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European Energy Transition

Germany in the Heart of Europe

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Executive Summary

The European Union acknowledges climate change as an existential threat and is pursuing a growth strategy through the European Green Deal that envisions the development of a resource-efficient and competitive economy while at the same time adhering to climate protection measures [1, 2]. These measures include Europe achieving net-zero greenhouse gas emissions by 2050. As an interim target, net greenhouse gas emissions are to be reduced by 55% by 2030 compared to 1990 levels [3]. Achieving these goals will require a holistic transformation of the European energy system. Against this background, the question arises as to which pathways and strategies are available to achieve these objectives in Europe and what role Germany will play given its central location.

For this study, a scenario for the transformation of the European energy system has been developed, which is aligned with the reduction targets set for Europe. The analyses are supplemented by further detailed studies in order to be able to map aspects such as the development of European hydrogen infrastructures and their robustness under various conditions. The analyses are carried out using the ETHOS (**E**nergy **T**ransformation **P**athway **O**ptimization **S**uite) model family, which was developed by the Jülich Systems Analysis institute (ICE-2) at Forschungszentrum Jülich [4]. This allows energy systems to be mapped on different scales, taking into account the interactions between the individual sectors. The model family includes, among others, models for the detailed mapping of wind power and photovoltaic expansion and generation potentials and for the mapping of global energy markets and possible energy imports and exports. In addition, integrated infrastructure analyses can be carried out while taking all relevant energy carriers into account.

The scenarios presented here show cost-optimized strategies for achieving the transformation of the European energy system. At the core of the analyses carried out here is the ETHOS.Europe energy system model, which maps the European energy supply with the infrastructures for electricity, natural gas and hydrogen and enables cost-optimal transformation strategies for Europe to be calculated with a high spatial resolution. While adhering to exogenously set framework conditions, which include greenhouse gas reduction targets, for example, the model minimizes the transformation costs for the European energy supply system. In doing so, the specified energy demand must be met every hour.

The analyses show that greenhouse gas neutrality can only be achieved through a fundamental restructuring of the European energy supply. From a technical and economic point of view, this restructuring is feasible, but it requires all European players to act collectively.

Our results show that ...

1. The **expansion rates of wind and PV plants** must be increased four to fivefold in order to ensure a cost-optimized greenhouse gas-neutral energy supply in Europe. The expansion of renewables will take place in all countries. The high expansion rates will promote domestic, competitive hydrogen production and reduce the need for extra-European hydrogen imports and reelectrification.

2. For a **collective transformation**, a significant **increase in exchange capacities** between countries is necessary in order to make optimal use of renewable energy potential. This applies to both the electricity and hydrogen networks. Expanding exchange capacities also promotes resilience to periods of low wind and low sunlight, as energy flows from unaffected regions can compensate for lower production times.

3. Higher expansion rates for renewables lead to lower overall system costs. If current average expansion rates continue and the expansion of renewables is thus delayed, overall costs will rise by 6%. In addition, **dependence on energy imports from outside Europe** will increase, as Europe cannot produce enough hydrogen at competitive costs.

4. **European hydrogen is competitive** with hydrogen imported from extra-European countries. In 2030, European hydrogen will be competitive at world market prices of €3.20/kg. In 2050, this will be the case at world market prices of €2.20/kg.

5. **Nuclear energy** is not competitive with PV and wind unless investment costs are drastically reduced. Even with low investment costs, the share of nuclear energy in electricity production will remain below 15%.

6. The expansion of hydrogen storage and reelectrification facilities can be used as additional **flexibility options** to compensate for **periods of low wind and low sunlight**. Underground hydrogen storage is a cost-effective option but has the disadvantage that the geological conditions are not suitable in all regions of Europe. Joint action is therefore even more important for the use of this option.

7. **Germany** will import most of its energy demand, as the location conditions for green electricity and hydrogen production are more economical in other regions of Europe. In this context, Germany benefits from its central geographical position.

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Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work, the authors used ChatGPT and DeepL to translate the original German written report and improve the language of the manuscript. After using this tool/service, the authors reviewed and edited the content as needed and they take full responsibility for the content of the published report.

1 Introduction

The European Union acknowledges climate change as an existential threat and is pursuing a growth strategy through the European Green Deal that envisions the development of a resource-efficient and competitive economy while at the same time adhering to climate protection measures [1, 2]. These measures include Europe achieving net-zero greenhouse gas emissions by 2050. As an interim target, net greenhouse gas emissions are to be reduced by 55% by 2030 compared to 1990 levels [3]. After Russia launched its war of aggression against Ukraine, the European Commission presented the REPowerEU plan, which sets out measures to achieve a more resilient energy system and a genuine energy union [5]. This plan aims to diversify supply and accelerate the energy transition. Concrete measures to be taken by 2030 include expanding renewable energy to over 1,200 GW, producing 10 Mt of green hydrogen domestically and importing 10 Mt of green hydrogen. Achieving these goals requires a transformation of the entire European energy supply.

This study aims to answer the question of how the goal of greenhouse gas neutrality can be achieved in all sectors across Europe. The analysis focuses on a joint European approach that takes into account the specific characteristics of each country. It is assumed that all countries will work together to achieve their objectives. The transformation path from 2030 to 2050 will be analyzed in detail. Furthermore, the analysis places particular emphasis on supplying Germany, which is characterized by its location in Central Europe, its large number of neighboring countries, its high population and its industry.

The analyses carried out here focus on the ETHOS.Europe energy system model, which maps the European energy supply with the infrastructures for electricity, natural gas and hydrogen and enables cost-optimized transformation strategies for Europe to be calculated with high spatial resolution. The model is part of the ETHOS (**E**nergy **T**ransformation Pat**h**way **O**ptimization **S**uite) model family developed at the Institute of Climate and Energy Research – Jülich Systems Analysis at Forschungszentrum Jülich, which can be used, among other things, to calculate cost-optimized greenhouse gas reduction strategies for Germany and Europe at various levels of detail.

2 Methodology

The analyses are carried out using the ETHOS (**E**nergy **T**ransformation **P**athway **O**ptimization **S**uite) model family, which was developed by the Institute of Jülich Systems Analysis (ICE-2) at Forschungszentrum Jülich [4]. This model can be used to map energy systems on different scales with high temporal and spatial resolution, taking into account the interactions between the individual sectors. An overview of the various model areas covered by ETHOS is presented in Figure 2-1. The wide range of models allows a variety of issues to be addressed. The advantages of the model family include [4, 6]:

- High temporal and spatial resolution
- Detailed mapping of sector coupling
- Location-specific potential analysis of renewables
- Modelling of future global energy markets
- Identification of robust greenhouse gas reduction strategies

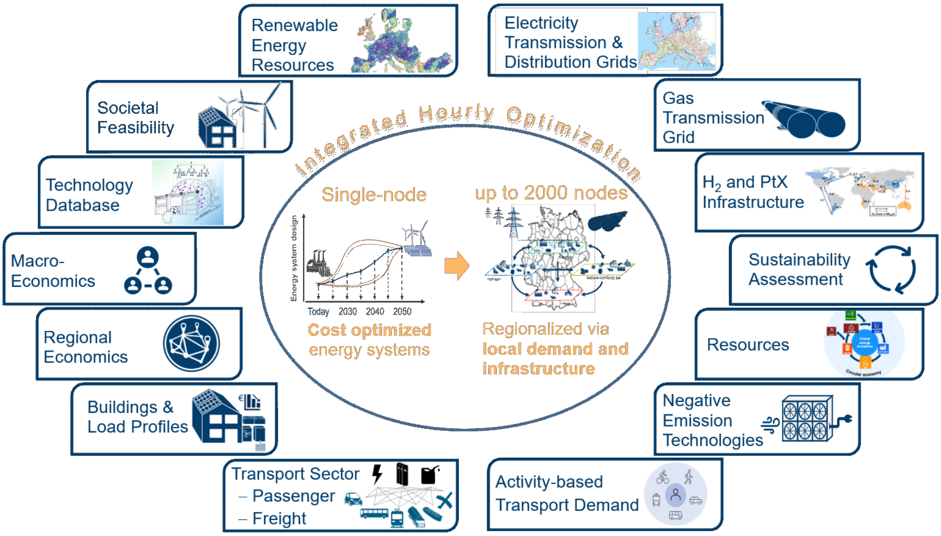


Figure 2-1. ETHOS model family [4] using the ETHOS.FINE framework [7].

The ETHOS.Europe energy system model has been developed for the present analyses, which uses the open-source Python package ETHOS.FINE (**F**ramework for **In**tegrated **E**nergy System Assessment) [7] as the modelling basis. ETHOS.FINE allows the modelling and optimization of energy systems with high spatial and temporal resolution. The objective function is to minimize the total annual costs of the energy system, while taking into account technical or other restrictions.

2.1 Modelling of the European energy system

Figure 2-2 shows an overview of the components modelled in the ETHOS.Europe model. The model depicts an energy system for the 27 member states of the European Union together with the United Kingdom, Norway and Switzerland. The countries are divided into regions based on the NUTS classification (Nomenclature des Unités territoriales statistiques) [8] . In order to ensure the computability of the model, the NUTS-1 subdivision was chosen for spatial representation. In Germany, this corresponds to the federal state level. This results in a total of 100 regions. In addition, 76 offshore regions were defined in order to be able to map the use of wind energy, natural gas production and the transport of energy sources at sea in greater detail. The region definition corresponds to the exclusive economic zones (EEZ) of the countries considered.

Modeling is carried out with hourly resolution, i.e. one year is optimized with 8760 time steps. The transformation path analysis is carried out for the years 2030, 2040 and 2050. The years considered are linked using a myopic approach [9]. The modeled years represent investment periods. Installed capacities from previous investment periods are carried over to subsequent years, provided that the technical service life has not been exceeded. Costs for the dismantling of technologies or components are not taken into account.

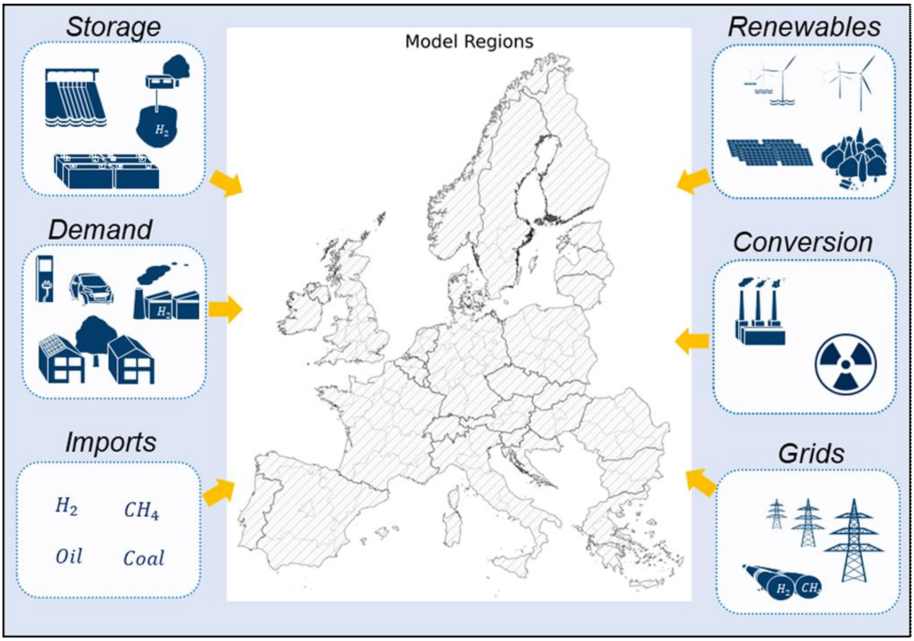


Figure 2-2. Overview of the ETHOS.Europe model.

The following sections provide a detailed description of the model components to give an overview of the model, starting with the modeling of renewables and then describing the conversion technologies, storage technologies and transport options taken into account. Another section covers the modeling of the imports and production of the energy carriers considered. The demand side is represented as purely exogenous. This means that the spatially and temporally resolved demands are determined in an upstream model and transferred to the Europe model as input. The description of the demand model and the generation of demand scenarios can be found in Section 2.2.

2.1.1 Renewable energy sources

In the model, onshore and offshore wind turbines, photovoltaics, hydropower and biomass are embedded as renewable energies.

For onshore wind, offshore wind, rooftop and ground-mounted photovoltaics, and hydropower, existing plants are considered in the model. The installed capacities and generation time series for hydropower are taken from [10] and date from the year 2015. Based on [11], no further expansion of hydropower capacity is planned in the model, as it is assumed that the capacity for hydropower plants in Europe is almost exhausted and no new plants will be built.

Data on the locations and capacities of existing wind turbines are taken from [12]. These data are processed in accordance with the methodology described at [13]. Missing information on turbine parameters, such as rotor diameter or hub height, is estimated based on the total number of installed turbines.

The existing capacities of existing rooftop and ground-mounted photovoltaic systems are derived from [14, 15]. For the simulation of electricity generation, the orientation of existing ground-mounted photovoltaic systems is assumed to be south-facing. Rooftop photovoltaic systems are assumed to be evenly distributed with south, south-west and south-east orientations. With regard to the tilt angle, an ideal tilt angle is considered for each country based on data from [16] and assigned to each system depending on its location. The locations of the existing systems are then simulated using the ETHOS.RESKit tool [17] for the weather year considered in the model run.

The ERA5 data set is used as the weather data set, using the methodology described in [13]. For wind turbines, wake effects and general turbine losses are also taken into account in accordance with the method described in [13], and the correction is applied to generation data from the International Energy Agency (IEA). ETHOS.RESKit thus provides hourly resolution generation time series for onshore wind, offshore wind, rooftop and ground-mounted photovoltaics per location, which are used as input for the European energy system model. Due to the ongoing expansion of renewable energies in Europe, existing capacities are scaled to the 2022 value based on data from the IEA [18]. Depending on the target year and technical service life, the decommissioning of existing plants is also taken into account based on IEA data.

In addition, capacity expansion potential for onshore wind, offshore wind, rooftop and ground-mounted photovoltaics are implemented in the model. The construction of new biomass CHP plants is also possible. The potential for ground-mounted photovoltaics comes from [19] and for offshore wind from [20]. The potential for onshore wind is based on [21]. For the rooftop photovoltaics potential, [22] is used, which provides the roof area potential as a 100m x 100m grid for Europe. Since the angle of inclination and orientation of the roof areas are not specified, a distribution based on [23] is assumed, which is based on real data for Germany. The *LG Electronics LG370Q1C-A5* module is used for rooftop and the *WINAICO WSx-240P6* module for ground-mounted systems, with efficiencies projected into the future according to [19] in order to simulate generation time series.

An overview of assumed capacities of existing plants and expansion potential can be found in Table 1. Investment costs for existing plants and expansion potential for onshore wind, rooftop and ground-mounted photovoltaics are taken from [24]. The investment costs for offshore wind are taken from [25].

Table 1. Assumed capacity of existing plants and expansion potential for renewable energies in Europe.

Technology	Existing plants [GW]	Expansion potential [GW]
Onshore wind	160	6,884
Offshore wind	26	11,178
Ground-mounted PV	59	14,512
Rooftop PV	235	3,589

2.1.2 Conversion

The model takes into account various energy conversion technologies in order to meet energy demands. These include the conventional power plant types available in Europe, including lignite-fired power plants, hard coal-fired power plants, nuclear power plants, gas-fired power plants and oil-fired power plants. The locations and installed capacities of existing plants are taken from powerplantmatching [14]. Efficiencies, emission factors and technical operating times are stored in the model on a technology-specific basis based on the assumptions from [24]. Due to current developments in the EU, it is assumed that the operating life of nuclear power plants will be extended to 60 years. As total emissions per country are limited, the operation of power plants with CO_2 emissions is only possible within the scope of these national restrictions. To determine the installed capacity per region, all existing power plants per region are aggregated and entered as input in the model.

Due to the long construction and planning times involved in nuclear energy, new capacity will not be available until after 2035. In addition, new construction can only take place in countries where, according to Global Energy Monitor [26], nuclear power plants are already under construction or planned. As some countries in Europe are planning to phase out nuclear energy and coal-fired power generation, the model takes into account the decommissioning of nuclear and coal-fired power plants. To this end, the planned year of phase-out of nuclear energy and coal-fired power generation was researched at country level and taken into account in the model.

Other conversion technologies considered include proton exchange membrane (PEM) electrolyzers for the production of green hydrogen, as well as fuel cells and gas turbines for hydrogen-based power generation. As it is assumed that some of the hydrogen will be imported into Europe in liquid form, the expansion of regasification plants is also permitted in import regions.

2.1.3 Storage

Storage technologies include options for storing hydrogen, natural gas, electricity and liquid hydrogen.

Natural gas storage facilities are available in the model in the form of geological storage facilities, with a distinction being made between caverns and aquifers. The capacities and locations of existing cavern and aquifer storage facilities are taken from the GIE Storage Database [27]. Offshore storage capacities are allocated to the nearest coastal region, as it is assumed that all the necessary infrastructure is already in place.

Hydrogen storage facilities are available in the model in the form of pressure vessels and geological storage facilities. Tanks are available for liquid hydrogen. Salt caverns are considered for the storage of hydrogen in geological storage facilities. Storage capacities in geological storage facilities can be realized by repurposing natural gas storage facilities or constructing new salt cavern storage facilities. The capacities available for caverns in the event of a conversion are calculated from natural gas capacities using an energy density approach based on [28]. This results in a hydrogen storage potential of up to 66 TWh in Europe. Potential for new salt caverns is taken from [29], taking into account a maximum distance of 50 km from the coast to account for economic and environmental constraints on brine disposal. The available potential totals 7,276 TWh and is independent of the target year.

Lithium-ion batteries, whose expansion is not restricted, are primarily considered for electricity storage. Existing pumped storage plants and storage hydroelectric power plants are also taken into account. Locations, capacities and feed-in time series for these are taken from [10] for the year 2015. Based on [11], no expansion of hydropower capacity is allowed in the model, as it is assumed that the capacity for pumped storage plants and storage hydropower plants in Europe is almost exhausted and no new plants will be built.

2.1.4 Transmission infrastructure

The model includes the transmission of electricity, hydrogen and natural gas via pipelines. For reasons of complexity, the modeling of transmission between regions by truck, ship or train has been omitted. Existing transmission infrastructure and its reassignment, as well as new construction, are taken into account.

For electricity exchange, both the existing high-voltage electricity grid and the construction of new power lines are taken into account. Dynamic calculation of electricity flows is not included. The capacities of the existing grid are extracted and calculated using the Python-based package PyPSA [30]. Incorrect data was corrected manually. In addition, projects already planned in the TYNDP 2024 [31] were added manually. The model allows for the construction of new power lines between regions that already have an electricity connection. In addition, offshore regions can be connected to the mainland via submarine cables.

The mapping of the existing natural gas network is based on a data set from Global Energy Infrastructure [32]. The maximum capacities of the pipelines are derived in a simplified manner from the pipeline diameters. The conversion is based on [33]. To calculate the transmission capacities between the model regions, the pipeline sections that run between two adjacent model regions are first selected. The capacity of all pipeline sections between the same model regions is then added up. Furthermore, the model allows for the reassignment of natural gas pipelines to hydrogen transport. The capacity is converted according to [33] and [34], according to which 80% of the transmission capacity of the natural gas network can be used for hydrogen. This value is based on the assumption that the flow velocity of hydrogen can be higher than that of natural gas, thus partially compensating for the lower energy density of hydrogen. The construction of new pipelines is only permitted along existing natural gas pipeline routes in order to better reflect terrain restrictions.

2.1.5 Imports and production of energy carriers

The model provides for the possibility of importing various energy carriers. Lignite, hard coal, oil and uranium can be purchased in unlimited quantities at a cross-regional price stored in the model. A restriction is imposed indirectly via the CO_2 emission targets, which are taken into account in the model. Additional electricity imports from regions outside the model boundaries are not modeled.

Natural gas can be produced within Europe or imported in the form of liquefied natural gas (LNG) or in gaseous form via pipeline. Intra-European natural gas production is possible at the current natural gas production sites. The locations and production volumes are taken from [35]. LNG imports are possible in regions with existing and planned LNG import terminals. The locations and capacities of LNG terminals are taken from [36]. Furthermore, natural gas imports via pipeline are possible at European borders. Transport capacities at border crossing points were calculated based on actual import volumes for 2019 according to Eurostat [37].

Solid biomass can be used as fuel in biomass power plants in the model, and liquid biomass can be converted into natural gas in biogas plants. Biomass potential and costs were determined based on the ENSPRESO database [38]. It is assumed that biomass is used in the immediate vicinity and is not transported across regional borders. Imports of solid or liquid biomass from regions outside the model boundaries are not modeled.

Hydrogen import costs are determined using a two-step approach: In the first step, a hydrogen supply chain based on 100% renewable energies within the hydrogen exporting country is modeled and export cost curves are determined. This is done in accordance with [39, 40], which describes the modeling of liquid hydrogen export infrastructure. In the second step, the costs for transporting hydrogen to European import points are determined. The transport options considered are the transport of gaseous hydrogen via pipeline and liquid hydrogen by ship. Separate supply chains are modelled for the transport options mentioned, which are shown in Figure 2-3.

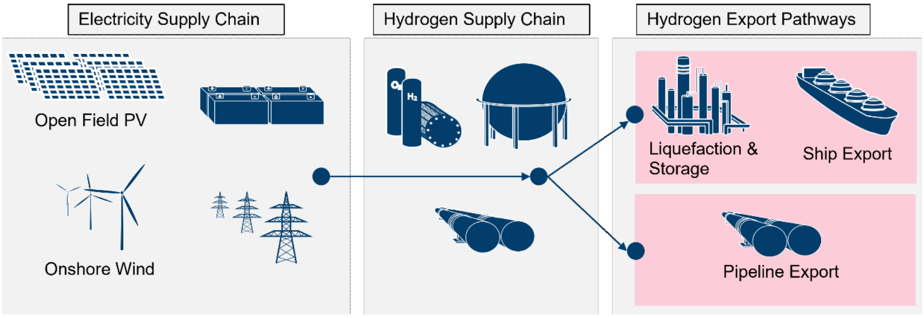


Figure 2-3. Modelled hydrogen supply chain in the hydrogen export regions.

The preferred regions defined by [40] were selected as hydrogen export regions and supplemented by Turkey. Hydrogen production and transport within the exporting country are mapped using an energy system model that models wind turbines and ground-mounted photovoltaics as possible sources of electricity. The electricity is converted into hydrogen via PEM electrolysis, compressed and then transported via hydrogen pipelines to a defined export point. The ports selected by [40] were primarily used as export points. As domestic demand for electricity and hydrogen is not taken into account, the maximum annual hydrogen export volume is limited to 25% of the available production potential.

An overview of the preferred regions with their respective export options can be found in Table 4 (Appendix). The export countries are modelled with an hourly resolution and a spatial resolution based on GID-1 to ensure a balance between infrastructure mapping and computing time [41]. To ensure consistent modelling, the same weather year and the same year for the techno-economic parameters used in the corresponding European scenario are applied for the modeling of the export regions. The resulting hydrogen costs are calculated by dividing the total annual costs by the annual export volume. In the case of a liquid hydrogen supply chain, the hydrogen is liquefied at the export point and stored in liquid hydrogen tanks. The modeling assumes that the export point must be served continuously. In the case of gaseous hydrogen, only pipeline transport, including an above-ground pressure storage facility as short-term intermediate storage, is modelled to the export point. It is assumed that the hydrogen produced is transported directly to the destination country in Europe without significant intermediate storage. This results in fluctuations in the volume of imports per hour.

In a second step, the costs for transporting hydrogen to European import points are determined. Current LNG terminals are available as import points. It is assumed that liquid hydrogen from all export regions considered can be imported to these terminals in the future. The transport costs for shipping hydrogen are taken from the transport model at [40]. The transport distances for shipping between the export ports and the European import points are determined along actual shipping routes. The Python package searoute-py [42] is used for this purpose. Pipeline imports are possible at existing pipeline crossing points in Sicily, Almeria and Kiri, as well as via an additional connection to Gibraltar. For existing pipeline transport capacities between, for example, North Africa and Europe, import volumes can be carried out in line with these existing capacities. In this case, costs for the reassignment of the pipelines are assumed. For import volumes exceeding this, costs for the construction of new pipelines are assumed. Pipeline imports can only be carried out from the connected export regions. For the cost estimate, import volumes of 2,000 TWh per year are assumed and calculated for the individual export countries. The costs for liquid hydrogen imports are based on the average of the three export regions with the lowest cost values. Each import point is assigned its own import costs. If several import points are located within the same model region, the import point with the lowest hydrogen costs is selected. For pipeline transport, the hydrogen costs correspond to the lowest cost value of the available export regions. The maximum import volume per year is not limited.

2.1.6 Additional restrictions

In ETHOS.Europe, various additional constraints can be defined, which enable for example the modeling of political and technical restrictions. For example, limits for CO_2 emissions for individual countries or expansion targets and restrictions for renewable energies can be defined. In addition, a minimum import quantity of hydrogen can also be defined.

Based on the EU's targets of greenhouse gas neutrality by 2050 and 62% reduction in EU ETS emissions by 2030 compared to 2005, maximum emissions per country and year are given as input into the model. For Germany, 2045 is additionally specified as the year of greenhouse gas neutrality. The emission limits for the years between 2030 and 2050 are determined by linear interpolation between the given values and stored in the model.

Furthermore, freely selectable expansion targets and minimum or maximum expansion rates for renewable energy sources can also be defined. The expansion of transmission components, storage components and conventional power plants can also be limited.

Based on [24], a 14-day synthetic dark lull, referring to a period when the level of solar and wind power generation is very low, in January is added to make the system more robust. It is assumed that only 30% of the maximum generation capacity of renewable energy is available during this period. Hydropower is excluded from this. Under standard assumptions, the dark lull periods are applied to north-western Europe and thus to Germany, the Netherlands, Belgium, France and the United Kingdom, which are located in the same climate zone according to [43].

2.2 Demand modeling for the building, industry and transport sectors

Demand trends are determined by using specific demand models for the sectors of commercial, trade, and services (CTS), households, industry and transport.

A stock model is used for demand modeling in the CTS and household sectors, which captures the effects of renovations and new buildings on energy demand. This stock model is based on a comprehensive database that describes building stocks in detail at country level and uses data on energy consumption by energy sources, building types, age groups, heating and hot water systems, and renovation status. The database is based on the Tabula, JRC-IDEES and Hotmaps databases at [44, 45, 46]. The modeling takes into account renovation rates, demolition and new construction of buildings in annual progress until the target year. Weather conditions, in particular heating and cooling degree days, influence energy consumption and are integrated to simulate the impact of climate change. For spatial and temporal disaggregation, the results are broken down to NUTS-2 regions and hourly resolutions. Spatial disaggregation is based on population density for households and on the number of employees for the CTS sector. For temporal disaggregation, a modified version of the Python-programmed tool when2heat [47] is used, which can be used to create load profiles for heating, cooling and hot water based on weather data and building types. These profiles break down annual energy consumption per region and building type to an hourly resolution in order to enable a more accurate representation of consumption peaks and temporal demand behavior. The model thus allows the effects of renovation measures, changes in population structure and climatic developments to be simulated and evaluated in detail.

The determination of energy demand in the transport sector is based on a multi-stage methodology that distinguishes between various modes of transport, including road, air, maritime and rail transport, as well as passenger and freight transport. First, current transport activity for each NUTS-2 region is calculated in passenger-kilometers and ton-kilometers per year. The Eurostat database and the IDEES databases for passenger road transport [45, 48, 49, 50] serve as the data basis for transport activities. Further information can be found at [51]. Future transport activity is then projected until 2050 on the basis of the EU Reference Scenario [52] and broken down into the relevant powertrains. Scenario-based market share forecasts are used for this purpose. In the fourth step, the respective energy consumption is determined using projected powertrain efficiencies and transport activity. The powertrain efficiencies are taken from [24, 53]. It is assumed that methanol, ammonia, synthetic kerosene, diesel and petrol are produced from hydrogen and CO_2. Energy consumption is therefore converted directly into hydrogen equivalents. Bio-based fuels are converted into biomass equivalents. Finally, annual energy consumption is distributed on an hourly basis, using constant load profiles for hydrogen demand and sector-specific load profiles for electricity demand according to [24].

The model for the development of energy demand in the industrial sector uses a system dynamics approach that follows the logic of the EU Emissions Trading System (EU ETS). As the availability of emission allowances in the EU ETS is capped and gradually reduced, CO_2 certificate prices rise. As a result, industry is expected to increasingly switch to low-emission production routes and decarbonized process heat supply. The assumed development is purely scenario-based and not cost-driven. Five data sets were created to prepare the model inputs: current production volumes per product based on [54], alternative process routes and decarbonization options for each product or sector, required temperature levels for process heat [55], application-specific energy consumption per sector and process based on IDEES and JRC Chemical Industry [45], and the development of production volumes until 2050 according to PotenCIA [56]. The development of production, with a possible change in production routes and energy sources, is scenario-based, based on the development of production volumes, the assumed switch to alternative process routes and the substitution of process heat supply by electricity, hydrogen or biomass. Spatial disaggregation of energy consumption is carried out at plant level, based on location and plant capacities calculated from European emissions databases and emissions benchmarks [57, 58], and plant capacities of the chemical industry and the steel sector from JRC Chemical Industry, GEM, and Eurofer [59, 60, 61]. A more detailed description of the modeling can be found at [51]. A constant load profile is assumed for the temporal evolution of industrial demand.

3 Scenario framework

3.1 General assumptions

All scenarios are based on the key assumption that the goal of greenhouse gas neutrality in 2050 and the interim targets for reducing greenhouse gas emissions will be achieved. In the reference scenario, Europe is optimized as far as possible without restrictions. Country-specific limits for CO_2 emissions from conventional power plants are capped at 62% compared to 2005, in line with the EU's 2030 targets. In line with the EU's goal of becoming greenhouse gas neutral by 2050, no CO_2 emissions are possible in the model in 2050. For Germany, greenhouse gas neutrality has been brought forward to 2045. Limits for the years between 2030 and 2050 are interpolated linearly. The respective countries' targets for phasing out coal and nuclear energy are taken into account on an annual basis. After the year of phase-out, existing power plants in the respective country cannot continue to operate and no new power plants can be built. Import quotas in line with the REPowerEU targets [5] and expansion targets for renewable energies are not included in the reference scenario, but are left open for optimization.

In order to better reflect restrictions on electricity grid expansion and hydrogen network expansion, it is assumed that a maximum of 2 GW of electricity grid expansion can take place between two regions within 10 years. This can be equated with the addition of a high-voltage direct current transmission line. For the construction of new hydrogen pipelines, it is assumed that a maximum capacity of 17 GW can be expanded between two regions within 10 years. This corresponds to the transmission capacity of a 42" pipeline. CO_2 infrastructures for the transport and storage of CO_2 are not included in the model. Hydrogen can be imported either via pipeline in gaseous form or by ship as liquid hydrogen, which must be regasified in an intermediate step. Hydrogen derivatives are not considered as an import option in the scenarios. It is assumed that these are produced locally at the point of use.

For a more robust design of the energy system, a synthetic dark lull period is taken into account in the analysis. It is assumed that only 30% of the maximum capacity from wind power and PV will be available for a period of two weeks in January. According to [19], such a long dark lull period occurs with a probability of less than 1% and thus represents an extreme scenario, but increases the robustness of the energy system. In the reference scenario, the dark lull is limited to north-western Europe and affects France, Germany, Belgium, the Netherlands, Denmark and the UK.

Population development at country level up to 2050 is assumed based on the United Nations' *World Population Prospects 2022* data set [62]. Table 2 summarizes the population for Germany and the entire model region in millions for the modeled years. Overall, a population decline is assumed, which is distributed differently across the individual countries.

Table 2. Population development in millions of inhabitants according to World Population Prospects 2022 [65] for Germany and the model region in 2020, 2030, 2040 and 2050.

	2020	2030	2040	2050
Germany	83.27	82.82	81.30	79.06
Model region	461.86	461.08	453.82	441.56

The following assumptions are made for economic development: The development of future production volumes per process is based on the assumptions made by PotenCIA [56]. Gross domestic product is not explicitly taken into account but is implicitly included in the production volumes used and is stated as having an average growth rate of around 1.4% per year over the period from 2015 to 2050 [56]. Future transport activity is projected until 2050 based on the EU Reference Scenario [52] and broken down into the relevant powertrains.

3.2 Demand development

Renovation rates serve as the main levers for the development of energy demand. In the model, building renovation rates can be specified according to minor renovation and major renovation, as well as system replacement rates and system update rates for installed heating systems. In line with the European Commission's target of doubling the current average renovation rate of 1% over the next 10 years [62], a linear increase from 1.3% p.a. to 2% p.a. in 2030 is assumed for the light building renovation rate [63]. In addition, according to analyses by BPIE [64], an increase in the deep renovation rate of buildings from 0.2% to 3% per annum in 2030 is assumed. After 2030, the renovation rate will remain constant at the 2030 level. In order to achieve a climate-neutral building stock, the European Commission is calling for an annual replacement rate of 4% p.a. for heating systems, see [62]. It is assumed that initially, the primary focus will be on system replacement, i.e. switching from gas heating to heat pumps. Once these changes have been completed, a system update, i.e. the replacement of an old heating system with an optimized system of the same type, will be possible. The demolition rate is estimated at approximately 0.3% p.a. for Germany based on historical data [45] and is dynamically adjusted to population trends. For the sake of simplicity, the same development in renovation rates is assumed for each country and for both the CTS and household sectors.

The development of energy demand in the transport sector is essentially determined by three factors: the development of transport volume, the development of market shares of different powertrains, and the development of fuel consumption efficiency in the respective transport sectors. The assumptions for this are described in [51] and are largely taken from [6, 52, 53, 65, 66]. International and intra-European air and maritime transport are also taken into account in the transport volume. Furthermore, complete decarbonization of the transport sector by 2050 is assumed. This results in a significantly higher demand for synthetic fuels. Parts of the synthetic fuel demand are also met using biomass. This process is not modeled here.

Figure 3-1 shows the development of energy demand in Europe for the energy sources electricity and hydrogen (including power-to-liquid (PtL)) considered in the model, based on the assumptions described. By 2030, hydrogen demand (including PtL) will already amount to almost 400 TWh in Europe. The majority of this, 340 TWh, will be accounted for by hydrogen demand to produce synthetic fuels (PtL), primarily for air transport and maritime freight transport. By 2050, hydrogen demand in the transport sector will rise to almost 2,000 TWh per year. Of this, 1,200 TWh will be used for the production of synthetic fuels, primarily for passenger air transport and maritime freight transport. In this scenario, the share of synthetic fuels for road transport is less than 3%. Direct hydrogen demand results from the assumed high penetration of fuel cell vehicles in road freight transport (55%, EHB) and a 15% market share of fuel cell vehicles in passenger road transport (EU Reference Scenario). Electricity demand in the transport sector for battery electric vehicles will be around 170 TWh in 2030 and will rise to 700 TWh by 2050.

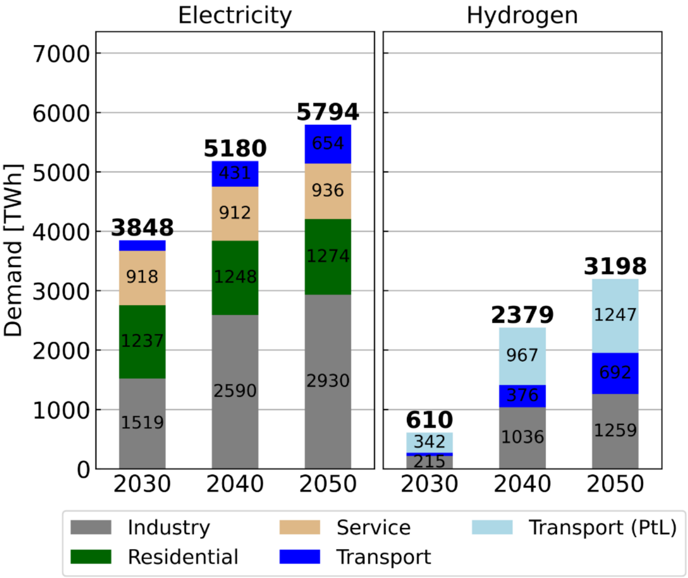


Figure 3-1. Development of energy demand in Europe for electricity and hydrogen.

The scenario assumes that the industrial sector will be fully decarbonized. For sectors with process-related CO_2 emissions, it is assumed that these will be offset either by direct air capture (DAC) or carbon capture measures. Essentially, two factors determine the development of electricity and hydrogen demand. On the one hand, the switch to alternative process routes and, on the other hand, the decarbonization of process heat supply. For process heat supply, a switch to electricity, hydrogen and biomass is assumed. The energy source used depends on the temperature level of the respective process. For process temperatures below 500°C, complete electrification is assumed, based on [67]. For process temperatures above 500°C, it is assumed that 70% of the heat demand will be covered by hydrogen and 30% by biomass. Alternative process routes are available in demand modeling, primarily for steel production, aluminum production and a variety of key chemical industry products such as methanol, ammonia and ethylene. The conversion of process routes and process heat supply is modeled using logistic curves, which predict complete penetration of alternative technologies by 2050.

Figure 3-2 shows the calculated hydrogen demand of all modeled countries for the year 2050, broken down by the industrial and transport sectors. Due to its industrial locations, Germany has the highest hydrogen demand, which is almost 300 TWh higher than that of France and the United Kingdom. High hydrogen demand arises in countries with high traffic volumes. This applies especially to countries with increased air and maritime traffic.

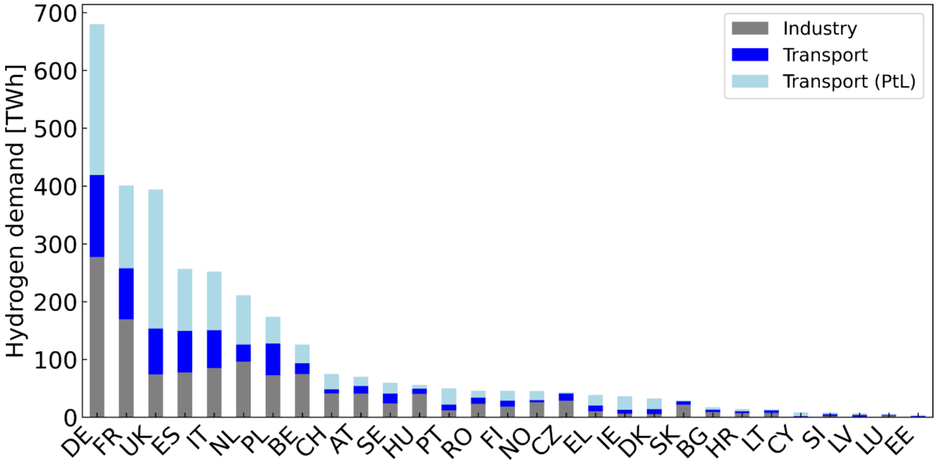


Figure 3-2. Hydrogen demand of the modeled countries in 2050.

3.3 Sensitivities

In addition, various sensitivity calculations are carried out focusing on nuclear energy, restrictions on the expansion of wind and solar energy, import costs and dark lull.

The **nuclear energy** focus area analyzes the competitiveness of nuclear energy in Europe. To this end, several model runs are carried out in two variants with different investment costs for nuclear energy. The investment costs for nuclear energy in the reference scenario are multiplied by factors of 0.5, 0.75, 1.25 and 1.5. In the first variant, the expansion of nuclear energy is only possible in countries that have not decided to phase out nuclear energy. In the second variant, the expansion of nuclear energy is possible without restriction in all European countries.

The **expansion restrictions** focus area serves to analyze the consequences of limited expansion of renewable energies in Europe. To this end, a business-as-usual scenario (BAU) is first created, which reflects the current expansion rates. For PV and wind power, the five countries with the highest expansion rates over the last five years are identified. An average value is calculated from these expansion rates and set as the expansion limit for each modeled country. This results in a maximum expansion of 3 GW/year for PV and 1.8 GW/year for onshore wind per country. In a further sensitivity analysis, the expansion rate is linked to the potential for renewable energies in the respective country. To this end, the maximum expansion of each country per year is limited to 0.25, 0.5, 1, 2 and 3% of the stored maximum technical potential in various scenarios.

In order to analyze the competitiveness of European hydrogen, sensitivities with regard to **hydrogen import costs** are calculated. To this end, the hydrogen import costs at the respective import points from the reference scenario are multiplied by the factors 0.7, 0.8, 0.9, 0.95, 1.1, 1.2 and 1.3 in various scenarios in order to reflect cheaper or more expensive hydrogen import costs.

In addition to the assumed 14-day **dark lull** in north-western Europe, the effects of different lengths of dark lull periods are analyzed. The length of the dark lull varies between 5 and 21 days. Furthermore, the effects of a dark lull in different regions of Europe are modeled. In variant 1, the dark lull is shifted to southern Europe, i.e. Portugal, Spain, Italy and Greece; in variant 2, it is shifted to northern Europe, i.e. Norway, Sweden and Finland; and in variant 3, it is shifted to the whole of Europe.

4 Results

The energy transition in Europe poses a dual challenge. On the one hand, it requires phasing out fossil fuel-based power generation, while at the same time households, transport and industry must be decarbonized. This requires fundamental changes in these sectors. Industrial processes must be converted to alternative, low-emission process routes, and fossil fuels such as natural gas and oil must be replaced by green energy sources. This will lead to a massive increase in demand for electricity and green energy sources. To meet this demand, a comprehensive transformation of the European energy system is necessary.

4.1 Development of electricity generation

In order to phase out fossil fuel-based electricity generation and meet the increased demand for electricity, a massive expansion of photovoltaics and wind energy will be necessary by 2050.Figure 4-1 shows the development of electricity generation in Europe from today until 2050. By 2030, wind, PV and nuclear energy will be the largest electricity producers in Europe, with 2,000 TWh (40%), 1,000 TWh (21%) and 800 TWh (17%) respectively. Electricity production from wind and PV will increase to 4,970 TWh (47%) and 4,870 TWh (46%) respectively by 2050. To achieve this, around 1,550 GW of wind energy plants and 2,900 GW of PV plants will be installed in the system by 2050.

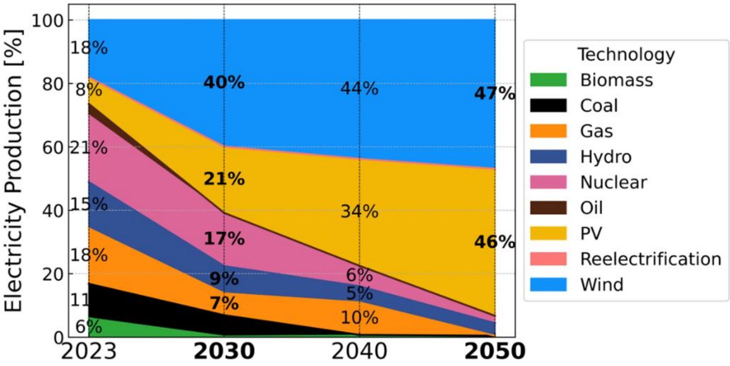


Figure 4-1. Development of electricity generation in Europe from today until 2050. Figures in percentages of the total amount of electricity supplied.

Electricity generation from gas and coal will decline completely by 2050 due to emission reduction targets and the decision to phase out coal. While coal will be used for electricity generation until 2030, gas will remain relevant until 2040. Between 2030 and 2040, additional gas-fired power plants will be built to compensate for the loss of coal-fired power generation. The share of nuclear energy in electricity production will decline, as the construction of new nuclear power plants is not competitive with the expected cost reductions in PV and wind power, and the old power plants are gradually exceeding their operating life.

Wind and PV will become the largest electricity producers by 2030, accounting for over 60% of production.

A significant proportion of electricity generation capacity will be needed to provide green electricity for intra-European hydrogen production. In 2050, 45%, or 4,675 TWh, of the electricity produced will be used for hydrogen production.

Wind and PV capacity will be expanded in all European countries. The electricity mix and the amount of electricity generated per country for 2030 and 2050 are shown in Figure 4-2. By 2050, Spain will be the largest electricity producer in Europe with an annual electricity generation of around 1,400 TWh. In 2050, electricity generation from PV will dominate in southern Europe, while electricity from wind energy will predominate in northern Europe.

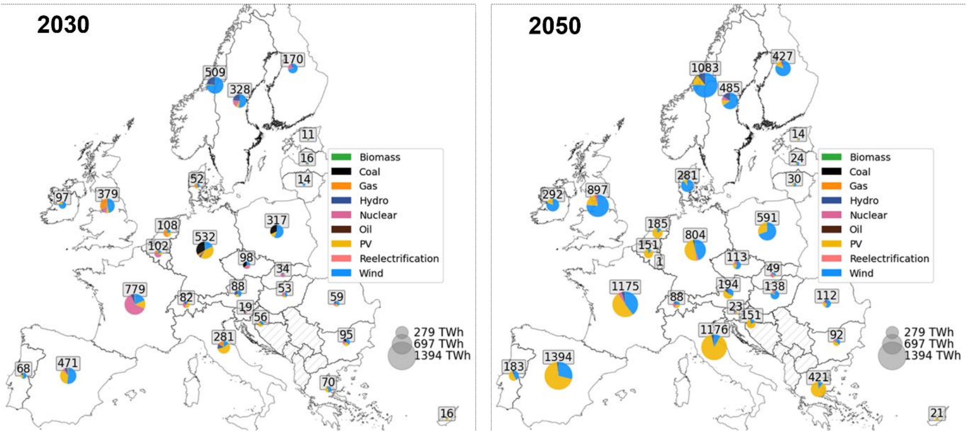


Figure 4-2. Electricity mix and electricity volumes supplied in individual European countries for 2030 and 2050.

By 2050, the largest increase in wind power capacity will be in Norway, France, the United Kingdom and Poland. The largest increase in PV capacity will be in Italy, Spain, France and Germany. These countries are characterized either by good conditions for wind and PV, as in Spain and Norway, or by high demand for electricity and hydrogen, as in Germany and France. Figure 4-3 shows that there will be no significant expansion of PV in Germany after 2040. This is because the potential for ground-mounted PV in Germany will already be almost completely exhausted by 2040. The model does not prioritize the expansion of rooftop PV for cost reasons.

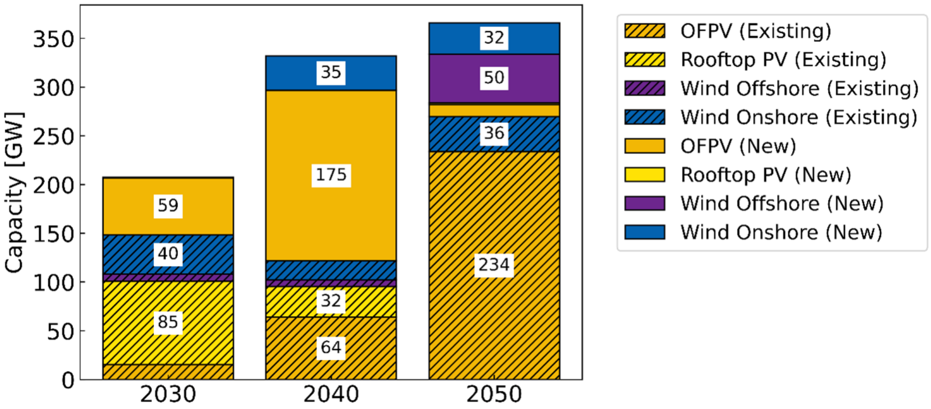


Figure 4-3. Expansion and existing capacity (hatched) of renewable energy in Germany over time.

In order to achieve the optimized capacities of approximately 1,550 GW wind and 2,900 GW PV shown in Figure 4-4, average annual expansion rates of 104 GW/year for PV and 55 GW/year for wind are necessary. Compared to the average expansion rates of the last 5 years of 23 GW/year for PV and 14 GW/year for wind in Europe, this represents an increase by a factor of 4 to 5. If the current average expansion rates were to continue until 2050, there would be a deficit of 900 GW for wind and 2,000 GW for PV.

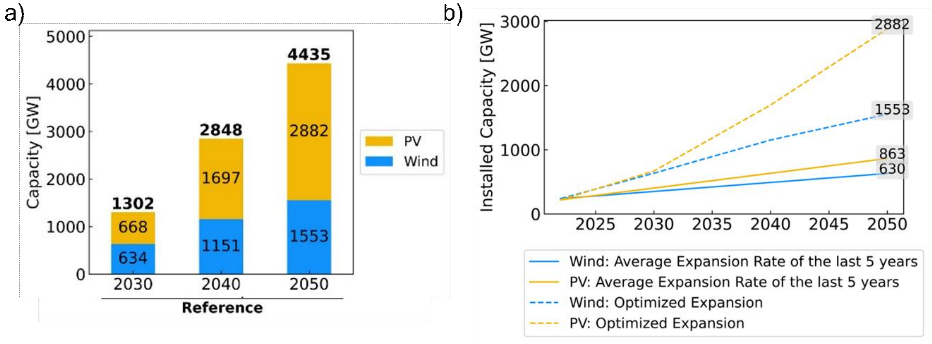


Figure 4-4. Expansion of renewables. a) Expansion of wind and PV over time. b) Comparison of the required expansion rates with today's average.

The results of the reference scenario show that Europe has sufficient economic renewable energy potential to meet its energy needs. To this end, 19% of the capacity potential of onshore wind, around 2% of the capacity potential of offshore wind and 20% of the capacity potential of ground-mounted photovoltaics will be realized in Europe by 2050.

Figure 4-5 shows the optimal expansion of interconnection capacities between countries in the electricity transmission network and the existing interconnection capacities by 2050. By 2030, 111 GW of additional interconnection capacities will already have been built, which corresponds to around 50% of the 224 GW of interconnection capacity that will be in operation by then. By 2050, a total of 371 GW of interconnection capacity will be added, in addition to the projects planned in the TYNDP 2024.

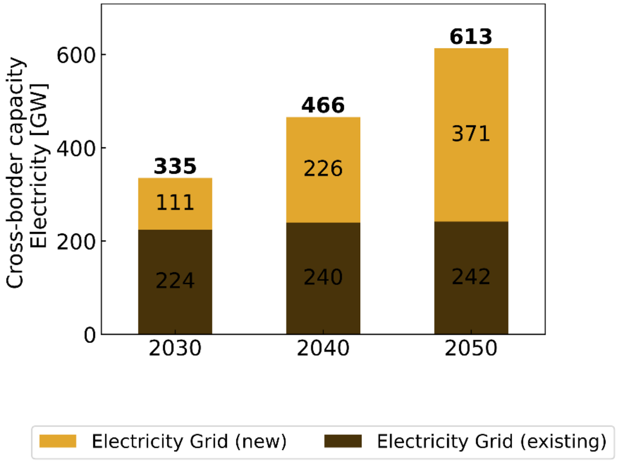


Figure 4-5. Development of interconnection capacities for electricity exchange between European countries. The electricity grid (existing) includes all projects listed in the TYNDP 2024.

The projects planned as part of the TYNDP are listed under existing capacity. According to this, exchange capacity will increase by a factor of 2.7 by 2050. This shows the relevance of expanding transmission capacity in the electricity grid between countries.

4.1.1 Detailed study: Nuclear energy

The results of the reference scenario show that, based on the assumed cost developments, there will be no expansion of nuclear power plants in Europe. This result was examined in more detail using a sensitivity analysis of the investment costs of nuclear power plants. To this end, various scenarios were calculated with investment costs of €4,400, €6,600, €8,800, €11,000 and €13,200 per kW for nuclear power plants. In addition, two variants were calculated in each case that limit the expansion at the spatial level. In variant 1, expansion in line with the reference scenario is only possible in countries that have not decided to phase out nuclear energy. In variant 2, expansion is possible in all European countries. Due to the long construction times, it is assumed that new nuclear power plants will not be available until after 2035.

The resulting share of nuclear energy in electricity generation in 2050 for the respective investment costs used is shown in Figure 4-6. It becomes evident that an expansion of nuclear energy will only take place if the investment costs are below €6,600 per kW. Assuming investment costs of €4,400 per kW, including nuclear power plants already in operation, nuclear energy would account for approximately 12% of the electricity mix in variant 1 and approximately 14% in variant 2.

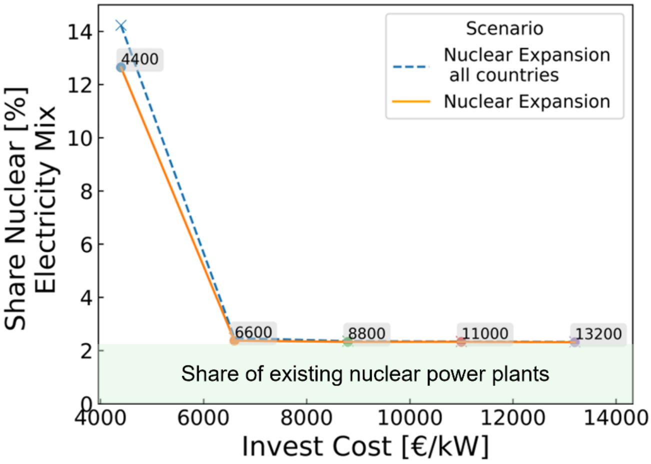


Figure 4-6. Share of nuclear energy in 2050 depending on investment costs. A distinction is made between the two variants: Variant 1) Expansion is only possible in countries that have not decided to phase out nuclear energy (orange). Variant 2) Expansion is possible in all countries (blue).

An expansion of nuclear energy in variant 2 would primarily take place in Germany, the United Kingdom, the Netherlands, Belgium and Switzerland. These countries are characterized above all by high demand for electricity in the industrial sector and limited renewable energy potential relative to total electricity demand. In Germany, almost 67% of domestic electricity production, or around 540 TWh, would be provided by nuclear energy in this scenario.

Compared to the costs of current European construction projects, the assumption of €4,400 per kW is very low. Construction costs of €17,500 per kW are expected for Hinkley Point C in the UK, €10,875 per kW for Flamanville 3 and around €6,875 per kW for Olkiluoto 3.

The results show that the construction of new nuclear power plants is not competitive with wind and PV. With investment costs of €4,400/kW, the share of electricity production in 2050 will remain below 15%.Figure 4-7 shows the development of electricity production over time. The shares of wind and PV will decrease only slightly compared to the reference scenario (refer to Figure 4-1).

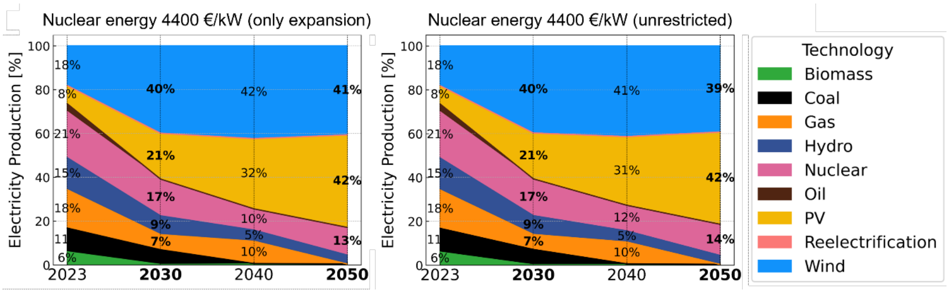


Figure 4-7. Electricity production over time with investment costs of €4,400/kW for nuclear energy. Left: Only new capacity allowed in countries that have not decided to phase out nuclear energy (variant 1). Right: Unrestricted new capacity possible (variant 2).

The construction of new nuclear power plants is not competitive to wind and PV.

4.2 Development of hydrogen supply

Figure 4-8 shows the origin of hydrogen in Europe until 2050. Most of the hydrogen demand by 2050 will be met within Europe. Only a small proportion will be imported via hydrogen pipelines from North Africa. This proportion will be around 17% in 2040 and around 5% in 2050. Ship imports will not be utilized. This applies provided that the optimized expansion rates for wind and PV can be achieved and the necessary hydrogen infrastructure can also be established. In this case, intra-European hydrogen production will be competitive with imports from the global market.

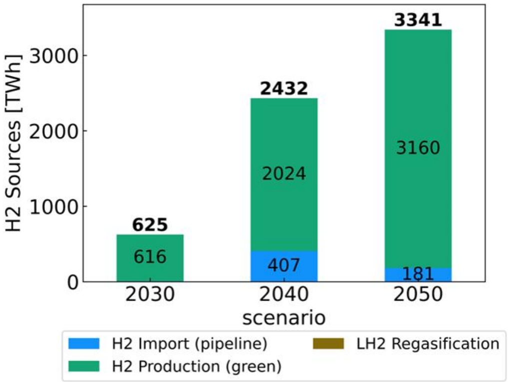


Figure 4-8. Development of hydrogen sources over the course of the system transformation. The share of LH2 regasification represents hydrogen imports by ship, which are not utilized in the reference scenario.

Figure 4-9(a) details this result and highlights the largest hydrogen exporters and importers within Europe in 2050. Norway, Italy, Spain and Greece will be the largest hydrogen suppliers. Germany, France, the Netherlands and the United Kingdom will be the largest hydrogen importers. With an import volume of just under 600 TWh per year, Germany is the largest hydrogen importer in Europe. This corresponds to an import quota of 81% of its hydrogen demand. For Norway, Italy, Spain, Greece and Finland as hydrogen exporters, this presents an opportunity to create a hydrogen market with an annual export volume of around €100 billion, the distribution of which is shown in Figure 4-9(b).

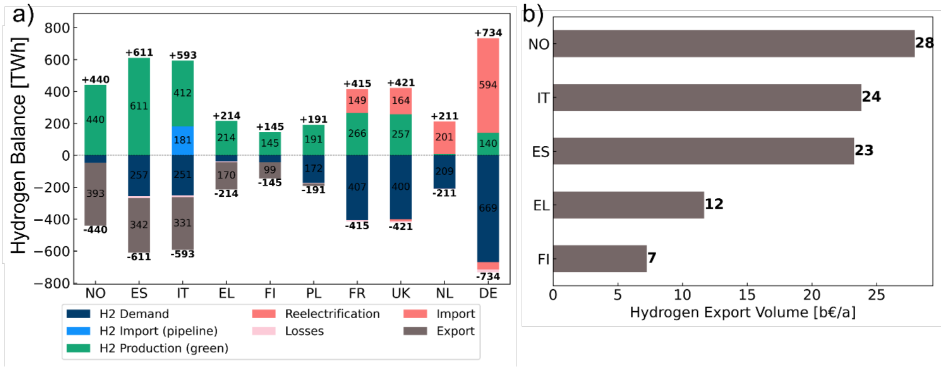


Figure 4-9. Hydrogen origin in Europe. a) Hydrogen balances for selected countries. b) Hydrogen export volumes of the countries with the largest hydrogen production.

Norway, Italy, Spain and Greece will become important players in the European hydrogen market. Germany will become the largest hydrogen importer.

In order to transport hydrogen from exporting countries to demand centers, it will be necessary to establish a hydrogen infrastructure in Europe. Figure 4-10 shows the development of the necessary interconnection capacities by 2050. The results show that 73% of the interconnection capacities for hydrogen can be implemented using existing infrastructure. A total of 780 GW of coupling capacity will be required between countries by 2050 to enable hydrogen exchange.

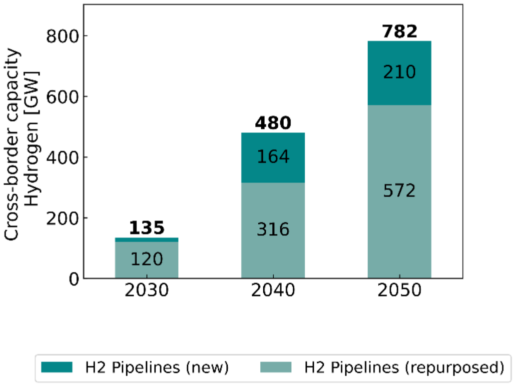


Figure 4-10. Development of interconnection capacities for hydrogen exchange between European countries.

The spatial and temporal development of the pipeline infrastructure with expansion and conversion from 2030 to 2050 is shown in Figure 4-11. By 2030, the first hydrogen production clusters will have formed in Norway and Spain, from where hydrogen will be transported primarily to Germany via repurposed pipelines. Hydrogen production will increase massively by 2040. While around 600 TWh of hydrogen will be produced in Europe in 2030, production will triple to almost 2,000 TWh per year by 2040. At the same time, interconnector capacities will also triple from 135 to 480 GW (see Figure 4-10). In 2040, hydrogen import routes and an expansion of hydrogen pipelines will be clearly visible (see Figure 4-11). In northern Europe, hydrogen will be transported from Norway to Germany in a manner similar to the currently assessed H2T corridor. Finland will continue to supply the Baltic states. Spain will transport hydrogen to France. Italy and Greece will export hydrogen to Switzerland, Austria and Germany. In 2050, additional hydrogen production centers in central Europe will be added, including northern Germany. At the same time, production in northern and southern Europe will be further expanded. New hydrogen pipelines will be built by 2050 to strengthen the connection between northern and central Europe. Furthermore, the connection between Spain and France will be expanded in a similar way to the planned H2med corridor, and additional capacity will be created to connect Germany and Italy via Switzerland as a transit country. This means that many of the corridors identified in the European Hydrogen Backbone can also be seen in the results.

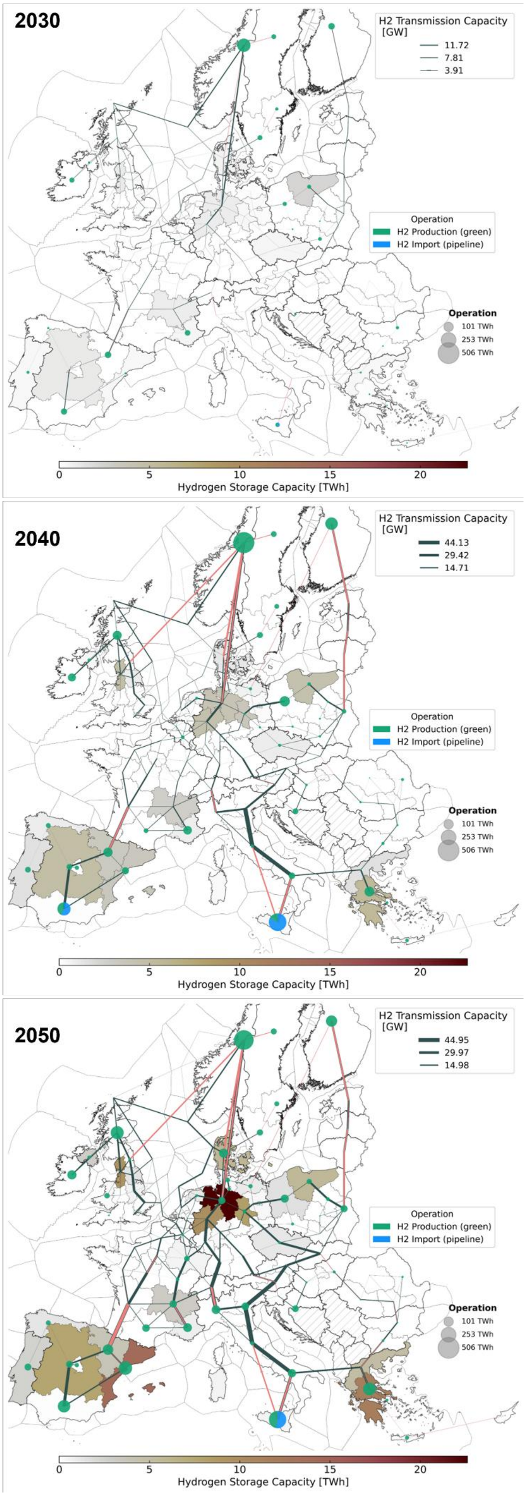


Figure 4-11. Development of interconnection capacities for hydrogen exchange between European countries.

In addition to the development of a hydrogen transport infrastructure, energy storage in the form of salt caverns for hydrogen storage is an essential component of the European energy supply. This allows seasonal fluctuations in hydrogen production from wind and PV to be balanced out. Furthermore, in the event of dark lull periods, large amounts of energy can be retrieved and converted into electricity in hydrogen-fired power plants or fuel cells as needed. Figure 4-12(a) shows the optimized development of the required cavern storage facilities in the target years.

While a moderate 11 TWh of capacity will be required in 2030, capacity will increase fivefold to 51 TWh by 2040. From 2040 to 2050, the required capacity will continue to increase to around 122 TWh. Of the 122 TWh required in 2050, 66 TWh can be realized by repurposing existing natural gas cavern storage facilities, which corresponds to a complete repurposing of the natural gas cavern storage facilities existing in Europe. Furthermore, 56 TWh of new cavern capacity will need to be built. With an average capacity of 250 GWh per cavern, this will require the construction of 224 salt caverns by 2050. Due to the long lead times of approximately 10 years until completion, construction must begin early to ensure security of supply in Europe.

Most of Europe's underground storage capacity will be realized in Germany, close to the demand centers. Germany can draw on existing natural gas cavern storage facilities, which can be reassigned to hydrogen. Unlike Italy, hydrogen producers Spain and Greece can develop new hydrogen cavern storage facilities due to geological conditions. In Italy, the absence of salt caverns is compensated for by the construction of more expensive above-ground hydrogen pressure storage facilities to enable short-term hydrogen storage, particularly over the course of the day.

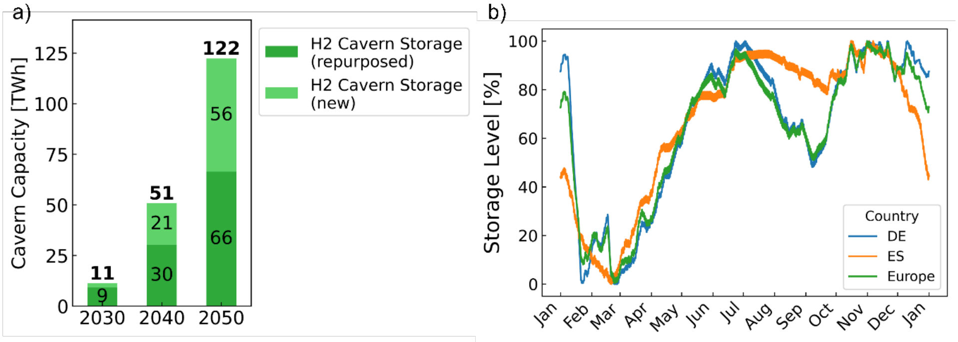


Figure 4-12. Use of hydrogen storage facilities in salt caverns in Europe. a) Development of hydrogen storage capacity in salt caverns. b) Storage level of hydrogen storage facilities in percent for Europe, Spain and Germany.

The results show that it also makes sense to store hydrogen close to where it is produced. This is particularly advantageous in countries with a high proportion of PV. Here, salt caverns can serve the system in two ways. During peak PV production at midday, electricity can be converted into hydrogen by means of electrolysis and then stored in hydrogen caverns. This means that PV systems need to be curtailed less. The ability to remove power from the system at peak times using electrolysis and hydrogen cavern storage also reduces the load on the electricity grids. Secondly, salt caverns enable the seasonal storage of hydrogen. In sunny regions, there is a surplus of electricity, especially in summer, which can be stored using electrolysis and hydrogen cavern storage. In winter, when solar radiation is weak, this can be used for reelectrification or, due to the low electrolysis capacity, to cover hydrogen demand. This is also shown in Figure 4-12(b), which depicts the aggregated storage level of hydrogen caverns over the year 2050 for Germany, Spain and Europe as a whole.

For Spain, which has a high capacity of PV in its system, hydrogen is stored from the beginning of spring until the end of summer and then released again during the following winter months, when there is little sunshine. The storage pattern is slightly different for Germany. In the reference scenario, north-western Europe, including Germany, is affected by a two-week dark lull in January. Hydrogen cavern storage facilities are used here to meet hydrogen demand during this period and to operate the 54 GW of hydrogen reelectrification capacity in Germany. As Germany also has significant amounts of PV installed, more electricity is made available for hydrogen production during the summer months, which is stored in hydrogen caverns. Another notable feature is the withdrawal of hydrogen from storage between July and September. This is due to a seasonal lull in wind speeds in northern Europe. Wind speeds decline sharply during this period compared to the annual average, leading to reduced electricity production. As a result, less electricity is available for hydrogen production in northern Europe, which is why hydrogen must be withdrawn from salt caverns.

4.2.1 Detailed analysis: Hydrogen import costs

The reference scenario has shown that European hydrogen is competitive with extra-European imports. In 2050, 95% of the hydrogen required in Europe will be produced within Europe. A sensitivity analysis was conducted to examine the impact of different hydrogen import costs on the import quota. The results are presented in Figure 4-13 for the years 2030 and 2050. They show the resulting hydrogen sources at different import costs. The import costs shown are derived from the resulting shares of ship and pipeline imports.

Figure 4-13(a) shows that European hydrogen will be competitive at costs of up to €3.2/kg in 2030. Only when import costs are lower will hydrogen imports be used more extensively to meet hydrogen demand. At a cost of €2.7/kg in 2030, more than 45% of European hydrogen demand would be met by imports, and at import costs of €2.1/kg, this figure would rise to almost 90%. In 2050, European hydrogen will be competitive at import costs of up to €2.3/kg. A supply of hydrogen imports at around €1.9/kg leads to an import quota of 58%. Around this cost point, the model also shows that more expensive imports via shipping routes become relevant, as they can deliver hydrogen directly to the hydrogen demand centers in the Netherlands, Germany, the United Kingdom and northern Italy. With import costs of €1.7/kg, the import quota rises to 75%.

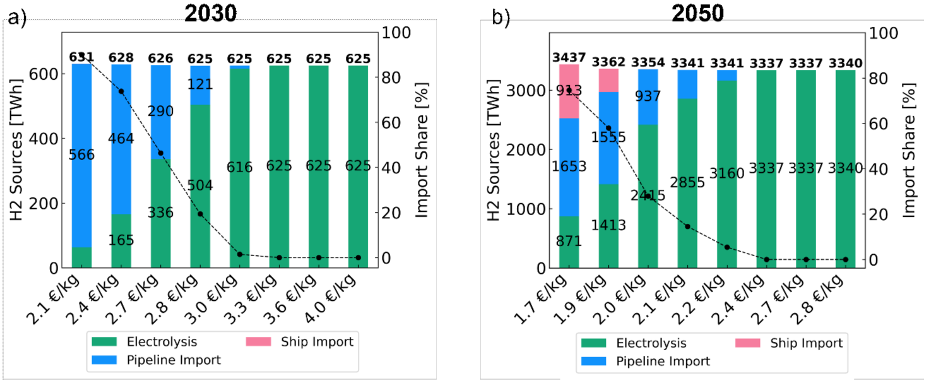


Figure 4-13. Hydrogen sources depending on the import costs (bars) and share of hydrogen imports (line). a) Results for the year 2030. b) Results for the year 2050.

An import quota of 75% has a significant impact on the European energy system, especially on the hydrogen infrastructure, as its design depends on hydrogen procurement. While the reference scenario envisages the construction of around 1,200 GW of electrolysis capacity, a 75% import quota would result in only 300 GW of electrolysis capacity being built. Furthermore, there is a drastic decline in the required renewable capacity from around 2,300 GW to 4,400 GW. In the case of a high import quota, the necessary import capacities must be created, which increase from 45 GW to 600 GW with a 75% import quota. A comparison of the values can be found in Table 3.

Table 3. Comparison of installed capacities for different import strategies.

H2 imports	**75**	**5**
Electrolysis	300 GW	1,200 GW
H2 import capacities	600 GW	45 GW
Renewable capacities	2,300 GW	4,400 GW

Figure 4-14 shows the hydrogen infrastructure with an import quota of 75% and 5% in 2050. In the event of a high import quota of extra-European hydrogen, hydrogen production in Norway and the associated corridors, which mainly supply Germany with hydrogen, could be discontinued. The corridors from southern Europe will remain in place, as a large proportion of the imported hydrogen comes via pipeline imports from North Africa. Ship imports are made on a demand-driven basis in Germany, the Netherlands and the United Kingdom.

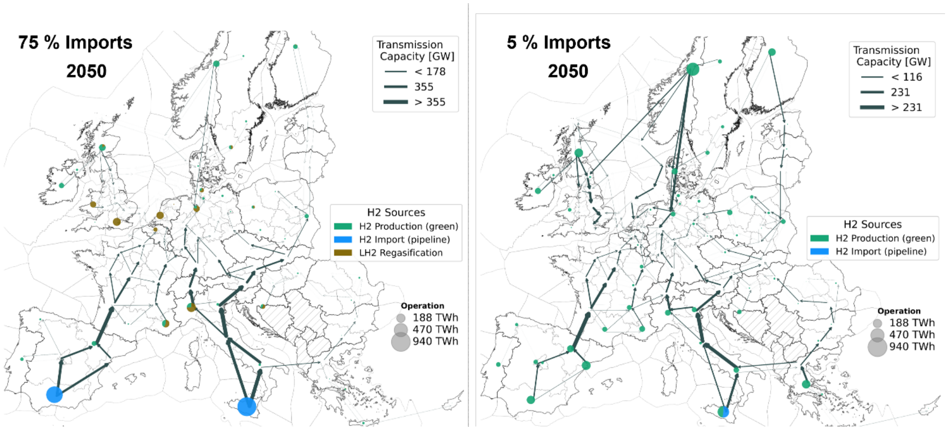


Figure 4-14. Hydrogen infrastructure with 75% and 5% coverage of hydrogen demand through extra-European hydrogen imports.

The results show that Europe needs a clear hydrogen procurement strategy, as different approaches have far-reaching implications for the required infrastructure. They also show that hydrogen produced within Europe is feasible and competitive. These and other findings from the detailed investigation of hydrogen imports are published in Dunkel et al. [69].

European hydrogen will be competitive in 2030 at a world market price of €3.20/kg.
In 2050, the threshold will be €2.30/kg.

4.2.2 Detailed study: Expansion constraints for renewable energies

In the reference scenario, an expansion of 1,550 GW of wind and 2,900 GW of PV by 2050 is assumed. This corresponds to an average annual expansion rate of 55 GW/year for wind and 104 GW/year for PV. Current expansion rates for wind and PV in Europe do not reach these values. Therefore, further calculations examine the effects of expansion restrictions on the European energy system in two variants. Variant 1 is a scenario that assumes the continuation of current expansion rates and limits the maximum capacity expansion for each country equally. Variant 2 limits the expansion rates of individual countries in different sensitivities depending on the determined potential for PV and wind.

Figure 4-15 shows the resulting capacity developments for wind and PV in comparison between the reference scenario and the business-as-usual scenario, in which the maximum annual expansion per country is limited to 3 GW/year for PV and 1.8 GW/year for wind. It becomes clear that the capacities for wind and PV determined in the reference scenario cannot be achieved as early as 2040. This mainly concerns the expansion of PV, where in 2050 there will be a gap of over 1,000 GW compared to the reference scenario. The expansion of wind power will be particularly restricted in 2040. As wind and PV are the main sources of European energy supply, this will lead to a gap in hydrogen production, as the installed renewable capacities will not be sufficient to meet hydrogen demand within Europe. Due to the limited expansion of PV and wind, sufficient hydrogen production is not possible in Norway, Spain, Italy and Greece (see Figure 4-16). As a result, it is necessary to rely on extra-European imports of 1,500 TWh, corresponding to an import share of 42%. Countries that previously produced only a small proportion of their own hydrogen will, under these conditions, produce more hydrogen than they need to meet their own demand. These countries include Estonia, Belgium, Lithuania, Latvia and Slovenia (see Figure 4-16). However, these are also countries that generally have very low hydrogen demand (compare Figure 3-2).

At the same time, this will lead to an increase in system costs of 6% in 2050. This is primarily due to the fact that limited expansion rates mean that cheap renewable potential in Europe cannot be optimally developed and utilized. As a result, parts of hydrogen production will be expanded to regions with lower expected full-load hours. In addition, hydrogen will have to be imported into Europe, as European hydrogen production will no longer be sufficient to meet demand.

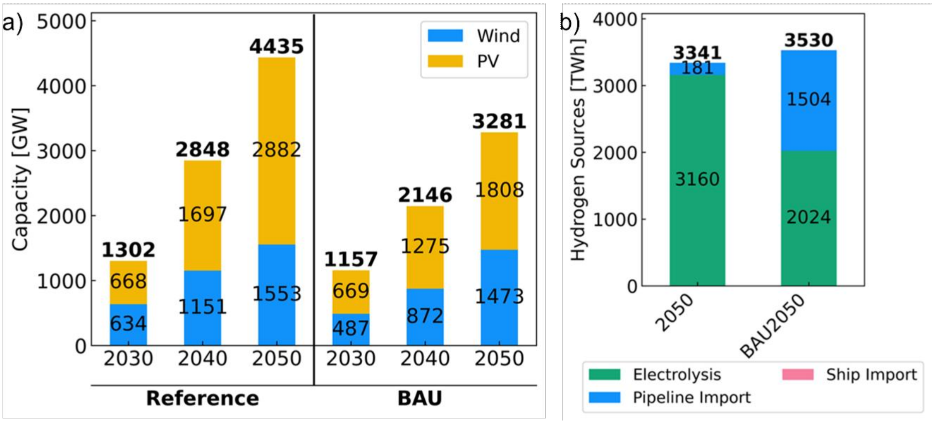


Figure 4-15. Expansion of renewables taking into account expansion constraints based on current average expansion rates (BAU: business-as-usual). a) Comparison of wind and PV capacity expansion between the reference and BAU scenario. b) Hydrogen sources in 2050 in the reference and BAU scenario.

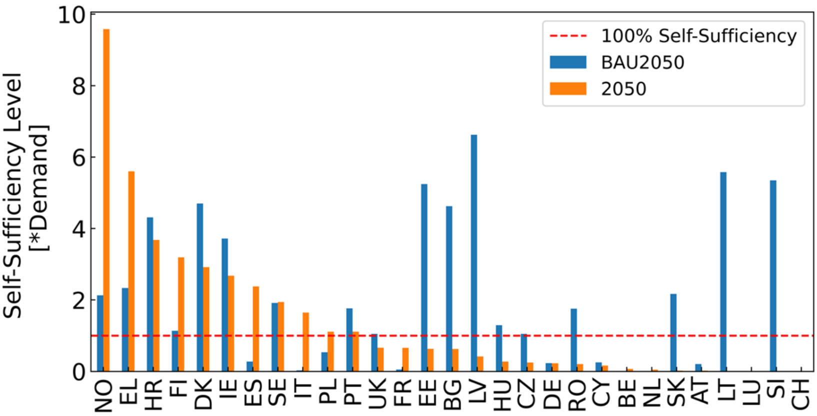


Figure 4-16. Hydrogen production of countries compared to their own demand. The situation in the reference scenario and business-as-usual (BAU) scenario is shown.

In variant 2, the expansion rates were limited in various scenarios based on the capacity potential per country. The hydrogen balances in Europe for these scenarios are shown in Figure 4-17(a). At the same time, Figure 4-17(b) highlights the resulting increase in total system costs compared to the reference scenario. It becomes clear that if expansion rates are limited to below 3% per annum, an increase in system costs can be expected. At 2% per annum, there is a moderate cost increase of 2.0%, which results from the shift in renewable capacities within Europe. With expansion restrictions of 1% per annum and below, hydrogen production can no longer be covered cost-optimally within Europe. As a result, there will be, on the one hand, an increase in imports, which in the 0.25% per annum scenario amount to 4,000 TWh per year and most of which are transported by ship. On the other hand, hydrogen demand for reelectrification will increase significantly, amounting to 1,500 TWh per year in this scenario.

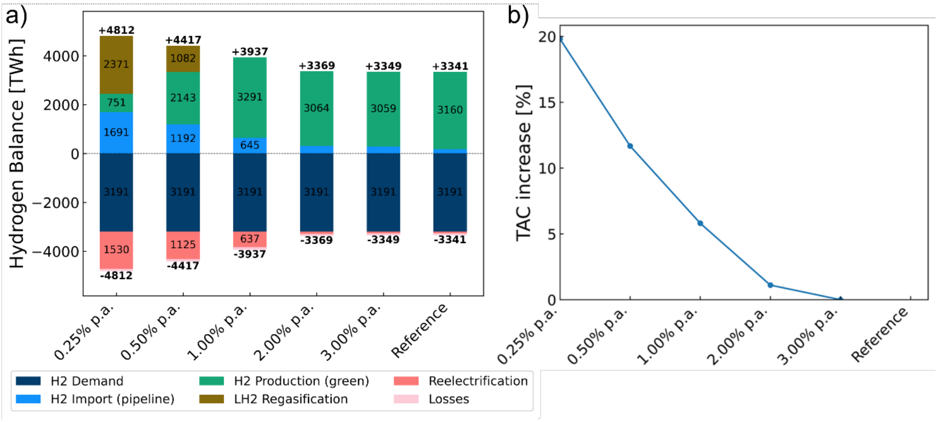


Figure 4-17. Hydrogen balances in 2050 depending on the expansion of renewables. a) Hydrogen balances for various expansion restrictions compared to the reference scenario. b) Impact on total system costs compared to the reference scenario.

When the annual restriction exceeds 1%, the renewable capacity installed in the countries is not sufficient to meet electricity demand at the same time. This illustrates that limited expansion of renewables has two distinct effects on the European energy system: Limited expansion restricts the possibilities for intra-European hydrogen production, thereby making extra-European hydrogen imports necessary. At the same time, it reduces security of supply, as the lower capacity of renewables means that the available electricity supply is insufficient, thus making it necessary to resort to more expensive hydrogen reelectrification. Accelerated expansion of renewables, as assumed in the reference scenario, promotes domestic, competitive hydrogen production while reducing system costs and the need for reelectrification capacities.

Accelerated expansion of renewables promotes domestic, competitive hydrogen production and reduces overall system costs and import dependency.

4.3 Impact of dark lull periods

In addition to the reference scenario, in which a two-week dark lull occurs in north-western Europe, three further variants are analyzed in which the dark lull periods affect southern Europe, northern Europe and Europe as a whole. Furthermore, the length of the dark lull periods was varied between 0 and 21 days. Dark lulls are considered particularly problematic for 100% renewable energy systems, as there is insufficient power available in the system to cover the load during periods of low PV and wind power feed-in. Hydrogen storage enables hydrogen to be provided during a dark lull for reelectrification and to cover hydrogen demand.

Figure 4-18 shows the electricity and hydrogen balance in the regions affected by the dark lull in the reference scenario during the two-week dark lull period in 2050. The reduced generation from wind and PV is evident in the electricity balance. This is compensated for on the one hand by electricity grid imports, battery storage and reelectrification. On the other hand, hydrogen production in the affected regions is completely halted during the dark lull. As a result, hydrogen must be retrieved from salt caverns to meet hydrogen demand and for hydrogen reelectrification.

During the dark lull, hydrogen demand in industry and transport, as well as for reelectrification, is covered in the affected regions exclusively by year-round hydrogen imports, imports from neighboring regions and withdrawals from salt caverns. Withdrawals from salt caverns account for 58.5% of hydrogen demand during this period. The results shown underline the relevance of flexibility options for ensuring security of supply.

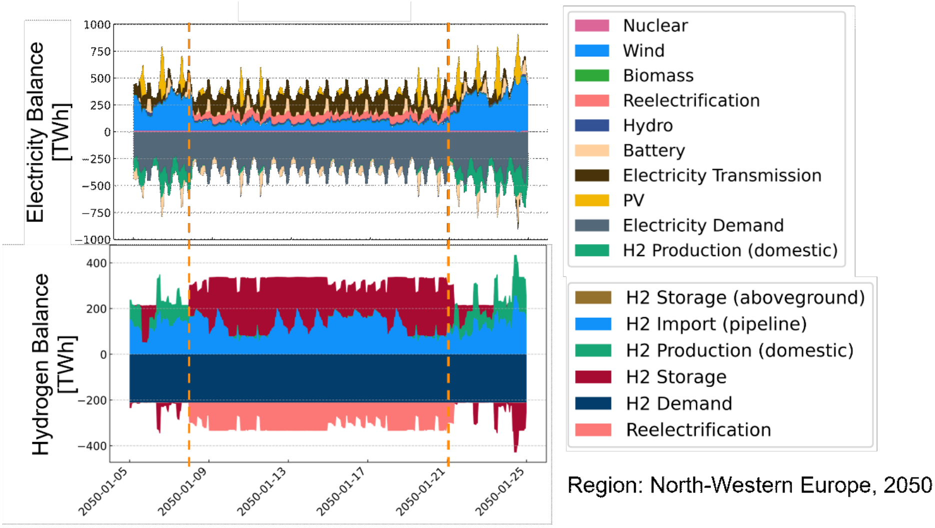


Figure 4-18. Electricity and hydrogen balance in 2050 in the regions of north-western Europe affected by a two-week dark lull. The dotted lines mark the beginning and end of the dark lull period.

An artificial dark lull was added to the model in the north-western European region in order to make the system design more robust. Figure 4-19(a) highlights the resulting additional costs for different lengths of dark lull periods in comparison to a system design without an artificial dark lull. It shows that the additional costs remain below 4% even when designing for longer dark lull periods. The necessary cavern storage capacities for these cases are shown in Figure 4-19(b). Here, an increase in the necessary cavern capacity can be observed with longer dark lull periods. During dark lull periods, north-western Europe can be supplied with energy imports from regions that are not affected by the dark lull. This requires appropriately designed networks and joint action by European countries.

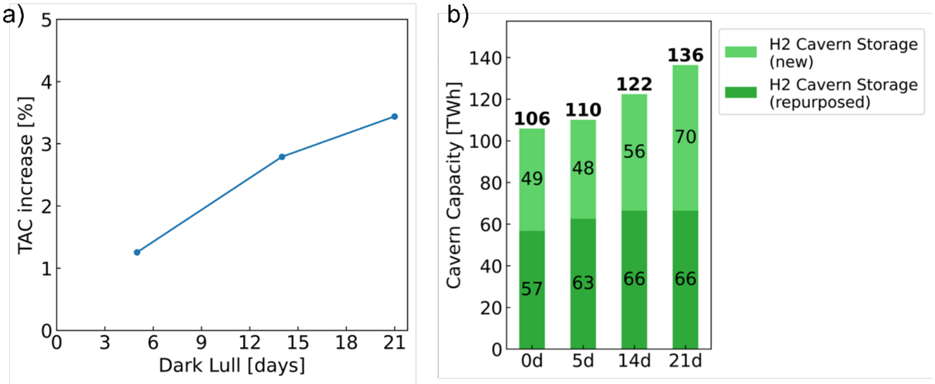


Figure 4-19. System impacts of dark lulls in north-western Europe. a) Increase in total system costs depending on the length of a dark lull. b) Hydrogen storage capacities in salt caverns depending on the length of a dark lull.

The analysis shows that even a three-week dark lull in north-western Europe can be collectively managed without significant cost increases. This is also evident in Figure 4-20, which shows the aggregated hydrogen flows during a two-week dark lull in north-western Europe. In addition, hydrogen storage from cavern storage facilities in the respective regions is highlighted in color. The regions affected by the dark lulls continue to be supplied with hydrogen from regions that are not affected by the dark lull, such as France by Spain and Germany by Norway. Furthermore, in northern Germany, for example, hydrogen is being withdrawn from the cavern storage facilities used to supply North Rhine-Westphalia and the Netherlands. The fact that hydrogen is being withdrawn from cavern storage facilities throughout Europe during the dark lull periods highlights the need for collective action in this scenario.

The electricity flows during the dark lull are shown in Figure 4-21. A similar pattern can be observed here as well. As already shown in Figure 4-18, almost 43% of the electricity demand in the affected regions during the dark lull is covered by electricity imports. All neighboring regions supply the affected regions during this period.

The expansion of long-term storage facilities and joint action across regional borders make the system robust against possible local dark lulls.

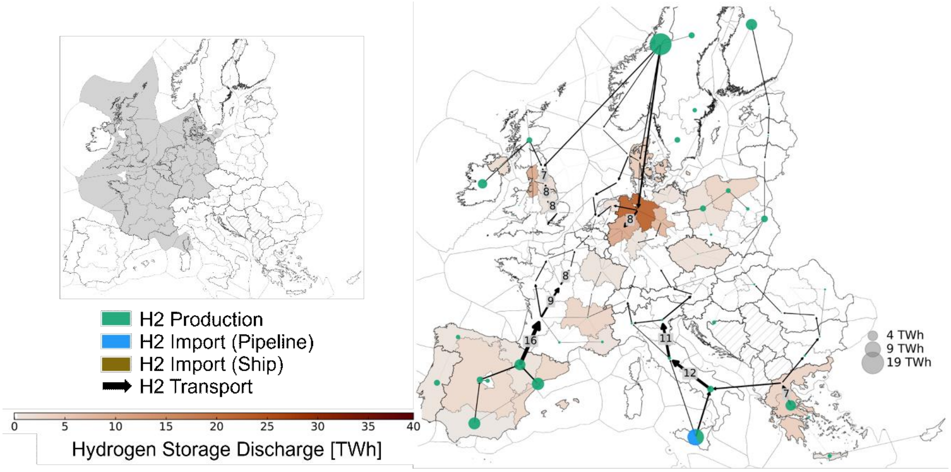


Figure 4-20. Hydrogen flows in TWh during a two-week dark lull in north-western Europe. The countries highlighted in grey (top left) are affected by the dark lull. Regions colored in red are storing hydrogen during the dark lull. Pie charts show hydrogen production and imports in the regions.

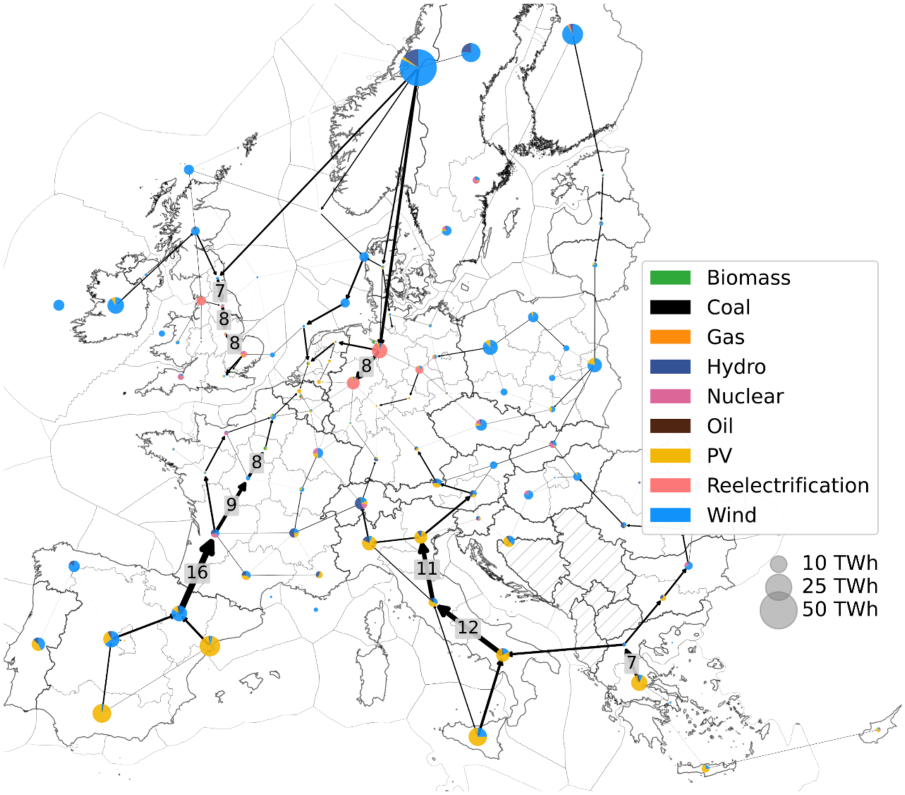


Figure 4-21. Electricity flows in TWh during a two-week dark lull in north-western Europe. Pie charts show electricity generation within the regions.

The effects of regionally varying dark lull periods are described below. The Figures Figure 4-22Figure 4-23Figure 4-24 show the hydrogen flows during the dark lull in southern Europe, northern Europe and Europe as a whole. Neither southern nor northern Europe need to be supplied with hydrogen from other regions during the dark lull. Exports from these regions to central Europe also take place during a dark lull. In the reference scenario, central Europe, especially Germany, the Netherlands and Belgium, is characterized by high hydrogen demand, which is primarily met by imports from northern and southern Europe. This is due, on the one hand, to high population density and low renewable energy potential and, on the other hand, to the more favorable location conditions for renewables in northern and southern Europe. With the exception of Italy, demand for hydrogen in southern and northern European countries is low compared to central Europe. Electrolysis capacities and associated renewable capacities are primarily being built for the purpose of hydrogen exports. During a dark lull, these regions can ensure their own supply of electricity and hydrogen thanks to their high installed renewable capacities. Only hydrogen production is reduced during this period. This is compensated for by the release of hydrogen from cavern storage facilities, so that in the case of Spain, export flows can be maintained. In the event of a dark lull in Norway, where no cavern storage facilities are available for hydrogen storage, export flows are reduced. This is compensated for by higher exports from southern Europe (see Figure 4-23).

During a dark lull affecting the whole of Europe, it is not possible to import from unaffected regions. The hydrogen flows are shown in Figure 4-24 and show that hydrogen production is completely shut down during this period. The hydrogen supply is therefore primarily ensured by cavern storage facilities, which store significant amounts of hydrogen and are correspondingly larger than in the reference scenario. Furthermore, this scenario shows an increased expansion of renewables, which is necessary to support hydrogen production outside of dark lull periods. Figure 4-25(a) shows the optimized cavern storage capacities for the regionally differing dark lull periods.

While the storage capacity required during dark lulls in northern Europe, southern Europe or north-western Europe remains at a consistent level of 108 to 122 TWh, a dark lull affecting the whole of Europe would require significantly more storage capacity at 323 TWh. At the same time, this shows that the system design is robust against local dark lulls. In the event of a dark lull affecting the whole of Europe, the required reelectrification capacity also increases significantly from around 74 GW in the reference scenario to 374 GW (see Figure 4-25(c)).

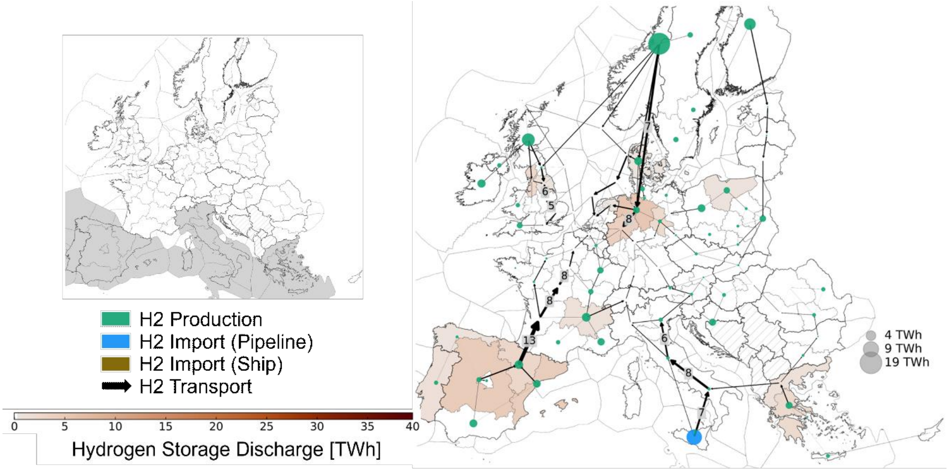


Figure 4-22. Hydrogen flows and hydrogen production during a two-week dark lull in southern Europe. The countries highlighted in grey are affected by the dark lull. Regions colored red withdraw hydrogen during the dark lull.

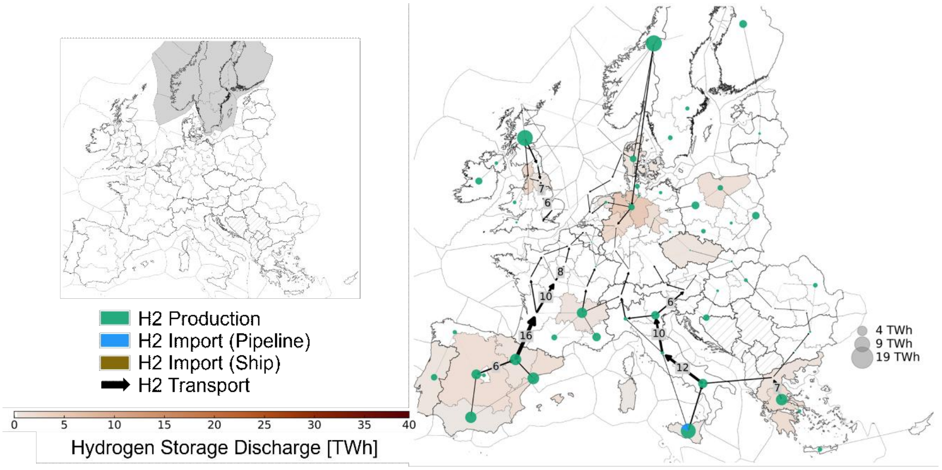


Figure 4-23. Hydrogen flows and hydrogen production during a two-week dark lull in northern Europe. The countries highlighted in grey are affected by the dark lull. Regions colored red withdraw hydrogen during the dark lull.

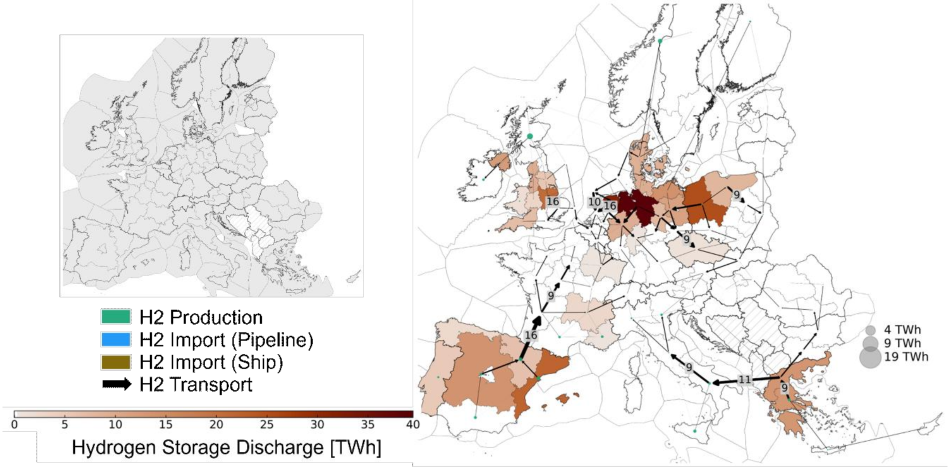
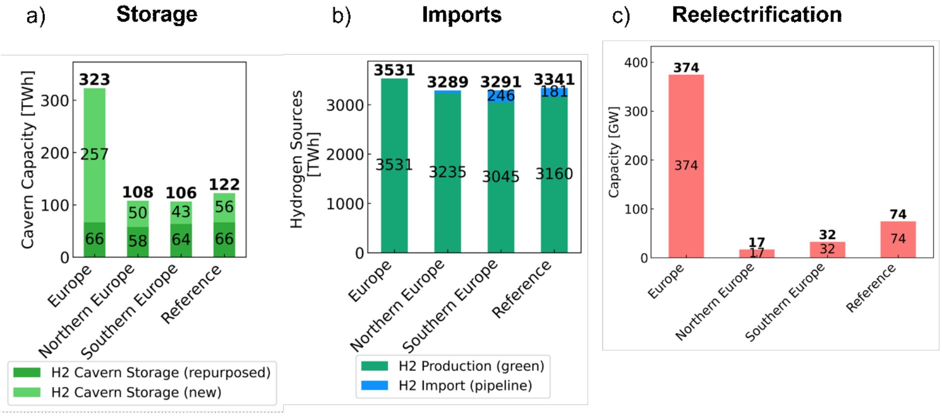


Figure 4-24. Hydrogen flows during a two-week dark lull in Europe. The countries highlighted in grey are affected by the dark lull. Regions colored red withdraw hydrogen during the dark lull.



Reference: Dark lull in northwestern Europe

Figure 4-25. Impact of a two-week dark lull in different regions on the European energy system in 2050. a) Design of hydrogen storage facilities. b) Design of hydrogen sources. c) Design of reelectrification.

In the reference scenario, the required reelectrification capacities are primarily located in Germany (54 GW) and the United Kingdom (18 GW), which have high electricity demand. In the event of a dark lull in northern and southern Europe, only 17 GW and 32 GW of reelectrification capacities are required, respectively. The decline in the event of a shift in the dark lull shows that reelectrification capacities are only needed to meet high electricity demand during a dark lull.

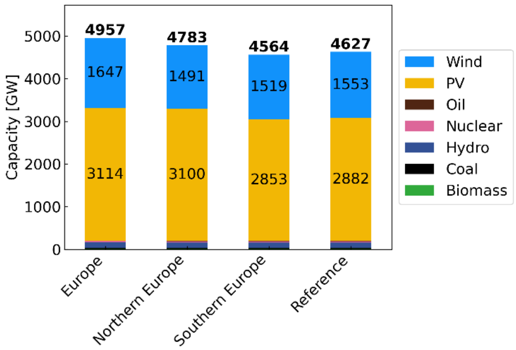


Figure 4-26. Electricity generation capacity during dark lulls in the whole of Europe, northern Europe, southern Europe and north-western Europe (reference).

Figure 4-26 shows the optimal electricity generation capacity in the various scenarios in 2050. It becomes apparent that during dark lulls in the whole of Europe, more PV and wind capacity will be expanded, and hydrogen imports will be dispensed with (see Figure 4-25(b)). This can be explained by the fact that additional wind and PV capacity will both better cover electricity demand during dark lull periods and enable more hydrogen to be produced throughout the year, which can be stored temporarily in cavern storage facilities.

Resilience to large-scale dark lull periods can be ensured by the placement of flexible power plants and the increased expansion of renewables. This will strengthen domestic hydrogen production and reduce dependence on extra-European imports.

4.4 Germany in the heart of Europe

Germany plays a special role within the European energy system. Due to its high industrial and population density, Germany has the highest energy demand in Europe. It is assumed that the high industrial and population density will remain unchanged in the future. In the reference scenario, Germany will have the highest electricity and hydrogen demand in Europe in 2050, at 1,005 and 670 TWh per year respectively. At the same time, the potential for renewables in Germany is limited due to the high population density and the associated land-use exclusions. This means that it is not economically viable to cover the demand for electricity and hydrogen entirely from domestic sources. This creates a need for energy imports.

While Germany currently exports low amounts of electricity on an annual basis – between 2015 and 2022, net exports never exceeded 50 TWh per year [68] – this changes in the reference scenario. By 2050, Germany's electricity imports will rise to 410 TWh per year, as shown in Figure 4-27(a). This corresponds to a self-sufficiency rate of 66% for electricity and indicates that sourcing part of the future electricity demand from abroad is more cost-effective for Germany than producing it domestically. The resulting interconnection capacities with neighboring countries are shown in Figure 4-27(b). Both new construction and total capacity are shown here. Overall, additional capacity of 81 GW will be added by 2050 to connect neighboring countries. It can be seen that interconnection capacities with all neighboring countries are being expanded. The significant expansion of the electricity grid will enable high levels of electricity imports. It will also reduce the need for power conversion capacity, as electricity can be imported from neighboring countries in the event of power shortages.

Unlike in other studies, the required reelectrification capacity is low at 54 GW. If the electricity grid were not to be developed beyond the expansion planned by the TYNDP, the demand for reelectrification capacity in Germany would rise to 77 GW, as further sensitivity calculations have shown. At the same time, significantly more renewable energy capacity would also have to be realized within Germany. This would increase the installed capacity of onshore wind turbines from 118 GW to 164 GW in 2050. Supply beyond the TYNDP would be feasible but would lead to an increase in total costs of around 9%.

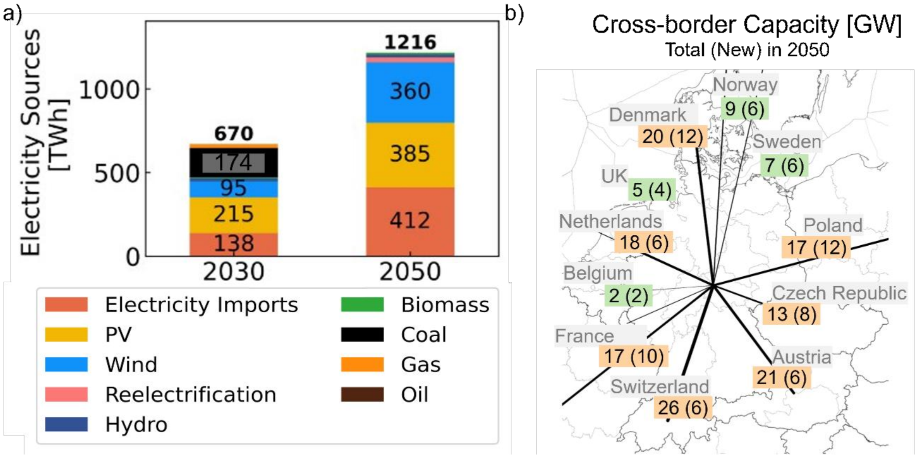


Figure 4-27. Electricity supply in Germany in the reference scenario. a) Electricity sources for 2030 and 2050. b) Installed interconnection capacities with neighboring countries in 2050. The value in brackets indicates the share of new construction required in GW.

In the baseline scenario, domestic electricity production in 2050 will be 385 TWh from PV and 360 TWh from wind. Other energy sources such as biomass and hydropower will not be used to any significant extent. In Germany, the hydrogen supply in 2030 and 2040 will be secured exclusively through pipeline imports from neighboring countries. In 2050, 19% of the hydrogen demanded will be provided by domestic production, while around 600 TWh per year will be imported from other regions of Europe. The construction of 200 GW of interconnector capacity will be necessary for hydrogen pipeline imports by 2050. Of this, 85% (170 GW) can be achieved by repurposing existing natural gas pipelines. New hydrogen pipelines will only be built to northern Europe, Denmark, Norway and Finland, as shown in Figure 4-28(b).

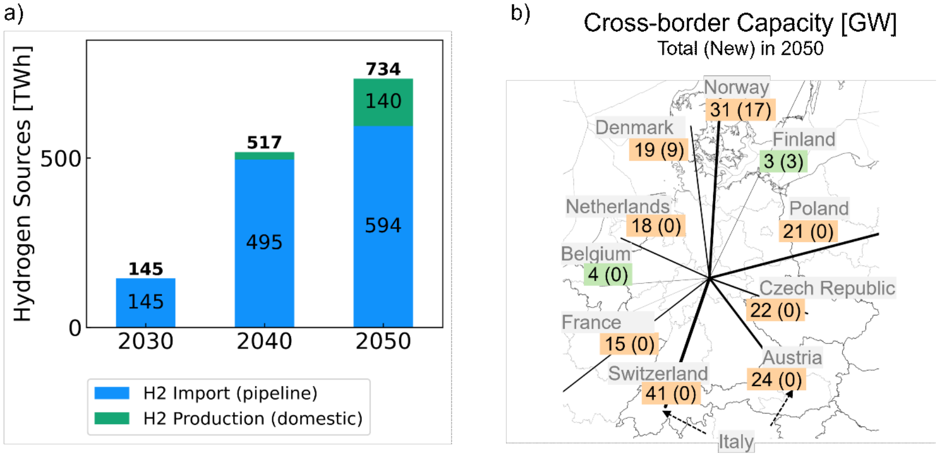


Figure 4-28. Hydrogen supply in Germany in the reference scenario. a) Hydrogen sources for the years 2030, 2040 and 2050. b) Installed interconnection capacities to neighboring countries in 2050. The value in brackets indicates the share of new construction required in GW.

Figure 4-29 shows the countries through which hydrogen is transported to Germany. In 2030, hydrogen will be imported to Germany mainly from Norway and Denmark. From 2040 onwards, imports from southern Europe via Switzerland and Austria and from eastern Europe via Poland will also be added. Most of the hydrogen imported into Germany will be used domestically. Around 20 to 25% of hydrogen imports will be forwarded to supply the Netherlands.

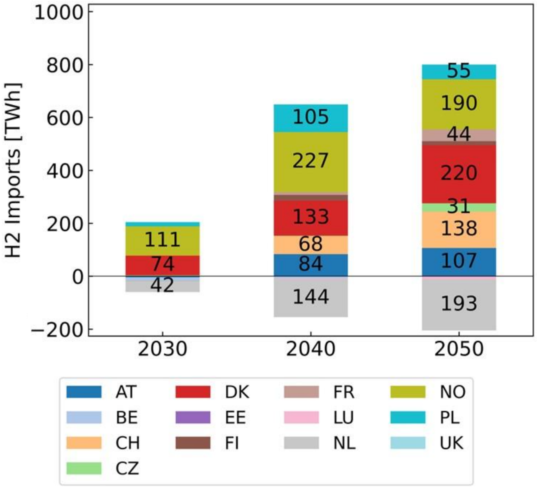


Figure 4-29. Origin of hydrogen imports for Germany. Some of the imported hydrogen is transported on to the Netherlands.

Germany also plays a special role due to the possibility of converting existing natural gas cavern storage facilities to hydrogen storage, which amounts to 42 TWh of storage volume for hydrogen. This conversion makes it possible to ensure security of supply both for supplying industry with hydrogen and for meeting the high demand for electricity in an emission-free manner by converting hydrogen back into electricity during dark lulls. Other European countries in south-eastern and northern Europe do not have this cost-effective option for repurposing salt caverns due to geological conditions.

The resulting levelized cost of electricity and hydrogen for Germany in this scenario are shown in Figure 4-30(a). Levelized cost of electricity (LCOE) in Germany will fall from 7 ct/kWh in 2030 to below 5 ct/kWh in 2050. This is primarily due to the decreasing costs of expanding PV and wind power. Figure 4-30(b) shows the levelized cost of hydrogen (LCOH) in Germany compared to Spain, Italy and Norway in 2050. This is the average LCOH based on installed electrolysis capacities. It becomes clear that LCOH in Germany, at around €3.15/kg, is higher than in southern and northern Europe. However, German hydrogen production will only be established at a later stage of the transformation than in Spain. In Spain, electrolysis capacities are being expanded at an early stage, resulting in higher investment costs. This also affects the LCOH, which is higher than in the other regions. Italy benefits from lower investment costs for PV due to the late expansion of electrolysis capacities, which also affect the LCOH.

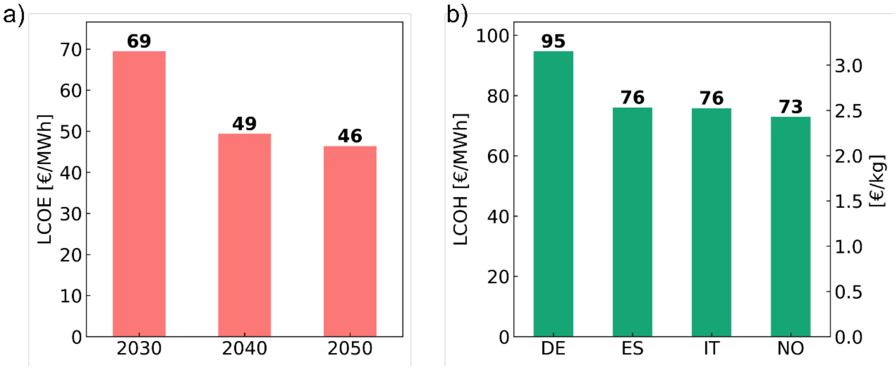


Figure 4-30. Levelized cost in Germany. a) Levelized cost of electricity (LCOE) in Germany over time. b) Levelized cost of hydrogen (LCOH) in 2050 for Germany compared to major exporting countries.

In conclusion, Germany's role in the heart of Europe can be summarized as follows: A European approach gives Germany the advantage of being able to access electricity and hydrogen imports from neighboring countries at low cost. In terms of gas, Germany's role is changing from a gas transit country to a hydrogen importer. In terms of electricity, Germany's role is changing from being largely self-sufficient to being a major importer of electricity. It should be noted that electricity imports from countries with more cost-efficient potential are advantageous for Germany, as this can lead to lower electricity prices.

With a European approach, Germany benefits from low-cost electricity and hydrogen imports from neighboring countries.

5 Summary

To achieve the European climate protection targets and the associated greenhouse gas neutrality by 2050, a holistic transformation of the European energy system is necessary. This study explores the pathways and strategies through which these objectives can be achieved in Europe and the role that Germany will play given its central location.

In addition to phasing out the use of fossil fuels in all end-use sectors and the associated switch to emission-free energy sources, achieving these targets will require a restructuring of the energy supply landscape. From a technical and economic point of view, this restructuring is feasible, but it requires all European players to act collectively and each sector to contribute to greenhouse gas reduction.

This restructuring means that the expansion rates of wind and PV plants must be significantly increased. The expansion of renewables will take place in all countries. The high expansion rates will promote domestic, competitive hydrogen production and reduce the need for extra-European hydrogen imports and reelectrification. A four- to five-fold increase in expansion rates would be cost-optimal. This would provide sufficient electricity to meet demand and keep dependence on imports from extra-European countries to a minimum. If the expansion rate of renewables can be increased, the production of green hydrogen within Europe will be competitive with hydrogen imported from extra-European countries.

However, analyses show that implementing a joint transformation would require a significant increase in electricity and hydrogen exchange capacities between countries. This approach would allow the renewable energy potential of each country to be exploited in the most efficient way.

Should the expansion of renewable energy remain at its current pace and is therefore delayed, overall system costs and dependence on extra-European energy imports are expected to increase, as Europe would not be able to produce sufficient electricity and hydrogen at competitive costs. To avoid this, it is essential to push ahead with the expansion of renewables.

As an alternative to renewables, increased use of nuclear energy is being investigated. As the analyses show, this is not competitive with PV and wind unless the investment costs for the construction of nuclear power plants fall significantly. Even with low investment costs for new nuclear power plants, the share of nuclear energy in electricity production remains below 15%. For this reason, the increased expansion of renewables is to be preferred.

To protect against possible regional and large-scale dark lull periods, it is necessary to integrate flexibility options. Storing hydrogen in underground storage during periods of high renewable energy feed-in can serve to meet hydrogen demand during dark lulls and enable flexible electricity generation in reelectrification plants. Through joint action by the European countries, regional fluctuations can be balanced out by energy flows from unaffected regions.

Due to its high population density and share of industry, Germany plays a special role in the transformation of the European energy system. Germany exhibits the highest energy demand. Meeting this demand entirely domestically turns out to be not economically viable. Germany's central location makes it possible to source electricity and hydrogen from other countries that have more cost-efficient locations for renewables. This requires an expansion of interconnection capacities at both the electricity and gas levels.

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EEZ	Exclusive Economic Zone
BAU	*Business-as-usual*
ETHOS	*Energy Transformation Pathway Optimisation*
FINE	*Framework for Integrated Energy System Assessment*
GuD	*Buildings and services*
IEA	International Energy Agency
LNG	*Liquefied natural gas*
NUTS	*Nomenclature of Territorial Units for Statistics*
PEM electrolysis	Proton exchange membrane electrolysis

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Appendix

Table 4. Modeled preferred regions for hydrogen export.

Preferred region	Port	Country	Export type
Patagonia	Comodoro Rivadavia	ARG	Ship
Iceland	Reykjavik	ISL	Ship
British Columbia	Vancouver	CAN	Ship
Newfoundland	St. John's	CAN	Ship
Quebec	Quebec	CAN	Ship
China	Shanghai	CHN	Ship
USA	Los Angeles	USA	Ship
Mexico	Ensenada	MEX	Ship
Peru	Callao	PER	Ship
Chile	Valparaiso	CHL	Ship
Western Sahara	Dakhla	ESH	Ship
Morocco	Casablanca	MAR	Ship
Algeria	Algiers	DZA	Ship
Libya	Benghazi	LBY	Ship
Egypt	Port Said	EGY	Ship
Namibia	Walvis Bay	NAM	Ship
South Africa	Cape Town	ZAF	Ship
Saudi Arabia	Yanbu	SAU	Ship
Oman	Salalah	OMN	Ship
Australia	Fremantle	AUS	Ship
Turkey	Tekirdag	TUR	Pipeline
Morocco	Casablanca	MAR	Pipeline
Algeria	Algiers	DZA	Pipeline
Libya	Benghazi	LBY	Pipeline

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