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A supply curve of electricity-based hydrogen in a decarbonized European energy system in 2050

Benjamin Lux*, Benjamin Pfluger

Fraunhofer Institute for Systems and Innovation Research ISI, Breslauer Straße 48, 76139 Karlsruhe, Germany

HIGHLIGHTS

- Hydrogen supply curve for decarbonized European energy system 2050.
- E-fuels do not restrain benefits of the expansion of the electricity transport grid.
- Flexibility and efficiency become the most important properties of electrolyzers.
- Marginal hydrogen generation costs of 110 EUR/MWh_{H2} for 1407 TWh_{H2} in Europe 2050.
- Excess electricity is not sufficient to provide substantial amounts of hydrogen.

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ABSTRACT

Alongside substituting fossil fuels with renewable energies and increasing energy efficiency, the utilization of electricity-based hydrogen or its derived synthetic fuels is a potential strategy to meet ambitious European climate protection targets. As synthetic hydrocarbons have the same chemical properties as their fossil substitutes, existing infrastructures and well-established application technologies can be retained while CO_2 emissions in energy conversion, transport, industry, and residential and services can be reduced. However, the conversion processes, especially the generation of hydrogen necessary for all e-fuels, are associated with energy losses and costs. To evaluate the techno-economic hydrogen production potential and the impact of its utilization on the rest of the energy system, a supply curve of electricity-based hydrogen in a greenhouse gas emission-free European energy system in 2050 was developed. It was found that hydrogen quantities of the order of magnitude envisaged in the 1.5 °C scenarios by the European Commission's long-term strategic vision (1536–1953 TWh_{H2}) induce marginal hydrogen production costs of over 110 €$_{2020}$/MWh_{H2} and electrolyzer capacities of more than 615 GW_{el}. Although the generation of these amounts of hydrogen using electrolysis provides some flexibility to the electricity system and can integrate small amounts of local surplus electricity, an additional 766 GW_{el} of wind power and 865 GW_{el} of solar power must be installed to cover the additional electricity demand for hydrogen production. It was furthermore found that the most important techno-economic properties of electrolyzers used in an energy system dominated by renewable energies are the ability to operate flexibly and the conversion efficiency of electricity into hydrogen. It is anticipated that the shown analysis is valuable for both policy-makers, who need to identify research, subsidy and infrastructure requirements for a future energy system, and corporate decision-makers, whose business models will be significantly affected by the future availability of electricity-based fuels.

1. Introduction

To counter the threats of global warming, the international community of states agreed in the 2015 Paris Agreement to limit the global temperature increase to well below 2 °C above pre-industrial levels [1]. Therefore, the European Commission (EC) reconfirmed the objective of reducing greenhouse gas (GHG) emissions in the European Union (EU) by 80–95% compared to 1990 by 2050 [2,3]. The key strategies of the EU for reducing GHG emissions include an increase in energy efficiency of at least 32.5% by 2030 [4], and a renewable energy target of at least 32% of total energy consumption by 2030 [5]. While energy efficiency measures and substituting fossil fuels with renewable energy sources

* Corresponding author.
E-mail addresses: benjamin.lux@isi.fraunhofer.de (B. Lux), benjamin.pfluger@isi.fraunhofer.de (B. Pfluger).

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(RES) are broadly accepted decarbonization strategies, the role of electricity-based hydrogen and other synthetic fuels in reducing GHG emissions remains a topic of discussion.

Hydrogen produced by electrolysis using renewable electricity offers the potential to reduce GHG emissions across sectors. In the electricity sector, wind and solar power are expected to dominate electricity supply in the long run due to their overall generation potential and their economic feasibility [6]. Given the weather-dependent availability of these energy sources, flexibility measures are required to synchronize electricity supply and demand at all times [7,8]. Electricity-based hydrogen can potentially provide flexibility: in hours of negative residual loads, i.e. an oversupply of renewable electricity generation, surplus electricity can be converted into hydrogen by electrolysis. Conversely, stored hydrogen can be converted back into electricity by hydrogen turbines, fuel cells, or other reconversion technologies in hours of high residual loads, i.e. hours of both low renewable electricity generation and high electricity demands. With its long-term storage property, hydrogen is suitable as a seasonal electricity storage medium [9].

Apart from the electricity sector, hydrogen produced from renewable electricity is an option for a GHG emission-free energy supply in transport [10,11], residential and services [12], and as an energy and feedstock supply in industry [13,14]. In these demand sectors hydrogen can either be used directly or after being synthesized into methane (power-to-methane) or liquid hydrocarbons (power-to-liquid).[1] These electricity-based fuels (e-fuels) provide a substitute for fossil fuels while being potentially climate-neutral, depending on the carbon source used in the synthesis processes [15,16] and on the assumption that only renewable electricity is used. As all these e-fuels – hydrogen, synthetic methane and synthetic liquid hydrocarbons – have the same chemical properties as their fossil substitutes, CO_2 emissions in the demand sectors can be reduced while maintaining well-established application technologies. In the cases of synthetic hydrocarbons, most existing infrastructures can be retained.

However, the conversion of electricity into secondary fuels is associated with energy losses and costs. Therefore, the use of hydrogen and its derived synthetic fuels is in competition with alternative flexibility options and decarbonization strategies in the different sectors. In the electricity sector, hydrogen as a storage medium competes with other storage technologies, performant European electricity grids and demand-side management for the most cost-efficient provision of flexibility [17]. In transport, industry, residential and services, where e-fuels can be both energy carriers and industrial feedstock, direct-electric processes and the use of biogenic energy sources are alternative defossilization options.[2] The deployment of e-fuels depends decisively on their costs and available quantities. The costs, in turn, depend to a large extent on the techno-economic properties of the generation processes of these fuels.

Several existing studies [18–23] examine the production costs of e-fuels to evaluate their future role in the energy system. These studies focus on the techno-economic properties of the e-fuel production units and neglect the interactions of these production units with the rest of the energy system. Yet the actual costs and potential applications of these fuels can only be assessed with due consideration of their competition with alternative decarbonization and flexibility options.

Based on these preliminary considerations and due to hydrogen being the basis of all e-fuels, the central research questions in this paper are:

- What is the techno-economic generation potential of electricity-based hydrogen?
- How does the generation of electricity-based hydrogen interact with this energy system?

Addressing these questions allows a better understanding of the technical requirements of hydrogen generation facilities, e.g. in terms of flexibility requirements and for weighing specific investment against conversion efficiency. Realistic long-term cost projections are necessary for determining potential uses of e-fuels and comparisons with other defossilization alternatives.

The analysis is performed for a de-fossilized European electricity system in 2050. In such a system the electricity used for hydrogen generation is by definition entirely renewable. This prevents from second order effects of increased electricity generation from fossil fuels in the interconnected electricity grid.

An energy system optimization model is used to determine a European supply curve of electricity-based hydrogen for the demand sectors. This systemic approach makes it possible to understand the interactions between renewable energies, electricity-based hydrogen production and other flexibility options in the electricity and heat system. Through parameter variations, different technological development paths of electrolysis are taken into account.

The paper is structured as follows: Section 2 introduces the modeling approach, scenario design, and most important input parameters of our analysis. The modeling results are shown in Section 3. In Section 4, findings are summarized and conclusions are drawn.

2. Methodology and data

2.1. Methodology

The working point of this analysis is a de-fossilized European energy system in 2050. In such a system the generation of electricity, heat, and hydrogen is interdependent and ultimately based on weather-dependent renewable energies. Therefore, the energy system optimization model *Enertile* [24], is applied to determine the production cost of electricity-based hydrogen. *Enertile* provides both an integrated perspective on the supply of all three energy forms and a high temporal and spatial resolution of RES in Europe.

2.1.1. Optimization model Enertile

Enertile is a detailed techno-economic optimization model for large, interlinked energy systems. Within a scenario framework, it identifies cost-efficient pathways for the development of the systems up to the year 2050. For every scenario year considered, *Enertile* determines the cost-minimal generation and infrastructure mix to meet exogenously specified electricity, heat and hydrogen demands; this includes both capacity expansion and unit dispatch of renewable energies, conventional power plants, electricity transport, heat and hydrogen generation technologies, energy storage facilities, and demand-side flexibility.

This paper focuses on the supply of hydrogen in an emission-free European energy system in 2050. This limitation with regard to emission requirements and the time frame is reflected in the settings of the model, i.e. only a single year is considered and no fossil generation technologies are available. It should be noted that neither the applied model nor the analysis in general draws conclusions on how the defossilization is achieved in terms of policy measures. The model or its parameterization is intentionally free of technological preferences, choosing the system components solely based on cost-efficiency and technical properties. In reality, different policy mixes could reach the

[1] Throughout the article the following naming convention is used: "E-fuels" is the umbrella term for all gaseous and liquid secondary energy sources produced from electricity. "Power-to-gas" includes all gaseous secondary energy sources produced from electricity, i.e. hydrogen (power-to-hydrogen) and synthetic methane (power-to-methane). "Power-to-liquid" describes all liquid secondary energy sources produced from electricity, e.g. synthetic methanol.

[2] Given the availability of permanent CO_2 storage facilities, there are fossil supply concepts that do not increase the CO_2 concentration in the atmosphere. Here, the CO_2 released during the use of fossil fuels must be extracted from the flue gas stream or the atmosphere and subsequently stored. These concepts are not considered in this paper.

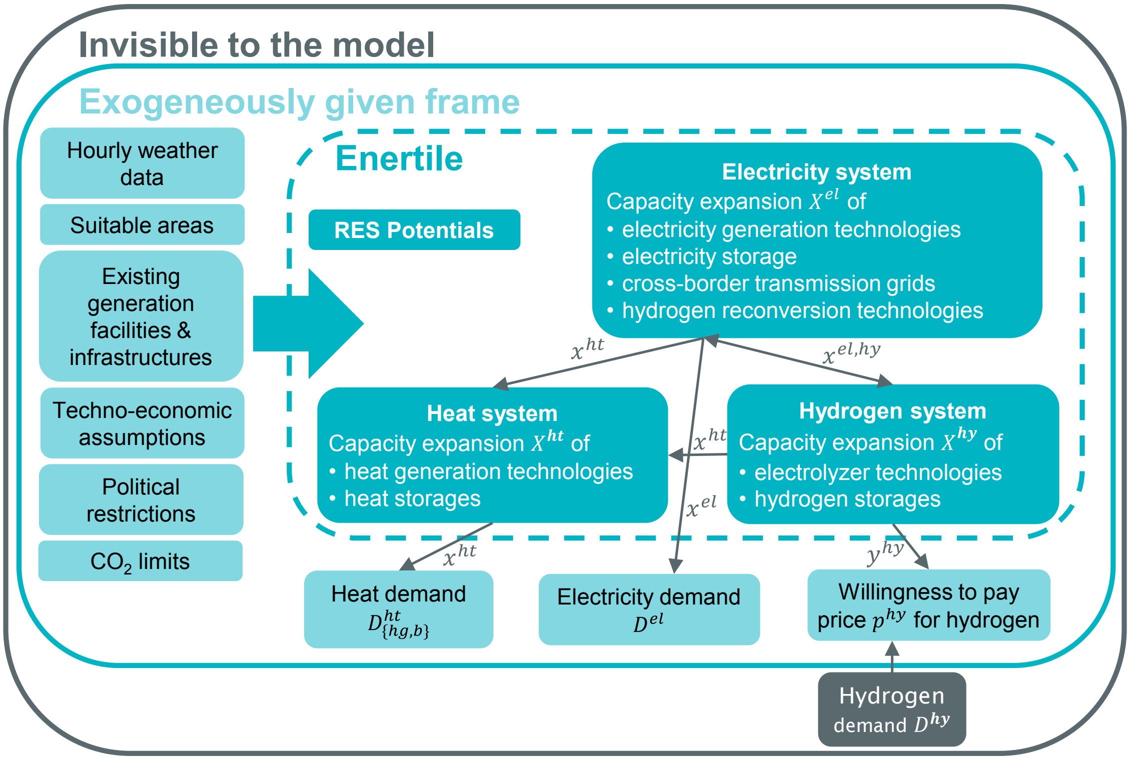

Fig. 1. Graphical illustration of the coverage and boundaries of the energy system model *Enertile*.

resulting or similar system configurations.

For calculations in this paper, *Enertile* was extended by a sales instance of hydrogen. The resulting model variant of *Enertile* is described below. A more extensive and detailed description of the base version of the model is given in [6,25], and [26].

2.1.1.1. Objective function. In *Enertile*, the supply of electricity, heat and hydrogen in Europe is described as a linear cost minimization problem of the overall energy system being considered. In the model, costs associated with the decision variables $\vec{X}$ representing installed capacities of relevant infrastructures and their corresponding unit dispatch $\vec{x}$ increase the overall system cost. Taxes and other levies are not included in the evaluation, since the focus is not on the behavior and reactions of individual market actors but on the overall economic perspective.

In the model, hydrogen supply is treated differently to the supply of electricity and heat. While exogenously specified electricity and heat demands need to be met at every hour considered, there is no explicit hydrogen demand (Fig. 1). Instead, *Enertile* can choose to build electrolyzers that can be used in two ways. Firstly, electrolyzers can be utilized to fill an energy storage unit within the conversion sector. Subsequently, the stored hydrogen can be converted into heat for district heating or reconverted into electricity. Secondly, hydrogen can be sold at price p^{hy} to demand sectors beyond the modeled part of the energy system, .e.g. fuel demand in transport. Potential hydrogen demands of these external sectors are therefore implicitly considered. The hydrogen selling price p^{hy} can be understood as the potential willingness of these sectors to pay for hydrogen. In the model the amount of hydrogen y^{hy} sold to these external demand sectors reduces the total cost of the system. Through the application of different hydrogen sales prices p^{hy}, the resulting hydrogen production potentials display a supply curve for electricity-based hydrogen for the external demand sectors.

The objective function (1) is the sum of costs for the supply of electricity, heat, and hydrogen, minus the remuneration for the sale of hydrogen to external demand sectors, over all regions $r \in R$ and in all 8760 hours $h \in H$ of the modeled year.

$$\min_{\vec{X},\vec{x},y} \sum_{r\in R} \left\{ \sum_{i\in I} \left(\underbrace{(c_i^{fix}\cdot X_{r,i}^{el})}_{\text{capacity expansion electricity supply}} + \underbrace{\sum_{h\in H} c_i^{var}\cdot x_{r,i,h}^{el}}_{\text{electricity generation}} \right) + \sum_{j\in J} \left(\underbrace{(c_j^{fix}\cdot X_{r,j}^{ht})}_{\text{capacity expansion heat supply}} + \underbrace{\sum_{h\in H} c_j^{var}\cdot x_{r,j,h}^{ht}}_{\text{heat generation}} \right) + \sum_{k\in K} \left(\underbrace{(c_k^{fix}\cdot X_{r,k}^{hy})}_{\text{capacity expansion hydrogen supply}} + \underbrace{\sum_{h\in H} c_k^{var}\cdot x_{r,k,h}^{hy}}_{\text{hydrogen generation}} \right) - \underbrace{p^{hy}\cdot y_r^{hy}}_{\text{hydrogen sold to demand sectors}} \right\} \quad (1)$$

Costs for the provision of all three energy forms comprise annuitized fixed costs for capacity expansion and variable costs of all employed technologies. Fixed costs $c^{fix}_{\{i,j,k\}}$ for expanding the capacity of a specific technology include fixed operation and maintenance costs and annuitized specific investments. Variable costs $c^{var}_{\{i,j,k\}}$ of utilizing a specific technology include fuel costs, CO_2 costs, and variable operation and maintenance costs. The underlying technology set I covering electricity supply contains renewable energy technologies, power storage plants, cross-border transmission grids and hydrogen reconversion technologies. The technology portfolio for the supply of heat J includes renewable heating sources, electric boilers, hydrogen boilers, large heat pumps, and heat storage units. Technologies covering the supply of hydrogen are contained in the technology set K and include electrolyzer technologies and hydrogen storage units.

2.1.1.2. Constraints. The central constraints of the minimization problem require that electricity, heat and hydrogen demands are met in every region at every hour of the year. On the one hand, exogenous demands for electricity D^{el} and heat in heat grids D^{ht}_{hg} and buildings D^{ht}_{b} are specified in the model. On the other hand, model endogenous demands can arise from the interdependence of the provision of the different energy forms. The combination of these demands results in so-called demand–supply equations $\mathrm{DS}_{\{\mathrm{el,hg,b,hy}\}}$ for the various energy forms and applications.

The demand–supply equation for electricity $\mathrm{DS}_{\mathrm{el}}$ is shown in Eq. (2). It requires that the sum of net electricity supply of technologies I must match the sum of the exogenously determined electricity demand D^{el}, the electricity demand for heat supply in heating grids and buildings, and the electricity demand for hydrogen generation in each region r and hour h. The net electricity supply includes the pure generation of electricity, the sum of net electricity imports and the net electricity extraction from storage units in a region. The provision of heat in heat grids HG causes electricity demands for the use of heat pumps hpg with conversion efficiency γ_{hpg} and electric boilers eb with conversion efficiency γ_{eb}. Similarly, the provision of heat in buildings B leads to electricity demands if heat pumps hpb with a conversion efficiency γ_{hpb} are used. Hydrogen is generated in the model with a proton exchange membrane electrolyzer pem having a conversion efficiency of γ_{pem}, and increases the electricity demand.

$$[DS_{el}]\quad \begin{aligned}\textstyle\sum_{i\in I} x^{el}_{r,i,h} = {} & D^{el}_{r,h}\\ & + \textstyle\sum_{hg\in HG}\left(\frac{1}{\gamma_{hpg}}\cdot x^{ht}_{r,hg,hpg,h} + \frac{1}{\gamma_{eb}}\cdot x^{ht}_{r,hg,eb,h}\right) \qquad \forall\, r,\, h\\ & + \textstyle\sum_{b\in B}\frac{1}{\gamma_{hpb}}\cdot x^{ht}_{r,b,hpb,h} + \frac{1}{\gamma_{pem}}\cdot x^{hy}_{r,pem,h}\end{aligned} \tag{2}$$

The demand–supply equations for the provision of heat in heat grids $\mathrm{DS}_{\mathrm{hg}}$ and buildings DS_{b} are shown in Eqs. (3) and (4). In both cases the equations require that the sum of net heat supply meets the exogenously specified heat demands $D^{ht}_{\{hg,b\}}$ in each region r and hour h. The net heat supply includes both the pure heat generation and the heat extraction from thermal storage units in a region. Different subsets of the heat supply technology portfolio J are available for the heat supplies in heating grids $L\subset J$ and buildings$M\subset J$.

$$[\mathrm{DS}_{\mathrm{hg}}]\ \sum_{l\in L} x^{ht}_{r,hg,l,h} = D^{ht}_{r,hg,h} \qquad \forall\, r,\, hg,\, h \tag{3}$$

$$[\mathrm{DS}_{\mathrm{b}}]\ \sum_{m\in M} x^{ht}_{r,b,m,h} = D^{ht}_{r,b,h} \qquad \forall\, r,\, b,\, h \tag{4}$$

Eq. (5) shows the demand supply equation of hydrogen $\mathrm{DS}_{\mathrm{hy}}$. It requires that the net supply of hydrogen provided by the technology portfolio K must cover the model endogenous hydrogen demands consisting of the following components: The provision of heat in heat grids HG causes hydrogen demands for the use of hydrogen boilers hyb with conversion efficiency γ_{hyb}. The reconversion of hydrogen into electricity uses the portfolio of reconversion technologies $N\subset I$ with the associated conversion efficiencies γ_n. Additionally, the "sale" of hydrogen y^{hy} to external demand sectors requires hydrogen generation. The net hydrogen supply includes both the pure hydrogen generation and the net hydrogen extraction from storage units in a region.

$$[DS_{\mathrm{hy}}]\quad \sum_{k\in K} x^{hy}_{r,k,h} = \sum_{hg\in HG}\frac{1}{\gamma_{hyb}}\cdot x^{ht}_{r,hg,hyb,h} + \sum_{n\in N}\frac{1}{\gamma_n}\cdot x^{el}_{r,n,h} + y^{hy}_{r} \qquad \forall\, r,\, h \tag{5}$$

Other constraints of the minimization problem require

- that hourly outputs of a generation unit do not exceed the installed capacity of this unit,
- that hourly electricity transfers between regions do not exceed transmission capacities,
- and that storage units only operate within the limits of their technical parameterization; i.e. the amount of energy stored or withdrawn in one time step does not exceed the installed capacity and that the minimum and maximum storage capacity is not violated at any time.

Additionally, political goals such as global or regional CO_2 reduction targets or certain renewable energy expansion targets, as well as technical restrictions such as losses in storage facilities and electricity transport grids can be included as constraints.

2.1.1.3. Temporal and spatial resolution. In the applied version of *Enertile,* the energy system of the year 2050 is modeled in an hourly resolution. This high temporal resolution allows for a realistic representation of the challenges in energy systems with a high proportion of renewable energies. Short-term weather-induced fluctuations in the generation of electricity or heat from renewable energies can be captured, as can long-term weather events such as lulls [27]. The model optimizes expansion and dispatch of relevant infrastructures using perfect foresight.

For the analysis of this paper, *Enertile* covers the energy system in Europe. The geographical coverage of such a large area becomes increasingly necessary as the proportion of renewable energy in the system increases. Shortages in the supply of electricity or heat from renewable sources due to local weather conditions can often be compensated for supra-regionally. Therefore, the spatial extension provides sources of system flexibility. The regional resolution of the model varies according to the subject considered: a very high spatial resolution is used for the potential calculation of renewable energies. In order to determine the possible generation of wind and solar energy, GIS-based models are used to determine renewable energy potentials on a grid with an edge length between 1 km and 10 km.

For other aspects of modeling, such as balancing electricity supply and demand, model regions based on the European national states are applied. Small or strongly interconnected national states are aggregated in some cases. A list and map of the resulting model regions can be found in Appendix C. Within a model region, no further locational information is taken into account during the optimization. This means, for example, that potential network restrictions within a model region are invisible to the model.

2.1.1.4. Renewable energy potential calculation. The electricity generation potential of renewable energies is represented in the optimization program using cost-potential curves. These cost-potential curves are determined for different renewable electricity generation technologies in detailed preliminary calculations. In these calculations, techno-economic data of the generation technologies, hourly weather data, and land use data are used to determine the possible electricity generation on a fine-grained grid for Europe. A more detailed description of the methodology is given in Section 2.2.3, along with a graphical representation of the resulting cost-potential curve used in the optimization.

2.1.1.5. Electricity grid representation. The representation of electricity grids in *Enertile* is reduced to the exchange of electricity between different model regions. Within a model region, potential grid bottlenecks are not taken into account — a so-called *copper plate* is assumed. Existing possibilities of electricity exchange between model regions are represented by a model of net transfer capacities (NTC), which defines the maximum possible exchange capacity for each border between regions. Besides initially available network capacities, the possible network expansion between model regions is influenced by network expansion cost, network losses and the technical and temporal realization possibilities of expansion projects. For each border, step functions define what network capacity is possible at what costs and in what time periods. On this basis, the model can decide which grid

Table 1
Electricity and heat demands in the modeled regions in 2050.

	Electricity (TWh_{el})			Heat (TWh_{th})		Data source
	General[a]	Flexible mobility[b]	Inflexible mobility[c]	District heating grids	Decentralized heat pump systems	
Austria	87.6	6.9	1.7	18.5	20.3	[28]
Other Balkans [d]	126.4 [e]	11.6[f]	2.9[f]	23.0[f]	23.8[f]	
Baltic States	30.3	3.6	0.9	15.6	10.2	[28]
Benelux Union	329.7	26.6	6.6	41.7	86.4	[28]
Bulgaria & Greece	91.1	10.4	2.6	22.1	14.6	[28]
Switzerland	56.2	6.7	1.7	12.7	11.0	[28]
Czech Republic	79.9	6.0	1.5	29.1	23.2	[28]
Germany	640.4	58.4	14.6	131.7	136.7	[28]
Denmark	40.6	5.7	1.4	21.9	18.6	[28]
Finland	103.7	6.3	1.6	24.6	25.0	[28]
France	531.3	62.3	15.5	35.6	138.3	[28]
Hungary & Slovakia	90.3	6.0	1.5	34.0	24.8	[28]
Iberian Peninsula	354.9	32.1	8.0	10.1	64.6	[28]
Italy	374.5	55.8	13.9	106.1	55.4	[28]
Norway	114.5	8.2	2.1	8.2	14.5	[28]
Poland	192.1	11.9	3.0	34.5	33.6	[28]
Romania	78.6	6.3	1.6	24.4	16.6	[28]
Sweden	167.6	13.7	3.4	31.0	19.4	[28]
British Islands	408.4	71.4	17.8	79.7	170.7	[28]
Total	**3898.1**	**409.9**	**102.4**	**704.6**	**907.7**	

[a] The “General” electricity demand is the total of electricity demands from the demand sectors industry, residential and services excluding the electricity demand for heat pumps in buildings.

[b] The electricity demand “Flexible mobility” only contains the electricity demand of cars and assumes that 80% of the cars are charged smartly.

[c] The electricity demand “Inflexible mobility” contains the inflexible load of cars (20%), trolley busses, trains, light duty vehicles, and trolley trucks.

[d] A definition of the model region “Other Balkans” is given in Appendix C.

[e] For member states of the EU “General” electricity demands are taken from the “Centralized” scenario of the REflex project [28]. Other demand estimates are used for the non-EU countries in “Other Balkans”. The basis of these estimates is the total net electricity consumptions in 2016 in these countries [29]. Population figures [30] are used to calculate per capita electricity consumptions in these countries. These per capita electricity consumptions are then extrapolated until 2050 using the average increase in per capita electricity consumption between 2017 and 2040 in the Middle East taken from [31]. With these estimated per capita electricity consumptions in 2050 and projections for population developments [30] the “General” electricity demands in these countries are calculated.

[f] Electricity demands for mobility and heat demands in “Other Balkans” are determined by applying the respective average European ratios of “General” electricity demand and the other demand categories (“Flexible mobility”, “Inflexible mobility, ”District heating grids“, ”Decentralized heat pump systems“). These ratios are used as scaling factors to translate the ”General“ electricity demand of ”Other Balkans“ to the other demand categories.

expansion is cost-efficient to cover the electricity demand in the individual regions.

2.2. Data

In order to investigate the possible supply of hydrogen in a European energy system in 2050, a parameter study is conducted with the energy system model *Enertile*. The focus of the parameter variation is on possible developments in the polymer electrolyte membrane (PEM) electrolysis technology and a varying willingness to pay for electrolytic hydrogen in the demand sectors. The following section presents the underlying scenario framework and techno-economic assumptions pertaining to the modeled technologies.

2.2.1. General framework and scenario design

The following general analysis framework is assumed:

- The cost-minimizing character of our modeling approach makes a substantial use of synthetic fuels at modest decarbonization levels below 80% unlikely. For a lower ambition level, there are more cost-efficient CO_2 reduction measures and flexibility options. This hypothesis was tested with model runs not discussed in this paper. In these scenarios, the resulting CO_2 abatement costs do not reach levels at which electricity-based fuels become competitive with their fossil counterparts. Therefore, the starting point of our analysis is the electricity and heat demands in an 80% decarbonization scenario.
- One option of achieving additional greenhouse gas reductions compared to an 80% decarbonization scenario is by replacing the remaining fossil fuels in the following sectors with e-fuels: energy conversion, transport, industry, residential and services. However, this only applies if the required hydrogen is produced in a CO_2-neutral process. Therefore, the ambition level in the electricity sector is raised and it is assumed that electricity may only be generated from emission-free sources. This includes an intermediate storage of electricity in the form of hydrogen and subsequent reconversion into electricity.
- In order to capture the competition between the use of synthetic energy carriers in the various applications of the demand sectors and their use in the explicitly modeled heat supply in heat grids, no fossil energy carriers are included in the heat generation mix either. Heat generation is therefore also assumed to be emission-free.
- Demands for hydrogen or other synthetic energy carriers by transport, industry, and residential and services are not explicitly modeled. Instead, the model can reduce system costs by selling hydrogen to the demand sectors. In a parameter study, the associated hydrogen sales price is increased in steps of 10 $€_{2020}/MWh_{H2}$.

In summary, a zero-emission generation fleet for electricity, heat and hydrogen is assumed in order to meet the energy demands in an otherwise “80% decarbonization scenario”. This means that the demand for sector coupling options like e-mobility or heat pumps is used widely, but the demand sectors still use a substantial amount of fossil fuels. This setting is chosen to observe the conversion sector at a working point, at which hydrogen or synthetic fuels would come into play. If demands for an almost fully decarbonized energy system were applied, the supply side would already cater for many new needs, e.g. electricity for e-mobility or hydrogen production.

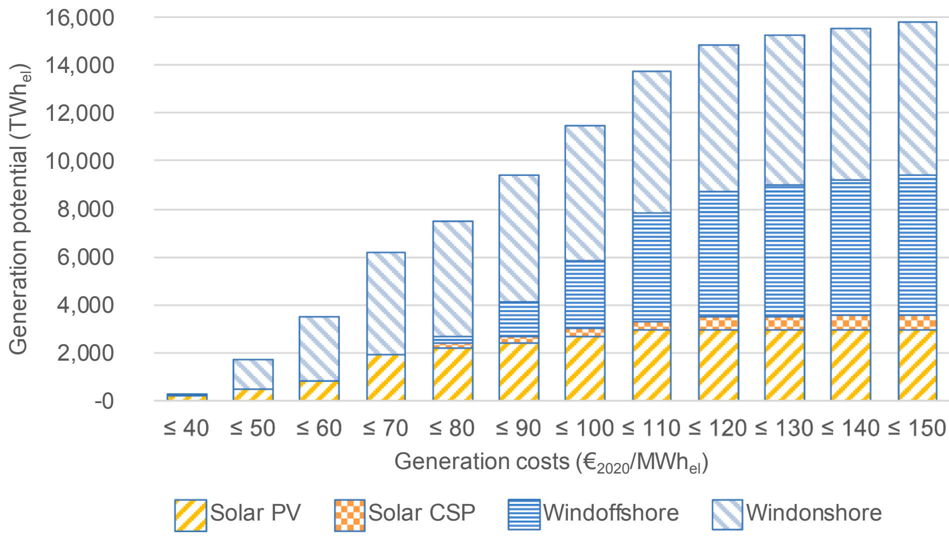

Fig. 2. Electricity generation potentials of renewable energies in all modeled regions in 2050.

2.2.2. *Energy demands*

The analysis in this paper is primarily based on the energy demands developed in the "Centralized" scenario of the European Union's Horizon 2020 project "REflex" [28]. This scenario aims at an 80% reduction in greenhouse gases compared to 1990 across all sectors in Europe. The overarching technological strategy in this scenario is to cover energy demands via central infrastructures if possible. Thus, for example, heat supply in cities is preferably provided by heat grids equipped with large-scale heat storage units and heat pumps. Table 1 shows the demand for heat and electricity in the model regions derived from this scenario. Since the REflex project only takes into account the member states of the EU, Norway and Switzerland, energy demands for non-EU countries analyzed in *Enertile* need to be estimated. The demand estimates for these countries are based on the net electricity consumptions in 2016, estimates on the increase in per capita electricity consumption, and projections of the population development until 2050.

The exogenously specified electricity demand in the model is divided into three categories: firstly, the general electricity demand; secondly, the partly flexible electricity demand from the transport sector (i.e. charging of battery electric vehicles (BEV) and plug-in hybrids (PHEV)); and thirdly, the inflexible demand from the transport sector. The inflexible mobility demand includes the electricity demand for inflexible charging of BEV, PHEV and light duty vehicles, and the electricity demands of trolley trains, trolley buses, and trolley trucks. Certain demand profiles are assumed for each of the three categories. The impact of deviating electricity demands on marginal hydrogen generation costs is analyzed in Section 3.6.

The modeled heat demand includes two categories: firstly, the heat demand in heat grids, and secondly, the heat demand of decentralized heat pumps in buildings.

2.2.3. *Electricity and heat generation*

In addition to the exogenously specified electricity and heat demands, techno-economic information on electricity generators and heat suppliers is included in *Enertile* to parameterize the optimization problem. Weather-dependent renewable electricity generation is included using cost-potential curves. These cost-potential curves are determined for four renewable electricity generation technologies in preliminary calculations before the scenario calculations of the energy system model *Enertile*: For solar energy, two different technologies are distinguished: photovoltaics (PV) and concentrating solar power (CSP). For wind energy, both onshore and offshore potentials are considered.

To determine the electricity generation potential of renewable energies, Europe is divided into tiles using a grid structure. Depending on the distance to the equator, these tiles have a size between 100 km^2 and 10 km^2. For each of the approximately 140000 tiles considered in the analysis of this paper, the renewable generation potential is determined in five steps [27]:

1. Identification of available areas: Based on the terrain (gradient, soil conditions, etc.) and the prevailing land use (nature reserves, buildings, agriculture, military zones, etc.), suitable areas for renewable energy generation are identified.
2. Determination of possible renewable capacities: Based on the available area, a definition of land-use factors for renewable electricity generation, and the specific area required for renewable energies, the possible renewable capacity per tile and technology is determined.
3. Determination of potential renewable electricity generation: Combining the possible renewable capacity with regionally resolved, hourly weather data, possible renewable generation quantities per technology and tile are determined. For wind energy hourly wind speeds over several years are considered. The calculation considers different hub heights, rotor-generator-ratios, wind turbine power characteristics and regional roughness. For solar energy hourly solar irradiation data over several years and module efficiencies are taken into account.
4. Calculation of specific electricity generation costs: The possible generation potentials are weighted with techno-economic data for the individual generation technologies.
5. Aggregation of the potentials within a model region: The renewable generation potentials of single tiles are aggregated according to their specific generation costs; typically, between 3 and 12 cost steps are considered per technology and region.

As a result, regional cost-potential curves for the various renewable generation technologies are available for system optimization, as well as the respective hourly generation profiles. The aggregated results for the modelled regions in 2050 are shown in Fig. 2.

It has to be noted that all long-term technology cost projections are subject to uncertainty; this is especially the case for relatively young technologies in a dynamic market, as is the case for wind and solar power technologies. In the past, especially projections for solar PV did not manage to foresee the fast cost reductions that were achieved [32]. It is almost impossible to forecast cost developments of RES technologies for the next 30 years accurately. However, electricity costs are the most important cost component of hydrogen generated using

Table 2
Techno-economic parameters of electricity generation utilities in 2050 as modeled in Enertile.

	Efficiency (%)	Lifetime (a)	Investment (€$_{2020}$/kW)	Fixed O&M (€$_{2020}$/kW)	Variable O&M (€$_{2020}$/MWh)
Combined cycle hydrogen turbine	60	30	950	11.25	3
Hydrogen turbine	40	30	450	7.5	2.7
Pumped hydro storage	89	40	1100	10	0.5

electrolysis. Since this paper does not attempt to cover all potential RES costs developments, a sensitivity analysis is performed to understand how higher or lower electricity generation costs of RES might impact on hydrogen costs. The impact of deviating electricity generation costs on hydrogen production costs is analyzed in Section 3.5.

The electricity generation capacities of hydropower and biomass are defined exogenously. In the case of hydropower, a distinction is made between run-of-river, which follows a monthly profile, and storage plants, for which the monthly energy sum is distributed by the model taking into account the installed capacities. Biomass power plants in 2050 are modeled like the storage hydropower plants, i.e. the amount of energy has to be distributed by the model.

Non-renewable electricity and heat generation technologies considered in the model are characterized in Table 2. For power generation, hydrogen turbines and combined cycle hydrogen turbines are considered as hydrogen reconversion technologies. At the present time, these technologies do not yet exist for pure hydrogen; however, due to the long experience with combustion processes, it can be assumed that they may be available by 2050. Their techno-economic parameterization in the model is based on comparable combustion plants operated with natural gas. Alternative electricity storage facilities are represented in the model by pumped storage hydropower plants. New nuclear power plants are defined exogenously for the countries that have no phase-out policy in place and see nuclear power as a part of their decarbonization strategy. However, the number of reactors is assumed to decrease compared to today due to their high specific costs.[3]

For heat generation in the model, Table 3 describes techno-economic parameters of hydrogen boilers, electric boilers, large heat pumps and heat storage units. All heating and power generating technologies are characterized by their efficiency, lifetime, specific investment, fixed operation and maintenance cost (fixed O&M) and variable operation and maintenance cost (variable O&M). To convert investment into annual costs in the model, constant weighted average costs of capital of 7% are assumed for all technologies.

Renewable heat generation in heating grids is assumed to account for 20% of the annual heat demand, with solar thermal and geothermal energy each accounting for half of the supply. The solar thermal heat generation follows the solar irradiation profile. The geothermal heat generation profile is assumed to be constant over time.

2.2.4. *Electrolysis*

Currently, there are three main technologies in water electrolysis: Alkaline Electrolysis (AEL), Polymer Electrolyte Membrane Electrolysis (PEMEL) and Solid Oxide Electrolysis (SOEL). The three technologies differ in terms of the electrolyte used, their development stage and their techno-economic properties. From the system perspective that is applied in the analyses presented in this paper, three dimensions of electrolysis characteristics are relevant: firstly, what costs are associated with the technology; secondly, how much energy is used by the technology to produce hydrogen; and thirdly, how flexibly the technology can respond to the fluctuating availability of renewable electricity.

AEL is the most mature electrolysis technology and has been used in industrial applications since the beginning of the 20th century [33]. The electrolyte in AEL is typically an aqueous alkaline solution of sodium hydroxide or potassium hydroxide. Its system efficiency in converting electrical energy into hydrogen is currently in the range of 51% to 60% based on the lower heating value [34]. Specific investments for AEL systems currently range between 800 €$_{2020}$/kW$_{el}$ and 1500 €$_{2020}$/kW$_{el}$ [34]. Operation with intermittent and fluctuating power sources is possible but leads to problems in pilot plants [35]. The minimum load of AEL is limited to 20% to 25% of nominal hydrogen production. While its cold start-up time lies between one and two hours, its warm start-up time ranges between one and five minutes [34].

In PEMEL an acidic proton exchange membrane is used as the electrolyte, which requires the use of noble metals as catalysts, anodes, and cathodes to prevent corrosion [34]. Due to the high material requirements, this electrolysis technology is currently considerably more expensive than AEL with a specific investment of 1400 €$_{2020}$/kW$_{el}$ to 2100 €$_{2020}$/kW$_{el}$ [34]. It is assumed that production costs comparable to those of AEL can be achieved in the mid-term through the upscaling of electrolyzer production and further developments in the materials used [36,37]. The efficiency of a PEMEL system currently ranges between 46% and 60% based on the lower heating value and is thus similar to an AEL system [34]. PEMEL features the most flexible operation of the three technologies, with short cold start-up times of between 5 and 10 min, warm start-up times of less than 10 s, and without technical limits of minimum load [34].

SOEL is still at the pre-commercial development stage. It is operated at 700 °C to 1000 °C and uses a ceramic electrolyte. The high operating temperature can reduce the direct power consumption of the technology, if external heat sources are available. The electrical system efficiency can therefore be increased to between 76% and 81% based on the lower heating value [34]. If no external heat is available, the SOEL's efficiency is similar to that of AEL or PEMEL. Even though SOEL allows for an operating range of -100% (meaning it operates as a fuel cell) to 100%, its flexible utilization is limited. The high operating temperature causes long cold start-up times of up to 10 h and relatively long warm start-up times of 15 min [34,37]. Material degradation caused by high temperatures and steep temperature gradients currently results in short lifetimes of 8000–20000 operating hours and an overall unsuitability of SOELs as a system flexibility option [34,38]. Due to the pre-commercial status, estimates on the current specific investment of SOEL are uncertain and range between 1350 €$_{2020}$/kW$_{el}$ and 3250 €$_{2020}$/kW$_{el}$ [37].

For the analyses in this paper only PEMEL is considered. It is particularly suitable for flexible operation in combination with fluctuating renewable power sources and has the potential to be the technology with the lowest hydrogen production cost in many potential fields of application by 2050. The techno-economic electrolyzer parameters used for the modeling in 2050 are shown in Table 4. Starting from a *central parameter scenario*, the specific investments, the electrical system efficiency, and the lifetime of a PEMEL system are individually varied by 10%. In the *progressive parameter scenario*, all three parameter dimensions are assumed to be simultaneously enhanced by 10%; in the *conservative parameter scenario*, all three parameter dimensions are assumed to be simultaneously weakened by 10%.

3. Results

Below the hydrogen generation potential in Europe in 2050

[3] The high costs are also the reason why the plants have to be defined exogenously; the optimization model chooses the technology only if unrealistically low specific costs are assumed.

Table 3
Techno-economic parameters of heat generation utilities in 2050 as modeled in Enertile.

	Efficiency (%)	Lifetime (a)	Investment (€$_{2020}$/kW)	Fixed O&M (€$_{2020}$/kW)
Hydrogen boiler	94	20	50	1.98
Electric heater	95	20	100	5.54
Large heat pump	variable[a]	20	600	2.4
Heat storage	99	20	22	0

[a] The conversion of power depends on the flow temperature and the hourly outdoor temperature.

Table 4
Techno-economic parameter variation of PEMEL as modeled in 2050.

	Efficiency (%)	Lifetime (a)	Investment (€$_{2020}$/kW)	Fixed O&M (€$_{2020}$/kW)
Progressive	**75**	**30**	**459**	**6.3**
Progressive investment	68	27	459	6.3
Progressive efficiency	75	27	510	7
Progressive lifetime	68	30	510	7
Central	**68** [37]	**27** [37]	**510** [37]	**7** [37]
Conservative investment	68	27	561	7.7
Conservative efficiency	61	27	510	7
Conservative lifetime	68	24	510	7
Conservative	**61**	**24**	**561**	**7.7**

resulting from the model runs is presented and analyzed. Of particular interest are the available quantities of hydrogen for the demand sectors of transport, industry, residential and services, the impact of hydrogen production on the electricity system, the regional distribution of electrolyzer capacities in Europe and the techno-economic drivers determining the deployment of electrolyzers.

3.1. Hydrogen supply curve for demand sectors in Europe in 2050

The hydrogen supply curves determined by the optimization model for transport, industry, residential and services in an emission-free European energy system in 2050 are shown in Fig. 3. Hydrogen production quantities for three different techno-economic development statuses of PEM electrolysis and different hydrogen sales prices (as ex works prices)[4] are given. Hydrogen utilized as an electricity storage medium in the conversion sector is included in the scenario runs, but not included in these supply curves.

The optimization results in Fig. 3 show a disproportional increase in the available quantity of hydrogen for the demand sectors with increasing hydrogen prices. In the *central parameter scenario*, the potential hydrogen supply increases from 0 TWh$_{H2}$ at a sales price of 50 €$_{2020}$/MWh$_{H2}$ to 4111 TWh$_{H2}$ at a sales price of 150 €$_{2020}$/MWh$_{H2}$. In compliance with the 1.5 °C target, the long-term strategic vision of the EC implies a hydrogen demand of about 1536 TWh$_{H2}$ to 1953 TWh$_{H2}$[5] in Europe for industry, transport, residential and services by 2050 [2,39]. The optimization results indicate that hydrogen demands of this order of magnitude entail marginal hydrogen generation costs between 110 €$_{2020}$/MWh$_{H2}$ and 130 €$_{2020}$/MWh$_{H2}$ in the *central parameter scenario*. In the event of a *conservative* techno-economic development of PEM electrolysis, the marginal hydrogen generation costs rise to between 120 €$_{2020}$/MWh$_{H2}$ and 150 €$_{2020}$/MWh$_{H2}$ to cover these hydrogen demands. In the opposite case of a *progressive* techno-economic development, the marginal hydrogen generation costs induced by these demands decrease to between 90 €$_{2020}$/MWh$_{H2}$ and 110 €$_{2020}$/MWh$_{H2}$. A more detailed analysis of the influence of the different techno-economic drivers on the hydrogen generation potential is given in Section 3.4.

3.2. Impacts of hydrogen generation on the electricity sector in Europe in 2050

Besides the potential utilization in the demand sectors, hydrogen can serve as an electricity storage and flexibility option in the conversion sector. In both cases the production of hydrogen using electricity has impacts on the electricity sector.

The results of the scenario analysis in Figs. 4 and 5 show that the production of substantial amounts of hydrogen requires a substantial expansion of the renewable electricity generation fleet. The electricity used to generate hydrogen, which is either used as storage for the conversion sector or to supply the demand sectors, increases from 507 TWh$_{el}$ at a hydrogen sales price of 50 €$_{2020}$/MWh$_{H2}$ to 6106 TWh$_{el}$ at a hydrogen sales price of 150 €$_{2020}$/MWh$_{H2}$. At the lower end of the sales prices at 50 €$_{2020}$/MWh$_{H2,}$ there is no sale of hydrogen to the demand sectors. The electricity consumed by electrolysis at this sales price is ultimately converted back into electricity or heat and therefore remains in the conversion sector. The 146 TWh$_{el}$ of reconverted hydrogen into electricity is the amount the model considers cost-efficient for balancing an electricity system based largely on fluctuating renewable energy. At a hydrogen sales price of 130 €$_{2020}$/MWh$_{H2}$ – which is necessary to reliably cover the hydrogen demands in industry, transport, residential and services in the 1.5 °C scenarios of the EC's long-term strategic vision – the overall electricity demand for hydrogen production rises to 3831 TWh$_{el}$. This increase in electricity demand for hydrogen production causes a capacity increase of 766 GW$_{el}$ wind power and 865 GW$_{el}$ solar power.

The results show positive effects of a flexible operation of electrolyzers and hydrogen storage units on the integration of fluctuating renewable energies into the energy system. Fig. 6 indicates that with an increasing hydrogen sales price up to 110 €$_{2020}$/MWh$_{H2}$ the curtailed renewable electricity is reduced in the model results by between 4% and 18% compared to the curtailment at 50 €$_{2020}$/MWh$_{H2}$. This

[4] The model answers the question of how much hydrogen the supply sector would produce if the willingness of the demand sectors to pay ex works, i.e. without incurring costs after production, such as transport costs etc., reached a given level.

[5] For the 1.5TECH scenario the EU long-term strategy [2,39] indicates the following demands for hydrogen-based energy sources for the industrial, residential & services and transport sectors in 2050: 67.7 Mtoe hydrogen, 44.7 Mtoe e-gas, and 40.7 e-liquids. For the 1.5Life scenario the demands in 2050 are: 60.7 Mtoe hydrogen, 40.7 Mtoe e-gas, 19.6 Mtoe e-liquids. In a simple estimation of the required hydrogen for e-gas and e-liquids production, it is assumed that e-gas is equivalent to synthetic methane and that e-liquids are equivalent to synthetic methanol. The necessary quantities of hydrogen are calculated using the demands of e-gas and e-liquids and the stoichiometric ratios in the Sabatier reaction and methanol synthesis.

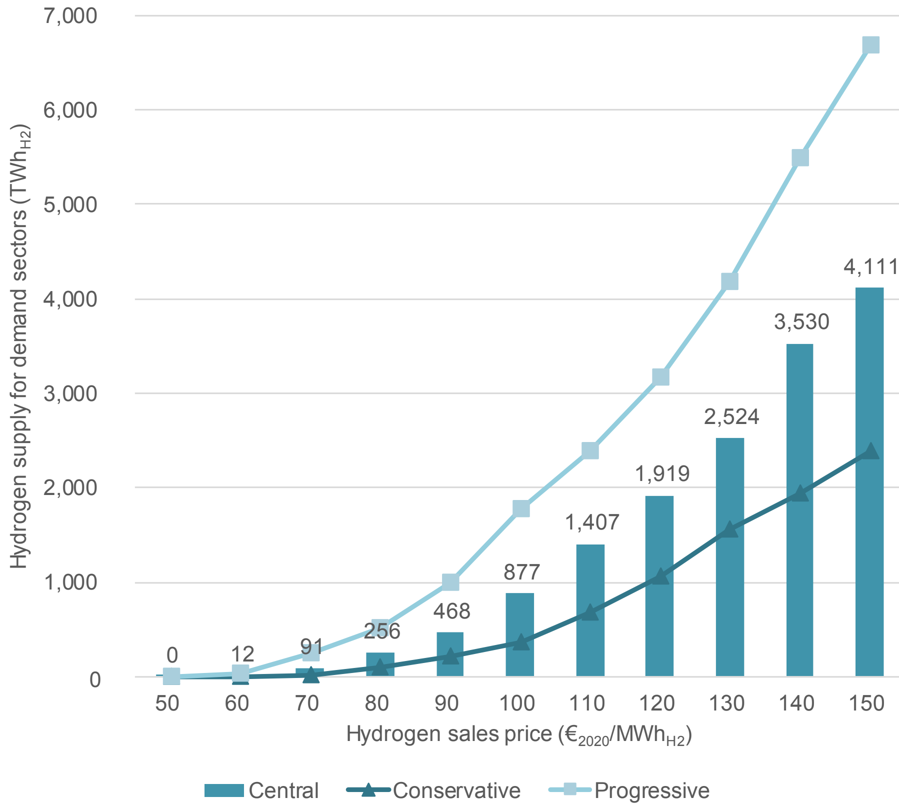

Fig. 3. Hydrogen supply curves for the demand sectors of transport, industry, residential and services in Europe in 2050. Depicted here are available quantities of electricity-based hydrogen at increasing sales prices (ex works) for three different techno-economic development statuses of PEM electrolysis.

happens despite an expansion of the installed renewable generation capacities. Therefore, a certain amount of surplus electricity is used by the model to generate hydrogen. However, hydrogen sales prices exceeding 110 €$_{2020}$/MWh$_{H2}$ lead to higher amounts of curtailed renewable electricity, as renewable capacities are further expanded.

The utilization of hydrogen as an electricity storage medium in the conversion sector decreases with increasing hydrogen sales prices for the demand sectors. While at a hydrogen sales price of 50 €$_{2020}$/MWh$_{H2}$ 146 TWh$_{el}$ of electricity are supplied from hydrogen reconversion, at a hydrogen sales price of 150 €$_{2020}$/MWh$_{H2}$ hydrogen reconversion decreases to 14 TWh$_{el}$ (see Fig. 6). This can be explained by two effects. Firstly, it is the opportunity costs that determine the type of use of electricity-based hydrogen. The model weighs the potential benefits from the sale of hydrogen to the demand sectors against the value of hydrogen as a storage option in the electricity and heating system. The possible profits from the sale of hydrogen to the demand sectors are determined by the price in the scenario definition. The value of hydrogen as an energy carrier and storage medium in the electricity and heating system is determined endogenously in the model on the basis of the supplies and demands in each hour considered. With increasing scenario-specific hydrogen sales prices for the demand sectors, there is an increasing number of alternatives in the electricity and heating system that can offer a supply below these opportunity costs. Secondly, the increase in hydrogen production is accompanied by an increase in the installed capacity of renewable energies. This additional electrical capacity reduces the residual load in hours of high demand and low supply of renewable energies. Consequently, this decreased residual load reduces the need for hydrogen as an electricity storage medium.

With increasing hydrogen sales prices, the generation of hydrogen for the demand sectors becomes the main flexibility option in the electricity system for dealing with an oversupply of renewable electricity. While the production of hydrogen for transport, industry, residential and services increases, the use of hydrogen for reconversion, pumped hydro storage power plants and cross-regional balancing via the transmission grid to integrate an oversupply in the electricity system decreases (see Fig. 6). While the installed capacity remains constant, the use of pumped hydro storage power plants at a hydrogen sales price of 150 €$_{2020}$/MWh$_{H2}$ is reduced by about 69% compared to its utilization at a sales price of 50 €$_{2020}$/MWh$_{H2}$. The total amount of electricity traded between model regions and thus the grid losses decrease by 53% with an increase in the hydrogen sales price from 50 €$_{2020}$/MWh$_{H2}$ to 150 €$_{2020}$/MWh$_{H2}$. However, the total transmission capacity of the grid decreases only slightly by 1%. This implies that at high hydrogen sales prices, local conversion of local electricity surpluses into hydrogen increases and distribution of these surpluses via the electricity grid decreases. Setting aside the regional distribution of hydrogen demands, it also implies that the installed transmission grid capacity is determined by the peaks of the residual loads and not by the provision of hydrogen to the demand sectors. On the other hand, electricity-based heat generation in heat grids increases with rising hydrogen sales prices. While at a hydrogen sales price of 50 €$_{2020}$/MWh$_{H2}$ 249 TWh$_{el}$ electricity are used to generate heat in heat grids, at a sales price of 150 €$_{2020}$/MWh$_{H2}$ the electricity demand for heat generation increases to 286 TWh$_{el}$ (see Fig. 6). This increase in flexible, electrical heat generation is caused by the higher installed capacity of renewable energies at increasing hydrogen production volumes.

3.3. *Installed electrolyzer capacities and full load hours*

The increased hydrogen generation at higher hydrogen sales prices coincides with increasing electrolyzer capacities. Fig. 5 shows in the *central parameter scenario* at hydrogen generation costs of 50 €$_{2020}$/MWh$_{H2}$ an installed electrolyzer capacity of 206 GW$_{el}$ in Europe in 2050. At a hydrogen sales price of 150 €$_{2020}$/MWh$_{H2}$ the electrolyzer capacity increases to 1629 GW$_{el}$. In order to securely meet the hydrogen demands of the demand sectors as postulated in the 1.5 °C scenarios of

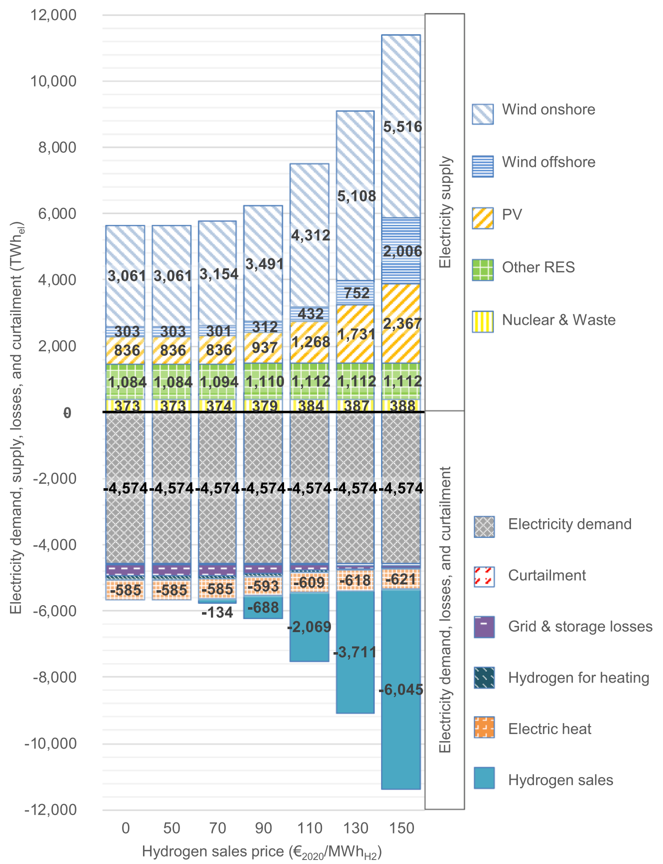

Fig. 4. Electricity demands and supplies in all modeled regions in 2050 with varying hydrogen supply prices for the demand sectors of transport, industry, residential and services. Optimization results are shown for the *central parameter scenario* of PEM electrolysis.

the EC [2,39], the model results indicate that in the *central parameter scenario* between 798 GW_{el} and 1020 GW_{el} of electrolyzers need to be installed.

The average full load hours (FLH) of the electrolyzers increase with rising hydrogen sales prices. At a hydrogen sales price of 50 $€_{2020}/MWh_{H2}$ the electrolyzers are operated at 1670 FLH. With a hydrogen sales price of 150 $€_{2020}/MWh_{H2}$ the model uses electrolysis in 2549 h of the year: the same FLH result for meeting the sectoral demands of the 1.5 °C scenarios of the EC's long-term strategic vision. This increase in electrolyzer FLH is mainly driven by the additional renewable electricity generation plants that are installed by the model to sell more hydrogen to the demand sectors. These additional power plants are not essential to meet other electricity demands and, increase the full load hours of the electrolyzers. Therefore, the proportion of the electricity used for electrolysis increases for the additional RES capacities built in the scenarios with the higher hydrogen sales prices.

3.4. Techno-economic drivers of electrolyzer deployment

The installed electrolyzer capacities and their utilization are strongly dependent on the techno-economic development of the electrolyzer technologies. Fig. 7 shows the changes in the hydrogen supply potential for the demand sectors if the following parameters are varied: specific investment, lifetime, and efficiency of PEM electrolysis.

In the *conservative parameter scenario*, the hydrogen generation potential for the demand sectors is reduced by 38% to 84% depending on the underlying specific hydrogen generation costs. In the opposite case of the *progressive parameter scenario*, the European hydrogen generation potential for the demand sectors increases between 62% and 168% compared to the central case.

The results of the individual parameter variation in Fig. 7 show that the electric efficiency of electrolyzers is most decisive for its deployment in a European energy system primarily based on renewables. While a variation of the specific investment or the lifetime by ± 10% leads to a maximum deviation of 23% in hydrogen generation for the demand sectors compared to the *central parameter scenario*, a variation of the electric efficiency by ± 10% causes a deviation in hydrogen production for the demand sectors of between 36% and 131% compared to the *central parameter scenario*.

Alternatively, the model results can be used to estimate the cost reduction of hydrogen production if the electrolyzer parameters are varied. For this purpose, the supply curves in Fig. 7 are determined by performing linear interpolation between the data points received in the model runs. This allows to determine the distance – i.e. the variation in marginal hydrogen production costs – between the curves for selected hydrogen production quantities. A reduction of the marginal hydrogen production costs would result in a left shift of the supply curve compared to the *central parameter scenario*. Fig. 8 shows the average variations in marginal hydrogen production costs for different parameter variations of PEM electrolysis. It can be seen that an increase in lifetime or a reduction of the specific investment only slightly reduces the marginal hydrogen production costs. While an increase in lifetime by 10% does not affect specific hydrogen production costs significantly, a reduction of the specific investment by 10% reduces the marginal hydrogen production costs on average by 1%. Conversely, a change in the system efficiency of PEM electrolyzers has a disproportionally high effect on the marginal hydrogen production costs: an increase in efficiency by 10% reduces the marginal hydrogen production costs on average by 12%. The disproportionately high effect of an increase in efficiency on marginal hydrogen generation costs is mainly based on the fact that an increase in efficiency by 10% reduces the electricity procurement costs of an electrolyzer – i.e. the most important cost component of hydrogen generation – in two ways. Firstly, the higher efficiency reduces the electricity demand of hydrogen production by 9%. Secondly, the average electricity procurement costs of an electrolyzer are reduced. The higher efficiency would allow an electrolyzer to produce the same amount of hydrogen in 9% fewer hours. Thus, the number of hours with high electricity procurement costs can be avoided. Both effects together allow for a disproportionate effect of an efficiency increase on marginal hydrogen production costs.

3.5. Impacts of renewable electricity cost on marginal hydrogen generation costs

The strong dependence of the electrolyzer deployment on the electric efficiency in the model results is based on the dominance of electricity costs in the hydrogen generation costs. Fig. 9 shows the specific cost components of hydrogen production by electrolysis for increasing hydrogen sales prices in the *central parameter scenario*. The annuitized investments of all electrolyzers – operated to provide both flexibility as electricity storage and supply to the demand sectors – are allocated to the overall amount of hydrogen generated in the model run. The figure shows that the proportion of hydrogen production costs represented by electricity costs increases with increasing hydrogen production from 41% at a hydrogen price of 50 $€_{2020}/MWh_{H2}$ to 87% at a hydrogen price of 150 $€_{2020}/MWh_{H2}$. While low hydrogen production volumes allow the integration of low-cost regional electricity surpluses, increasing production volumes induce the use of electricity with higher procurement costs.

Electricity costs are the most important component of hydrogen generation costs and the electricity system is dominated by fluctuating renewable electricity generation. Therefore, the calculated hydrogen generation costs are sensitive to deviations from the assumed costs for renewable electricity.

Fig. 10 shows the deviations in hydrogen generation from the *central*

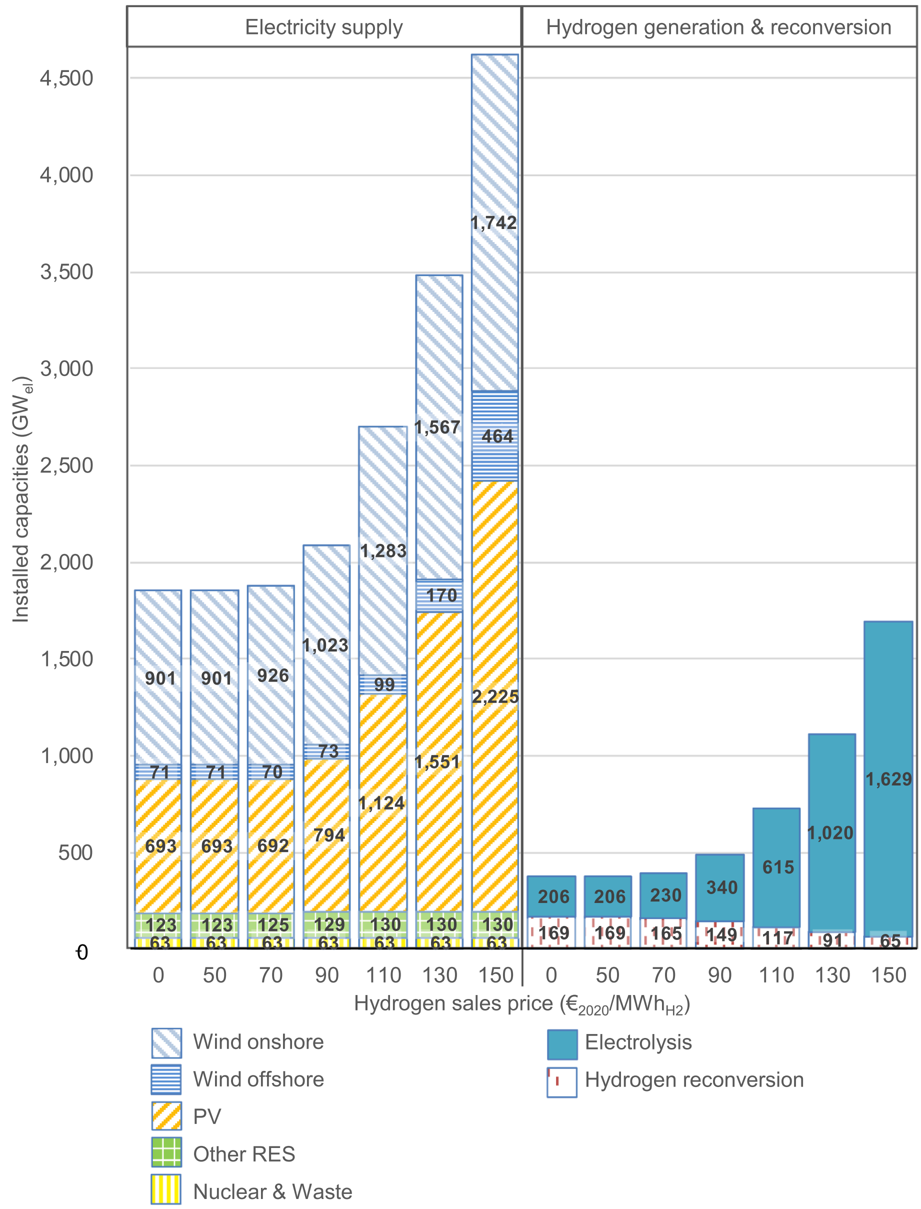

Fig. 5. Installed electric capacities in all modeled regions in 2050 with varying hydrogen sales prices for the demand sectors of transport, industry, residential and services. Optimization results are shown for the *central parameter scenario* of PEM electrolysis.

parameter scenario if renewable electricity generation costs are varied. The supply curves between successive data points are determined by linear interpolation. A reduction of the marginal hydrogen production costs would result in a left shift of the supply curve compared to the central parameter scenario. Fig. 11 shows the average deviations in marginal hydrogen production costs for different changes in RES generation costs, i.e. the distance between the supply curves for selected hydrogen production quantities. The model results in Fig. 10 and Fig. 11 show that the production costs of weather-dependent renewable energies are – as expected – important determinants of the marginal production costs of electricity-based hydrogen. The marginal hydrogen production costs change slightly under-proportionally in the case of a simultaneous reduction of the electricity generation costs from solar and wind energy. A simultaneous decrease in electricity production costs from both wind and solar energy by 10% leads to a decrease in marginal hydrogen production costs by 8%. An equivalent reduction of these electricity generation costs by 20% leads to a reduction of the marginal hydrogen production costs by 17%. The disproportionately lower reduction of hydrogen production costs compared to the decrease in electricity generation costs has two main reasons. Firstly, hydrogen generation costs have other, fixed cost components (see Fig. 9). These fixed cost components remain unaffected by a reduction in electricity cost. Secondly, electricity generation costs of RES are the major, but not the only cost component of the electricity system, both in reality and in the model. Additional costs stem for example from expanding and maintaining the electricity grids and electricity storages. Therefore, reducing RES costs by 10% reduces electricity costs of the whole electricity system by less the 10%.

The model results in Figs. 10 and 11 also reveal that a change in electricity generation costs from wind energy has a greater influence on

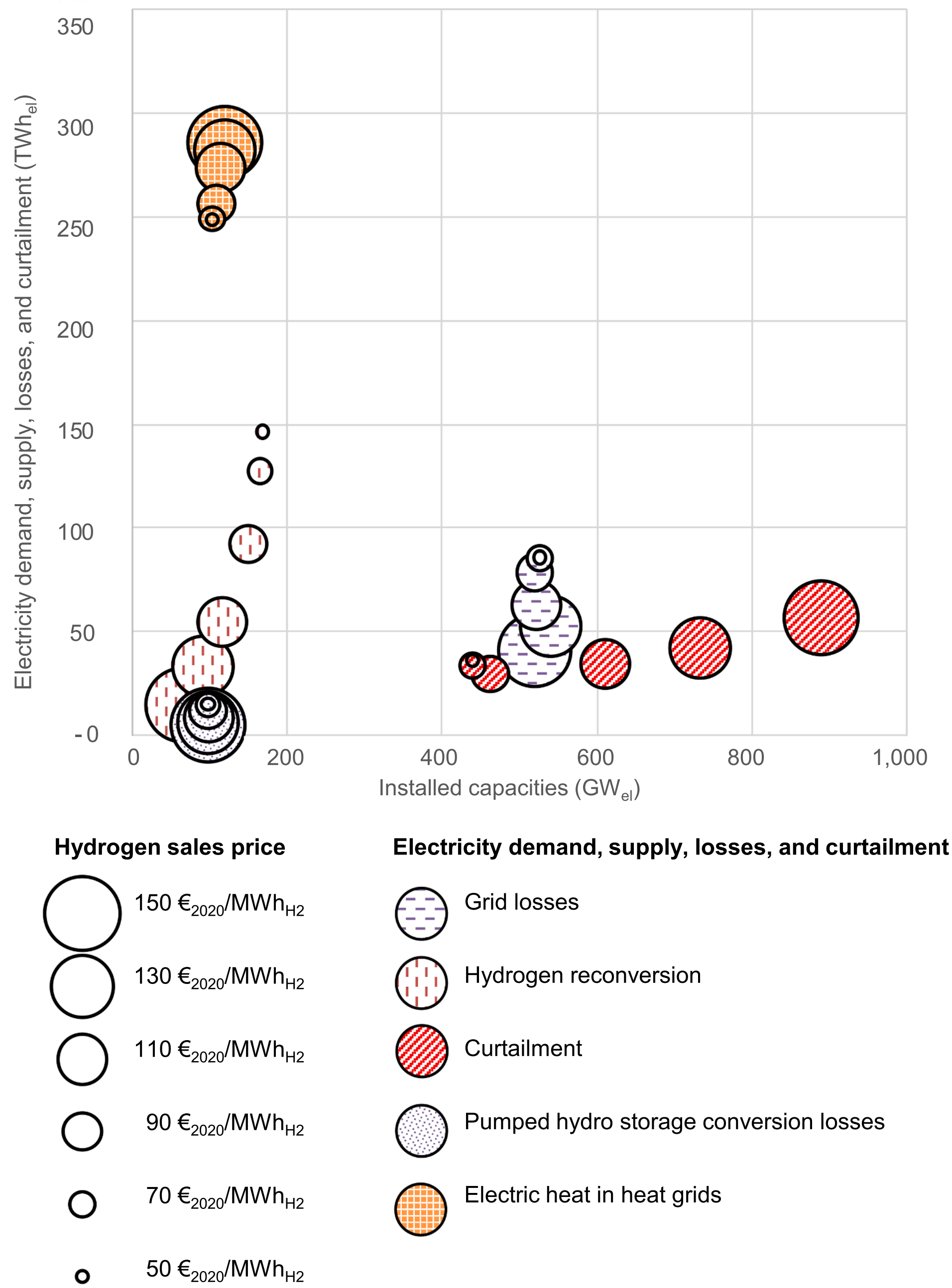

Fig. 6. Influence of increasing hydrogen production quantities at increasing hydrogen sales prices for the demand sectors on other flexibility options in the conversion sector. Optimization results are displayed shown for the central parameter scenario of PEM electrolysis.

marginal hydrogen production costs than changing the costs of solar energy. While a 10% reduction in electricity production costs from wind energy leads to an average reduction in marginal hydrogen production costs of 6%, an equivalent 10% reduction in electricity production costs from solar energy only results in an average reduction in marginal hydrogen production costs of 3%.

3.6. Impact of demand variations on marginal hydrogen generation costs

According to our model results, a change in the total European electricity demand is only expected to have a minor impact on the hydrogen production potential in Europe in 2050. Fig. 12 shows the deviations in hydrogen quantities generated for the demand sectors with varying electricity demands. Simultaneous variations of 10% of both flexible and inflexible electricity demands (as defined in Table 1) are investigated. Applying the same methodology as for the sensitivity analysis of electrolyzer parameters and RES cost – i.e. measuring the side-shift of the supply curve for demand variations – hydrogen generation cost variations are determined. This approach shows that demand variations of ± 10% lead to deviations in hydrogen production costs of up to ± 2%. The deviation of hydrogen generation costs for many points of the supply curve is close to 0%. These results suggest that the generation costs of hydrogen are not substantially depended on other electricity demands and indicate that other parameters have a

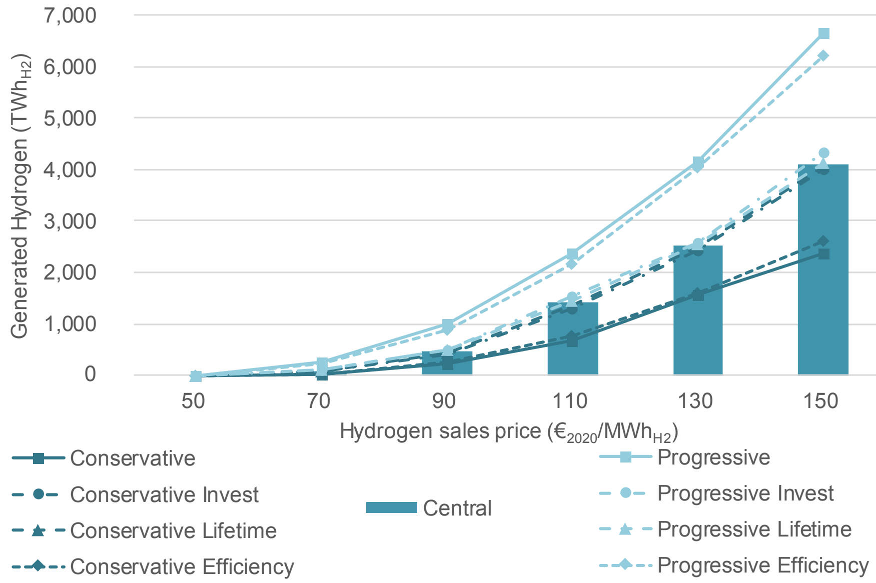

Fig. 7. Hydrogen supply curves for the demand sectors at different hydrogen sales prices (ex works) and with variations of ± 10% in the electric system efficiency, the specific investment, and the lifetime of PEM electrolyzers in Europe in 2050.

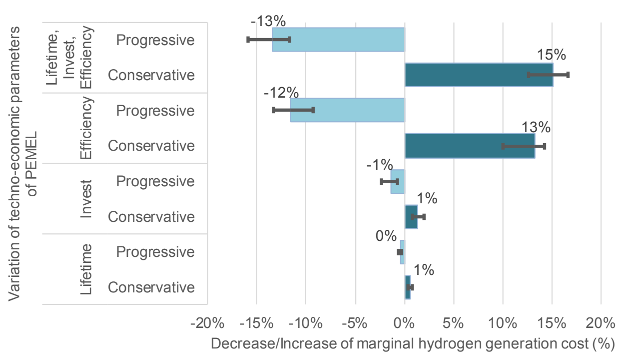

Fig. 8. Variations of the marginal hydrogen production costs for variations of ± 10% in the electric system efficiency, the specific investment, and the lifetime of PEM electrolyzers (The values are determined by calculating the distances between the supply curves of the *central parameter scenario* and the model results of the parameter variations in Fig. 7. The distances are calculated for hydrogen production quantities between 500 TWh_{H2} and 3000 TWh_{H2} in 500 TWh_{H2} steps. The bars represent the mean values of the variations determined. The error bars show the minimum and maximum variations.).

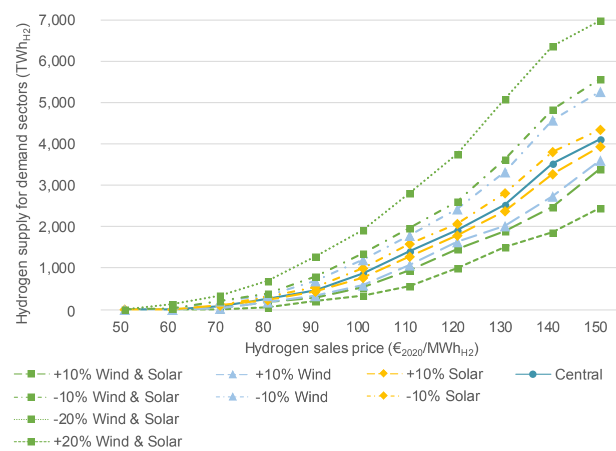

Fig. 10. Hydrogen supply curves for the demand sectors at different hydrogen sales prices (ex works) and with variations of wind and solar based electricity generation costs by ± 10% and ± 20% in Europe in 2050.

much higher impact.

3.7. Regional distribution of hydrogen generation in Europe in 2050

The hydrogen generation potential to supply the demand sectors varies between regions in Europe. Fig. 13 shows the regional distribution of these generation potentials in the model results. While in the *central parameter scenario* in Austria and Switzerland no hydrogen is produced for the demand sectors even at a hydrogen sales price of 150 $€_{2020}/MWh_{H2}$, the generation potential at this price in the UK and Ireland is 689 TWh_{H2}.

The regional distribution of the hydrogen generation potential mainly depends on the quality of national RES potentials still available after the prevailing electricity demand is covered. This characteristic allows the regions modeled in *Enertile* to be grouped into two categories. In regions of the first category, the model chooses to meet the prevailing electricity demands by net electricity imports from other regions in addition to exploiting regional RES potentials. These regions have no substantial hydrogen generation potential. In Europe, these countries include Austria, Switzerland, Germany, the Czech Republic,

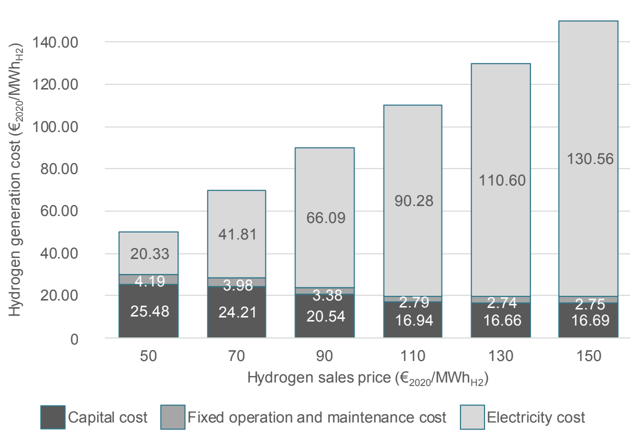

Fig. 9. Price components of electricity-based hydrogen in the *central parameter scenario* of PEM electrolysis.

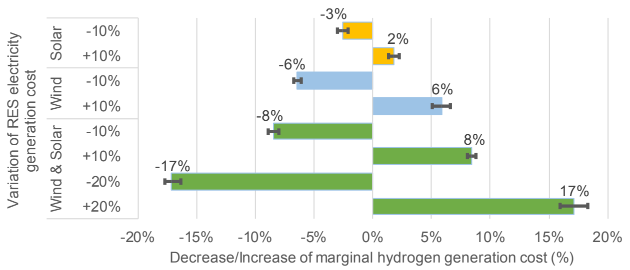

Fig. 11. Variations of the marginal hydrogen production costs for variations of wind and solar based electricity generation costs (The values are determined by calculating the distances between the supply curves of the *central parameter scenario* and the model results of the parameter variations in Fig. 10. The distances are calculated for hydrogen production quantities between 500 TWh_{H2} and 3000 TWh_{H2} in 500 TWh_{H2} steps. The bars represent the mean values of the variations determined. The error bars show the minimum and maximum variations.).

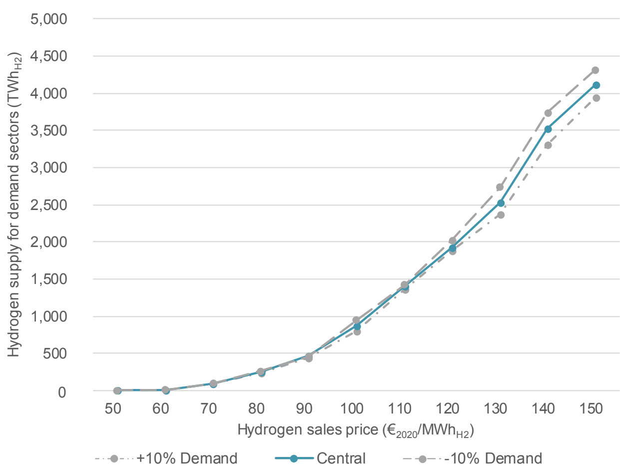

Fig. 12. Hydrogen supply curves for the demand sectors at different hydrogen sales prices (ex works) and with variations of electricity demands in Europe in 2050.

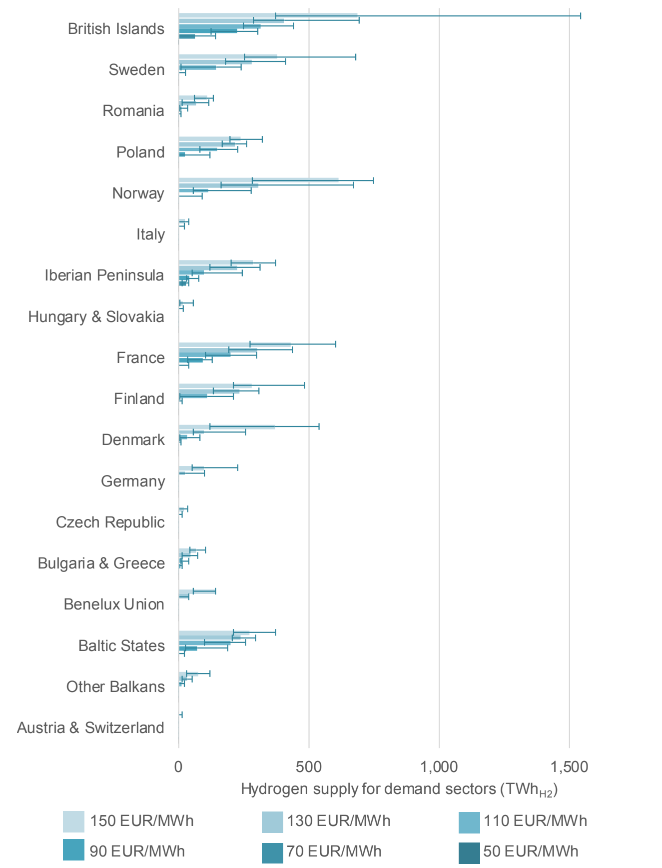

Fig. 13. Hydrogen generation potential for the demand sectors by region in Europe in 2050. The bars show the optimization results of the *central parameter scenario* of PEM electrolysis, while the error bars show the deviations from that result in the *conservative* and the *progressive parameter scenarios* respectively.

Hungary, Slovakia, Italy, and the countries of the Benelux Union. These are countries with a low or costly renewable electricity generation potential compared to their electricity demand. At a sales price of 130 $€_{2020}/MWh_{H2}$, the hydrogen generation potential for the demand sectors of these countries, at 71 TWh_{H2}, accounts for about 3% of the total generation potential in Europe.

The regions in the second category can be characterized by relatively higher RES generation potentials compared to their electricity demands. At a hydrogen sales price of 50 $€_{2020}/MWh_{H2}$, i.e. when no hydrogen production for the demand sectors occurs, these regions are net electricity exporters to regions with a less beneficial ratio between electricity demands and RES potentials. These exporting regions can be distinguished by the type of RES that is predominantly exploited when hydrogen is produced for the demand sectors at higher sales prices. In the UK, Ireland, Sweden, Poland, Finland, Denmark, France, and the Baltic States the high hydrogen generation potentials are driven by the good wind potentials. In these countries, at a hydrogen sales price of 130 $€_{2020}/MWh_{H2}$, 70% of the additional renewable electricity generated in order to produce hydrogen for the demand sectors originates from wind power. By contrast, in Bulgaria, Slovakia and Romania over 70% of hydrogen generation for the demand sectors at a sales price of 130 $€_{2020}/MWh_{H2}$ is covered by an expansion of electricity generation from solar power. In Norway, Portugal and Spain the origin of additional electricity generation for hydrogen production is, at a sales price of 130 $€_{2020}/MWh_{H2}$, more evenly distributed between wind and solar power.

4. Summary and conclusions

This paper examines the production potential for electricity-based hydrogen in a de-fossilized European energy system in 2050. The analysis was carried out using an extended version of the energy system optimization model *Enertile*. The study focuses on possible hydrogen production quantities if certain levels of willingness to pay for hydrogen are assumed. The interactions of the resulting hydrogen production with the rest of the energy system, and the influence of techno-economic electrolyzer characteristics on the hydrogen production potential are analyzed. While the focus of the analysis is on the target state of a de-fossilized European energy system in 2050, the model results allow conclusions on options and needs for action for today's decision makers in politics and economy.

The model results show that hydrogen production of small amounts up to 12 TWh_{H2} starts at marginal production costs of 60 $€_{2020}/MWh_{H2}$. Hydrogen quantities of at least 1536 TWh_{H2} as envisaged in the 1.5 °C scenarios by the EC's long-term strategic vision induce marginal hydrogen production costs of over 110 $€_{2020}/MWh_{H2}$. These costs take into account only the costs of hydrogen production and exclude potential costs of transport and distribution infrastructures or the conversion to other energy carriers such as methane. Based on these long-term cost projections, potential uses of e-fuels can be identified and compared to alternative de-fossilization strategies. For example, a steel producer can use this cost estimate to check whether it is feasible to transform the steel production process to direct reduction with hydrogen generated from renewable electricity in Europe.

In order to generate hydrogen amounts of the order of magnitude envisaged in the EC's scenarios in Europe, electrolyzers with a capacity greater than 798 GW_{el} must be installed. Due to the low demand, electrolyzers are currently manufactured on a small scale only. In 2016, the global annual production volume of electrolyzers was estimated to be below 100 MW_{el}/a [37]. If electricity-based hydrogen produced in Europe at the shown costs is to play a substantial role in the future European energy system, both the available electrolyzer sizes and the production capacity of electrolyzers must be significantly increased soon.

The generation of substantial hydrogen quantities has considerable effects on the electricity system. To provide the electricity required for the production of the hydrogen quantities determined in the EC's scenarios, an additional 766 GW_{el} of wind power and 865 GW_{el} of solar power need to be installed. In 2017 the installed capacities in the EU amounted to 169 GW_{el} of wind power and 107 GW_{el} of solar photovoltaic power [40]; i.e. to cover the additional electricity demand of electrolysis, it would be necessary to increase the installed capacity of wind power by more than four and half times and the installed capacity of solar photovoltaic power by more than eight times. In energy systems dominated by renewable energies the 'fuel' of electrolyzers – electricity – is scarce. Economic evaluations of e-fuel concepts must therefore take into account the competition among electricity consumers for cheap renewable electricity. The expansion of renewable energies should therefore be intensified if e-fuels are to be produced in Europe. Given this order of magnitude of additional renewable energy power plants in the pursuit of strategies with substantial e-fuel quantities, questions of acceptance for these power plants must be addressed.

Due to the long-term storage property of hydrogen and the flexible operation of PEM electrolyzers, a power system dominated by renewable energies can in principle be provided with flexibility through the electrolytic production of hydrogen. The model results show that a high willingness to pay up to 110 $€_{2020}/MWh_{H2}$ for electrolytic hydrogen by the demand sectors can reduce curtailment of renewable energies by 4%, the utilization of electricity transport grids by 27% and the utilization of other storage facilities by 45%. The expansion of grid capacities and installed storage capacities, however, are not reduced in the model results. Therefore, the generation of e-fuels can help to some extent to integrate RES into electricity generation, but it does not undermine the economic benefit of the expansion of electricity transport grids.

The model results show that there are two key techno-economic properties of electrolyzers used in energy systems dominated by renewable energies: Firstly, the technical capability to operate flexibly and secondly, its conversion efficiency of electricity into hydrogen. On the one hand, the results of the system cost minimization show that on average electrolyzers are operated in less than 30% of the hours of a year across all model regions and that their loads often change quickly. This implies that electrolyzers must be able to react flexibly to the fluctuating conditions in an electricity system dominated by renewables. On the other hand, variations of different techno-economic electrolyzer parameters show that in such an electricity system the conversion efficiency of electrolyzers has the greatest influence on marginal hydrogen production costs. By increasing the efficiency by 10%, the specific hydrogen production costs can be reduced by 12% on average. Equivalent improvements in the specific investment or system lifetime of an electrolyzer have a substantially lower impact on specific hydrogen production costs. For the application of electrolyzers in energy systems dominated by renewable energies, the future technological development of electrolyzers should therefore focus on optimizing flexible operation and increasing conversion efficiencies.

Electricity procurement is the largest cost component for hydrogen produced with electrolysis. In a future decarbonized electricity system, wind and solar energy will dominate electricity supply. However, the cost developments of these technologies in the next 30 years are subject to high uncertainty. Therefore, a sensitivity analysis was performed analyzing the impacts of higher and lower electricity generation costs. Reducing the costs of both wind and solar energy by 10% and 20% leads to a decrease in marginal hydrogen production costs by 8% and 17%, respectively. This shows that a steeper technological learning in renewable electricity generation would also allow substantially reduced hydrogen production costs.

Hydrogen production potential is unevenly distributed across Europe. It correlates with the generation potentials for renewable electricity that are not required to cover the remaining electricity demand. Setting aside a hydrogen transport infrastructure that delivers the produced hydrogen to potential customers, the largest and most cost-efficient hydrogen production potential is in the United Kingdom due to its vast wind energy resources. Given this regionally dispersed hydrogen production potential, a European hydrogen transport infrastructure is potentially necessary and should be further explored.

Considering the obtained hydrogen supply curve, it remains unclear whether substantial amounts of hydrogen will be produced in Europe using electrolysis. Actual European production will also depend on hydrogen procurement costs from alternative sources. Firstly, it is possible to import electricity-based hydrogen from regions with more favorable renewable energy potentials such as the MENA (Middle East and North Africa) region. Secondly, the use of carbon storage systems also makes it possible to use hydrogen obtained from natural gas via steam reformation or similar techniques.

CRediT authorship contribution statement

Benjamin Lux: Conceptualization, Methodology, Software, Investigation, Visualization, Data curation, Writing - original draft. **Benjamin Pfluger:** Conceptualization, Methodology, Investigation, Writing - original draft, Supervision.

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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Appendix A. Nomenclature

See Tables A1–A4.

Table A1
Index sets.

Index set	Description
B	Set of building types
H	Set of hours of the year
I	Set of electricity generating technologies, electricity storage technologies, and cross-border transmission grid technologies
J	Set of heat generating technologies and heat storage technologies
K	Set of electrolyzer and hydrogen storage technologies
L	Subset of heat generating technologies and heat storage technologies in heat grids
M	Subset of heat generating technologies and heat storage technologies in buildings
N	Subset of electricity generating technologies for hydrogen reconversion
R	Set of scenario regions
HG	Set of heating grids

Table A2
Indices.

Index	Description
b	Building type index
h	Hour of the year index
i	Electricity generation, electricity storage, and cross-border transmission grid technology index
j	Heat generation and heat storage technology index
k	Electrolyzer and hydrogen storage technology index
l	Heat generation and storage technology in heat grids index
m	Heat generation and storage technology in buildings index
n	Hydrogen reconversion technology index
r	Region index
eb	Electric boiler (part of heating technologies)
hg	Heat grid index
hpb	Heat pump in building (part of heating technologies)
hpg	Heat pump in heat grid (part of heating technologies)
hyb	Hydrogen boiler (part of heating technologies)

Table A3
Parameters.

Parameter	Description
p^{hy}	Hydrogen sales price for external demand sectors €$_{2020}$/MWh$_{H2}$
c_i^{fix}	Annuitized specific fixed cost of technology i in €$_{2020}$/MW$_{el}$
c_i^{var}	Specific variable cost of technology i in €$_{2020}$/MWh$_{el}$
c_j^{fix}	Annuitized specific fixed cost of technology j in €$_{2020}$/MW$_{th}$
c_j^{var}	Specific variable cost of technology j in €$_{2020}$/MW$_{th}$
c_k^{fix}	Annuitized specific fixed cost of technology k in €$_{2020}$/MW$_{H2}$
c_k^{var}	Specific variable cost of technology k in €$_{2020}$/MWh$_{H2}$
$D_{r,h}^{el}$	Electricity demand in region r, and hour h in MWh$_{el}$
$D_{r,hg,h}^{ht}$	Heat demand in region r, heat grid hg, and hour h in MWh$_{th}$
$D_{r,b,h}^{ht}$	Heat demand in region r, building b, and hour h in MWh$_{th}$
γ_{hpg}	Conversion efficiency (electricity to heat) of heat pump in heat grids in %
γ_{eb}	Conversion efficiency (electricity to heat) of electric boiler in %
γ_{hpb}	Conversion efficiency (electricity to heat) of heat pump in buildings in %
γ_{pem}	Conversion efficiency (electricity to hydrogen) of PEM electrolyzers in %
γ_n	Conversion efficiency (hydrogen to electricity) of hydrogen reconversion technology in %
γ_{hyb}	Conversion efficiency (hydrogen to electricity) of hydrogen reconversion technology in %

Table A4
Variables.

Variable	Description
$X_{r,i}^{el}$	Capacity of technology i in region r in MW_{el}
$X_{r,j}^{ht}$	Capacity of technology j in region r in MW_{th}
$X_{r,k}^{hy}$	Capacity of technology k in region r in MW_{H2}
$x_{r,i.h}^{el}$	Unit of electricity supplied or demanded by technology i in region r, and hour h in MWh_{el}
$x_{r,n,h}^{el}$	Unit of electricity supplied by hydrogen reconversion technology n in region r, and hour h in MWh_{el}
$x_{r,j,h}^{ht}$	Unit of heat supplied or demanded by technology j in region r, and hour h in MWh_{th}
$x_{r,b,m,h}^{ht}$	Unit of heat supplied by technology m in region r, building b, and hour h in MWh_{th}
$x_{r,hg,eb,h}^{ht}$	Unit of heat supplied by electric boiler eb in region r, heat grid hg, and hour h in MWh_{th}
$x_{r,hg,hpg,h}^{ht}$	Unit of heat supplied by heat pump hpg in region r, heat grid hg, and hour h in MWh_{th}
$x_{r,hg,hyb,h}^{ht}$	Unit of heat supplied by hydrogen boiler hyb in region r, heat grid hg, and hour h in MWh_{th}
$x_{r,k.h}^{hy}$	Unit of hydrogen supplied or demanded by technology k in region r, and hour h in MWh_{H2}
y_{r}^{hy}	Unit of hydrogen sold to external demand sectors in region r in MWh_{H2}

Appendix B. Abbreviations

See Table B1.

Table B1
Abbreviations.

Abbreviation	Explanation
AEL	Alkaline electrolysis
BEV	Battery electric vehicles
CSP	Concentrating solar power
DS	Demand-supply equation
EC	European Commission
EU	European Union
e-fuels	Electricity-based fuels
FLH	Full load hours
GHG	Greenhouse gas
MENA	Middle East and North Africa
O&M	Operation and maintenance cost
PEM	Polymer electrolyte membrane
PEMEL	Polymer electrolyte membrane electrolysis
PHEV	Plug-in hybrid electric vehicles
PV	Photovoltaics
RES	Renewable energy source
SOEL	Solid oxide electrolysis

Appendix C. Enertile regions

See Fig. C1 and Table C1.

Fig. C1. Map of regions as modeled in *Enertile*.

Table C1
Definition of regions as used in Enertile, Table 1, Fig. 13, and Table D1.

Enertile region code	Countries	Term Table 1	Term Fig. 13/ Table D1
AT	Austria	Austria	Austria & Switzerland
CH	Switzerland	Switzerland	Switzerland
DE	Germany	Germany	Germany
FR	France	France	France
IBEU	Spain, Portugal	Iberian Peninsula	Iberian Peninsula
BEU	Belgium, Luxembourg	Benelux Union	Benelux Union
HUK	Hungary, Slovakia	Hungary & Slovakia	Hungary & Slovakia
UKI	United Kingdom, Ireland	British Islands	British Islands
PL	Poland	Poland	Poland
BUG	Bulgaria, Greece	Bulgaria & Greece	Bulgaria & Greece
BAK	Slovenia, Croatia, Bosnia and Herzegovina, Serbia, Kosovo, Montenegro, Albania, North Macedonia	Other Balkans	Other Balkans
BAT	Estonia, Lithuania, Latvia	Baltic States	Baltic States
CZ	Czech Republic	Czech Republic	Czech Republic
DK	Denmark	Denmark	Denmark
IT	Italy	Italy	Italy
NO	Norway	Norway	Norway
RO	Romania	Romania	Romania
SE	Sweden	Sweden	Sweden
NL	Netherlands	Benelux Union	Benelux Union

Appendix D. Regional results

See Table D1.

Table D1
Hydrogen generation potential for the demand sectors by region in all modelled regions in 2050 as shown in Fig. 13.

	Conservative parameter scenario						Central parameter scenario						Progressive parameter scenario					
	50 $€_{2020}$/MWh	70 $€_{2020}$/MWh	90 $€_{2020}$/MWh	110 $€_{2020}$/MWh	130 $€_{2020}$/MWh	150 $€_{2020}$/MWh	50 $€_{2020}$/MWh	70 $€_{2020}$/MWh	90 $€_{2020}$/MWh	110 $€_{2020}$/MWh	130 $€_{2020}$/MWh	150 $€_{2020}$/MWh	50 $€_{2020}$/MWh	70 $€_{2020}$/MWh	90 $€_{2020}$/MWh	110 $€_{2020}$/MWh	130 $€_{2020}$/MWh	150 $€_{2020}$/MWh
Austria & Switzerland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12
Other Balkans	0	0	0	11	34	75	0	0	0	0	13	31	0	0	2	21	55	123
Baltic States	0	1	74	199	236	271	0	0	27	98	206	212	0	24	191	260	296	373
Benelux Union	0	0	0	0	39	143	0	0	0	0	0	57	0	0	0	0	39	143
Bulgaria & Greece	0	0	9	14	47	68	0	0	1	11	14	43	0	1	13	42	74	105
Czech Republic	0	0	0	0	0	19	0	0	0	0	0	0	0	0	0	0	16	38
Germany	0	0	0	0	27	98	0	0	0	0	0	54	0	0	0	0	101	226
Denmark	0	0	0	35	97	370	0	0	0	6	55	123	0	0	8	84	259	538
Finland	0	0	2	111	234	280	0	0	0	8	135	209	0	0	13	210	310	484
France	0	0	93	202	303	429	0	0	35	103	196	274	0	40	130	302	437	602
Hungary & Slovakia	0	0	0	0	5	19	0	0	0	0	0	8	0	0	0	0	20	56
Iberian Peninsula	0	27	41	97	224	286	0	15	32	54	122	202	0	39	80	244	314	373
Italy	0	0	0	0	0	26	0	0	0	0	0	0	0	0	0	0	21	39
Norway	0	0	0	116	305	613	0	0	0	57	164	283	0	0	91	280	670	748
Poland	0	0	25	150	218	238	0	0	0	82	169	200	0	0	123	226	262	322
Romania	0	0	0	13	66	109	0	0	0	6	12	60	0	0	8	34	115	133
Sweden	0	0	0	145	281	380	0	0	0	9	180	254	0	0	26	240	409	682
British Islands	0	63	225	313	406	688	0	0	125	247	289	373	0	141	306	442	692	1541

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