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The role of hydrogen in a greenhouse gas-neutral energy supply system in Germany

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ABSTRACT

Hydrogen is widely considered to play a pivotal role in successfully transforming the German energy system, but the German government's current "National Hydrogen Strategy" does not specify how hydrogen utilization, production, storage or distribution will be implemented. Addressing key uncertainties for the German energy system's path to greenhouse gas-neutrality, this paper examines hydrogen in different scenarios. This analysis aims to support the concretization of the German hydrogen strategy. Applying a European energy supply model with strong interactions between the conversion sector and the hydrogen system, the analysis focuses on the requirements for geological hydrogen storages and their utilization over the course of a year, the positioning of electrolyzers within Germany, and the contributions of hydrogen transport networks to balancing supply and demand. Regarding seasonal hydrogen storages, the results show that hydrogen storage facilities in the range of 42 TWh_{H2} to 104 TWh_{H2} are beneficial to shift high electricity generation volumes from onshore wind in spring and fall to winter periods with lower renewable supply and increased electricity and heat demands. In 2050, the scenario results show electrolyzer capacities between 41 GW_{el} and 75 GW_{el} in Germany. Electrolyzer sites were found to follow the low-cost renewable energy potential and are concentrated on the North Sea and Baltic Sea coasts with their high wind yields. With respect to a hydrogen transport infrastructure, there were two robust findings: One, a domestic German hydrogen transport network connecting electrolytic hydrogen production sites in northern Germany with hydrogen demand hubs in western and southern Germany is economically efficient. Two, connecting Germany to a European hydrogen transport network with interconnection capacities between 18 GW_{H2} and 58 GW_{H2} is cost-efficient to meet Germany's substantial hydrogen demand.

1. Introduction

In order to achieve the 1.5 °C target established in the Paris Agreement 2015 [1], the European Commission (EC) aims for net zero greenhouse gas (GHG) emissions in 2050 in the European Green Deal [2]. The German Federal Government has committed itself to achieving the European targets in Germany's Federal Climate Change Act [3]. The transformation of the energy system is pivotal to meeting the stated climate protection targets [4], and the German government assigns GHG-neutral hydrogen a key role in this transformation [5]. Following the current trend that sees hydrogen becoming part of the global energy system transition [6], Germany has created a framework to support innovations and investments in hydrogen technologies in its national hydrogen strategy [5]. However, this strategy still lacks a concrete outline of future hydrogen supply infrastructures. The design of these hydrogen supply infrastructures depends on various influences.

Firstly, the amount of hydrogen demand has a high impact on hydrogen supply. Lux and Pfluger (2020) [7] show increasing electrolyzer capacities for increasing hydrogen production volumes in Europe in 2050. Similarly, in a parameter study, Husarek et al. (2021) [8] show

Abbreviations: AEL, Alkaline electrolysis; CCS, Carbon capture and storage; CHP, Combined heat and power; CSP, Concentrated solar power; EC, European Commission; el, Electric; EU, European Union; GHG, Greenhouse gas; MENA, Middle East and North Africa; O&M, Operation and maintenance; PEMEL, Polymer electrolyte membrane electrolysis; PtG, Power-to-Gas; PtL, Power-to-Liquid; PV, Photovoltaics; th, thermal.

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different configurations of a German hydrogen transport infrastructure for increasing hydrogen demand levels. However, Neuwirth et al. (2022) [9] claim that the level of future hydrogen demand in Germany is largely uncertain. Commissioned by the National Hydrogen Council, a meta-study [10] of current energy system studies for Germany achieving GHG reductions of at least 90 % shows that hydrogen demand in the demand sectors in 2050 ranges between 0 and 316 TWh_{H2} depending on the underlying scenario. Today, robust decisions regarding the development of hydrogen supply infrastructures need to take these uncertainties in the development of hydrogen demand into account.

Secondly, to design suitable hydrogen supply infrastructures, the entire value chain of generation, storage, and transport should be considered. With an analysis of hydrogen supply potentials in Europe and the Middle East and North Africa (MENA), Sens et al. (2022) [11] contribute to this requirement in two respects: First, even though electrolytic hydrogen production costs in the MENA region are cheaper than using electrolyzers in Germany, the export costs for supplying this hydrogen to Germany are in the same order of magnitude as for on-site production within Germany due to transport surcharges. Second, Sens et al. show that the use of salt caverns for seasonal storage of hydrogen can reduce hydrogen supply costs by up to 50 %. Consequently, for a comprehensive analysis of hydrogen supply in Germany, it is not sufficient to consider only hydrogen production with electrolyzers; hydrogen storage and transport must be considered too.

Thirdly, the components of these hydrogen supply chains interact strongly with the rest of the energy system. On the one hand, producing high hydrogen quantities using electrolysis translates directly into high electricity demand and additional expansion of renewable power generation technologies [7]. As a result, hydrogen increasingly competes with other applications for low-cost electricity. On the other hand, flexible hydrogen production with electrolyzers can help to integrate weather-dependent renewable energies [12]. Gils et al. (2021) [13] show that hydrogen as a storage medium can offset seasonal effects in renewable electricity generation and electricity demands. In the latter case, renewable electricity is stored in geological formations at negative residual loads, i.e., at times when renewable electricity generation exceeds the load, and is then withdrawn at subsequent positive residual loads, i.e., at times when the load exceeds renewable electricity generation. Consequently, hydrogen supply must be considered in the context of the energy system.

Finally, analyses on the German energy system need to address the European context. Bernath et al. (2019) [14] show that in Germany both the deployment of renewable energies in the electricity system and the decarbonization of district heating grids through heat pumps strongly depend on the integration of Germany into the European energy system. Therefore, the alternative sector coupling technologies of hydrogen supply in Germany should also be investigated in an integrated European energy system.

In summary, the challenges in defining a concrete rollout of hydrogen supply technologies are considering the entire value chain of hydrogen production, storage, and transport simultaneously, the interactions of this value chain with the rest of the German and European energy system, and its dependence on future hydrogen demand. Although there is a rapidly growing body of literature on hydrogen supply, there are only few studies for Germany with a system perspective that consider these aspects at least partly. Lux and Pfluger (2020) [7] develop hydrogen supply curves for a decarbonized European energy system in 2050. The results of this energy system cost minimization show that there is a substantial but regionally heterogeneous hydrogen production potential in Europe. The balancing of these regional differences via a hydrogen network to meet hydrogen demands is however not considered. In a subsequent study [15], this European hydrogen supply potential is compared to import curves from the MENA region. Similar to Sens (2021) [11], this comparison shows that low-cost electrolytic hydrogen production at locations with favorable renewable energy potentials in the MENA region is offset by transportation costs. Welder et al. (2018) [16] analyze three different scenarios for power-to-hydrogen supply infrastructures meeting mobility and industry demands in a future German energy system. Applying a mixed integer linear program, they find the cost of hydrogen for mobility is below current hydrogen retail prices. Their results indicate that the utilization of underground hydrogen storages reduces the system costs for a renewable-based German energy system. However their modeling approach has limitations: The temporal resolution is limited to typical days, the geographical scope is limited to Germany, the electricity grid is not part of the optimization, and only onshore wind is considered for renewable power generation. Gils et al. (2021) [13] analyze the interaction of hydrogen infrastructures with other sector coupling technologies in a GHG-neutral German energy system. They apply an integrated optimization of the supplies of electricity, heat, hydrogen, and methane with a strong focus on Germany. Analyzing a single scenario including several sensitivities, they find that flexible hydrogen production is key for the integration of renewables and seasonal balancing. However, they do not analyze sector coupling options or hydrogen transport infrastructures in a European context. Husarek et al. (2021) [8] use a multi-modal energy system model to analyze hydrogen supply chains for Germany in 2050. They show that hydrogen imports are pivotal for meeting German hydrogen demand and that a north-south hydrogen pipeline connection within Germany is a no-regret option. The geographic resolution of their modeling for Germany is high, however, they only estimate hydrogen import potentials based on four exemplary routes taken from literature values. They do not consider interactions of German hydrogen imports with the European power generation system.

The literature review shows that none of the previous studies addresses all the described challenges in defining a concrete strategy for the buildup of hydrogen supply infrastructures. There is the need for technically, spatially, and temporally highly resolved analyses of hydrogen supply as part of an integrated European energy system. This paper aims to close the identified research gap by investigating the interaction of hydrogen supply infrastructures with the energy system in different scenarios that all achieve GHG neutrality in Germany by 2050. The analysis focuses on Germany, but considers this in the wider context of a fully integrated European energy system. Using the energy system model *Enertile* and following the hydrogen supply chain of production, storage, and transport, this paper addresses the following research questions:

- Where should electrolyzers be positioned in Germany?
- What are the requirements for geological hydrogen storages and how are storage facilities managed over the course of a year?
- What contribution can hydrogen transport networks make to balancing supply and demand?

Addressing these questions using a detailed modeling approach and covering a broad solution space with different scenarios aims to provide policy makers with robust guidance for concretizing Germany's hydrogen strategy.

The paper is structured as follows: Section 2 introduces the modeling approach, scenario design, and most important input parameters. Model results are presented in Section 3 and discussed in Section 4. Section 5 derives key conclusions.

2. Methods and data

This chapter introduces the overall scenario design (section 2.1), presents the employed modeling tools (section 2.2), and provides an overview of the input data used (section 2.3).

2.1. Scenario design

This study focuses on hydrogen supply infrastructures in Germany in the context of a GHG-neutral European energy system. In order to derive

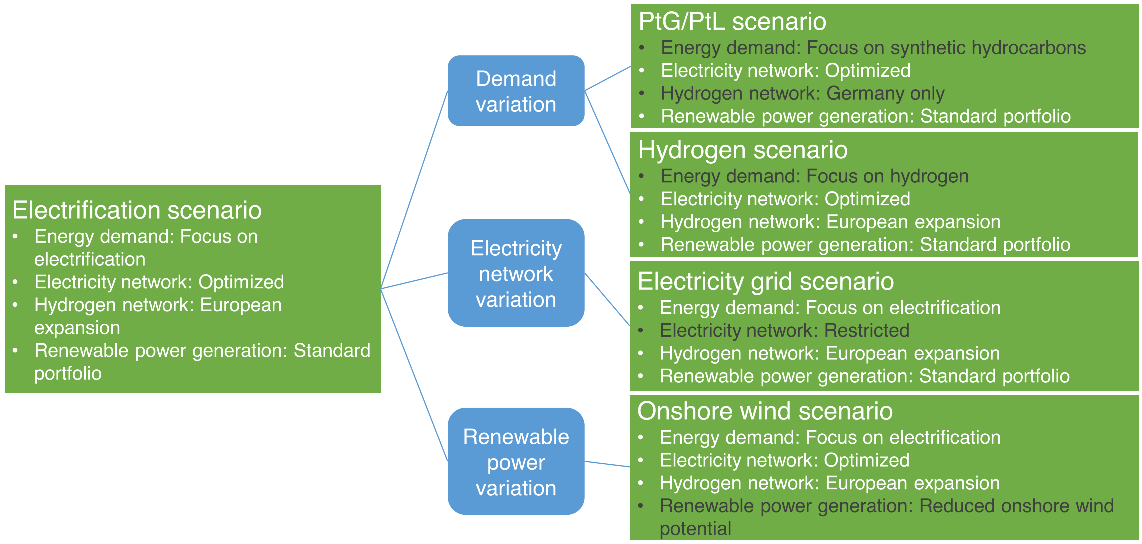

Fig. 1. Scenario tree.

robust characteristics of a German hydrogen supply system, the analysis in this paper compares five scenarios. Starting with an *electrification scenario*, the scenario design varies along three main dimensions: Development of energy demands, composition of the renewable electricity generation portfolio, and availability of expansions in the electricity transmission networks. For the energy demand variation, a *hydrogen scenario* assumes an increased hydrogen usage in end-use applications and processes. Likewise, a *power-to-gas/power-to-liquid* (*PtG/PtL) scenario* assumes an increased usage of synthetic hydrocarbons. The composition of energy demand follows consistent scenario storylines across all sectors and results from detailed bottom-up models. For the renewable power generation variation, an *onshore wind scenario* assumes a reduced onshore wind potential in Europe. For the electricity network variation, an *electricity grid scenario* assumes a freeze of the European electricity transmission grid expansion. Fig. 1 shows an overview of the scenario tree. Subsequent paragraphs describe these variations in more detail.

2.1.1. *Demand variations*

Germany's overarching strategy for reducing GHG emissions is to first reduce energy consumption (the so called "efficiency first principle"), second to directly substitute fossil fuels with renewable energies where possible, and third, to electrify applications and operate them with renewable electricity [4]. Nonetheless, there remain processes where a direct use of renewable energy in general or renewable electricity in particular is either not possible or where alternative defossilization strategies are being discussed. Currently, there is no consensus on the most efficient CO_2 mitigation strategy for certain industrial processes such as steel production and transport applications such as aviation and long-distance transport [17]. Reducing GHG emissions in these processes requires the use of carbon-neutral energy or feedstock. In essence, these comprise all energy forms derived from non-fossil sources, or fossil sources for which emissions are fully sequestered and stored, e.g., through carbon capture and storage (CCS). However, the regulatory framework in Germany excludes both nuclear energy, for which a phase-out policy is in place, and CCS. Effectively, the only long-term options for climate-neutral energy in Germany are renewable electricity, hydrogen, or synthetic hydrocarbons. Therefore, this study analyzes three demand variations with a pronounced use of one of these secondary energy forms, deliberately illuminating the corners of the solution space. This section briefly outlines the philosophy of the three scenarios in the demand sectors. German energy demand was determined using independent detailed sector models [18] and use as the input to the supply modeling and analyses in this paper. A detailed presentation of the assumptions and modeling used to determine these demand data is not part of this paper, but section 2.3.1 provides a summary of the obtained values. The analysis in the remainder of this paper focuses on how to meet these energy demands – especially for hydrogen – cost efficiently.

The *electrification scenario* relies on a strong use of renewable electricity. The use of hydrocarbons in 2050 is limited to the biomass potential considered sustainable. Nevertheless, a significant amount of hydrogen is needed to achieve the goal of greenhouse gas neutrality in this scenario. In the energy demand sectors of industry, transport, residential and services, applications and processes are shifted towards a direct use of electricity where possible. In the industrial sector, this mainly means that the majority of process heat is provided electrically. Hydrogen is used only where direct electrification is not possible, e.g., because the energy sources are used as feedstocks (e.g. for the production of olefins). In the transport sector, the private car segment and lightweight and medium-sized commercial vehicles are dominated by battery-electric drive systems in the long run. One third of heavy-duty vehicles are also battery-electric. The remaining fleet consists of hybrid trolley trucks wherever possible. In aviation and shipping, biogenic fuels dominate and alternative powertrains are only used to a small extent. In this scenario, heat supply in buildings is mainly provided by heat pumps, district heating, and biomass. Processes and applications in the residential and services sectors are electrified extensively.

The *PtG/PtL scenario* relies on high utilization of synthetic hydrocarbons. The central idea in this scenario is to substitute fossil hydrocarbons with their synthetic or biogenic, GHG-neutral counterparts. This allows the retention of existing infrastructures and processes that are rendered GHG-neutral 'from the outside', i.e., without requiring substantial changes on the usage side. In addition to the use of sustainable biomass, the required amounts of hydrocarbons are imported from regions outside Europe. The structural changes in the industrial sector are less profound than in the other two scenarios. Typically, industrial furnaces are already fired with natural gas. One exception is blast furnaces in steel production, which switch to methane in this scenario. In the transport sector, battery-electric vehicles dominate the segments of passenger cars and small and medium-sized commercial vehicles in this scenario as well. Diesel vehicles continue to be used for heavy-duty vehicles and hydrocarbons continue to be used in international air and sea transport. Gas boilers remain the most important heating technology for buildings, although heat pumps and heat grids make a greater

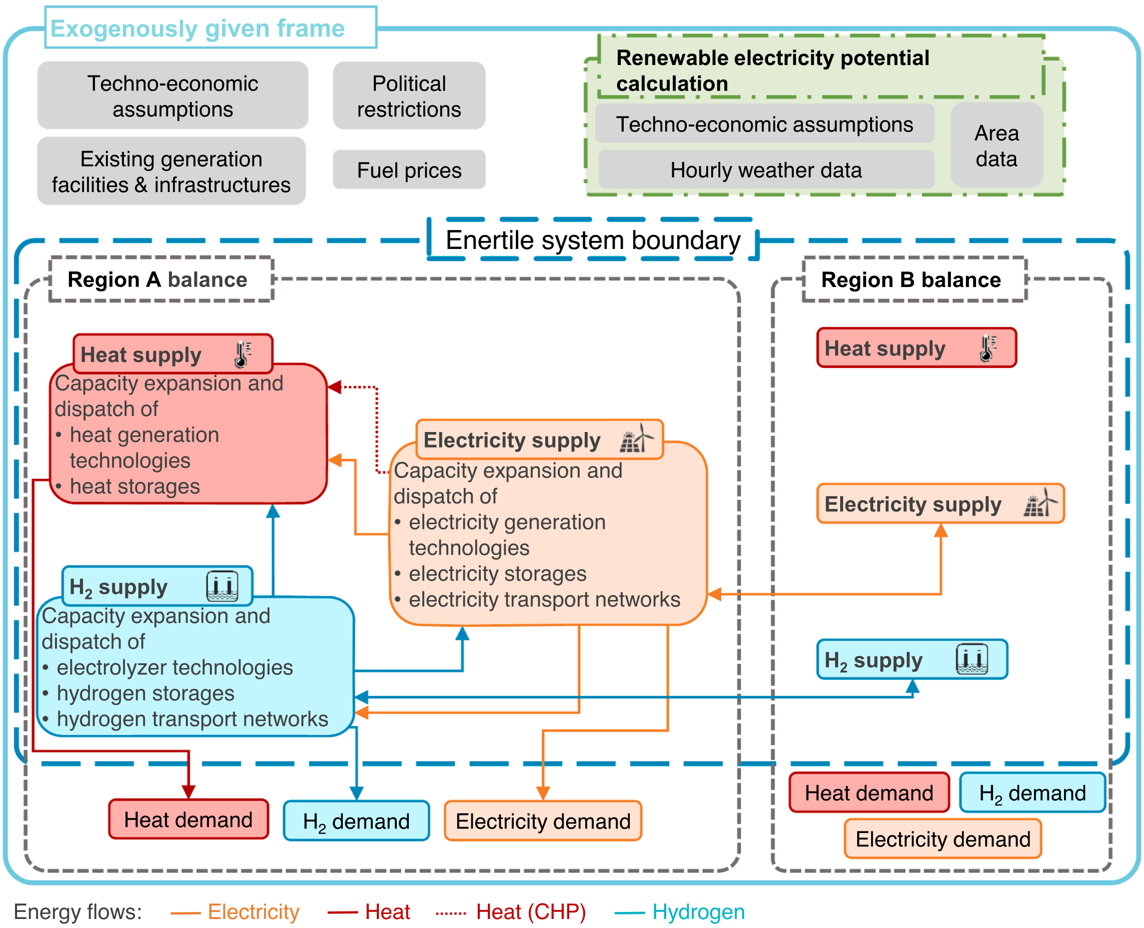

Fig. 2. Schematic representation of the modeled quantities, interactions, and boundary conditions in the cost minimization of the energy supply-side model *Enertile*.

contribution than today.

The *hydrogen scenario* aims at high hydrogen utilization in all sectors, which implies a substantial switch from fossil fuels to hydrogen. This requires a high level of adaptation in applications and infrastructures. In the industrial sector, for example, hydrogen is used as an energy carrier for process heat generation and as a feedstock and reducing medium in steel production. In the transport sector, fuel cell vehicles are increasingly used in addition to battery electric vehicles, with fuel cells especially prevalent in the passenger car and heavy-duty vehicle segments. Decentralized hydrogen boilers are used for heating buildings in this scenario in addition to heat pumps and heat grids.

2.1.2. *Electricity network variation*

Future energy systems based on renewable energies will have an increasing need for flexibility options to compensate for weather effects [19]. Hydrogen as a seasonal storage medium is one flexibility option. The electricity grid is another important option providing supra-regional balancing. These flexibility options are in competition with each other. Therefore, in order to investigate robust results for a hydrogen supply infrastructure, this study varies the electricity grid expansion option in the optimization. The *electricity grid scenario* only realizes the Ten Year Network Development Plan 2018 with slight delays. In all other scenarios, the optimization can expand power transmission network within certain capacity limits. A complete list of maximum network capacities in the optimization is provided in Appendix C.

2.1.3. *Renewable power variation*

Onshore wind is one of the key power generation technologies in the GHG-neutral electricity system. At the same time, there are acceptance problems for the expansion of wind power plants [20]. For the design of a robust hydrogen supply infrastructure, this study varies the potential of onshore wind. In the *onshore wind scenario*, only half of the land is available for wind turbine expansion compared to all the other scenarios. A complete list of land use factors for renewable electricity generation is provided in Appendix D.

2.2. *Methods*

The energy system model *Enertile* [21] was used to calculate and analyze the conversion sector and hydrogen supply system. The following paragraphs describe the model's main architecture.

2.2.1. *Renewable electricity generation potential calculation*

Renewable energy potential is an important input for the cost minimization of the energy supply system. *Enertile* uses cost-potential curves determined in detailed bottom-up modeling prior to the energy system optimization and differentiates the technologies of onshore wind, offshore wind, concentrated solar power (CSP), utility scale photovoltaics (PV) and rooftop PV. For this analysis, the world is mapped onto a grid of so-called "tiles" that measure 42.25 km^2. This grid combines data on land use, weather, and power generation technologies. The high-resolution tile results are summarized as cost-potential curves for the system optimization. The individual stages of these cost-potential curves contain the following information for each technology:

- sum of the generation potential on the tiles,
- average full-load hours on the tiles,
- average generation cost on the tiles, and
- the aggregate weather profile on the tiles.

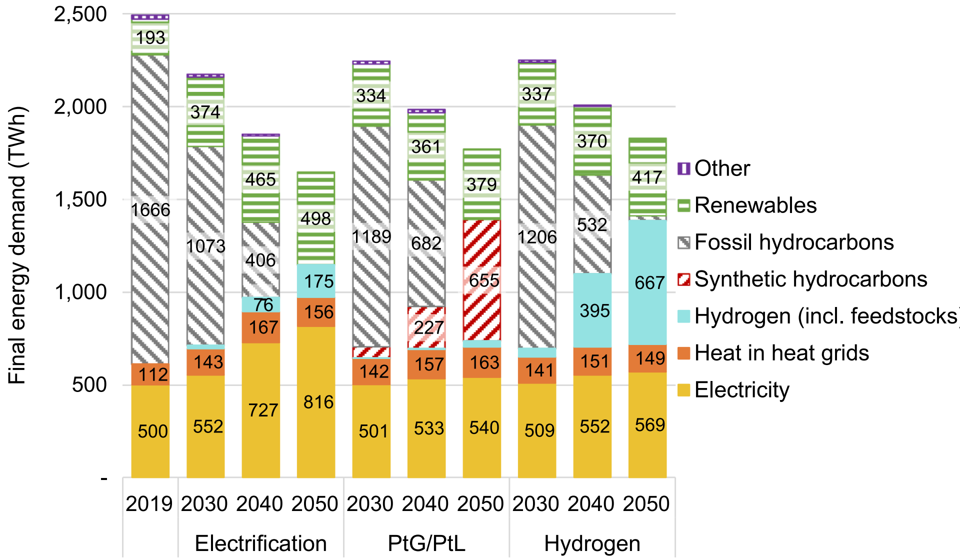

Fig. 3. Final energy demand of the sectors industry, transport, residential, and services in the three demand variations in Germany. The demand for electricity, heat in heat grids, and hydrogen (including feedstocks) is met by optimizing the energy supply in *Enertile*. Meeting other energy demand is not part of the optimization in *Enertile*. Values for 2019 are taken from [22], values for the years 2030, 2040, and 2050 are determined by detailed sector models in [18].

Enertile subsequently makes autonomous expansion decisions for the individual renewable technologies based on the potential curves in a model region and the expansion targets set in the scenarios. Subsequently, the expansion and dispatch results of the optimization can be re-projected onto the tile grid. This results in a spatially detailed picture of the expansion of renewable energies in the scenarios. A more extensive description of calculating the renewable potential is given in [15].

The development of the other renewable technologies of hydropower, geothermal power, and wave and tidal power is specified exogenously. For these technologies, endogenous expansion is not appropriate for various reasons, e.g., either the unexploited potential is tightly constrained, as is the case for hydropower in Germany and Europe, or the current costs of these technologies are so high that the model would not expand them endogenously, as is the case for wave, tidal, and geothermal power. This analysis assumes that European countries will realize their existing expansion plans for these technologies, but that no expansion beyond these will take place.

2.2.2. Energy system optimization model Enertile

Modeling the energy supply side is done with the cost minimization model *Enertile*. It simulates the simultaneous supply of electricity, heat in heat grids, and hydrogen. The goal of the optimization is the expansion and dispatch of technologies for the generation, conversion, and distribution of these energy forms to meet exogenously specified demands at least cost. For the supply of electricity, this includes conventional and renewable power generation technologies (including combined heat and power (CHP) plants), storage technologies, and electricity transmission networks. For the supply of heat in heat grids, this includes conventional and renewable heat generation technologies and heat storages. For hydrogen supply, this includes electrolyzer technologies, hydrogen storages, and hydrogen transport pipelines.

Enertile's objective function adds up the fixed and variable costs of the energy system components shown in Fig. 2. In the linear problem formulation, the decision variables are the installed capacities of the system components and their dispatch.

The key constraints of the linear optimization require that the hourly demand for electricity, heat, and hydrogen is met in each model region. Interactions between the supplies of the different energy forms shown in Fig. 2 are taken into account. A mathematical formulation of the linear optimization problem is given in Appendix B.

Enertile has a high level of technical, temporal, and spatial detail. The scenario calculations in the conversion sector cover the years 2030, 2040, and 2050 with hourly resolution. The expansion and deployment of infrastructures across all years are jointly considered in a single model run. This means that the model must account for the consequences of a decision in 2030 in subsequent years. Perfect foresight is assumed. In this paper, the modeling of energy supply covers the countries of the European Union (EU), Norway, Switzerland, the United Kingdom, and the Balkan states in all scenarios. This makes it possible to consider cross-regional balancing effects of electricity and hydrogen transport networks. Model regions correspond to either one or more national states (cf. Appendix A for a definition of the model regions), apart from Germany, which is divided into seven subregions. This regional split is based on potential bottlenecks in the electricity transmission grid. The expansion and use of electricity and hydrogen transport networks between model regions is modeled by means of net transfer capacities.

The model Enertile has already been described and used in many studies for the analysis of energy supply systems. Pfluger (2014) [23] described the modeling of the European electricity system in more detail and investigated different pathways in ambitious climate protection scenarios. Deac (2019) [24] described the coupling of the power and heat system in the model and investigated the impact of heat grids on the integration of renewable energies in Germany. Bernath et al. (2019) [14] examined the sector coupling technology heat pump in the context of a European energy system. The coupling of electricity, heat, and hydrogen generation is described and investigated in Lux and Pfluger (2020) [7] for a European system and in Lux et al. (2021) [15] for a system in the MENA region. Franke et al. (2021) [25] described the model representation of hydrogen grids for the first time and examined a GHG-neutral energy system in China. With its broad coverage of sector coupling options and high technical, temporal, and spatial resolution, Enertile is an appropriate tool for investigating hydrogen supply in Europe. This paper uses the integrated optimization of electricity, heat, and hydrogen supply including hydrogen networks (cf. Fig. 2) analyzing a European energy system for the first time.

2.3. Data

This section provides the input data on energy demands in the different demand scenarios (section 2.3.1), on fuel and CO_2 prices (section 2.3.2), on constraints to the linear optimization problem (section 2.3.3), on utilized parameters on hydrogen infrastructures (section

Table 1
Fuel and CO_2 prices used in the different scenarios and simulation years.

Scenario	Category	Unit	2030	2040	2050
All	Natural gas	€/MWh	22	22	22
	Hard coal	€/MWh	6	6	6
	Lignite	€/MWh	4	4	4
	Oil	€/MWh	32	31	29
	Hydrogen (from outside Europe)	€/MWh	101	91	81
	CO_2	€/t	75	125	500
PtG/PtL scenario	Synthetic methane (from outside Europe)	€/MWh	126	110	94

2.3.4), and on renewable electricity potential used in the optimization (section 2.3.5).

2.3.1. Energy demands

Germany's energy and climate policy goals as of May 2021 require a fundamental restructuring of the energy system that affects all sectors of the economy. The analysis of hydrogen's role in the conversion sector of a GHG-neutral economy in Germany in this paper is based on data from the project 'BMWi Long-term Scenarios' [18]. This project uses a series of models representing different sectors and infrastructures and develops consistent scenarios with high technical, spatial and temporal resolution. These scenarios are not intended to predict the future, but show possible developments that are consistent with German energy and climate policy. The overarching goal of the scenarios is to identify robust strategies for achieving GHG neutrality.

The demand for electricity, hydrogen, and district heating in other European countries are based on values taken from the EU Horizon 2020 project "SET-Nav". All SET-Nav pathways achieve a GHG reduction of 85–95 % across sectors in 2050. This paper's *electrification scenario* and *hydrogen scenario* adopt the demand of the SET-Nav pathway "Directed Vision" for regions outside Germany. The *PtG/PtL scenario* in this paper adopts the energy demand of the SET-Nav pathway "Diversification" for regions outside Germany. These energy demand pathways outside Germany were selected as they have a similar quality in terms of modeling technique and level of detail as the modeling approach for Germany and pursue similar objectives as in the scenario narratives for Germany.

Fig. 3 shows the final energy demand of the demand sectors industry, transport, residential, and services in the three demand variations investigated. The demand for electricity, heat in heat grids, and hydrogen is met by cost minimizing the energy supply in *Enertile*. The demand of other energy forms are balanced externally to *Enertile*.

As the option of GHG reduction via direct electrification is the dominant solution in many applications, electricity demand increases in all three scenarios by 2050. This happens despite substantial energy efficiency improvements in all demand sectors. The increase is most pronounced in the *electrification scenario,* which has a final energy demand for electricity of about 816 TWh_{el} in 2050. Electric heat generation for industrial processes (214 TWh_{el}), heat pumps in buildings (72 TWh_{el}), as well as e-mobility (155 TWh_{el}) are the main drivers of the increased electricity demand in this scenario. In the *hydrogen scenario* and the *PtG/PtL scenario*, the increase in electricity demand is less pronounced. The lowest final energy demand for electricity is in the *PtG/PtL scenario* with about 540 TWh_{el} in 2050.

The importance of heat grids increases substantially in all three scenarios. The final energy demand for district heating increases from 112 TWh_{th} in 2019 [22] to 149 TWh_{th} in the *hydrogen scenario* and to 163 TWh_{th} in the *PtG/PtL scenario*. For the supply of heat in buildings, the *electrification scenario* differs from the *hydrogen scenario* and the *PtG/PtL scenario* in terms of renovation ambition[1]. In order to realize high shares of electric heat generation, the *electrification scenario* focuses on high building efficiency through insulation, ventilation systems with heat recovery, and ambitious new building standards. There are lower ambitions for building efficiency in both the *PtG/PtL scenario* and the *hydrogen scenario*. The differences in renovation depth have implications for using heat grids to supply heat in buildings. The amount of heat provided in buildings by heat grids increases by 79 % to 109 TWh_{th} between 2020 and 2050 in the *electrification scenario*. In the *PtG/PtL scenario* and the *hydrogen scenario*, the amount of heat provided by heat grids in buildings increases by 54 % to 94 TWh_{th} between 2020 and 2050. In all scenarios, the number of buildings connected to heat grids increases due to both densification in areas where heat grids already exist and through the construction of new heat grids. The remaining demand for district heating comes from the industrial sector for the provision of process heat.

The final energy demand for hydrogen (including feedstocks for industrial processes) differs significantly in the different scenario narratives. Additional hydrogen demand results from the use of hydrogen as a storage medium in the conversion sector[2]. The utilization of hydrogen as a storage medium is calculated endogenously when minimizing supply costs and is discussed in the results section 3.2. The *hydrogen scenario* has the highest final energy demand for hydrogen with a total of 667 TWh_{H2} in 2050. The *PtG/PtL scenario* has the lowest final energy demand for hydrogen at 34 TWh_{H2}. The *electrification scenario* is in-between these two extreme positions with a hydrogen demand of 175 TWh_{H2} in 2050. The different hydrogen demand levels in the scenarios are due to different types of use. In the *PtG/PtL scenario*, the final energy demand for hydrogen is limited to the transport sector. Here, a relatively low diffusion of fuel cell vehicles is assumed. This demand amounts to 34 TWh_{H2} in 2050. The other demand sectors in this scenario rely on synthetic, carbon-based energy carriers instead of hydrogen to achieve climate neutrality. These synthetic energy carriers are imported as defined in the scenario and the hydrogen required for their production is not generated in Germany. In the *electrification scenario*, hydrogen demand from the transport sector is supplemented by demand from industry. Hydrogen is used, for example, in the chemical industry as a feedstock or in the steel industry as a reducing agent. In 2050, the hydrogen demand amounts to 20 TWh_{H2} in the transport sector and 156 TWh_{H2} in industry. Only in the *hydrogen scenario* is hydrogen used for heating buildings as well. In 2050, 359 TWh_{H2} of hydrogen demand is accounted for by industry, 129 TWh_{H2} by transport, and 178 TWh_{H2} by heating buildings. The complete hydrogen balances - including model endogenous demands from the conversion sector and hydrogen supply - are shown in Fig. 6 in the results.

2.3.2. Fuel and carbon dioxide prices

Fuel and CO_2 prices are key input parameters in energy system modeling. The level and interaction of fuel prices have a direct impact on the expansion and dispatch decisions for technologies in Enertile. All scenarios assume the same price developments for natural gas, hard coal, lignite, oil, hydrogen imports from outside Europe, and CO_2 certificates. Only the *PtG/PtL scenario* uses synthetic energy carriers. Table 1 shows the prices used in this analysis.

Price trends for hard coal, oil, and natural gas are based on the

[1] This aspect of the scenario design accounts for one of the central arguments for the use of PtG and hydrogen for heating as an alternative to the renovations measures that are, at least to some extent, required for an efficient electrification of heat demand in buildings.

[2] Since synthetic hydrocarbons are imported from outside Europe, the hydrogen demand does not include an intermediate product in synthetic fuel production.

Table 2
Parametrization of hydrogen infrastructures in the scenario runs.

Technology	Parameter	Unit	2030	2040	2050
Electrolyzer (low temperature)	Efficiency	%	66	68	71
	Specific investment	€/kW_{el}	575	481	388
	Lifetime	a	20	20	20
	Fix OPEX	€/kW_{el}	16.00	15.75	15.50
Hydrogen turbine	Efficiency	%	41	41	41
	Specific investment	€/kW_{el}	400	400	400
	Lifetime	a	30	30	30
	Fix OPEX	€/kW_{el}	7.5	7.5	7.5
	Var OPEX	€/kWh_{el}	1.5	1.5	1.5
Hydrogen turbine (CHP)	Efficiency (el)	%	33	33	33
	Efficiency (CHP)	%	85	85	85
	Specific investment	€/kW_{el}	730	730	730
	Lifetime	a	30	30	30
	Fix OPEX	€/kW_{el}	30	30	30
	Var OPEX	€/kWh_{el}	2.7	2.7	2.7
Combined cycle hydrogen turbine	Efficiency	%	59	60	61
	Specific investment	€/kW_{el}	775	750	750
	Lifetime	a	30	30	30
	Fix OPEX	€/kW_{el}	11.63	11.25	11.25
Hydrogen boiler	Efficiency (th)	%	104	104	104
	Specific investment	€/kW_{th}	50	50	50
	Lifetime	a	25	25	25
	Fix OPEX	€/kW_{th}	1.8	1.8	1.8
	Var OPEX	€/kWh_{th}	0.9	0.9	0.9
Combined cycle hydrogen turbine (CHP)	Efficiency (el)	%	48	48	48
	Efficiency (CHP)	%	88	88	88
	Specific investment	€/kW_{el}	950	950	950
	Lifetime	a	30	30	30
	Fix OPEX	€/kW_{el}	30	30	30
	Var OPEX	€/kWh_{el}	3.00	3.00	3.00
Hydrogen pipeline	Specific investment	€/(km MW_{H2})	1120	1120	1120
	Fix OPEX	% of invest	1	1	1

Sustainable Development Scenario of the World Energy Outlook 2019 [26]. The World Energy Outlook only shows prices up to 2040; for this analysis, prices were extrapolated to 2050 based on previous trends. The conversion of prices to euros is based on the average interbank exchange rate of 2018. In general, the prices of hard coal (6 €/MWh) and natural gas (22 €/MWh) remain at constant levels. The oil price decreases slightly, from 32 €/MWh in 2030 to 29 €/MWh in 2050. For lignite, a flat price of 4 €/MWh is assumed in all scenario years. Overall, the importance of fossil fuel prices decreases in ambitious climate change mitigation scenarios.

To reduce fossil fuels, a key steering parameter in supply side modeling is the CO_2 price. This CO_2 price penalizes emissions from the use of oil, hard coal, lignite, and natural gas for electricity and heat generation. To realize GHG-neutrality by mid-century, the CO_2 price increases from 75 €/t_{CO2} in 2030 to 500 €/t_{CO2} in 2050 in all scenarios.

The electricity and heat supply modeling in Enertile can use hydrogen and synthetic methane as GHG-neutral energy carriers. In addition to the model's endogenous production and distribution of hydrogen within Europe, GHG-neutral hydrogen can also be imported from outside Europe at fixed prices. The hydrogen import price decreases from 101 €/MWh in 2030 to 81 €/MWh in 2050. Synthetic methane is only used in the *PtG/PtL scenario* and is successively blended with natural gas. The assumed blending rates are 5 % in 2030, 25 % in 2040 and 100 % in 2050. Synthetic methane is imported from outside Europe and the import price drops from 126 €/MWh in 2030 to 94 €/MWh in 2050. The import price time series of hydrogen and synthetic methane are based on modeling work for the MENA region [15]. The time series from Lux et al. (2021) [15] were adjusted to the WACC of 2 % generally assumed in this paper.

2.3.3. Constraints

In all scenarios, the system change towards a GHG-neutral energy supply follows guiding principles that are formulated as constraints in the optimization. These constraints reflect, among other aspects, some basic tenets of Germany's energy and climate legislation. However, not all legislation is implemented to allow the model to make decisions in the optimization. For example, the statutory sector targets for the year 2030 are not reflected in the scenarios.

In all scenarios, the phase-out of nuclear energy by 2022 [27] and the step-wise phase-out of coal until 2038 [28] are implemented as stipulated in the respective laws.

Renewable energy expansion corridors are also specified for Germany. For 2030, between 71 GW_{el} and 80 GW_{el} of onshore wind capacity must be installed. For offshore wind, an installed capacity of at least 20 GW_{el} must be reached in 2030 and must increase to at least 40 GW_{el} until 2040. The photovoltaic target sets a minimum expansion to 100 GW_{el} by 2030.

The National Hydrogen Strategy in Germany [5] is implemented in all scenarios. This requires electrolyzer capacities in Germany of at least 5 GW_{el} by 2030 and of at least 10 GW_{el} by 2040. The utilization of these capacities – i.e., the production of hydrogen – can be optimized freely by the model.

Due to the limited availability of sustainable biomass and sectoral competition for the available biomass, the conversion sector quasi-exits the use of biomass for electricity and heat generation after 2030 in all scenarios. Existing biomass power plants leave the system depending on their technical lifetime and year of installation. The only remaining plants are those that run on waste landfill and sewage gas. As a consequence, the capacity of biomass power plants is reduced to 800 MW_{el} in the conversion sector by 2050.

Electricity imports from other European countries are indirectly limited in order to prevent an electricity import dependency exceeding the level perceived as politically feasible. For this purpose, different minimum generation quantities of renewable electricity are defined in the scenarios for the year 2050. This defines a minimum generation within Germany that cannot be replaced with imports. In the *electrification scenario* and the *hydrogen scenario*, a minimum of 900 TWh_{el} of renewable electricity must be generated in Germany in the year 2050. In the *PtG/PtL scenario*, the overall electricity demand is lower and there is a national minimum renewable electricity generation of 650 TWh_{el} in the year 2050.

Fossil fuels may no longer be used for electricity and heat generation in 2050. In all scenarios except the *PtG/PtL scenario*, natural gas-based conversion technologies are no longer part of the technology portfolio. In the *PtG/PtL scenario*, gas technologies are still allowed, but the gas used must be completely GHG-neutral. The phase-out of oil and coal-based electricity generation already happens before 2040.

2.3.4. Hydrogen infrastructures

For the expansion and use of hydrogen infrastructure in the cost minimization, its techno-economic parameterization is of central importance. Table 2 summarizes the assumptions regarding specific investments, variable operation and maintenance costs (O&M), fixed O&M, technical lifetimes, and the system efficiencies of hydrogen technologies available in the model. All scenarios assume the same price developments for these technologies.

Costs resulting from investments are considered in the cost optimization based on annuities. When calculating these annuities, a weighted

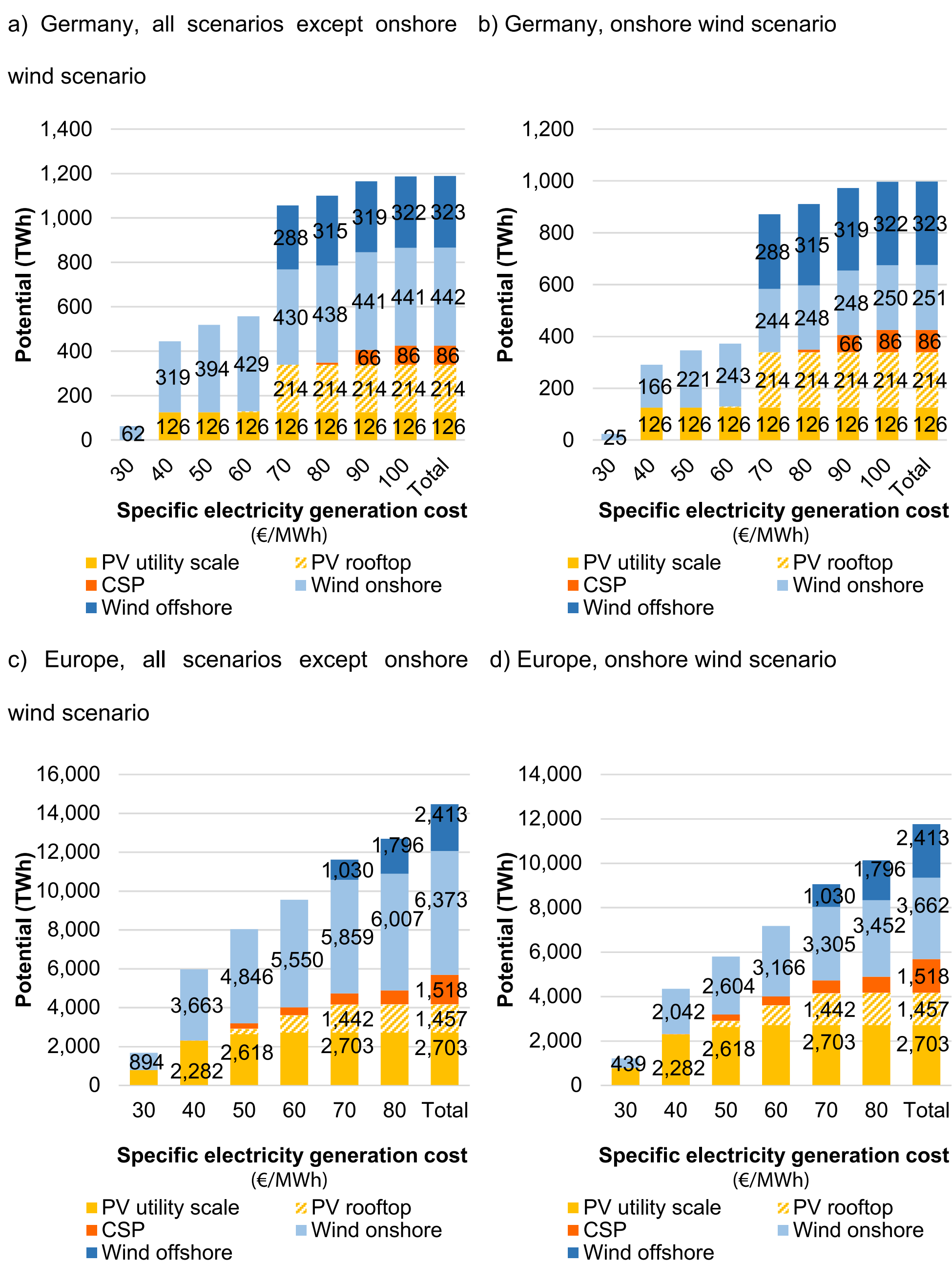

Fig. 4. Electricity generation potential of the technologies onshore wind, offshore wind, CSP, PV utility scale, and PV rooftop in Germany and Europe in 2050. The potential for the *onshore wind scenario* (b) & (d), and all other scenarios (a) & (c) is displayed.

average cost of capital of 2 % is assumed for all technologies, regions, and simulation years.

The parameterization of hydrogen-based heat and power generation technologies (i.e., hydrogen turbines (CHP and non-CHP), combined cycle turbines (CHP and non-CHP), hydrogen boilers) is based on the techno-economic parameters of natural gas-based technologies. Hydrogen-based technologies are not yet available on an industrial scale today. This paper assumes that the existing extensive experience with combustion units of natural gas can provide benefits, and that hydrogen technologies with similar technical characteristics will be developed.

In electrolytic hydrogen production, a distinction can be made between low-temperature and high-temperature electrolyzers. High-temperature electrolyzers can achieve high electrical efficiencies if the heat supplied from other sources is available at a high temperature level. If there is no high-temperature source available and the heat has to be provided by auxiliary electrical heating, high-temperature electrolysis processes are not more efficient than low-temperature processes. In order to be independent of external heat sources in the siting decision of electrolyzers, electrolysis parameters of the low-temperature technologies alkaline electrolysis (AEL) and polymer electrolyte membrane electrolysis (PEMEL) are used in this paper. These technologies are already more advanced and thus less expensive than high-temperature electrolyzers. The energy system model *Enertile* cannot sufficiently resolve the technical differences between AEL and PEMEL to decide between the two technologies. Therefore, the model parameterization assumes values averaged between these technologies. More detailed reviews on the techno-economic properties of the different electrolyzer technologies are given in [29].

At present, hydrogen pipelines are only used for short point-to-point connections or in relatively small grids connecting industrial clusters; i.e., there is no transnational pipeline-based hydrogen infrastructure in Europe. Potentially, parts of the existing European natural gas transport

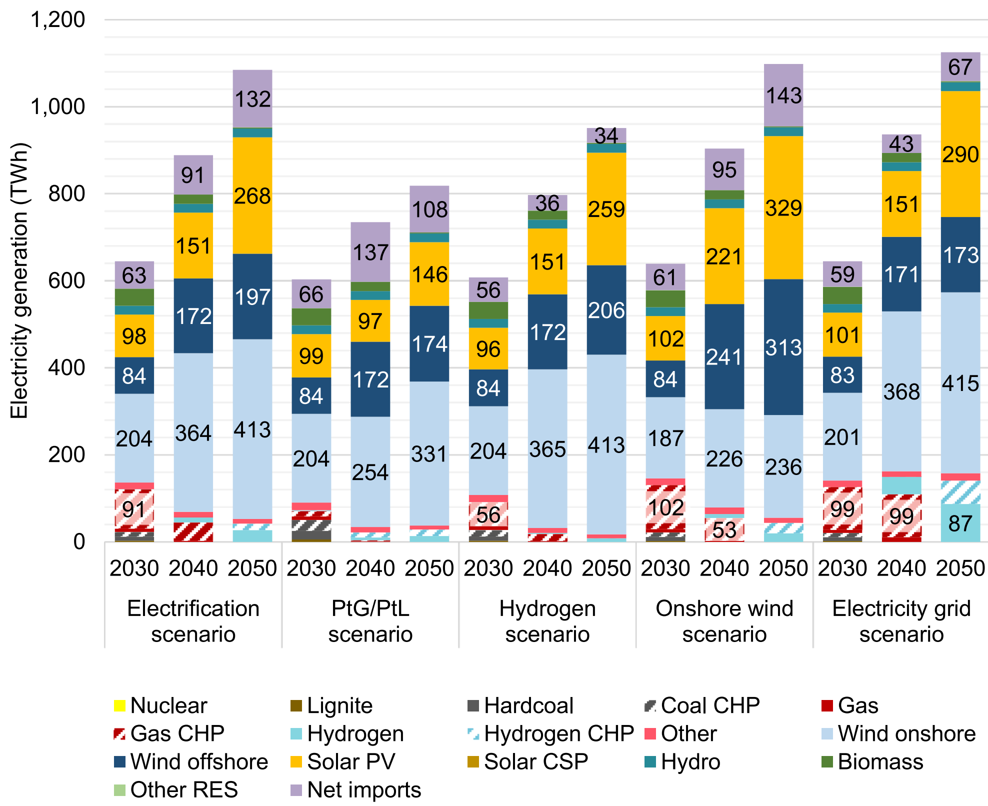

Fig. 5. Development of electricity supply in the optimization results of the different scenarios up to the year 2050.

network could be repurposed into a hydrogen network if fossil gas is phased out. However, which pipelines will be available at which point in the future depends on multiple parameters, including the natural gas supply and demand structures for Europe. Therefore, this paper conservatively assumes a greenfield approach to the development of hydrogen transport pipelines in Europe. The parameters for pipeline construction are based on [30].

2.3.5. *Electricity generation potential of renewable energies*

Fig. 4 shows the renewable electricity generation potential of the renewable technologies onshore wind, offshore wind, CSP, utility scale PV, and rooftop PV for Germany and Europe in 2050. These potentials serve as input for the energy system optimization in Enertile. In all scenarios except the onshore wind scenario, the renewable potential in Germany totals about 1,200 TWh. There are mainly onshore wind and utility scale PV potentials at electricity generation costs below 60 €/MWh. Offshore wind and rooftop PV show higher electricity generation costs. Onshore wind has the greatest potential at 442 TWh. The potential in Europe amounts to over 14,000 TWh. Onshore wind has the highest potential with 6,373 TWh. In the *onshore wind scenario*, the onshore wind potential decreases to 251 TWh in Germany and 3,662 TWh in Europe.

3. Results

This section describes the results of the energy supply optimization for the different scenario variants. These focus on the underlying electricity systems (section 3.1), the hydrogen balances in Germany (section 3.2), the geographical distribution of hydrogen production and demand within Germany (section 3.3), the European hydrogen transport flows (section 3.4), the deployment of hydrogen infrastructures over the course of the year (section 3.5), and the overall system costs (section 3.6).

3.1. *Electricity supply*

Since more than half of Germany's power is currently generated by fossil energy sources, the German power sector is subject to major changes in all analyzed paths to GHG neutrality. Fig. 5 shows the developments of electricity supply in the optimization results up to the year 2050. Several trends can be observed.

First, the increased demand for electricity requires a substantial increase in electricity supply over time in all scenarios. There are two underlying reasons for this increase: Firstly, the sectoral electricity demand determined by the simulation models increases for all three underlying demand scenario variants over time (cf. section 2.3.1). This increase is most pronounced in the *electrification scenario*, *onshore wind scenario*, and *electricity grid scenario*, which are all based on the demand variation focused on an electrification of end-use applications. This type of electricity demand is an exogenous input into the *Enertile* model. Secondly, the electricity supply in Fig. 5 also covers the increasing and partly model-endogenous electricity demand of heat pumps and electric boilers for the provision of heat in district heating grids, of electrolyzers, as well as grid losses, and storage losses. Especially the electricity consumption of power-to-hydrogen in 2050 increases to between 130 TWh in the *electrification scenario* and 257 TWh in the *hydrogen scenario*. Similarly, the electricity consumption of power-to-heat in 2050 increases to between 110 TWh in the *PtG/PtL scenario* and 131 TWh in the electrification scenario. In total, electricity supply in 2050 ranges between 819 TWh_{el} in the *PtG/PtL scenario* and 1,126 TWh_{el} in the *electricity grid scenario.*

A second major trend is that renewables increasingly dominate electricity supply. In all scenarios, except the *PtG/PtL scenario*, minimum renewable generation levels are implemented as implicit import restrictions. In these scenarios, renewable electricity generation increases up to 900 TWh_{el} in 2050. In the *PtG/PtL scenario,* renewable generation exceeds the minimum target of 650 TWh_{el} and reaches 674 TWh_{el} in 2050. Onshore wind dominates the electricity mix in the optimization

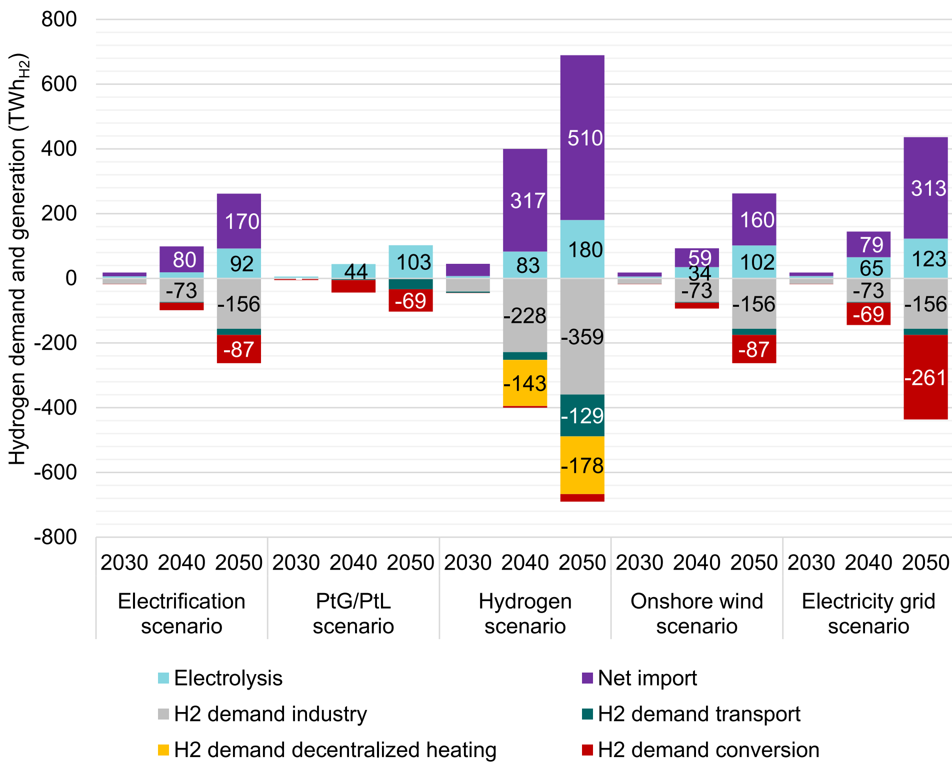

Fig. 6. Annual hydrogen balances for all scenarios in Germany. Demand from the sectors industry, transport, and tertiary is exogenous. The use of hydrogen in the conversion sector is a modeling decision. Hydrogen imports and electrolytic hydrogen production in Germany are optimization results.

results unless its potentials are constrained by scenario design in the *onshore wind scenario*. In all scenarios, except the *PtG/PtL scenario,* the available onshore wind potentials in Germany are almost fully exploited. In all scenarios, except the *onshore wind scenario*, this onshore wind potential amounts to 442 TWh_{el} in 2050; the more restricted configuration in the *onshore wind scenario* totals 251 TWh_{el} in 2050. The *PtG/PtL scenario* also reaches a high level of onshore wind generation with 331 TWh_{el} in 2050. In all scenarios except the *PtG/PtL scenario*, PV is the second most important generation technology. This contributes between 146 TWh_{el} in the *PtG/PtL scenario* and 329 TWh_{el} in the *onshore wind scenario* to the power generation mix. Especially the potential of ground mounted PV is almost fully exploited in all scenarios except the *PtG/PtL scenario*. Offshore wind, as a relatively expensive technology, is only expanded beyond the specified minimum policy target of 40 GW_{el} in the *electrifications scenario*, the *hydrogen scenario*, and the *onshore wind scenario*. In these scenarios, generation from offshore wind reaches 197 TWh_{el}, 206 TWh_{el}, and 313 TWh_{el} respectively. In all other scenario variants, offshore wind contributes only 174 TWh_{el} in 2050. Especially in all scenarios based on the demand variations focused on electrification and hydrogen, the available renewable electricity generation potential in Germany is strongly exploited by 2050. The *PtG/PtL scenario* meets its goal of lower utilization of the German renewable electricity generation potential.

A third trend is that Germany becomes a net importer of electricity in all scenarios. In 2050, imports increase to between 34 TWh_{el} in the *hydrogen scenario* and 143 TWh in the *onshore wind scenario*. Electricity imports increase strongly between 2030 and 2050, and remain constant only in the *hydrogen scenario* and the *electricity grid scenario*. If there were no implicit import restrictions for Germany, the electricity imports from other European countries would be even higher in all scenarios in 2050 except the *PtG/PtL scenario*. These electricity imports are accompanied in the modeling results by a corresponding increase in electricity generation capacities in the exporting European countries.

A fourth major trend is that flexible and controllable electricity generation units change from gas to hydrogen in all scenarios. The capacity of hydrogen power plants in 2050 ranges between 26 GW_{el} in the *hydrogen scenario* and 82 GW_{el} in the *electricity grid variation*. It is noteworthy that, even in the *PtG/PtL scenario*, gas-fired power plants using synthetic methane are displaced by hydrogen power plants in 2050.

3.2. Hydrogen balances

Fig. 6 shows the German hydrogen balances in all scenarios for the different simulation years. The hydrogen demand of the sectors industry, transport, and decentralized building heat is given exogenously and varies greatly in the underlying demand variations (cf. section 2.3.1). The hydrogen supply and the use of hydrogen in the conversion sector for the generation of electricity and heat for heat grids result from modeling decisions in the cost optimization. In contrast to all other scenarios, hydrogen imports from neighboring European countries are not permitted in the *PtG/PtL scenario*[3]. Overall, the supply of electricity-based hydrogen in Germany increases to between 103 TWh_{H2} in the *PtG/PtL scenario* and 690 TWh_{H2} in the *hydrogen scenario* in 2050.

The comparison between the scenarios shows clear differences with regard to the use of hydrogen in the conversion sector. Three realizations in the optimization results may be distinguished: firstly, in the electrification scenario 87 TWh_{H2} of hydrogen are used to generate electricity and heat in heating networks. In comparison, a variation in the onshore wind potentials or a shift of energy demands towards PtG/PtL in the demand sectors show only minor impacts on the hydrogen utilization in the conversion sector. Secondly, a substantial increase of hydrogen utilization in the conversion sector results from a reduced provision of flexibility by the electricity transport network. In the *electricity grid scenario*, 261 TWh_{H2} of hydrogen are converted to electricity

[3] It is assumed that with the continued strong usage of methane networks an international hydrogen backbone spanning the continent will not be established.

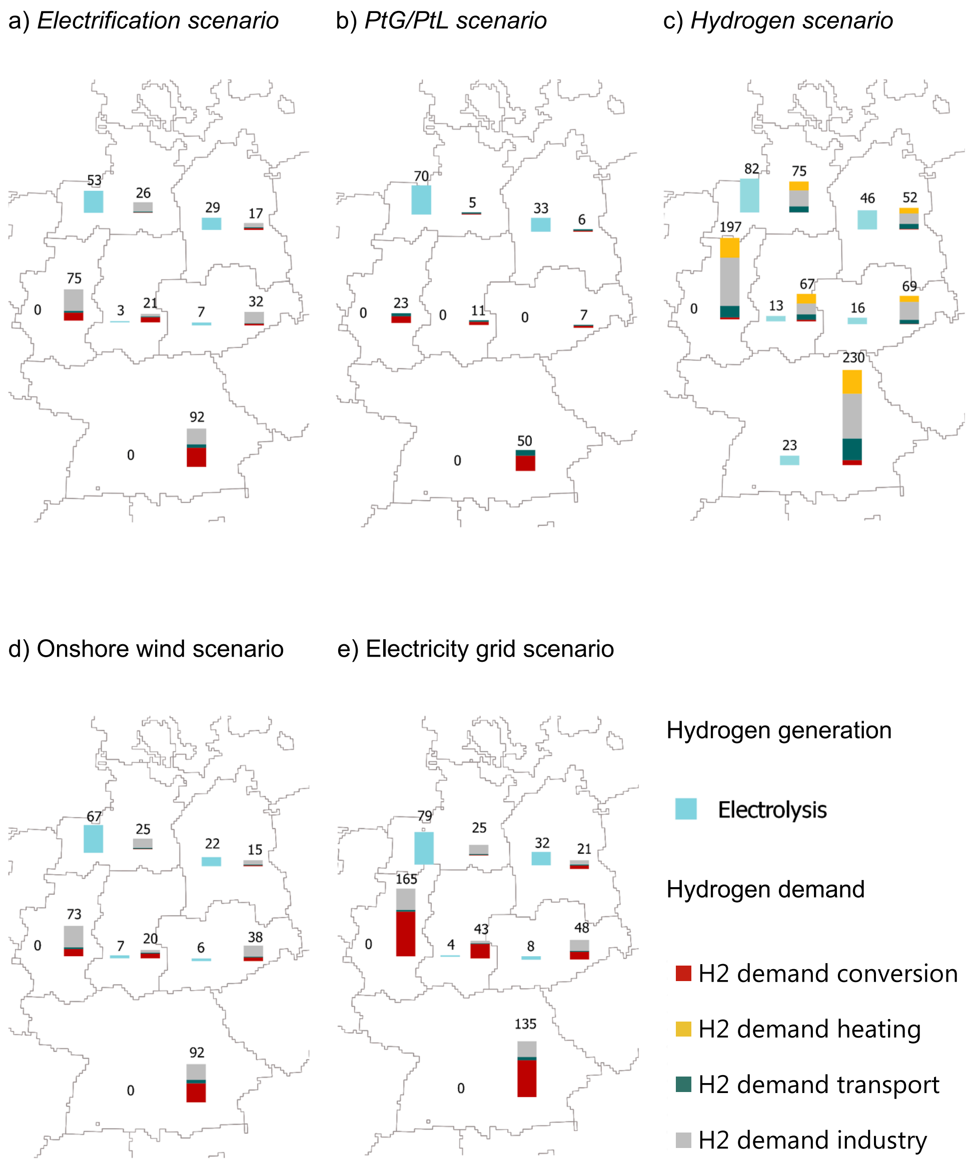

Fig. 7. Regional distribution of hydrogen production via electrolysis and hydrogen demand by various sectors in 2050 in Germany for the a) *electrification scenario*, b) *PtG/PtL scenario*, c) *hydrogen scenario, d) onshore wind scenario, and e) electricity grid scenario*. Demand from the sectors industry, transport, and heating in buildings is given exogenously. The use of hydrogen in the conversion sector and the electrolytic hydrogen production is a modeling decision.

and heat in heat networks. Thirdly, hydrogen use in the conversion sector is significantly reduced in the *hydrogen scenario* with 23 TWh_{H2}. The reason for the reduced use of hydrogen in electricity and heat generation in this scenario is the overall higher hydrogen demand level from the other sectors. The high hydrogen demand results in an increased model endogenous hydrogen price – 68 €/MWh_{H2}[4] in the *hydrogen scenario* vs. 59 €/MWh_{H2} in the *PtG/PtL scenario* – making a utilization in the conversion sector less attractive for the optimization.

If the model has the option of expanding a European hydrogen network, it meets the main part of the German hydrogen demand with imports from Europe. In the *electrification scenario*, about 170 TWh_{H2} of hydrogen are imported from other European countries. In comparison to the *electrification scenario*, reduced onshore wind potentials do not have a substantial impact on the level of hydrogen imports. As more processes and applications are converted to the use of hydrogen in the *hydrogen scenario* and the sectoral demands in Germany are consequently increased, the highest hydrogen imports of 510 TWh_{H2} can be observed. If electricity imports are limited by a reduced electricity network expansion, the model deviates to hydrogen imports. In the *electricity grid scenario*, hydrogen imports of 313 TWh_{H2} are higher than in the electrification scenario. In the *PtG/PtL scenario*, imports are not included in the scenario design. The remaining hydrogen demand is provided through electrolytic hydrogen production within Germany.

In the *electrification scenario*, the domestic electrolyzer capacity in 2050 amounts to 41 GW_{el}. Due to the lack of a European hydrogen transport infrastructure in the *PtG/PtL scenario*, the required hydrogen must be produced in Germany and the electrolyzer capacity is slightly increased to 43 GW_{el}. In the *onshore wind scenario*, a substantial part of the reduced electricity generation with onshore wind is replaced by PV (cf. section 3.1). To integrate the increased PV midday peaks, the electrolyzer capacity is increased to 54 GW_{el} in this scenario. In the *electricity grid scenario*, the optimization increases the electrolyzer capacity to 61 GW_{el} to compensate for the reduced integration capability of the grid with respect to renewable energy by a flexible consumer. The increased

[4] Model endogenous hydrogen prices can be read as shadow prices from the optimization results of the hydrogen demand constraints.

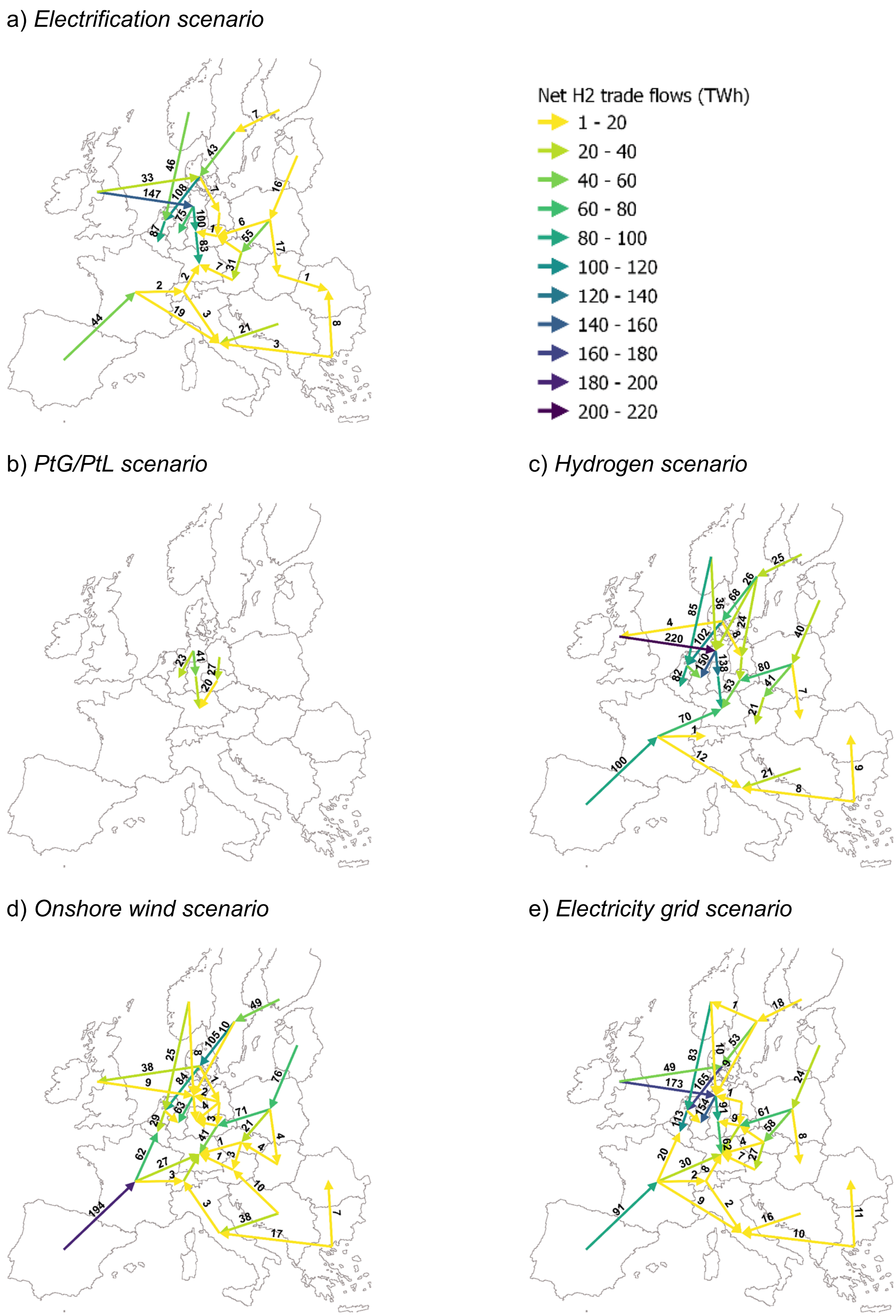

Fig. 8. Net hydrogen trade flows in 2050 in the a) electrification scenario, b) PtG/PtL scenario, and c) hydrogen scenario, d) onshore wind scenario, and d) electricity grid scenario.

demand for hydrogen in the *hydrogen scenario* is met by an increased electrolyzer capacity of 75 GW_{el} alongside a substantial increase in imports. The full load hours of these electrolyzers range between 2,700 h in the *onshore wind scenario* and 3,500 h in the *hydrogen scenario*.

3.3. Geographical distribution of hydrogen demand and generation

For all scenarios, Fig. 7 shows a concentration of electrolytic hydrogen production in the northern coastal regions in 2050. At least 71 % of the total German hydrogen production in 2050 takes place at the North Sea and the Baltic Sea, independent of the underlying scenario. The joint absolute hydrogen production volumes of these two regions range between 83 TWh_{H2} in the *electrification scenario* and 129 TWh_{H2} in the *hydrogen scenario*. To produce these amounts of hydrogen via electrolysis, a total electrolyzer capacity of between 37 GW_{el} in the *electrification scenario* and 55 GW_{el} in the *hydrogen scenario* are installed in these northern German regions by the year 2050. The concentration of electrolyzer capacities allows the model to integrate high capacities of wind power at the coast, which would otherwise require greater expansion of the electricity grid.

The scenario comparison in Fig. 7 shows that with increasing hydrogen demand, hydrogen production increasingly takes place in

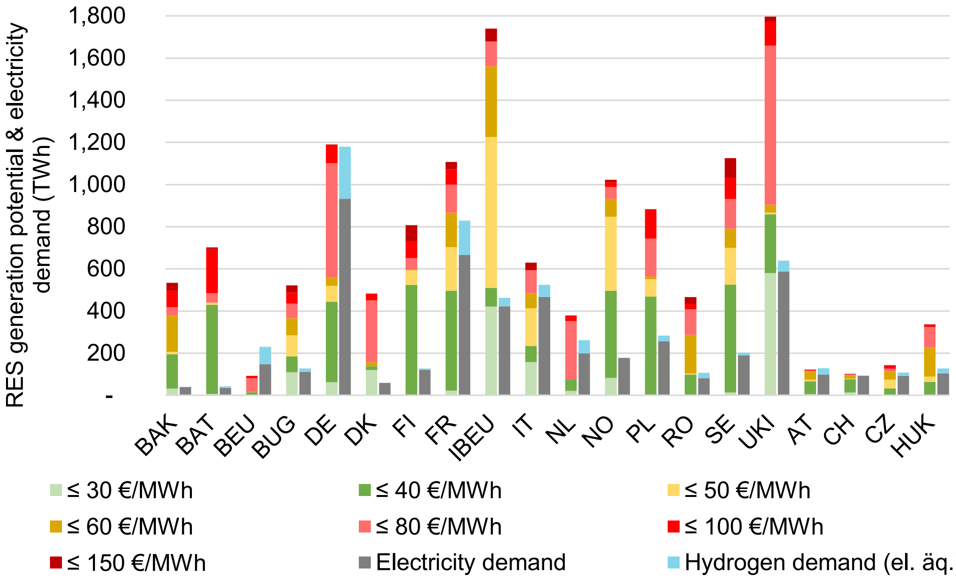

Fig. 9. Comparison of renewable electricity generation potential and electricity demand in the different model regions (cf. Figure A1) in the *electrification scenario* for the year 2050. The electricity demand includes the exogenous electricity demand of the demand sectors, the electricity usage for heat generation and the electricity equivalent of hydrogen demand. This representation does not take into account storage losses or infrastructure requirements for cross-regional electricity or hydrogen trade.

central and southern Germany as well. In the *PtG/PtL scenario* – with the lowest hydrogen demand of 103 TWh_{H2} – electrolysis takes place exclusively in the two coastal regions. With a higher hydrogen demand of 262 TWh_{H2} in the *electrification scenario*, there is also hydrogen production totaling 10 TWh_{H2} in central and eastern Germany. In the *hydrogen scenario* – with the highest hydrogen demand of 690 TWh_{H2} – hydrogen is produced everywhere except western Germany, which is the region with the lowest renewable electricity generation potential compared to its electricity demand. With rising hydrogen demand, increasingly expensive renewable electricity potential must be used for hydrogen production in regions with already high electricity loads.

Hydrogen demand is concentrated in western and southern Germany in all scenarios. This includes both the exogenous hydrogen demand from the sectors industry, transport, and heating buildings, and the model-endogenous hydrogen demand from the conversion sector. Regardless of the underlying scenario, the hydrogen demand of the two model regions in western and southern Germany account for at least 59 % of the total hydrogen demand in 2050. Compared to the electrification scenario, reduced expansion of the electricity transmission grid in the *electricity grid scenario* substantially increases hydrogen use in the conversion sector in western and southern Germany. Due to their high electricity demand and low renewable potential, these regions are dependent on energy imports. If these cannot be realized via the electricity grid, the model converts hydrogen imports into electricity.

3.4. European hydrogen transport flows

Depending on the scenario, regional deviations of hydrogen demand and production can be compensated supra-regionally by hydrogen pipeline networks. Due to the low hydrogen demand compared to all other scenarios, the hydrogen transport network in the *PtG/PtL scenario* is limited to hydrogen trade flows between the different German subregions by design. In all other scenarios, hydrogen demand and supply can be additionally balanced via a European hydrogen network.

Fig. 8 shows that there is a stable hydrogen transport route from the coast in the north to western Germany in all scenarios. Similarly, the optimization results show pronounced hydrogen transport flows from the two coastal regions to southern Germany in all scenario variants except the onshore wind variation. These optimization results balance the high hydrogen demand in southern and western Germany and high hydrogen production at the German coast (cf. Fig. 7). The net hydrogen trade flows leaving the coastal region to the southwest range between 23 TWh_{H2} in the *PtG/PtL scenario* and 154 TWh in the *electricity grid scenario*. The associated hydrogen transport capacities amount to between 3 GW_{H2} and 18 GW_{H2}. Excluding the onshore wind scenario, the net hydrogen flows departing the two northern German zones southwards amount to between 68 TWh_{H2} in the *PtG/PtL scenario* and 164 TWh_{H2} in the *hydrogen scenario* in 2050. The associated hydrogen transport capacities departing Northern Germany southwards lie between 8 GW_{H2} and 19 GW_{H2}. In the *hydrogen scenario*, some of the hydrogen required is not produced in these two regions, but transits Northern Germany from the British Isles and Scandinavia. A reduced availability of onshore wind in the *onshore wind scenario* shifts hydrogen production across Europe towards available PV potentials and thereby changes the hydrogen transport infrastructure. As a result, the north–south link in Germany is less pronounced. The hydrogen transport capacities departing the two northern German zones southwards amount to 2 GW_{H2} transporting 14 TWh_{H2} in 2050 in this scenario.

In all scenarios that allow the expansion of a European hydrogen transport infrastructure, the optimization makes use of this option. Excluding the *PtG/PtL scenario*, by 2050, Germany has a total interconnection capacity with other European countries of between 18 GW_{H2} in the *onshore wind scenario* and 58 GW_{H2} in the *hydrogen scenario*. All these scenarios show pronounced net hydrogen flows from the edges of Europe towards Central Europe. Based on the scenario comparison in Fig. 8, four major hydrogen transport routes can be identified: Firstly, if wind onshore potentials are not restricted, the British Isles become the largest net exporter of hydrogen. These exports contribute predominantly to meeting hydrogen demand in Germany. Net hydrogen flows between 147 TWh_{H2} in the *electrification scenario* and 220 TWh_{H2} in the *hydrogen scenario* are transmitted from the British Isles to Germany in 2050. With constant hydrogen flows over the year (cf. section 3.5), the hydrogen interconnector capacity for these amounts is between 17 GW_{H2} in the *electrification scenario* and 25 GW_{H2} in the *hydrogen scenario*. As most of the hydrogen on the British Isles is produced using wind power, this transport route is considerably reduced in the *onshore wind scenario*: With a transport capacity of 1 GW_{H2}, only 9 TWh_{H2} hydrogen are exported to Germany. Secondly, the Scandinavian countries generate export surpluses to supply Central Europe in all scenarios. In the electrification scenario, Norway, Sweden, Finland, and Denmark provide a total of 162 TWh_{H2} to supply the Benelux Union and Germany in 2050. In the *hydrogen scenario,* the supply to Central Europe along this route increases to 280 TWh_{H2}. Thirdly, the Iberian Peninsula is connected to the European hydrogen supply via France. In the *electrification scenario*, the Iberian Peninsula provides 44 TWh_{H2} to meet hydrogen demand in France and Italy. In the *hydrogen scenario*, the net hydrogen

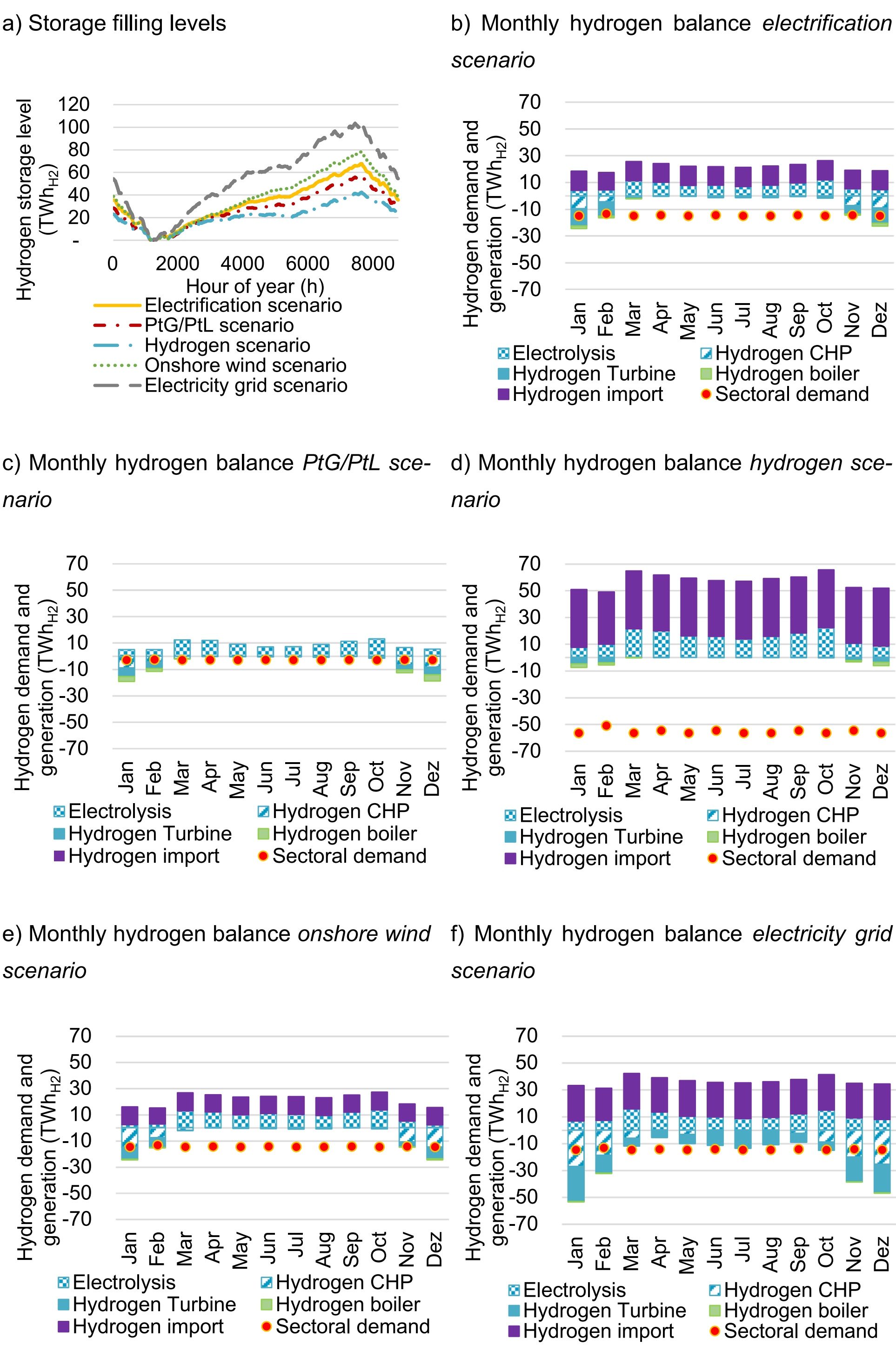

Fig. 10. Hydrogen storage management in the optimization results for Germany in 2050. a) Storage level for all scenarios over 8,760 h of the year 2050. Monthly hydrogen demand and supply in the b) *electrification scenario*, c) *PtG/PtL scenario*, and d) *hydrogen scenario*, e) *onshore wind scenario*, f) *electricity grid scenario*.

exports from the Iberian Peninsula increase to 100 TWh$_{H2}$. In addition to France and Italy, Germany benefits from these higher exports. In the *onshore wind scenario*, the Iberian Peninsula becomes the largest hydrogen exporter due to its abundant and low-cost PV power generation potential. A net hydrogen trade volume of 194 TWh$_{H2}$ is exported via France to supply Central Europe. Fourthly, high hydrogen demand in the *hydrogen scenario* results in hydrogen flows from the Baltic States and Poland to Central Europe. In total, these Eastern European countries provide 121 TWh$_{H2}$ to supply Germany, the Czech Republic and Austria. Increased trade flows can also be observed on this route in the *onshore wind scenario*: In the *electrification scenario*, there is still untapped PV potential in Eastern Europe that is exploited in this scenario. Route-independent, hydrogen trade flows from the edges of Europe towards Central Europe increase in the *electricity grid scenario* compared to the *electrification scenario*.

For a deeper understanding of hydrogen trade flows in Europe, Fig. 9 shows the relationship between electricity demand and cumulative renewable electricity generation potentials in the *electrification scenario* in 2050. The electricity demand includes the exogenously specified electricity demand and the electricity equivalents of the hydrogen demand in the different model regions. The total renewable electricity generation potential is the sum of the individual potentials for onshore

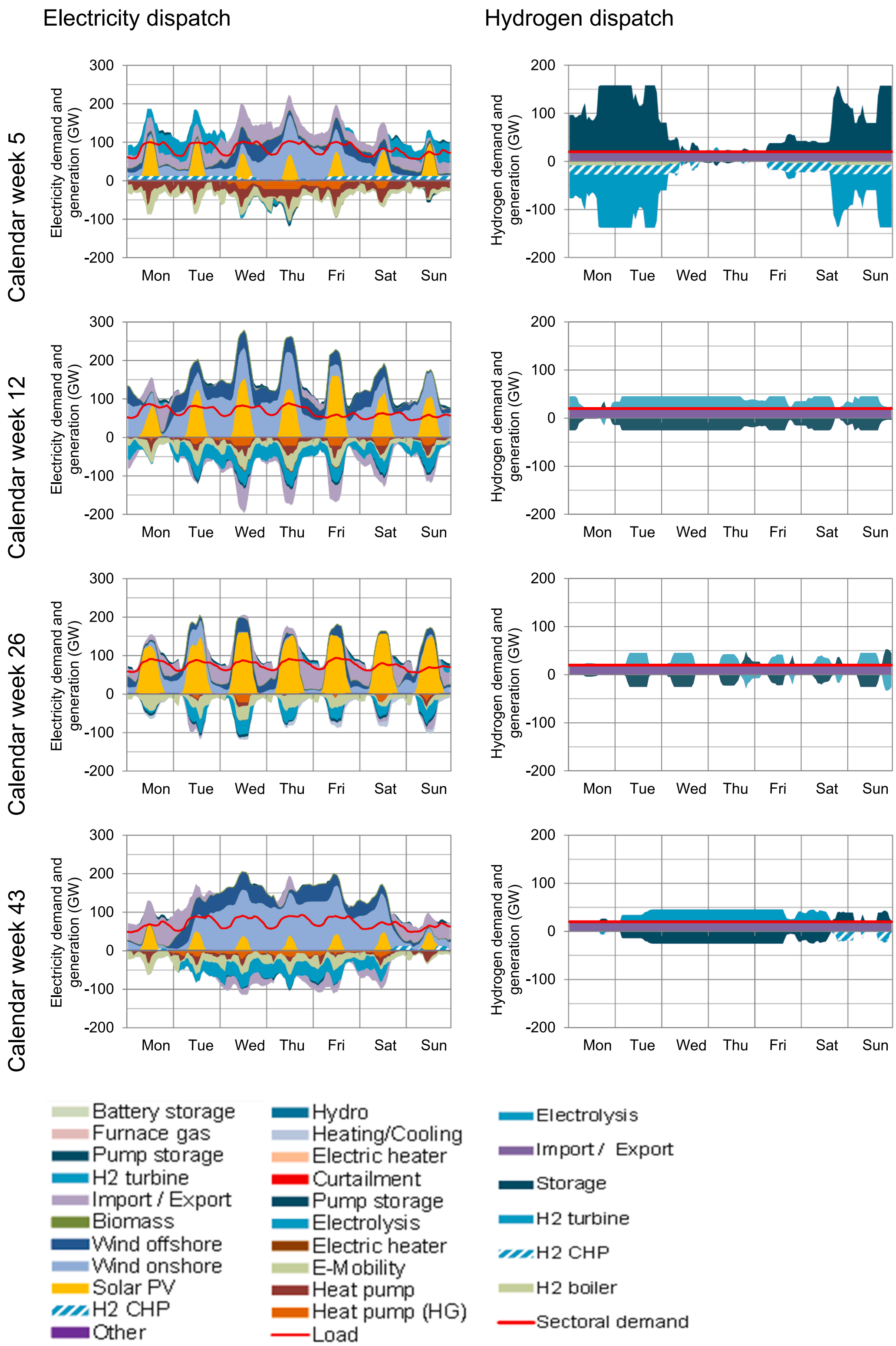

Fig. 11. Hourly electricity and hydrogen balances in the *electrification scenario* for selected weeks of the simulation year 2050 covering all four seasons.

wind, offshore wind, PV, and CSP. This graph does not provide information on the balancing of hourly supply and demand profiles, the use of storage, or electricity trade flows between the model regions. The figure illustrates that energy imports are very attractive for Germany. Compared to other European countries, Germany is characterized by its high demand for electricity and hydrogen and its limited, low-cost potential for renewable electricity generation. If Germany had to meet its electricity demand autonomously using its own renewable potential, this would incur electricity production costs of 100 €/MWh and reach the limits of its potential. In contrast, the hydrogen exporting regions on all four identified main transport routes to Germany have available renewable potential at levelized cost of electricity of 40 €/MWh even after domestic electricity demands are met. In the optimization result, these regions therefore contribute to the German hydrogen supply via a European hydrogen transport grid.

In the analyzed scenarios, hydrogen demand is met only by domestic

European hydrogen production, there are no hydrogen imports from outside Europe.

3.5. Hourly dispatch and seasonal hydrogen storage management

Hydrogen serves as a long-term energy storage medium in all scenarios. Fig. 10 shows a working gas volume of 68 TWh_{H2} hydrogen storage in the electrification scenario. This hydrogen storage is reduced in both demand variations. In the *PtG/PtL scenario*, storage with a working gas volume of 57 TWh_{H2} is sufficient for the optimization due to decreased hydrogen demand. In the *hydrogen scenario*, comparatively little hydrogen is used in the conversion sector to balance residual loads in winter (cf. Fig. 10). In addition, a large part of the increased sectoral demand is met by imports (cf. section 3.2). Both lead to a reduced demand for hydrogen storage with a working gas volume of 42 TWh_{H2}. In the *onshore wind scenario*, the hydrogen storage required for Germany in 2050 increases to a working gas volume of 78 TWh_{H2}. This results from the electrolyzers integrating higher PV capacities in summer and the slightly increased use of hydrogen for electricity and heat generation in winter (cf. Fig. 10). The highest hydrogen storage demand with 104 TWh_{H2} is shown in the optimization results for the *electricity grid scenario*. If the scenario design limits the use of the electricity grid as a central flexibility option, the optimization deviates to the alternative, more expensive flexibility option of storing hydrogen.

Fig. 10 shows that the utilization of hydrogen storage in the optimization results has a pronounced seasonal profile in all scenarios. In winter, hydrogen demand exceeds hydrogen supply and storage facilities are emptied. In spring and fall, hydrogen reservoirs are refilled. In summer, the scenarios differ slightly. While in the *hydrogen scenario,* the storage status remains almost unchanged from May to August, all other scenarios show a slight rise in hydrogen storage levels. Hence, seasonal energy storage in the form of hydrogen helps to balance a GHG-neutral energy system throughout the year.

The decrease in the hydrogen storage level in winter can be explained in all scenarios by lower renewable electricity feed-in. As an example, Fig. 11 shows low electricity generation from solar and wind energy due to fewer hours of sunshine and lower wind levels for calendar week 5 (weather year 2010) in the *electrification scenario*. At the same time, there is an increase in both electricity demand – driven in particular by the use of domestic heat pumps – and heat demand in district heating networks. As a result, electricity becomes a scarce resource and inflexible electricity consumers are preferentially supplied rather than electrolyzers. This reduced renewable electricity generation is partially offset by the use of hydrogen technologies. In all scenarios except the *hydrogen scenario*, substantial amounts of stored hydrogen are converted into electricity and heat in November, December, January, and February (cf. Fig. 10). Together, these effects are responsible for the depletion of hydrogen storage facilities. Except for the *electricity grid scenario*, there is almost no hydrogen utilization in the conversion sector in the remaining months of the year. In the *electricity grid scenario*, hydrogen is used for power generation throughout the year to compensate for bottlenecks in the power grid.

The optimization results show a higher deployment of electrolyzers in spring and fall months than in the remaining months of the year in all scenarios (cf. Fig. 10). Fig. 11 shows that these seasons are characterized by high feed-in of onshore wind power. This wind power, which in some cases occurs constantly over several days, is integrated via electrolyzers. Since very little hydrogen is needed to stabilize the conversion sector, the seasonal hydrogen storage facilities are replenished during these months.

Fig. 11 shows that the main use of electrolyzers in summer is to integrate high PV generation peaks. In a few low-wind nighttime hours, hydrogen power plants have to balance the electricity system in the absence of imports. Overall, there is less wind in the summer than in the spring and fall for the weather year 2010, which is typical for Germany. Hydrogen production from electrolysis therefore decreases somewhat in a seasonal comparison.

3.6. System costs

All the scenarios shown in this paper achieve GHG-neutrality in Germany by 2050. While the energy demand input data was calculated along consistent scenarios with simulation models, the energy supply in this paper is cost-optimized. Taking all sectors into account, the cost comparison identifies the *electrification scenario* as the most cost-efficient path to GHG-neutrality. An alternative, increased use of synthetic hydrocarbons in the *PtG/PtL scenario* increases the cumulative system costs by 359 billion euros in Germany by 2050. Similarly, an alternative, increased use of hydrogen in end-use applications and processes in the *hydrogen scenario* leads to cumulative additional system cost of 246 billion euros by 2050. The *electrification scenario* will become more expensive if the expansion of the electricity transmission grid is inhibited or less space is available for the expansion of onshore wind. In the *electricity grid scenario*, the cumulative system costs increase by 82 billion euros by 2050 compared to the *electrification scenario*. Similarly, the *onshore wind scenario* results in cumulative additional costs of 197 billion euros compared to the *electrification scenario*.

4. Discussion

The optimization results in all scenarios show substantial and rapid increases in renewable electricity capacity. The average net expansion rate of PV, onshore wind, and offshore wind combined in Germany in the scenario results for the period between 2020 and 2050 is between 6.4 GW/a in the *PtG/PtL scenario* and 13.6 GW/a in the *onshore wind scenario*. However, these capacity increases contrast with the expansion rates in Germany in recent years: The average net expansion rate of PV, onshore wind, and offshore wind combined in Germany was 6.4 GW/a between 2015 and 2020 [31]. It is therefore ambitious to realize the expansion rates shown in the optimization results. These rates are, however, necessary to achieve the GHG-neutrality target.

Compared to today, the use of CHP is significantly reduced in the optimization results and shows a dispatch profile with fewer full-load hours. In the overall cost optimization of energy systems for electricity, heat and hydrogen, CHP is used when there is a positive residual electricity load and simultaneous heat demand. CHP always competes with other cost-efficient and emission-free technologies for electricity or heat generation. Consequently, two sides are relevant for CHP utilization: heat demand, and electricity demand. In summer, there is usually low heat demand and high PV generation on the electricity side (cf. Fig. 11). This means that there is no potential for the cost-efficient use of CHP. In winter, there is higher heat demand and less PV generation. If there is little wind feed-in as well, there is a resulting shortage on the electricity supply side and CHP can then therefore efficiently cover electricity and heat demand. Even today CHP plants are experiencing decreasing hours of operation in electricity systems with a high penetration of intermittent renewables [32]. Hence, the use of CHP in an optimized GHG-neutral energy supply system is limited and hydrogen CHP plants have between 1,200 and 2,500 full-load hours in the optimization results.

In the scenario results, the demand for geological hydrogen storage in Germany is between 42 and 104 TWh_{H2}. Caglayan et al. (2020) [33] estimate Germany's hydrogen storage potential in salt caverns to be 94 PWh_{H2}. Currently, natural gas storage facilities with a working gas capacity of 240 $TWh_{naturalgas}$ [34] are operated in geological subsurface structures in Germany. Salt caverns are considered especially suitable for storing hydrogen [33]. About 62 % [34] of the subsurface natural gas storages are caverns in salt structures with a total working gas capacity of 149 $TWh_{naturalgas}$. If rededicated, the existing salt caverns could only store about 45 TWh_{H2} of hydrogen due to the lower volumetric energy density of hydrogen. In principle, the storage potential is therefore sufficiently large to meet the hydrogen storage requirement in all scenarios. However, even if the demand for natural gas storage decreases fast enough, the reallocation of such storage facilities can only partially cover the hydrogen storage demand in the scenario results; the construction of new cavern storage facilities is necessary. The storage potential is concentrated in northern Germany [33] and therefore close to the electrolyzer sites in the scenario results (cf. Fig. 7).

In the modeling, the exogenously specified hydrogen demand is assumed to be uniformly distributed over the year. The requirement and use of hydrogen as a seasonal storage medium in the model results is therefore shaped by the seasonal conditions in the conversion sector. In reality, seasonal fluctuations in hydrogen demand from other sectors would potentially increase the seasonality of the storage profile.

In all scenario results, Germany is an energy importer. Except for the *onshore wind scenario*, most hydrogen is imported from the British Isles. A study by Clees et al (2021) [35], modeling gas and hydrogen networks, shows that operating a hydrogen-only network benefits from this hydrogen flow direction. In light of Brexit, it seems however questionable whether the population in the UK would tolerate a substantial expansion of wind turbines dedicated to producing hydrogen for export to mainland Europe. Still, as an optimization result, it shows the economic potential of the region in this regard.

In line with the findings in Lux et al. (2021) [15], the results of the optimization in this paper show that an inner-European hydrogen supply is more cost-efficient than imports from the MENA region. The advantages of the MENA region in terms of renewable power generation are offset by the costs of transporting hydrogen to Europe. If the expansion of renewable energies in Europe stagnates due to acceptance problems, imports from outside Europe may still become necessary.

5. Conclusions

In a scenario study, this paper examined the supply of hydrogen and its potential use in the conversion sector on different pathways to greenhouse gas neutrality in Germany. The scenarios were deliberately designed to address uncertain and influential drivers of the future energy system: Firstly, consistent variations in energy demand in the demand sectors industry, transport, households, and services illuminate the corners of the possible solution space. Three different pathways to achieve climate neutrality were modeled assuming a high deployment of either electricity, or hydrogen or synthetic hydrocarbons. Secondly, the renewable energy portfolio was varied by limiting the onshore wind potential in one case. Thirdly, in another case, a key flexibility option in the future electricity system was varied by limiting the expansion of the electricity transmission grid. The analysis was carried out using the cost-minimizing energy system model *Enertile* and focused on Germany, but in the context of a European energy system. The aim of the analysis is to support a concretization of the German hydrogen strategy using model calculations to answer three research questions.

The first research question addressed the need for and utilization of hydrogen storage facilities over the course of a year. A robust result of the energy supply optimization is the utilization of hydrogen as a storage medium in the conversion sector with a pronounced seasonal profile. Primarily, this use of hydrogen can shift high electricity generation from onshore wind in spring and fall into the winter when there is lower renewable supply from solar energy and increased electricity and heat demands. To function as this seasonal storage, the scenario results calculated a hydrogen storage volume in the range of 42 TWh_{H2} to 104 TWh_{H2}. High storage volumes are mainly caused by a lack of flexibility in the power transmission grid. Repurposing suitable, currently operated natural gas storage facilities in salt caverns could cover about 45 TWh_{H2} of this hydrogen storage requirement. For storage demands beyond this, new hydrogen cavern storage facilities would have to be built. There is a sufficiently large geological potential of 94 PWh_{H2} available.

Hydrogen storage is used in the scenario results as a flexibility provider in the conversion sector on both the supply and demand side. On the electricity demand side, electrolyzers, in particular, help to integrate high PV peaks and high wind onshore feed-in. In the scenario results, electrolyzer capacities between 41 GW_{el} and 75 GW_{el} are used in Germany in the long term. On the electricity supply side, hydrogen turbines and hydrogen CHP compensate for shortfalls in renewable power generation or bottlenecks in the electricity transmission network. Hydrogen power plants replace gas-fired power plants, even if these are switched to synthetic methane. In the scenario results, hydrogen power plant capacities between 26 GW_{el} and 82 GW_{el} are used in Germany in the long run. This requires the construction of electrolyzers and hydrogen power plants in Germany.

The second research question is dedicated to the site selection of electrolyzers. In the scenarios, hydrogen demand from both industry and the conversion sector mainly occurs in southern and western Germany. Despite this, electrolytic hydrogen production is almost exclusively concentrated in northern Germany in the cost minimization results. At least 71 % of hydrogen production takes place at the German coasts in the scenario results. The optimization follows the available low-cost electricity generation potential when selecting electrolyzer site locations and therefore decides against locating hydrogen production close to its consumption. The electrolyzers at the North Sea and the Baltic Sea are able to integrate high volumes of wind power.

The third research question concerned the contribution of a German or European hydrogen transport infrastructure to a cost-efficient energy supply system. Within Germany, the cost minimization results show that a hydrogen transport infrastructure between northern Germany and southern or western Germany is economically efficient to balance hydrogen supply via electrolysis and hydrogen demand. According to the scenario results, this requires the construction of hydrogen transport pipelines from northern Germany to the southwest with a transport capacity between 3 GW_{H2} and 18 GW_{H2}. If onshore wind expansion is not inhibited by factors beyond techno-economic drivers, a north–south pipeline link within Germany is a robust optimization result. In the scenario variants, the capacity of this link ranges between 8 GW_{H2} and 19 GW_{H2}.

Connecting Germany to a European hydrogen transport network is a robust optimization result in scenarios with substantial hydrogen demand in Germany. The ratio of electricity demand and low-cost renewable electricity generation potential is less favorable in Germany than in many other European countries. In the scenario results, Germany therefore imports most of its hydrogen demand from other European countries. Hydrogen imports are particularly pronounced if many end-use applications are converted to hydrogen and hydrogen demand in Germany is consequently very high, or if electricity imports from other European countries are inhibited. The main hydrogen export regions are the British Isles, Scandinavia, and the Iberian Peninsula. These trade flows require the construction of a European hydrogen pipeline network. Due to declining fossil gas demand, it might be possible to convert existing natural gas pipelines for this purpose. Germany's interconnection capacity to other European countries ranges between 18 GW_{H2} and 58 GW_{H2} in the scenario results. In the model results, no hydrogen is imported from outside Europe. The optimization model favors a domestic European hydrogen supply over imports from the MENA region due to the associated transportation costs and decreasing absolute cost benefits of renewable power generation in this region in the long run. From a cost perspective, trading partners in Europe are the primary candidates.

Overall, hydrogen will play an important role on the supply side of the energy system. The optimization results show the range in which electrolyzers, hydrogen storage facilities, and hydrogen transport networks may be used. However, the scenario results also demonstrate that hydrogen is an expensive form of energy due to the high conversion losses in its production. In the optimization, the use of hydrogen in the conversion sector for power and heat generation is price-sensitive.

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CRediT authorship contribution statement

Benjamin Lux: Conceptualization, Methodology, Software, Investigation, Data curation, Visualization, Writing – original draft, Writing – review & editing. **Gerda Deac:** Software, Data curation. **Christoph P. Kiefer:** Visualization, Investigation. **Christoph Kleinschmitt:** Software, Data curation. **Christiane Bernath:** Software, Data curation. **Katja Franke:** Software, Data curation. **Benjamin Pfluger:** Writing – original draft, Supervision. **Sebastian Willemsen:** Methodology, Data curation. **Frank Sensfuß:** Conceptualization, Supervision, Funding acquisition.

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.

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A. Enertile model regions

See Fig. A1 and Table A1 for the definition of the Enertile model regions.

Fig. A1. Map of model regions in *Enertile*.

Table A1
Definition of regions as used in Enertile.

Enertile region code	Countries
AT	Austria
CH	Switzerland
DE_1 - DE_6, DE_1O	Germany
FR_0	France
IBEU_0	Spain, Portugal
BEU_0	Belgium, Luxembourg
HUK_0	Hungary, Slovakia
UKI_0	United Kingdom, Ireland
PL_0	Poland
BUG_0	Bulgaria, Greece
BAK_0	Slovenia, Croatia, Bosnia and Herzegovina, Serbia, Kosovo, Montenegro, Albania, North Macedonia
BAT_0	Estonia, Lithuania, Latvia
CZ_0	Czech Republic
DK_0	Denmark
IT_0	Italy
NO_0	Norway
RO_0	Romania
SE_0	Sweden
NL_0	Netherlands

B. Linear optimization problem in Enertile

The objective function in Enertile of the linear cost minimization problem for supplying electricity *el*, heat *ht*, hydrogen *H*2 in an energy system is formulated in equation (B.1). It sums the cost of all included generation, transmission, and storage infrastructures in all regions $r \in R$ and all hours $h \in H$ of all considered simulation years $a \in A$. There are two types of decision variables in the objective function: First $\overrightarrow{X}$ describing installed capacities of considered infrastructures, and second $\overrightarrow{x}$ describing the unit dispatch of these infrastructures. Costs for the supply of electricity, heat, and hydrogen are the coefficients of the various decision variables and are grouped into fixed costs and variable costs. Fixed cost $c^{fix}_{\{i,j,k\}}$ contain annuitized investments, capital cost, and fixed operation and maintenance cost of respective technologies. Variable cost $c^{var}_{\{i,j,k\}}$ contain fuel cost, CO_2 emission certificate cost, and variable operation and maintenance cost. The technology portfolio *I* for the provision of electricity contains conventional electricity generation technologies (including CHP and hydrogen power plants), renewable electricity generation technologies, electricity storage technologies, and simplified electricity transmission networks. The set of technologies *J* for the provision of heat contains conventional heat generation technologies (including hydrogen boilers), renewable heat generation technologies, electric heat generators, and heat storages. The technology set *K* for the provision of hydrogen contains electrolyzers, hydrogen storage technologies, and simplified hydrogen transport networks.

$$\begin{aligned}\min_{\overrightarrow{X},\overrightarrow{x},\overrightarrow{y}}\sum_{a\in A}\Bigg[\sum_{r\in R}\Bigg\{\sum_{i\in I}\Bigg(\underbrace{\left(c^{fix}_{a,i}\cdot X^{el}_{a,r,i}\right)}_{capacity\ expansion\ electricity\ supply}+\underbrace{\sum_{h\in H}c^{var}_{a,i}\cdot x^{el}_{a,r,i.h}}_{electricity\ generation}\Bigg)+\sum_{j\in J}\Bigg(\underbrace{\left(c^{fix}_{a,j}\cdot X^{ht}_{a,r,j}\right)}_{capacity\ expansion\ heat\ supply}+\underbrace{\sum_{h\in H}c^{var}_{a,j}\cdot x^{ht}_{a,r,j,h}}_{heat\ generation}\Bigg)\\+\sum_{k\in K}\Bigg(\underbrace{\left(c^{fix}_{a,k}\cdot X^{H2}_{a,r,k}\right)}_{capacity\ expansion\ H2\ supply}+\underbrace{\sum_{h\in H}c^{var}_{a,k}\cdot x^{H2}_{a,r,k.h}}_{H2\ generation}\Bigg)\Bigg\}\Bigg]\end{aligned} \tag{B.1}$$

The central constraints of the cost minimization – so called demand–supply equations $DS_{\{el,hg,b,H2\}}$ – are region- and hour-specific balancing equations for electricity, heat, hydrogen. These equations ensure that the demands of these goods are met. There are two types of demands: Firstly, exogenous demands from other sectors for electricity D^{el}, heat $D^{ht}_{\{hg,b\}}$ in heat grids *hg* and buildings *b*, and hydrogen D^{H2}. Secondly, model endogenous demands that result from interdependencies of the different balancing spaces modelled in Enertile.

Equation (B.2) shows the electricity demand–supply equation DS_{el}. It ensures that the sum of model endogenous electricity demands for heat supply in heat girds and buildings, and for hydrogen supply via electrolysis along with the exogenously specified electricity demand D^{el} is met for each hour *h* of a simulation year *a* and each region *r* by the net electricity generation of technologies *I*. Supplying heat in heat grids *HG* or buildings *B* with electrical technologies increases electricity demands. Electric boilers *eb* convert electricity into heat with efficiency γ_{eb}. The electric conversion efficiencies $\gamma_{\{hpg,hpb\}}$ of both heat pumps for heat grids *hpg* and buildings *hpb* depend on the prevailing ambient temperature. The supply of hydrogen with electrolyzers *ely* increases the electricity demand as a function of the electrolyzer efficiency γ_{ely}.

$$\begin{aligned}[\mathrm{DSel}]\sum_{i\in I}x^{el}_{a,r,i,h}&=D^{el}_{a,r,h}+\sum_{hg\in HG}\left(\frac{1}{\gamma_{a,r,hpg,h}}\cdot x^{ht}_{a,r,hg,hpg,h}+\frac{1}{\gamma_{a,eb}}\cdot x^{ht}_{a,r,hg,eb,h}\right)\\&+\sum_{b\in B}\frac{1}{\gamma_{a,r,hpb,h}}\cdot x^{ht}_{r,b,hpb,h}+\sum_{ely}\frac{1}{\gamma_{a,ely}}\cdot x^{H2}_{a,r,ely,h}\forall a,r,h\end{aligned} \tag{B.2}$$

Equations (B.3) and (B.4) show the heat demand–supply equations. The demand–supply equation for heat in heat grids DS_{hg} (B.3) ensures that the exogenously specified heat demand in heat grids D_{hg}^{ht} is met for each hour h of a simulation year a and each region r by the net heat generation of technologies $N\subset J$ and $Q\subset I$. The technology set N includes pure heat generation technologies and heat storage systems suitable for the use in heat grids; the technology set Q includes hydrogen CHP plants whose heat generation for heat grids is coupled to electricity generation via the power-to-heat ratio $\gamma_q^{chp,ht}$. The demand–supply equation for heat in buildings DS_b (B.4) ensures that the exogenously specified heat demand in buildings D_b^{ht} is met for each hour h of a simulation year a and each region r by the net heat generation of the subset of heating technologies $O\subset J$ suitable for supplying buildings.

$$[\mathrm{DShg}]\sum_{n\in N}x_{a,r,hg,n,h}^{ht}+\sum_{q\in Q}\gamma_{a,q}^{chp,ht}\cdot x_{a,r,q,h}^{el,chp}=D_{a,r,hg,h}^{ht}\forall a,r,hg,h \tag{B.3}$$

$$[\mathrm{DSb}]\sum_{o\in O}x_{a,r,b,o,h}^{ht}=D_{a,r,b,h}^{ht}\forall a,r,b,h \tag{B.4}$$

Equation (B.5) shows the hydrogen demand supply equation DS_{H2}. It ensures for each hour h of a simulation year a and each region r that the net hydrogen supply of technology portfolio K meets the model endogenous hydrogen demands and either explicitly specified exogenous hydrogen demands from other sectors D^{H2} or implicitly imposed hydrogen demands. Endogenous hydrogen demands include the provision of heat in heat grids HG using hydrogen boilers $hyb\in N$ with conversion efficiency γ_{hyb}, the reconversion of hydrogen into electricity using the portfolio of pure hydrogen-to-electricity reconversion technologies $P\subset I$ with associated conversion efficiencies γ_p, and the co-generation of electricity and heat using the portfolio of CHP reconversion technologies $Q\subset I$ with associated conversion efficiencies $\gamma_q^{chp,H2}$.

$$[\mathrm{DSH2}]\sum_{k\in K}x_{a,r,k,h}^{H2}=\sum_{hg\in HG}\frac{1}{\gamma_{a,hyb}}\cdot x_{a,r,hg,hyb,h}^{ht}+\sum_{p\in P}\frac{1}{\gamma_{a,p}}\cdot x_{a,r,p,h}^{el}+\sum_{q\in Q}\frac{1}{\gamma_{a,q}^{chp,H2}}\cdot x_{a,r,q,h}^{el,chp}+D_{a,r,h}^{H2}\forall a,r,h \tag{B.5}$$

C. Boundaries for the electricity transmission grid capacities

See Table C1.

Table C1
Boundaries for the electricity transmission grid capacities in the system optimization.

Region 1	Region 2	Electricity grid scenario 2030 (MW, fixed)	2040 (MW, max)	2050 (MW, max)	All other scenarios 2030 (MW, fixed)	2040 (MW, max)	2050 (MW, max)
AT_0	BAK_0	950	950	950	950	3950	7900
AT_0	CH_0	870	870	870	870	3870	7740
AT_0	CZ_0	800	800	800	800	3800	7600
AT_0	HUK_0	1550	1550	1550	1550	4550	9100
AT_0	IT_0	1335	1800	1800	1800	4800	9600
BAK_0	HUK_0	190	190	190	190	3190	6380
BAK_0	RO_0	500	500	500	500	3500	7000
BAT_0	FI_0	1000	1000	1000	1000	4000	8000
BAT_0	PL_0	3500	3500	3500	3500	7000	14,000
BEU_0	FR_0	3000	3000	3000	3000	6000	12,000
BEU_0	NL_0	2400	2400	2400	2400	5400	10,800
BUG_0	BAK_0	1268	1268	1268	1268	4268	8536
BUG_0	LY_0	0	0	0	0	3000	6000
BUG_0	RO_0	510	510	510	510	3510	7020
CH_0	FR_0	2850	3150	3150	3150	6300	12,600
CH_0	IT_0	3700	4000	4000	4000	8000	16,000
CZ_0	HUK_0	1150	1150	1150	1150	4150	8300
CZ_0	PL_0	1300	1300	1300	1300	4300	8600
DE_1	DE_2	3121	3506	3506	3506	7012	14,024
DE_1	DE_3	5006	8006	8006	8006	15,506	26,506
DE_1	DE_4	1305	1466	1466	1466	4466	8932
DE_1	DE_6	3560	4000	4000	4000	4000	4000
DE_1	DK_0	1780	2000	2000	2000	5000	10,000
DE_1	NL_0	846	950	950	950	3950	7900
DE_1	NO_0	1246	1400	1400	1400	4400	8800
DE_1	SE_0	534	600	600	600	3600	7200
DE_1	UKI_0	1246	1400	1400	1400	4400	8800
DE_1O	DE_1	30,000	37,500	48,500	30,000	37,500	48,500
DE_1O	DE_3	0	0	0	0	5000	15,000
DE_1O	DE_6	0	0	0	0	5000	15,000
DE_1O	DK_0	0	0	0	0	5000	15,000
DE_1O	NL_0	0	0	0	0	5000	15,000
DE_1O	NO_0	0	0	0	0	5000	15,000
DE_1O	UKI_0	0	0	0	0	5000	15,000
DE_2	DE_4	1235	1388	1388	1388	4388	8776
DE_2	DE_5	5485	6163	6163	6163	12,324	23,324
DE_2	DE_6	1780	2000	2000	2000	2000	2000

(continued on next page)

Table C1 (*continued*)

Region 1	Region 2	Electricity grid scenario 2030 (MW, fixed)	2040 (MW, max)	2050 (MW, max)	All other scenarios 2030 (MW, fixed)	2040 (MW, max)	2050 (MW, max)
DE_2	DK_0	534	600	600	600	3600	7200
DE_2	PL_0	1335	1500	1500	1500	4500	9000
DE_2	SE_0	623	700	700	700	3700	7400
DE_3	BEU_0	890	1000	1000	1000	4000	8000
DE_3	DE_4	1513	1700	1700	1700	4700	9400
DE_3	DE_6	3293	3700	3700	3700	7400	14,800
DE_3	NL_0	534	600	600	600	3600	7200
DE_4	DE_5	2648	2975	2975	2975	5975	11,950
DE_4	DE_6	3783	4250	4250	4250	8500	17,000
DE_5	CZ_0	445	500	500	500	3500	7000
DE_5	DE_6	5340	6000	6000	6000	12,000	23,000
DE_5	PL_0	645	725	725	725	3725	7450
DE_6	AT_0	5896	6625	6625	6625	13,250	24,250
DE_6	BEU_0	2715	3050	3050	3050	6100	12,200
DE_6	CH_0	4450	5000	5000	5000	10,000	20,000
DE_6	CZ_0	668	750	750	750	3750	7500
DE_6	FR_0	2670	3000	3000	3000	6000	12,000
DK_0	UKI_0	980	1400	1400	1400	4400	8800
HUK_0	PL_0	600	600	600	600	3600	7200
HUK_0	RO_0	900	900	900	900	3900	7800
IBEU_0	DZ_0	0	0	0	0	3000	6000
IBEU_0	FR_0	4000	4000	4000	4000	8000	16,000
IBEU_0	MA_0	650	650	650	650	3650	7300
IT_0	BAK_0	1840	2200	2200	2200	5200	10,400
IT_0	BUG_0	500	500	500	500	3500	7000
IT_0	FR_0	2700	2700	2700	2700	5700	11,400
IT_0	TN_0	1000	1000	1000	1000	4000	8000
NL_0	DK_0	700	700	700	700	3700	7400
NO_0	DK_0	1640	1640	1640	1640	4640	9280
NO_0	FI_0	925	925	925	925	3925	7850
NO_0	NL_0	700	700	700	700	3700	7400
SE_0	DK_0	2440	2440	2440	2440	5440	10,880
SE_0	FI_0	2650	2650	2650	2650	5650	11,300
SE_0	NO_0	4995	4995	4995	4995	9990	19,980
SE_0	PL_0	600	600	600	600	3600	7200
UKI_0	BEU_0	1000	1000	1000	1000	4000	8000
UKI_0	FR_0	7690	9700	9700	9700	17,200	28,200
UKI_0	NL_0	1000	1000	1000	1000	4000	8000
UKI_0	NO_0	980	1400	1400	1400	4400	8400

D. Land use factors for renewable electricity generation

See Table D1.

Table D1
Land use factors in the potential calculation of renewable electricity generation technologies. Values in parentheses show the deviations in the *onshore wind scenario* from all other scenarios.

Category	PV rooftop	PV utility scale	CSP	Onshore wind
Barren	0 %	16 %	12 %	18.0 % (9.0 %)
Cropland	0 %	2 %	2 %	14.4 % (7.2 %)
Forest	0 %	0 %	0 %	10.8 % (5.4 %)
Grassland	0 %	2 %	2 %	18.0 % (6.0 %)
Savannah	0 %	2 %	12 %	18.0 % (9.0 %)
Shrubland	0 %	2 %	12 %	18.0 % (9.0 %)
Snow and ice	0 %	4 %	0 %	10.8 % (9.0 %)
Urban	16 %	0 %	0 %	0.0 % (0.0 %)
Water	0 %	0 %	0 %	0.0 % (0.0 %)
Wetlands	0 %	0 %	0 %	0.0 % (0.0 %)

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