a full climate-neutral energy system can be observed in the electricity demand for the heating sector and the strong seasonal operation profile. This can only be satisfied partially using intermittent resources and relies on additional supply via CHP plants and gas turbines. Both backup technologies can use biogas, but also rely on synthetic gases warranting seasonal storage strategies for gases. The operation of methanation plants also shows a strong seasonal behaviour. This dispatch shows strong similarities to the output of CSP plants, which are used in addition to PV generation to supply electricity especially during off-peak hours. This allows for a constant operation profile for the production of methane during the summer months and reduces the need for electrical energy storage.

The temporal pattern in the use of the different energy storage technologies is also closely related to the VRE availability, but also to the demand profiles (Figure 11). Electricity storage technologies such as pumped hydro storage and batteries are predominantly used for daily shifting from midday to evening hours. This can be traced back mainly to household

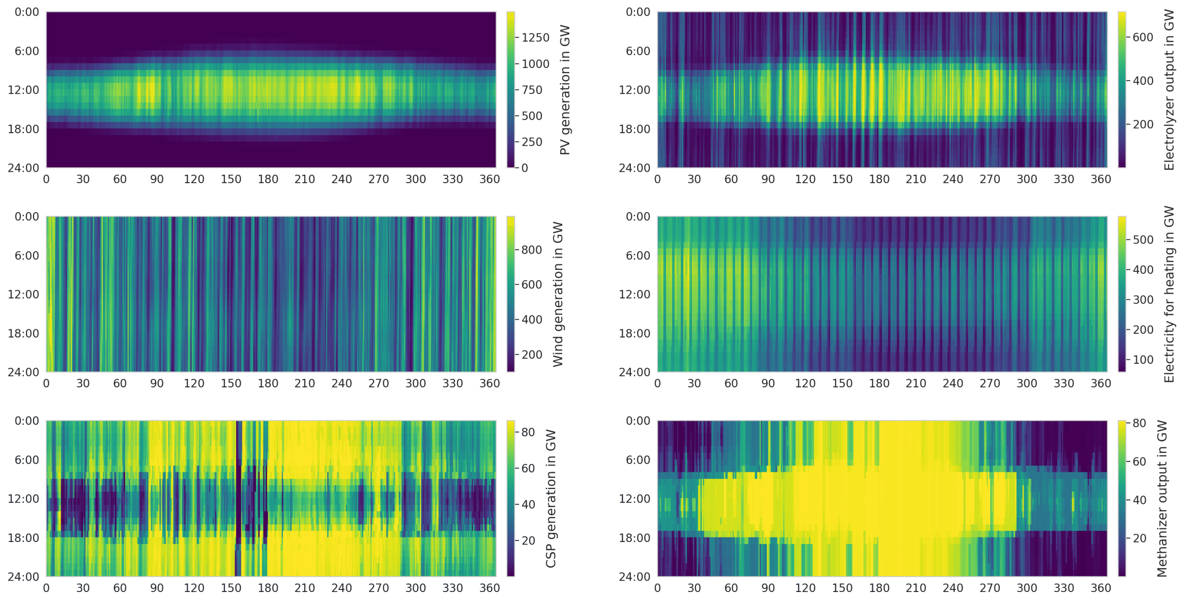

Figure 10: Hourly dispatch patterns for the main power generation technologies wind energy, PV and CSP (left) and the flexible demand technologies electrolyser, electrical heating and methanation (right). The hours of the day are plotted along the y-axis, the days of the year along the x-axis. The figures show the story-line focused on energy sovereignty in continental Europe with a moderate grid expansion of 50 TWkm.

demand, electrical heating and BEV as more flexible consumers such as electrolysers are switched off before the discharging starts. Hydrogen storage shows a more intermediate operational pattern which is strongly linked to the hydrogen production from wind power. This interaction with wind power is underlined by the energy to power (E2P) ratios of 10 - 30 for countries with only hydrogen tanks and 160 - 300 for countries with good wind resources and access to hydrogen cavern storage potentials such as the British Isles. In contrast, methane storage shows a strong seasonal utilisation pattern, which is mainly caused by the utilisation of methane in the heating sector. Thus, we observe a continuous filling of the methane storage over the summer months and the lowest level towards the end of the heating period. This seasonally used storage volume amounts to 200 - 300 TWh, which is substantially exceeded by the current gas cavern capacities of around 1454 TWh. Note that this difference comes in large parts from the perfect foresight method chosen in the modelling approach. In addition to the seasonally used capacities, further capacities for strategic reserves as back-up for industry, CHP and flexible gas turbine power plants will still be necessary in the future, which are not explicitly modelled in our analysis.

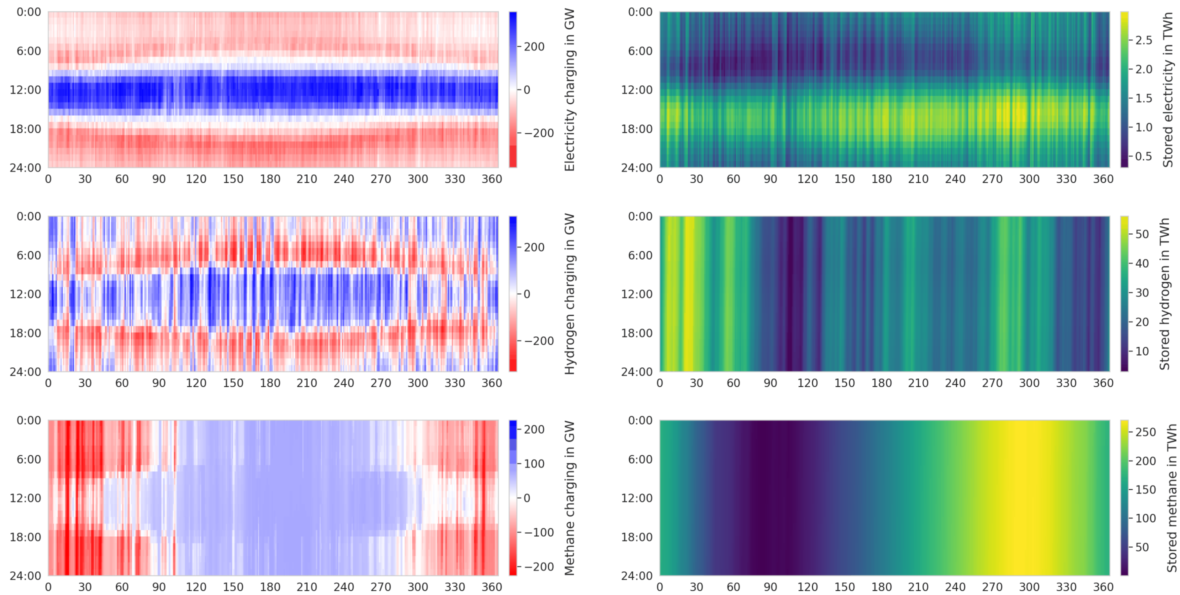

Figure 11: Hourly storage charging patterns and corresponding storage levels. The hours of the day are plotted along the y-axis, the days of the year along the x-axis. The figures show the story-line focused on energy sovereignty in continental Europe with a moderate grid expansion of 50 TWkm.

4 Limitations

This analysis shows different alternatives for a future carbon neutral energy system in Europe, however the modelling of complex systems warrants limitations on the system scope to keep the optimisation problem tractable. In addition limitations on the data side and assumptions on the availability of technologies put additional constraints on the system and therefore also on the possible conclusions.

One of the main limitations posed on optimisation models is related to the number of variables and constraints. During this work we put the emphasis on the hourly dispatch to properly capture the characteristics and interactions of VRE power supply in detail. This on the other hand limits the spatial granularity with impacts on the variability of VRE feed-in and representation of network infrastructure. Bottlenecks in the network infrastructure can only be captured on a national level and not within individual model regions, likewise also spatial balancing inside of model regions is neglected. This effect of spatial resolution on model results has been shown by Frysztacki et al. [31]. To further improve this case study especially a higher spatial resolution and capturing of gas infrastructure as individual model regions would be beneficial. This would allow explicitly capturing the connectivity of infrastructure such as import terminals for LNG and liquid hydrogen (LH2) and gas cavern storage in more detail. Similarly a high resolution modelling of network infrastructures is especially relevant for modelling repurposing natural gas pipelines in a regional context, as a complete switch from natural gas to hydrogen inside a distribution networks and all end users in a given network is required.

In addition to green gaseous energy carriers, to which this study is limited to, liquid energy carriers such as electrofuels offer an additional option for large-scale global transport of energy carriers and can reuse existing petrol infrastructure. Similarly other liquid carriers such as liquid organic hydrogen carriers (LOHC) or ammonia can be utilised as a carrier medium for hydrogen or as a precursor for direct usage in the chemical industry, shifting parts of the value chain to areas rich in RES. In conclusion all additional imports of liquid carriers can reduce the scale of energy supply, but increase import dependence on the other hand.

In the analysis we limited carbon sources to DAC which in turn is only constructed close to methanation plants. If additionally industrial carbon sources are considered such as cement production, this can have an impact on the optimal locations and cost for green methane production. Similarly, Bioenergy with Carbon Capture and Storage (BECCS) was not considered in the study but faces similar problems as CCS in the cement industry or at power plants as adequate storage solutions are required. One possible solutions could be extending the model

5 Conclusion

The results of this research show a carbon neutral energy system in continental Europe is technically feasible and leaves several degrees of freedom in the concrete technical and political implementation. The main driver of overall system costs is the allowed degree of network expansion with a cost increase of up to 15.2% to prevent any additional network expansion and 6.8% if only moderate network expansion is feasible. Forfeiting the option of energy partnerships with the Maghreb region and the British Isles leads to a minor increase in overall system costs of 2.8%, but has a significant impact on the layout of the network infrastructure and siting of methanation plants. Therefore, this is a decision to be made in a timely manner, to prevent large stranded investments in the long term.

We identify several technologies which can be considered as robust investments under the given assumptions on techno-economic data and demand for hydrogen and methane. This includes 1.63 TW PV predominantly constructed in the Iberian peninsula and Italy, 492 GW onshore wind energy mainly built in the British Isles, France, and Sweden and 570 GW offshore wind energy capacities in the British Isles, France, and the BeNeLux states. Similarly around 470 GW of electrolyser capacities located in the Iberian peninsula, France and the British Isles are robust investments indicating a preferred production close to RES potentials.

With respect to network infrastructure there are three distinct results. First, large shares of CSP can only be enabled if significant investments into the electrical grid (more than 100 TWkm) are feasible and accepted from a societal perspective. Second, if limited network expansion is considered repurposing of natural gas pipelines to hydrogen is a no-regret option. The prevalent hydrogen flows depend mainly on the presumed story-lines, but in both cases enable the supply of the two demand centres Germany and Italy. Third, in the case of energy partnerships methane is the prevalent energy carrier, whereas in the continental European system the focus shifts more towards hydrogen including construction of hydrogen underground storage.

CRediT author statement

Manuel Wetzel: Conceptualization, Methodology, Software, Data curation, Formal analysis, Investigation, Writing - Original draft, Writing - Reviewing and Editing, Visualization. Hans Christian Gils.: Conceptualization, Data curation, Formal analysis, Investigation, Writing - Original draft, Writing - Reviewing and Editing, Funding acquisition. Valentin Bertsch: Supervision, Formal analysis, Investigation, Writing - Reviewing and Editing.

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