Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach

AUTHOR

David Schlund

EWI Working Paper, No 08/23

December 2023

Institute of Energy Economics at the University of Cologne (EWI)
www.ewi.uni-koeln.de

Institute of Energy Economics
at the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Str. 321a
50827 Köln
Germany

Tel.: +49 (0)221 277 29-100
Fax: +49 (0)221 277 29-400
www.ewi.uni-koeln.de

CORRESPONDING AUTHOR

David Schlund
Institute of Energy Economics at the University of Cologne (EWI)
david.schlund@ewi.uni-koeln.de

ISSN: 1862-3808

Integrating Cross-Border Hydrogen Infrastructure in European Natural Gas Networks: A Comprehensive Optimization Approach

David Schlund*

Institute of Energy Economics at the University of Cologne (EWI)
Vogelsanger Str. 321a, 50827 Cologne, Germany

Abstract

The introduction of clean hydrogen as a future energy commodity has prompted significant interest in developing dedicated transportation and storage infrastructures as an enabler for cross-border hydrogen trade and cost-efficient supply. This paper addresses the complex challenges associated with the development of a European hydrogen infrastructure within the existing natural gas network while maintaining the security of supply for natural gas. Through an extension of an existing dispatch model for European natural gas supply and transportation by endogenous investments in hydrogen production, transportation, and storage infrastructure, a comprehensive analysis of the interplay between natural gas and hydrogen supply becomes accessible. The new model is formulated as a mixed-integer linear program in order to explicitly consider the binary decision of repurposing natural gas pipelines. The results offer insights into the cost-efficient strategic planning of a European hydrogen network by simulating a range of scenarios with varying economic and technical constraints. The case study finds a dominant role of the availability of renewable energy sources in shaping the network. Also, providing flexibility through flexible imports, production, or hydrogen storage becomes an essential element in a future hydrogen supply chain. The interconnection of all European countries with dedicated hydrogen pipelines is robust across all scenarios. However, the sizing and choice of large import pipelines strongly depend on the assumed techno-economic constraints.

Keywords: hydrogen economics, hydrogen infrastructure, hydrogen storage, hydrogen trade, strategic energy planning, mixed-integer linear program.
JEL classification: C61, L95, M20, Q41, Q42, Q48.

1. Introduction

The role of hydrogen in future net-zero energy systems has widely been acknowledged by research, politics, and industry. Various energy system studies and scenario reports predict an increased uptake of

*Corresponding author
Email address: david.schlund@ewi.uni-koeln.de (David Schlund)

clean hydrogen to decarbonize existing hydrogen demand, to deploy hydrogen in new applications in order to eliminate CO_2 emissions, and to use hydrogen as a long-term energy storage (e.g., Otsuki et al. (2023); IEA (2022); WEC (2019); IRENA (2023); Staffell et al. (2019)). Hydrogen has physical properties making it a well-suited element for large-scale and long-term energy storage in renewable energy (RE) dominated energy systems and facilitating global trade in clean energy commodities. Several governments have published national hydrogen strategies, and private actors are planning and developing gigantic projects to build clean hydrogen supply chains. Unlike fossil fuels, which are geographically bound to locations with natural resources, hydrogen can be produced from many different primary energy carriers. In particular, it can be produced with electrolysis, which splits water into oxygen and hydrogen. The total emission balance is zero, if electricity is exclusively sourced from RE. Globally, resources for RE are available anywhere, which enables every country to produce clean hydrogen and enables more diversified energy supply. However, potentials for RE vary significantly between regions and some countries might be favored for electricity production from RE. Against this background, inter-regional hydrogen transportation could create a new market for hydrogen as an energy commodity.

In the European Union (EU), recent geopolitical conflicts have revealed the bloc's vulnerability caused by its dependency on a few single energy exporters. The interruption of energy supplies from Russia has motivated the EU to reduce its dependency on energy imports and increase the speed of expanding RE, in particular, the production and utilization of clean hydrogen (EC, 2022). One essential aspect is the development of a pan-European dedicated hydrogen infrastructure to foster trade of hydrogen in the EU and with neighboring countries, as well as to phase out fossil gases until 2050 (EC, 2021; EUC, 2023). Also, the EU plans to trade hydrogen globally as ammonia or other derivatives (EC, 2022).

An integrated European hydrogen market will need infrastructure for transportation and storage. Today, Europe already has a well-developed pipeline infrastructure for natural gas, connecting all continental countries and the British Isles with a total length of more than 200,000 km (referring to transmission pipelines) (ACER, 2021). The partial conversion of this infrastructure to hydrogen is a promising approach to give the pipelines a second life in a climate-neutral energy system and to save the costs of building a dedicated hydrogen network. Simultaneously, increased awareness of security of energy supply, particularly of supply diversification, poses challenges to decision-makers to balance economic, political, and technical interests of all involved parties.

This paper presents an extension to an existing model for natural gas transportation and storage in Europe to incorporate investments in hydrogen infrastructure, production, storage, and import capacity while ensuring a sufficient supply of natural gas. The model formulation explicitly considers the possibility of repurposing natural gas pipelines, which is expected to be more cost-efficient than greenfield investments in a dedicated hydrogen network. While the primary focus of this paper is to introduce and explain the methodological approach of the model extension, it is also applied to a use case consisting of different scenarios to show the effect of different parameter choices on the model's investment and dispatch decision. These effects provide important insights for strategic infrastructure planning and further research on integrated European energy markets and infrastructures. The research objectives can be summarized under the following research questions: How can the development of a dedicated cross-border hydrogen infrastructure be integrated in an existing natural gas transportation model? How do different technical and economic conditions impact the cost-optimal investment and dispatch decisions?

In the paper, the natural gas infrastructure model TIGER, which was initially developed by Lochner (2011c), is extended on various levels: Investments in hydrogen infrastructure and production equipment are introduced, whereby existing natural gas pipelines can be repurposed, or new infrastructure can be built. Infrastructure assets include cross-border pipelines, seaborne hydrogen import terminals, and underground cavern storage. Production equipment can be either dedicated[1] RE (solar photovoltaics (PV), wind onshore, wind offshore) with electrolysis, or steam methane reforming (SMR) with carbon capture and storage (CCS). Since hydrogen and natural gas demand, supply, and infrastructure are integrated in one model, the simulation uses a reduced spatial resolution and only considers cross-border interconnection pipelines instead of all domestic pipeline segments. The model is applied to an exogenous data set on natural gas demand and supply, hydrogen demand, and RE production potentials. The emerging hydrogen market is characterized by high uncertainty regarding demand, supply, and technology costs. These uncertainties are captured by simulating different scenarios with varying economic and technical parameters along the supply chain to understand better the effects of the parameter choices on infrastructure development.

This work makes important contributions to the ongoing research on the economics of transforming energy systems. It is one of the first models to optimize natural gas and hydrogen infrastructure in Europe in an integrated model. This is of particular interest since security of natural gas supply must be ensured in a transitional period while ramping up a hydrogen infrastructure. Second, it considers the effect of changing geopolitical conditions and their effect on energy markets. The scenario analysis shows the model's capabilities to provide insights and plausible results for the strategic planning of a European hydrogen network, but it can also be extended in future research, e.g., through an improved integration of hydrogen, natural gas, and electricity markets.

The remainder of this paper is structured as follows: The subsequent Section 2 reviews recent literature on hydrogen supply chain and network modeling. The literature review emphasizes the contribution of this paper to the ongoing research in the field. In Section 3, the extended model formulation is introduced and numerical assumptions for the scenario analysis are defined. The results are presented in Section 4 along the dimensions investment decision, dispatch decision, costs, and impact on natural gas supply. Since the

[1] The current model formulation only considers electricity demand from hydrogen production.

model uses many numerical and conceptual assumptions, the model and the results are critically discussed in Section 5. Also, contributions of future research are suggested. Section 6 concludes the paper and gives an outlook.

2. Literature review

This work is embedded in an existing body of literature on the uptake of hydrogen in future energy systems. Research on this topic is manifold and this paper mainly builds on two different streams of previous work.

The first stream is concerned with modeling cost-optimal investment and dispatch decisions of energy supply or infrastructures for gaseous energy carriers. These types of models typically follow the rationale of simulating energy markets as partial equilibrium models to minimize system costs. Nunez-Jimenez and De Blasio (2022) develop a mixed-integer linear optimization model that allows them to globally analyze scenarios for cost-optimal green hydrogen supplies, including domestic production and imports. The essential decision variables represent domestic hydrogen production, trade between countries, and transportation infrastructure (pipeline diameters or number of ships). The model assumes three different options for transportation: gaseous via newly built hydrogen pipelines, shipping as liquid hydrogen, and seaborne ammonia trade. Hydrogen production is considered as production potentials and levelized cost of hydrogen (LCOH) per resource. Schönfisch (2022) develops and simulates a global hydrogen market model, which is formulated as a mixed complementarity problem. Nodes represent countries and edges are either pipelines or shipping routes. The analyzed scenarios differ in the availability and costs of different clean hydrogen production technologies, i.e., hydrogen from RE, from natural gas reforming with CCS, and from coal gasification with CCS. For Europe, the study finds that hydrogen is imported chiefly from North African countries (where it is generated with solar PV), or produced in windy Northern countries. A similar approach can be found in Lippkau et al. (2023), where a global energy system model is used to investigate the global trade of hydrogen and derived fuels. Neumann et al. (2023) analyze the trade-off between building a hydrogen network and power grid reinforcement with a linear optimization model. European countries are spatially resolved in 181 regions to improve the visibility of within-country infrastructure investments. The model optimizes investment and dispatch of energy generation, transportation, conversion, and transportation assets and is applied to four scenarios to quantify the system value of energy infrastructure expansions. Hydrogen networks can be newly built or repurposed from existing natural gas pipelines. However, natural gas supply is not considered in the model, and hydrogen pipeline imports from North African countries are out of the model's scope. Similarly, Frischmuth et al. (2022) introduce an investment and dispatch model, covering natural gas and hydrogen supply, infrastructure, and demand. Hydrogen networks can be either newly built or developed from repurposing existing natural gas pipelines. Each country is represented as one node, and pipeline interconnection capacities are aggregated. In Schlund and Schönfisch (2021), a

European natural gas dispatch and an investment model for electricity are coupled to analyze the effect of a mandatory quota for green gases (hydrogen and synthetic methane) on electricity and natural gas prices, welfare distribution, and natural gas flows. Many other tools and models have been developed to determine cost-optimal designs of hydrogen pipeline networks, e.g., in Germany (Krieg, 2012; Robinius, 2015; Baufumé et al., 2013; Welder et al., 2018), in the United Kingdom (UK) (Moreno-Benito et al., 2017; Samsatli et al., 2016), or France (André et al., 2014). Most of these studies use technical and economic modeling to determine the cost-optimal trajectory of a national hydrogen grid to supply a given or endogenously determined demand at optimal cost. While many studies acknowledge the physical representation of gas flows, the technical modeling limits the spatial and temporal scope of the use cases. The option of repurposing natural gas pipelines, which is expected to reduce investment costs significantly, is addressed in only a few publications. Repurposing reduces transport capacities for natural gas and potentially endangers security of supply. Thus, incorporating natural gas supply is crucial to assess a transition from natural gas to hydrogen networks. Also, the possibility of repurposing single strings of parallel interconnection pipelines and the option of importing hydrogen via pipelines from North African countries is out of the scope of many previous analyses.

The non-academic initiative "The European Hydrogen Backbone (EHB)" regularly publishes and updates a visionary concept of a future European hydrogen network across different countries.[2] While documenting the underlying cost parameters of repurposing and constructing new hydrogen pipelines, the report doesn't introduce a methodology for the published maps of a European hydrogen network. Transmission grid operators have published similar documents for visionary network concepts on a national level, e.g., Germany (FNB, 2023), the Netherlands (Gasunie, 2023), or the UK (ENA, 2021).

The second stream of literature, which is relevant for this work, is considered with the analysis of costs and potentials of future hydrogen supply. For instance, Brändle et al. (2021) analyze the production cost of hydrogen from RE, natural gas with CCS, and pyrolysis in 94 different countries. For a set of countries, import costs are derived by calculating transportation costs for hydrogen via new or repurposed pipelines or seaborne liquefied hydrogen. Moritz et al. (2023) extend this work and consider hydrogen derivatives, such as green ammonia or synthetic methane. Kakoulaki et al. (2021) perform a spatially resolved analysis of green hydrogen substitution in the European industry sector. The authors argue that technical RE potentials exceed demand for green hydrogen in most assessed regions, even after subtracting electricity demand for electrification. Sens et al. (2022) present a method to design cost efficient systems for producing, storing, and transporting hydrogen from RE within Europe and its neighboring regions. The model considers investments in RE generation, hydrogen production, storage, and transportation equipment. Their results stress the enormous supply potentials from North African countries, which could bring down hydrogen

[2]See EHB (2023) for the latest visionary hydrogen network maps and van Rossum et al. (2022) for technical details.

supply costs in Europe to 2 EUR/kg in 2050. They also emphasize the relevance of hydrogen cavern storage, which decreases hydrogen supply costs for countries with high seasonality of RE. Many other papers have investigated and simulated potentials and costs of green hydrogen supply chains with data-rich models and methods (e.g., Heuser et al. (2020); Pfennig et al. (2023); Panchenko et al. (2023); ElSayed et al. (2023); Franzmann et al. (2023); Bai et al. (2023))

While previous work provides important insights in the topology of a future hydrogen grid and estimates costs, the geographical scope has often been limited to single countries or the interaction of the hydrogen infrastructure with the natural gas sector in the transition period hasn't been part of the analysis. Against this background, this work contributes to the existing body of literature by introducing an integrated optimization model for the investment and dispatch of hydrogen and natural gas supply in Europe.

3. Methodology

This section introduces the methodological approach and documents the numerical assumption for the simulation. The model extends the European natural gas infrastructure model TIGER (Lochner, 2011c) by endogenous investment decisions in hydrogen production equipment and infrastructure.

The simulation results can provide information and important insights for long-term planning and strategic decisions around hydrogen infrastructures, however, they should not be misinterpreted as technical simulations for operational grid planning.

3.1. Model Formulation

The TIGER model has previously been applied to various analyses of European natural gas supply (Schlund and Schönfisch, 2021; Lochner, 2011a,b; Dieckhöner, 2012). It is originally formulated as a linear program (LP) and thus assumes perfect foresight in a fully competitive market. The following extensions are made to create an integrated economic investment and dispatch model for natural gas and hydrogen: investments in (i) hydrogen production equipment (RE generation capacities, electrolysers, SMR with CCS) and (ii) infrastructure (repurposed or new hydrogen pipeline interconnectors, seaborne hydrogen import terminals, hydrogen storage). The original TIGER model has a daily temporal resolution and covers all major gas transport pipeline segments, each individual liquefied natural gas (LNG) regasification terminal, and each storage site in Europe. For the extended model, the resolution is reduced for computational efficiency since the model extension increases the complexity through several new model variables. The decision to repurpose natural gas pipelines is only possible for an entire pipeline. To correctly reflect this decision, a binary variable is introduced, changing the type of the problem from an LP to a mixed-integer linear program (MILP). The extended model has a monthly temporal resolution and covers each pipeline interconnector between countries without explicitly modeling pipelines within a country. An overview of the model variables, parameters, and sets can be found in the Appendix A.

The objective function Eq. 1 minimizes total costs TC of natural gas and hydrogen (gas) supply in year y, which is the sum of discounted (a) capital costs (including fixed operative and maintenance costs f) for all types of investments C_{tech}, variable commodity cost $opex^{import}$ for natural gas and hydrogen imports I, domestic natural gas production P, variable cost $opex^{CCS}$ for CCS (including CO_2 costs for uncaptured emissions), and variable cost for transportation (T) and storage flows (S). Further equations on the implementation of natural gas supply are omitted here and it is referred to the introduced previous model publications.

$$\begin{aligned} min \quad TC_y = & \sum_{tech,t} (a_{tech} + f_{tech}) * C_{tech,y} * capex_{tech,y} \\ & + \sum_{i,gas,t} opex^{import}_{i,gas,t} * I_{i,gas,t} \\ & + \sum_{i,ng,t} opex^{prod}_{i,ng,t} * P_{i,ng,t} \\ & + \sum_{i,H2,t} opex^{ccs}_{i,H2,t} * P^{ccs}_{i,H2,t} \\ & + \sum_{i,j,gas,t} opex^{trans}_{i,j,gas,t} * T_{i,j,gas,t} \\ & + \sum_{i,gas,t} opex^{stor}_{gas,t} * S_{i,gas,t} \qquad \forall\, t \in y \end{aligned} \tag{1}$$

The hydrogen node balance Eq. 2 ensures that hydrogen flows entering a node i from another node j equal the flows exiting the node in each period t, considering transportation T, net storage flows S, aggregated production from electrolysers and SMR P, imports I, and demand d.

$$P^{H2}_{i,t} + S^{H2}_{i,t} + I^{H2}_{i,t} + T^{H2}_{j,i,t} \quad = \quad d^{H2}_{i,t} + T^{H2}_{i,j,t} \qquad \forall\, t, i \neq j \tag{2}$$

The model allows for *green* hydrogen production, using electricity from RE and electrolysis, as well as *blue* hydrogen from SMR with CCS. The upper bound of blue hydrogen production is defined by the installed SMR capacity $C^{H2,blue}$, including the efficiency $\eta^{H2,blue}$ (Eq. 3). The scaling factor s distributes annual capacities over periods t and the lower heating value ϵ converts MWh into $\mathrm{mcm}_{\mathrm{H2}}$.[3]

$$P^{H2,blue}_{i,t} \quad \leq \quad C^{H2,blue}_{i,y} * \eta^{H2,blue}_{i,t} * \epsilon * s \qquad \forall\, i, t \in y \tag{3}$$

Blue hydrogen production increases demand for natural gas, which is considered in the natural gas node balance Eq. 4. The conversion factor γ translates mcm^{ng} into mcm^{H2}.[4]

[3]Lower heating value of hydrogen: $\epsilon = 3\ \frac{kWh}{cm_{H2}}$

[4]$\gamma = 3.7\ \frac{cm_{H2}}{cm_{ng}}$

$$P_{i,t}^{NG} + S_{i,t}^{NG} + I_{i,t}^{NG} + T_{j,i,t}^{NG} \quad = \quad d_{i,t}^{NG} + T_{i,j,t}^{NG} + P_{i,t}^{H2,blue} * \frac{1}{\eta_{i,t}^{H2,blue} * \gamma} \qquad \forall\, t, i \neq j \tag{4}$$

Domestic green hydrogen production Eq. 5 is limited by electrolyser capacities C^{H2} considering the conversion efficiency η and generation from all installed RE capacities C_{res}. Heterogeneity in RE output (defined by the location and time specific capacity factor $c_{res,i,l,t}$) is modeled through different cost levels l. Each RE cost level is characterized by an individual capacity factor and annual generation potential (Eq. 6). The technologies solar PV, onshore wind, and offshore wind are considered. The model allows for hybrid electricity supply, hence, the electricity can be sourced from different RE.

$$P_{i,t}^{H2} \quad \leq \quad C_{i,y}^{H2} * \eta * s \quad \leq \quad \sum_{res,l} C_{res,i,l,y} * c_{res,i,l,t} * \frac{1}{\epsilon} * \eta^{H2,green} * s \qquad \forall\, i, t \in y \tag{5}$$

Electricity produced from RE is only used to feed electrolysers, electricity trading at wholesale markets is not allowed. Electricity generation exceeding the consumption of electrolysers is discarded. While this approach aims to comply with the *additionality* obligation of the current EU legislation, in order to ensure that RE are built in addition for hydrogen production, it neglects the opportunity of RE to interact with electricity markets. Section 5 discusses this simplification in more detail.

Investments in RE capacities are limited by maximum potentials for each technology and cost level (Eq. 6).

$$C_{i,l}^{RES} \quad \leq \quad pot_{i,l}^{RES} \qquad \forall\, i, l \tag{6}$$

Seaborne hydrogen and natural gas imports I_{gas} are imported as hydrogen derivatives[5] and LNG, respectively, and require import terminals C_{gas} (Eq. 7).

$$\sum_{t} I_{i,gas,t} \quad \leq \quad C_{i,gas,y}^{imp} * s \qquad \forall\, i, gas, t \in y \tag{7}$$

Production in ammonia and LNG exporting countries are not modeled and are fed into the model as supply curves, defined by potentials and costs per cost level (Eq. 8).

$$\sum_{i,t} I_{i,gas,t} \quad \leq \quad \sum_{l} pot_{gas,l,y}^{imp} \qquad \forall\, gas, t \in y \tag{8}$$

Hydrogen cross-border flows are limited by existing pipeline capacities cap^{H2} and pipeline expansions, which can either be built as new pipelines $C^{pipe,H2}$ or through repurposing natural gas pipelines with given capacity cap^{NG}. The following Eq. 9 formalizes the conversion process through introducing a binary variable

[5] As Section 3.2 explains, the scenario analysis assumes ammonia is imported as hydrogen derivative. In principle, the model can consider different import fuels when parameterized with according data.

B which ensures repurposing of a whole pipeline only. Repurposing a pipeline from natural gas to hydrogen reduces its transport capacity by the fixed value δ.

$$T^{H2}_{i,i,t} \quad \leq \quad cap^{H2}_{i,j,t} + C^{pipe,H2}_{i,j,t} + B_{i,j,t} * cap^{ng}_{i,j,t} * \delta * \gamma \qquad \forall\, t, i \neq j \tag{9}$$

Repurposing an existing natural gas pipeline cap^{ng} removes it from the natural gas transmission system (Eq. 10).

$$T^{ng}_{i,j,t} \quad \leq \quad cap^{ng}_{i,j,t} - B_{i,j,t} * cap^{ng}_{i,j,t} \qquad \forall\, t, i \neq j \tag{10}$$

Pipeline investments and repurposing is always symmetrical, which means that capacities are generated in both directions i, j and j, i. Decommissioning of infrastructure is not considered.

Hydrogen storage can only be built as new investments and operational constraints are equivalent to natural gas storage constraints, introduced in Lochner (2011c).

For each capacity investment, a time continuity constraint Eq. 11 is added.

$$C_{tech,t-1} \quad \leq \quad C_{tech,t} \qquad \forall\, t \tag{11}$$

All variables are non-negative, except for storage flows (S).

3.2. Model Parameterization and Calibration

The main purpose of this paper is to present a novel model formulation to allow for integrated assessments of natural gas and hydrogen infrastructure investments and dispatch. In order to demonstrate and validate the model capabilities, a simulation with exogenous data and simplifying assumptions is made. The model is parameterized with numerical assumptions for hydrogen and natural gas demand, supply, and technology costs.[6] The type of model and the large uncertainty about the future development in the energy sector create an unreasonably large solution space. To better represent real-world conditions in the European energy sector, some assumptions and constraints are defined to calibrate the model and reach more realistic results. These assumptions are documented in this section and discussed in Section 5. An overview of all numerical assumptions can also be found in the Appendix B.

3.2.1. Infrastructure

Specific investment costs of LNG regasification terminals are site-specific and project budgets are often confidential. The model makes no distinction between floating storage and regasification unit (FSRU) or onshore terminals. Capex data for LNG terminals is determined by calculating average specific investment costs of recent regasification terminal projects in Europe, which yields 155 MEUR_{2022}/bcmpa (GEM,

[6] Currency conversions assume a rate of 0.9 EUR/USD.

2023). As a comparison, Lochner (2011c) calculates with a similar approach average specific costs of 116 $\mathrm{MEUR_{2010}}$/bcmpa (corresponding to 146 $\mathrm{MEUR_{2022}}$/bcmpa). Lifetime of LNG regasification terminals is estimated with 25 years.[7] Existing and planned LNG terminals in Europe have been updated based on GEM (2023), GIE (2022), and publicly available information. The energy crisis 2022 has led to numerous announcements on LNG terminal expansions. Only projects have been considered, which disclosed information on a final investment decision, capacities, and commissioning dates, thus, LNG regasification capacities are assumed to increase from 240 bcmpa in 2020 to 364 bcmpa in 2040.

Seaborne hydrogen imports are assumed to be transported as liquid ammonia and converted to hydrogen at the port of entry. In general, there are further options for seaborne hydrogen imports, such as liquid hydrogen, methanol, synthetic natural gas, or liquid organic hydrogen carriers. Recent studies consider ammonia one of the most promising import fuels, and the EU targets ammonia to be imported in large quantities (Moritz et al., 2023; Alsulaiman, 2023; EC, 2022; IEA, 2023). While the model can consider different imported hydrogen derivatives, ammonia is an exemplary import fuel for the scenario analysis. Specific investment costs of ammonia import terminals are estimated at 298 EUR/$\mathrm{kcmpa_{H2}}$ (Moritz et al., 2023; IEA, 2021), which include investment costs for the reconversion unit (ammonia cracker) and an ammonia storage tank. Ammonia terminals are only allowed to be built at locations of existing or planned LNG terminals, thus, no greenfield port infrastructure investment is considered. The import cost includes variable costs of converting ammonia to hydrogen (see Section 3.2.2).

New hydrogen interconnectors can be built or repurposed along the existing natural gas networks, meaning greenfield investments for entirely new pipeline connections between two countries are not allowed. Capital costs for new hydrogen pipelines show a high variation in the literature, ranging from 41 to 492 $\mathrm{EUR_{2022}}$/$\mathrm{mcm_{H2}}$pa*km (Ball and Wietschel, 2009; Brändle et al., 2021; van Rossum et al., 2022). As input, a value of 198 EUR/$\mathrm{mcm_{H2}}$pa*km is assumed for new hydrogen pipelines (including compressor stations) and 59 EUR/$\mathrm{mcm_{H2}}$pa*km for repurposed natural gas pipelines. Hydrogen has a lower energy content per cubic meter, however, through increasing the operating pressure in the retrofitted pipeline, around 80% of the energy throughput of natural gas pipelines can be reached for hydrogen (Galyas et al., 2023; Haeseldonckx and D haeseleer, 2007). The EU has implemented an Entry-Exit-Regime for pricing natural gas transportation within and across European gas hubs. The tariffs reflect capital costs and variable costs for transportation. For hydrogen, no such tariff scheme has been implemented so far and thus capital and variable transportation costs are explicitly considered in the model. The latter essentially consist of energy costs for compressor stations. Energy consumption of 0.6 Wh/$\mathrm{kg_{H2}}$*km is assumed (Krieg, 2012; Sens et al., 2022) with electricity price projections from Brändle et al. (2021) and Gierkink et al. (2022), which result in variable costs for hydrogen transmission between 1.6 to 6.2 EUR/$\mathrm{mcm_{H2}}$*km.

[7]The model uses economic lifetimes.

The EU and the UK already have well-developed underground storage infrastructure for natural gas, capable of storing approximately 30% of annual gas demand (GIE, 2023). The storage capacities are predominantly used to balance seasonal natural gas demand, which is substantially higher in the winter. Hydrogen storage will presumably fulfill two purposes: while it will also balance seasonal demand patterns, hydrogen storage becomes an increasingly important topic in energy systems with high penetration of fluctuating RE since it allows to decouple electricity generation for hydrogen production from hydrogen demand. This second function of hydrogen storage is relatively short-term oriented and will shift the requirements of hydrogen storage in terms of injection and withdrawal capacity. Since the model uses monthly temporal resolution, the storage function focuses more on seasonal balancing than short-term flexibility and provides insights on seasonal storage utilization. Costs are based on van Gessel and Hajibeygi (2023) with investment cost of 1.7 MEUR/mcm$_{\mathrm{H2}}$ and operational costs of 6,750 EUR/mcm$_{\mathrm{H2}}$. In reality, specific investment cost may vary and depend on site specific characteristics.

3.2.2. Hydrogen and Natural Gas Production and Import costs

Global hydrogen trade could emerge similar to today's trade in LNG, requiring assets for converting hydrogen to liquid fuel in the exporting country and regasification in the importing country. For seaborne transport, hydrogen must be liquefied or transformed into another energy carrier, such as methanol, ammonia, synthetic natural gas, or liquid organic hydrogen carrier (LOHC) (Moritz et al., 2023; IEA, 2021). While there is no consensus in the literature about the optimal mode of transportation, recent publications indicate ammonia to be a suitable transportation medium (IRENA, 2023; IEA, 2022; EC, 2022; Salmon and Bañares-Alcántara, 2021). In the model, hydrogen from overseas can be imported as ammonia from Australia, Canada, Chile, Egypt, Namibia, Saudi Arabia, and the United Arab Emirates. The selected countries only represent a sample of possible exporters with high export potentials at comparably low cost. Import costs and potentials are based on the baseline scenario in Moritz et al. (2023) and include all production, transportation, and reconversion costs, except investment cost for import terminals.

Domestic hydrogen production considers investments in RE capacities and electrolysers in the EU[8], UK, Switzerland, Ukraine, and Norway. Additionally, hydrogen production and exports from Libya and Algeria to Europe are modeled, since both countries are connected to the European gas grid. Maximum installable RE capacities and capacity factors per cost level are determined for each country. Solar PV potentials are categorized in 26 cost levels. Data on production potentials and full load hours per cost level is retrieved from Pietzcker et al. (2014). For wind onshore, average capacity factors and installable wind power capacities are determined for 10 cost levels. Data on production potentials and capacity factors is based on Bosch et al. (2017). Offshore wind generation potentials are ranked in two cost levels. Besides installable capacities and

[8] Malta and Cyprus are not connected to the European gas grid and therefore excluded from the analysis.

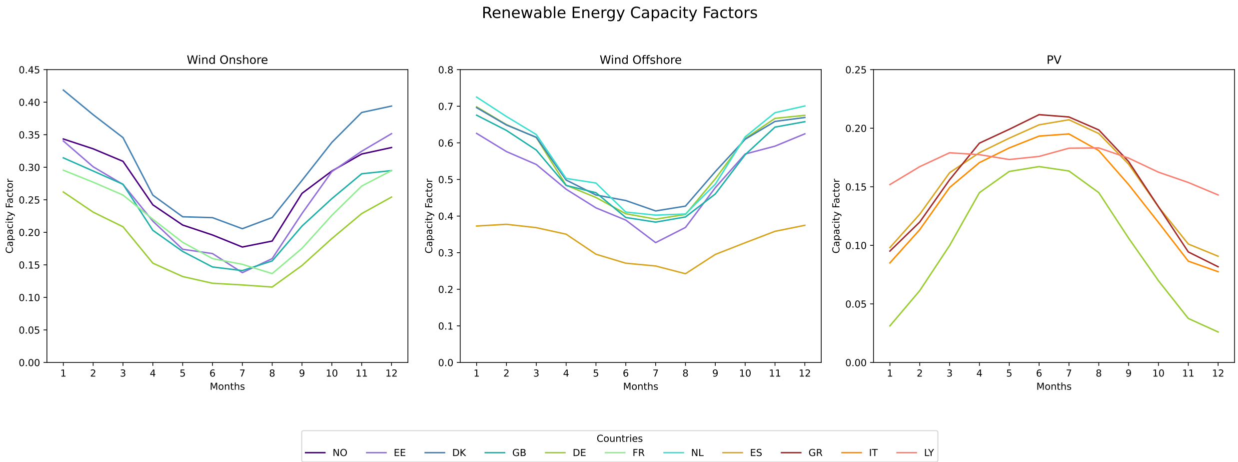

Figure 1: Quantity-weighted capacity factor profiles for exemplary countries (own calculations based on Pietzcker et al. (2014); Bosch et al. (2017, 2019); ESMAP (2020); Marinelli et al. (2014))

average capacity factors, also water depth is considered for offshore wind (Bosch et al., 2019). For water depths above 25 m, capital costs are assumed to be 40% higher (Brändle et al., 2021). For each country and RE, temporally resolved RE generation profiles are generated, using data from Marinelli et al. (2014).[9] The profile is scaled for mean capacity factors for each RE cost level to obtain temporally resolved capacity factor profiles for each country, RE, and cost level. Due to limited data availability, only solar PV is considered for Libya and Algeria, using monthly generation profiles from ESMAP (2020).

In Fig. 1 average capacity factor profiles are shown for countries with high capacity factors in each respective RE class. Germany is added as a comparison. Solar PV shows typical seasonal patterns with high generation in summer months and lower generation during winter. Libya has an almost flat capacity factor profile, since the country is located more closely to the equator and solar irradiation has less seasonality. For wind onshore and offshore, months with strong generation are usually winter months. Countries in the North, located close to the sea, exhibit the highest capacity factors in Europe.

Since technical RE capacity potentials tend to be overwhelmingly high and lead to unrealistic expansion of RE in linear optimization models, two different cases are considered: One scenario assumes high RE potentials according to the methodology as described above. The reference case limits total installable RE capacities to the double of projected installed capacities in 2050 from ENTSOE and ENTSOG (2022) for each country and RE technology. Annual capacity expansion is limited by a linear increase until the target year of 2050. This constraint should represent a tighter expansion path for RE in European countries and allows to better understand the interplay of hydrogen network expansion and the availability of RE generation. The techno-economic assumptions for all RE technologies are listed in the Appendix B.

[9] The dataset provides historical hourly capacity factors for the years 1982–2019. As a representative year, an average capacity factor is calculated.

Blue hydrogen from natural gas requires SMR plants including CCS units. Investment costs are assumed with 1,300 EUR/kW_{H2} (IEA, 2021) with a constant efficiency over time of 69% and a CO_2 capture rate of 90%. Uncaptured emissions are priced with an increasing carbon price according to IEA (2022). Costs for carbon storage are considered as variable costs, which decrease from 50 EUR/t_{CO2} to 30 EUR/t_{CO2} in 2050 (IEA, 2021), thus aggregated operational costs begin with 15 EUR/MWh_{H2} and decline to 12 EUR/MWh_{H2} in 2050. Variable costs for feed gas is endogenously determined in the integrated model. Investment cost for electrolysis is assumed to start at 1,240 EUR/kW_{el} in 2020 and decrease to 300 EUR/kW_{el} in 2050. Efficiency increases from 64% in 2020 to 74% in 2050 (IEA, 2021).

While natural gas dominates gas supply today, synthetic methane or biomethane could increasingly substitute fossil gases. The scenarios in ENTSOE and ENTSOG (2022) project a strong uptake of these climate-neutral gases. Fossil and non-fossil gases can be treated as substitutes for network operation and energy consumption. Therefore, the assumed production potentials include natural gas, synthetic methane, and biomethane production. Production potentials within the EU are retrieved from ENTSOE and ENTSOG (2022). Production capacities in Algeria, Libya, Azerbaijan, and other non-EU countries are based on Rystad (2023). For the simulation, a complete cessation of gas supplies from Russia into the EU is assumed. LNG import potentials crucially depend on natural gas production and liquefaction capacities in exporting countries. A modeling of the global gas market is out of the scope of this paper, instead, it is assumed that global natural gas export capacity expansions are sufficient to meet European LNG demand.

3.2.3. Hydrogen and Methane Demand

Methane and hydrogen demand follow the Global Ambition (GA) scenario developed for the Ten-Year-Network-Development-Plan (TYNDP) 2022 (ENTSOE and ENTSOG, 2022).[10] For the year 2030, hydrogen demand is adjusted to the EU commission's target in the REPowerEU plan (EC, 2022).[11]

Methane demand in the EU and the UK includes demand for conventional natural gas, synthetic natural gas, and biomethane. In the model, no differentiation is made between different methane sources. For 2030, natural gas demand is reduced according to political goals in the REPowerEU plan (EC, 2022). The development of methane demand is shown in Fig. 2. The strong decline in demand between 2022 and 2030 arises from the ambitious plan of the EU to reduce demand by at least 155 bcm (1,722 TWh) from 2021 through energy efficiency measures, fuel switches, reduced consumption, and switching to hydrogen (EC, 2022).[12]

[10]The publishing institutions stress that the scenarios have been developed and issued before the invasion of Ukraine by Russia with a subsequent change in the European energy policy. In this paper, the supply side assumptions predominantly reflect changing conditions on energy markets.

[11]The REPowerEU plan was launched by the European Commission in May 2022 to react to Russia's invasion in Ukraine and the following energy crisis in the EU in order to improve energy efficiency, energy supply diversification, and reduce greenhouse gas (GHG) emissions.

[12]For other European countries, demand assumptions are based on Rystad (2023).

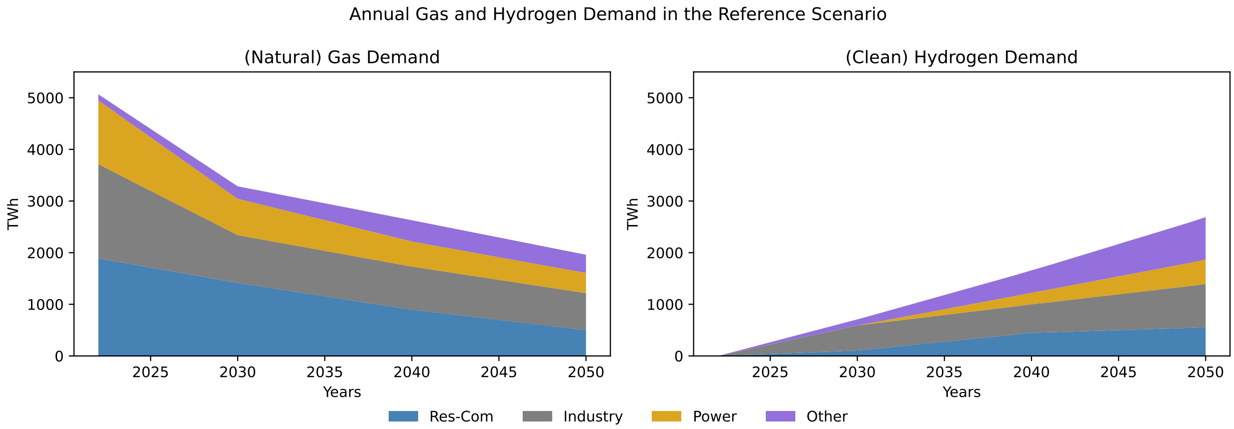

Figure 2: Assumed methane and clean hydrogen demand per sector in the EU and the UK (own figure based on ENTSOE and ENTSOG (2022); EC (2022); Eurostat (2023))

Demand for clean hydrogen in EU countries is assumed to rapidly increase until 2030 to meet the European Commission's goals of 20 Mt (equivalent to 667 TWh) in 2030 (EC, 2022) (Fig 2). After 2030, hydrogen demand in the EU increases to 45 Mt (1,500 TWh) in 2040 and 72 Mt (2,400 TWh) in 2050 (ENTSOE and ENTSOG, 2022). Whereas early hydrogen consumption in dominated by the industry sector in the scenario, demand growth in the electricity and residential and commercial sector take over between 2030 and 2040. Also, demand in the transport sector rapidly increases after 2030, comprising almost one third of European clean hydrogen demand in 2050. For countries outside the EU, only the UK is considered. While smaller non-EU countries will likely have increasing clean hydrogen demand as well, it is assumed that they will not have a decisive impact on the European hydrogen network development. See Fig. B.9 in Appendix B for a country-level demand distribution in 2050.

Hydrogen demand is nationally and temporally resolved for the sectors industry, residential and commercial, power, and transport. A flat demand profile is assumed to characterize industrial hydrogen demand, since it will mostly be used by heavy industry with high utilization rates. Residential and commercial demand profiles are scaled according to historical natural gas demand from households, assuming that hydrogen will mostly be used for heating homes and heating water. Power sector demand profiles are also assumed to follow historical natural gas demand from the power sector. Transport sector demand is assumed to have a flat demand profile. See Fig. B.10 in Appendix B for the temporal demand profile in 2050.

The weighted average cost of capital (WACC) for investments is assumed with 8% and to be constant over all countries and technologies. Investment costs are converted to equivalent annual cost, using the annuity factor a:

$$a = \frac{r * (1 + r)^n}{(1 + r)^n - 1} \tag{12}$$

3.3. Scenarios

Scenario analyses offer a valuable tool for modeling and evaluating complex and uncertain energy futures. Combinations of essential assumptions are varied to demonstrate the model's capabilities and interdependencies of input parameter choices. Table 1 summarizes the simulated scenarios and the varied assumption.

The reference scenario (*REF*) represents the baseline case with numerical assumptions as described in the previous Section 3.2. In the high renewable scenario (*High-RES*), capacity constraints for RE expansions are raised so that the technical RE potentials form the upper limit for installed capacities instead of expansion trajectories of the TYNDP (ENTSOE and ENTSOG, 2022). In the low hydrogen demand scenario (*Low-H2*), demand for clean hydrogen is reduced by 40% over all countries and sectors. The reduction rate has been determined based on a comparison of the demand scenarios in TYNDP with other energy system studies (e.g. IEA (2022); van Rossum et al. (2022); Deloitte (2023)). In the fourth scenario, hydrogen imports from North African countries and from overseas are deactivated (*No-imports*) to assess a case, where Europe is self-sufficient in hydrogen supplies. Another scenario analyses the effect on hydrogen supply and infrastructure, if no hydrogen storage is allowed to be built (*No-storage)*. While this scenario is most unlikely, it should show the economic benefits of hydrogen storage on the system level. In the long-term, most countries strive for green hydrogen production, using electrolysis and RE, but blue hydrogen from SMR with CCS is another option to fill supply gaps. The scenario *Blue-H2* allows for hydrogen production from natural gas. The last scenario assumes less hydrogen is used in the residential and commercial sector, where it is mostly used to heat homes (*Low-H2-heating*). This case is of interest, since heating demand has a high seasonality and using less hydrogen with seasonal demand patterns could have an impact on the supply and infrastructure. It is assumed that the residential and commercial sector's hydrogen demand is 80% lower compared to *REF*.

Table 1: Scenario outline

Scenario	**RES potentials**	**H2 demand**	**Imports**	**H2 storage**	**Blue H2**
REF	2 * TYNDP capacity	TYNDP GA	Allowed	Allowed	Not allowed
High-RES	Technical potentials	TYNDP GA	Allowed	Allowed	Not allowed
Low-H2	2 * TYNDP capacity	TYNDP GA - 40%	Allowed	Allowed	Not allowed
No-imports	2 * TYNDP capacity	TYNDP GA	Not allowed	Allowed	Not allowed
No-storage	2 * TYNDP capacity	TYNDP GA	Allowed	Not allowed	Not allowed
Blue-H2	2 * TYNDP capacity	TYNDP GA	Allowed	Allowed	Allowed
Low-H2-heating	2 * TYNDP capacity	TYNDP GA - 80% Res-Com	Allowed	Allowed	Not allowed

For each scenario the model is simulated for 2030, 2040, and 2050. The model is implemented with the mathematical programming language GAMS[13] and solved using the IBM CPLEX Optimizer.

4. Results

The following section presents the results of the scenario simulations along the dimensions (i) investments and capacity expansion, (ii) dispatch decision, and (iii) costs. The focus of all three sections will be on hydrogen-related outcomes. The last section will provide more general insights into the natural gas supply perspective.

4.1. Investments and Capacity Expansion

The country coloring in Fig. 3 indicates installed electrolyser capacities per country in *REF* for the year 2050. Green hydrogen production is mainly located in North Africa (Libya, Algeria), Southern Europe (Greece, Italy, Spain), and North(west) Europe (Norway, Denmark, UK, Ireland). High-demand countries in Central and Western Europe have also significant hydrogen production to satisfy domestic demand and to avoid long-distance transportation. In total, 512 GW_{el} of electrolyser capacities are installed in *REF* in 2050, with 427 GW_{el} being located in Europe.

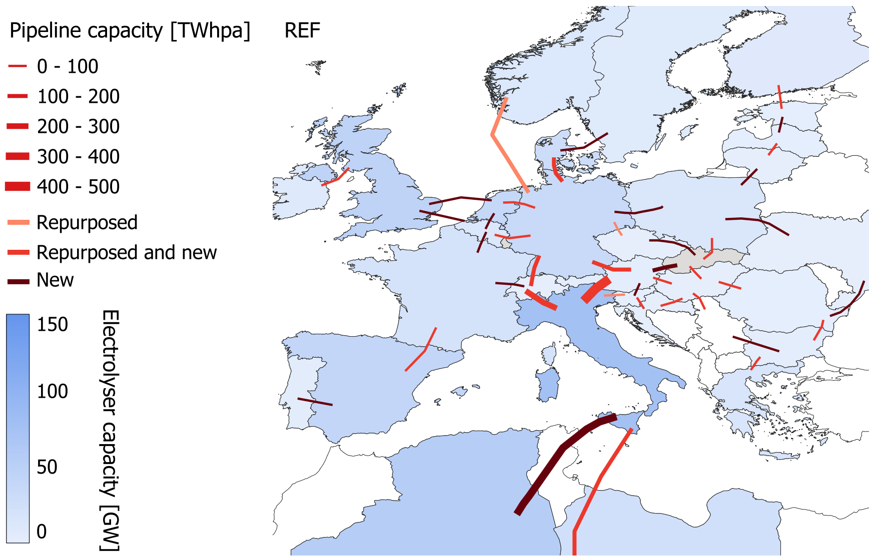

Figure 3: Hydrogen production and cross-border transportation capacities in 2050 in the reference scenario

Unsurprisingly, RE capacities are mostly built in countries with high RE capacity factors, with solar PV focused in the South and wind turbines mostly located in the North and Central European countries. In some countries the assumed RE potentials are fully utilized and become a binding constraint in the

[13] Generic Algebraic Modeling System

model.[14] Already in the year 2030 all EU countries[15], the UK, Switzerland, and Norway are connected to a pan-European hydrogen grid in each scenario. Hydrogen pipeline infrastructures develop primarily along import corridors from production towards consumption centers. Supply corridors from North Eastern Europe (Baltic States, Finland) and Spain are surprisingly low. In the Baltic States, this is because, although RE generation potentials are high, the existing pipeline infrastructure is needed to ensure sufficient natural gas supply in those countries, and consequently, hydrogen pipelines have to be newly built at higher cost. Spain, on the other hand, has significant RE production potentials, which is used to supply domestic demand and provide some exports to France and Portugal. However, the existing natural gas cross-border capacities between Switzerland, Austria, and Germany are substantially larger compared to the interconnection capacity between the Iberian peninsula and France. As a consequence, hydrogen exports from Spain require cost-intensive investments for new hydrogen pipelines, while the import corridor from Libya and Italy can make use of large repurposed pipelines, making the route more cost-competitive. As a result, Italy, Austria, and Switzerland emerge as hydrogen hubs with several interconnections to neighboring countries and significant pipeline capacities of up to 50 GW.

An increase of the RE potentials is assumed in *High-RES*. Wind and solar capacities considerably shift and hydrogen production becomes more concentrated in RE rich countries in Europe, such as Norway, Denmark, Italy, and Greece (see Fig. 4). The total installed electrolyser capacity roughly stays the same, but European capacities increase by 18% and decrease in North Africa to reduce transportation cost. The allocation of electrolyser (and accompanying RE) capacities within and across the scenarios emphasize the overwhelming dominance of RE availability for the distribution of hydrogen production capacities in Europe. With restricted imports from overseas and North African countries (*No-imports*), electrolyser capacities increase in European countries, and RE potentials are exploited to a high degree. Greece, the British Isles and Denmark become production centers with high export shares. Italy, Spain, the Netherlands, and Germany also have substantial hydrogen production capacities in *No-imports*, but largely use their production to satisfy domestic demand for clean hydrogen. Hydrogen production capacities in Europe increase by 23%. Adding blue hydrogen (*Blue-H2*) to the supply mix has a very little effect on electrolysers, in-fact, the aggregated installed capacity roughly stays the same and only the spatial distribution is affected. The share of blue hydrogen in the supply mix is 3% in 2040 and 2050, and below 1% in 2030. Blue hydrogen is only used to supply demand during high demand periods (see Section 4.2). Hydrogen storage balances seasonal hydrogen production and demand (see Section 4.2 for details). Eliminating the possibility of building hydrogen storage increases the installed electrolyser capacity in 2050 by 6% (equal to 30 GW_{el}, roughly the combined capacity of Norway and Spain in this scenario). Lastly, a decline in the seasonality

[14] Note that RE potentials are restricted based on an exogenous scenario and do only reflect technical potentials in *High-RES*, see Section 3 for details.

[15] Excluding Malta and Cyprus due to their missing connection with the continental natural gas infrastructure today.

and aggregated level of demand (*Low-H2* and *Low-H2-Heating*) has a limited impact on the allocation of electrolysers in Europe. The reduction of electrolyser capacities in comparison to *REF* is proportional to the reduced demand of approximately -40% and -14% respectively.

In *High-RES*, pipeline connections between RE rich countries in Europe are enforced (see Fig. 4 and Fig. C.12 in the Appendix C). In particular, export pipelines from Norway, Denmark, and Greece are added, with Germany becoming another important hydrogen hub. Lower hydrogen demand in *Low-H2-Heating* and *Low-H2* leads to an overall reduced expansion of hydrogen cross-border pipelines. Without hydrogen storage, more capacity is built for hydrogen imports from North African countries, and cross-border pipeline capacities between high-demand countries in Europe are expanded. The lowest grid expansion can be found in *No-imports* since each country has a higher self-supply rate. Over all scenarios, the hydrogen interconnectors between EU countries do not change too much. In particular, in Eastern and South Eastern Europe, the differences in the pipeline cross-border capacities are only minor. Hydrogen demand and production in the region are relatively low, and the development of hydrogen interconnectors is driven mainly by the origin of imports (e.g., Greece, Italy, Central Europe). However, import pipelines (e.g., from Norway and North Africa) are more sensitive to changes in economic and technical conditions. The distribution within Europe, e.g., from Italy and Germany to neighboring countries, is mainly affected by changing import routes (North Africa and Norway, respectively).

Most pipeline retrofits take place after 2030, in most scenarios the share of repurposed pipelines in the hydrogen grid varies between 53 and 68%, referring to Table 2. Least repurposing occurs in *No-storage*. Repurposed pipelines have lower cost than building new ones, but hydrogen flows need to be higher than the break-even quantity in order for repurposed pipelines to become cost-competitive. Large import pipelines from Norway, which are reasonable import routes for green hydrogen to Central Europe, are only repurposed between Norway and Germany. The large pipeline capacity requires significant production volumes to fill the pipeline over the year and production volumes in Norway are restricted by the available RE potentials. Apart from that, routes with high shares of pipeline repurposing are mostly where alternative natural gas import routes are present, e.g., in Southeast Europe, where natural gas can be imported from the Southern Gas Corridor (Turkey, Caspian region, Middle East), from Central and Southwest Europe, or as LNG. Also, in Central and Northwestern Europe (e.g., Germany/Austria, Germany/Netherlands, Poland/Slovakia), redundant natural gas pipelines exist, thus, pipelines can be retrofitted without risking a shortage in gas supply. Note that the model does not simulate gas and hydrogen flows within a country.

Table 2: Share of repurposed and newly built cross-border hydrogen pipelines in 2050

Scenario	REF	High-RES	Low-H2	No-imports	No-storage	Blue-H2	Low-H2-Heating
Repurp.	56%	59%	68%	63%	53%	59%	61%
New	44%	41%	32%	37%	47%	41%	39%

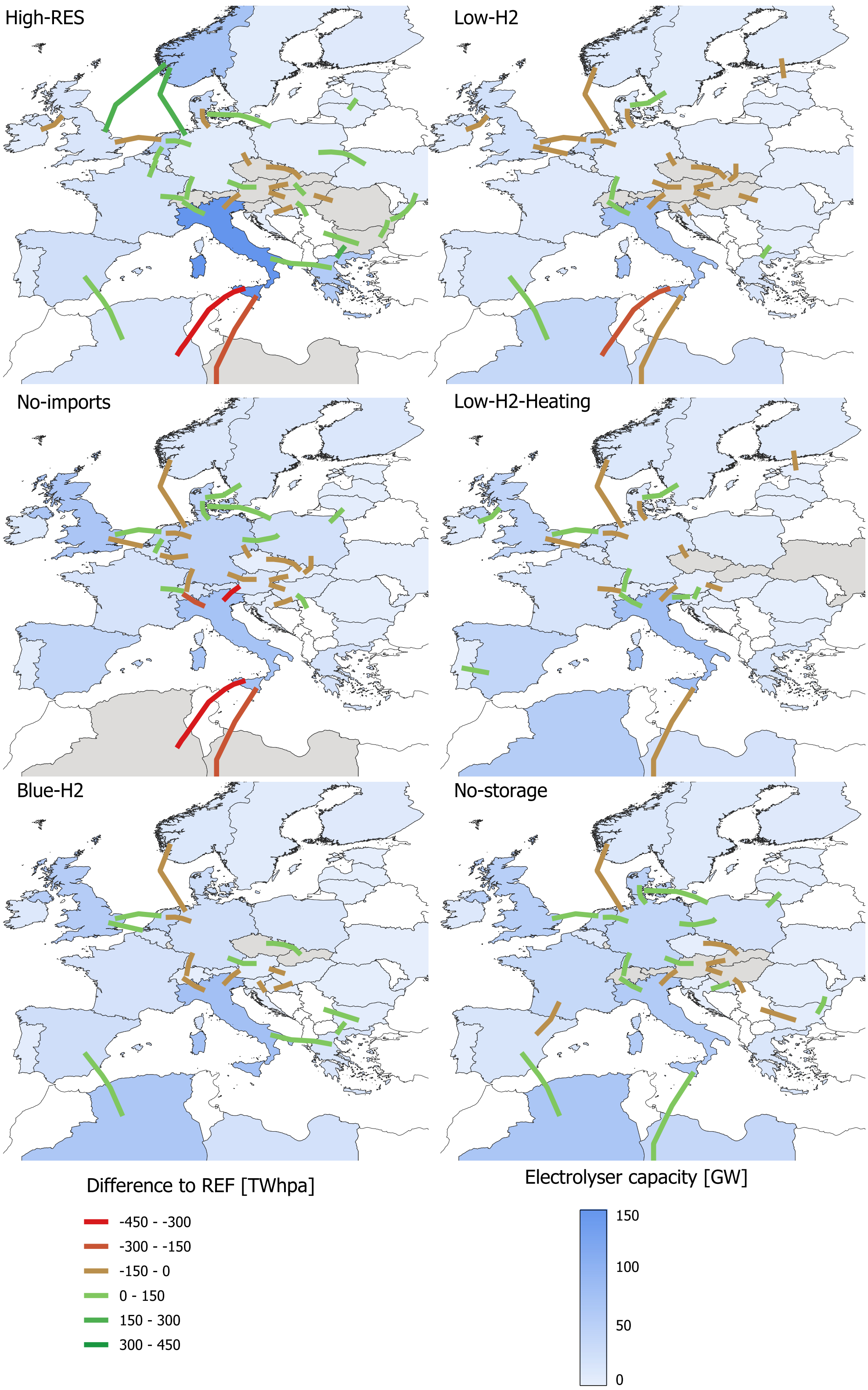

Figure 4: Hydrogen production capacities in 2050 and cross-border capacity differences compared to the reference scenario

Currently, the EU has a well developed natural gas storage infrastructure with an aggregated storage capacity of 30% of annual demand (GIE, 2023). Storage capacities for hydrogen are comparably lower and are mostly developed until 2040, as shown in Fig. 5. The total storage capacity relative to demand is between 6% and 12% in 2040 and between 4% and 7% in 2050. Least capacities are built in *Low-H2-heating* (87 TWh or 29 bcm_{H2} aggregated capacity), most storage capacity is added in *No-imports* (197 TWh or 66 bcm_{H2}). Also, low hydrogen storage capacities are built in *Blue-H2*. Hydrogen storage caverns can be newly built or developed by repurposing natural gas caverns (in the model, only newly built ones are considered). However, when repurposing natural gas storage caverns to hydrogen, the (energetic) storage capacity decreases by approximately 80% (NWR, 2021; DBI, 2022). In 2021, the EU and the UK had an aggregated natural gas storage capacity in salt and rock caverns of 244 TWh (GIE, 2021). Converting all natural gas caverns to hydrogen would result in a storage potential of approximately 50 TWh for hydrogen, substantially below the required storage capacities in the scenarios, ranging from 88 to 197 TWh. Thus, introducing hydrogen as an energy carrier might need additional investments in new hydrogen storage caverns or technological improvements in using other types of underground storage (aquifers, depleted fields) for hydrogen.

Capacities for seaborne hydrogen imports are highest in *No storage* with an annual capacity of 561 TWhpa in 2050 and lowest in *Blue-H2* (58 TWhpa) and *Low-H2-heating* (8 TWhpa). Across all scenarios the relevance of seaborne imports is very low, since pipeline imports from adjacent regions are available at lower cost. Most import capacities are added in Northwest Europe, where most hydrogen demand is located, and in peripheral regions, like the Baltic States, where the interconnectivity with other countries is weak. In the model, hydrogen storage, import capacities, and blue hydrogen production are interchangeably used to provide flexibility to the system (see Section 4.2 for more details).

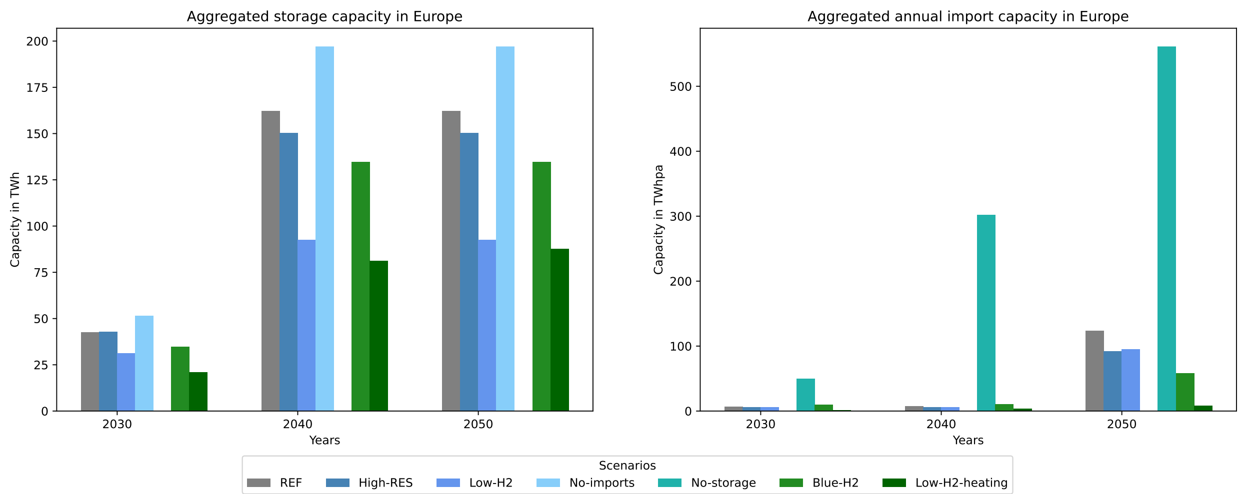

Figure 5: Hydrogen storage and import capacities for different scenarios

4.2. Dispatch and Infrastructure Utilization

The arithmetic mean of cross-border capacity utilization is between 76% and 81% in 2050. The highest utilization rates occur in the scenario *Blue-H2* and lowest in *No-storage*. The interconnectors from North Africa to Europe have a high capacity factor of more than 90%. In contrast, the retrofitted hydrogen pipeline from Norway to Germany is only used at a rate of 63 to 80%. Transit routes between large distribution hubs tend to have a higher capacity factor than interconnectors between countries with lower demand.

The mean utilization mostly follows the demand seasonality with increased flows in the winter months and reduced utilization during the summer, as illustrated on the left in Fig. 6 for 2040. Without hydrogen storage (*No-storage*), the mean utilization has a much stronger seasonal profile with 65% utilization in summer months and 88% during the winter.

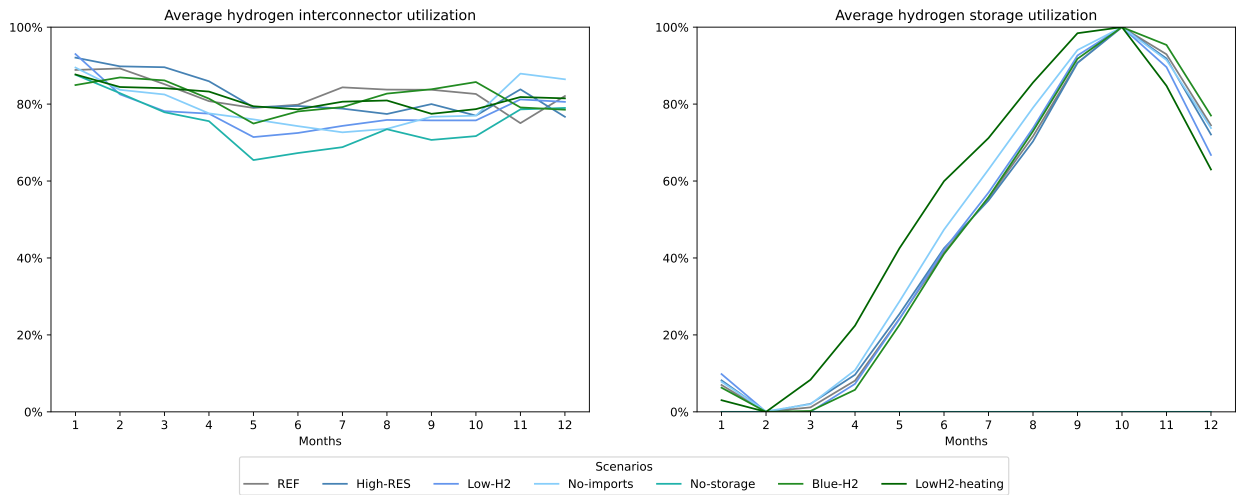

Figure 6: Average cross-border pipeline utilization and hydrogen storage levels in 2040 for different scenarios

Hydrogen storage is mostly filled during summer months and emptied in winter to supply seasonal demand, thus, storage is similarly used to natural gas storage today. The utilization of storage assets is almost equal across different scenarios, as shown on the right in Fig. 6. Only the scenario *Low-H2-heating* shows a slightly different storage profile, with a temporal shift to the left. However, these results only hold for this study's defined system scope. In future energy systems, hydrogen storage could play an essential role to provide backup energy for the electricity system during periods with low RE generation and storage profiles could be more dependent on electricity generation and demand.

As found in the previous section, ammonia import, blue hydrogen production, and storage capacities fulfill a similar purpose of providing supply flexibility to the system. Ammonia import terminals have an average utilization rate of 25%, with little variation between the scenarios, however, with a strong temporal profile. Seaborne imports are particularly high during months with high demand and become zero during summer. The same effect applies to blue hydrogen production, with an average capacity factor of 40%. While storage, seaborne imports, and blue hydrogen could provide valuable flexibility to the hydrogen system, it is unclear whether price-based incentives are sufficient to motivate investments in these assets.

4.3. Costs

In Fig. 7, normalized cost differences are shown relative to *REF* for the simulated scenarios, years, and each system component's contribution. In all scenarios, the predominant cost component is energy supply from RE to produce electricity for hydrogen electrolysis. The second largest costs are capital costs for hydrogen production equipment with relatively constant shares of 11% to 13% over all years and scenarios. Transportation costs are also almost stable over all scenarios and years and account for 8% of hydrogen supply costs on average. Storage contributes between 3% and 10% to hydrogen supply costs. The benefit of hydrogen storage materializes in the long term. In 2030, the unit costs in *No storage* are still lower, while they increase significantly in 2040 and 2050 without the ability to invest in storage capacities. The lowest storage cost share is found in *Blue-H2* and *Low-H2-heating*. In the former, blue hydrogen production provides additional flexibility and can thus reduce the need for hydrogen storage. In contrast, in the latter, the need for hydrogen storage is reduced through less seasonal hydrogen demand. In comparison with *REF*, unit supply costs increase between 3% and 13% in 2050, when hydrogen imports (*No-imports*) or hydrogen storage (*No-storage*) is restricted. Higher RE potentials (*High-RES*) decrease the costs by 3%. With blue hydrogen production, total hydrogen supply costs roughly stay the same (*Blue-H2*), however, this only holds for hydrogen supply and does not include higher costs for methane supply, since natural gas prices increase with higher demand for SMR.

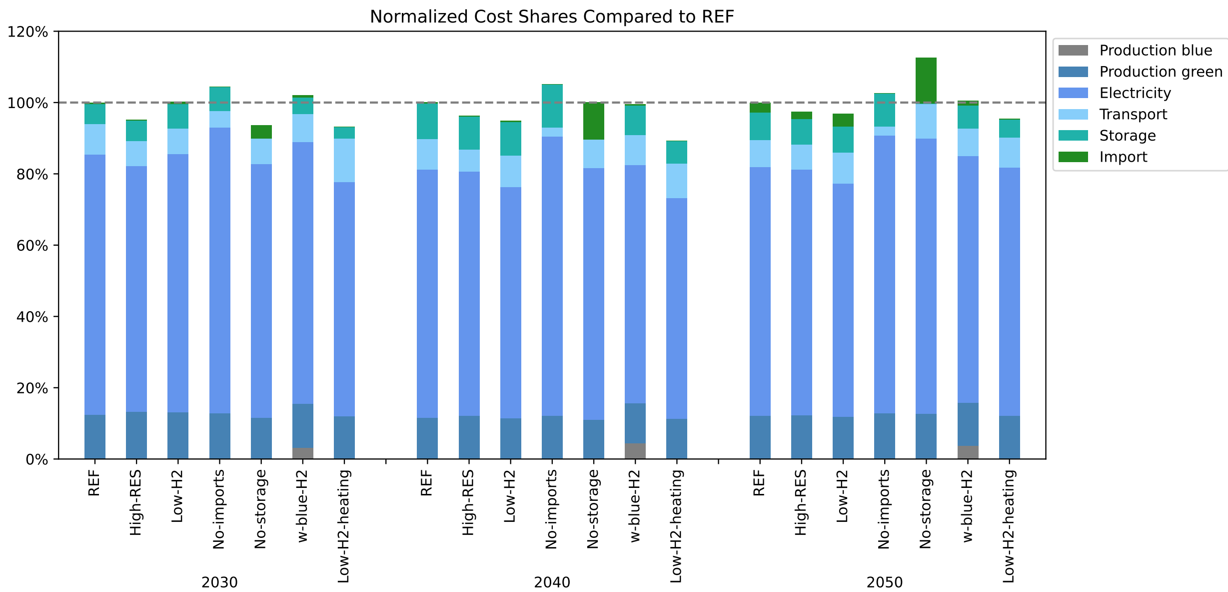

Figure 7: Relative and normalized cost differences for hydrogen investments in the scenarios compared to *REF*

The total LCOH of clean hydrogen supply in Europe (including production, imports, transportation, and storage) decrease from 2.6 EUR/kg in REF_{2030} to 2 EUR/kg in 2050. The supply cost are highest in the scenarios *No imports* and *No storage*. Average import costs are comparably higher and thus production within Europe and neighboring regions is more cost competitive. Imports are economically only reasonable to fill supply gaps during high demand periods.

4.4. Impact on Natural Gas Supply

Converting natural gas pipelines to hydrogen instead of building an entirely new infrastructure saves costs and time. However, it is crucial to secure natural gas supply in the transition period toward a European hydrogen infrastructure. The presented model can optimize both the development of a hydrogen infrastructure and the dispatch of the existing natural gas network.

The European gas supply has been under pressure after supplies from Russia have been halted over the Nord Stream and Yamal corridor in 2022. European countries reacted with expansion of LNG import capacities and demand reduction plans. The scenario simulations show that in the event of a full cessation of Russian gas supplies to Europe, supply would still be sufficient and no additional LNG capacities would need to be built (apart from the announced expansion projects). Aggregated LNG imports are 1,200 TWh (108 bcm) in 2030 and increase over time, since domestic production and import volumes from North African countries and Norway decline.[16]

Norway becomes the most important supplier of natural gas for the European market until 2030, however, due to decreasing production, export volumes decline onward. Pipeline imports from Norway are at the same level over all scenarios. Repurposing pipelines of this import corridor does not impact gas supplies, since sufficient spare capacities exist. Declining pipeline imports and domestic production are mostly replaced with LNG imports, contributing up to 77% of European natural gas supply in 2050. LNG import terminals have an average utilization rate between 6% and 100% in 2050, with highest utilization rates in Northwestern Europe and the Baltic States, as shown in Fig. 8. Algeria continues to export significant amounts of natural gas to Europe at a relatively constant rate. In some scenarios, imports from Libya fall to zero, since natural gas pipelines are repurposed and no redundant gas pipelines exist. However, at least one interconnection from Algeria to either Italy or Spain remains operational to maintain natural gas flows in every scenario.

Previous analysis has shown that natural gas pipeline imports into Europe are unlikely to increase, and more LNG is imported from the global market instead (Schlund et al., 2023). Spare capacities in LNG regasification terminals enable increased natural gas imports in the case of a supply shortage or increased demand. Thus, repurposed import pipelines have a limited effect on the security of supply for natural

[16] The results should be carefully interpreted since they only consider one demand and supply scenario and are determined in a simulation with monthly time resolution.

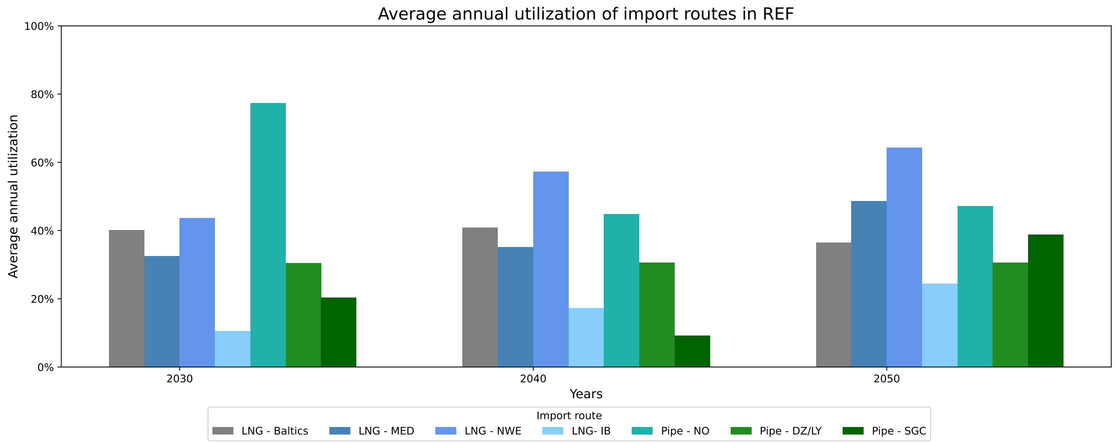

Figure 8: Average annual utilization of natural gas import routes in *REF*[17]

gas. The distribution and cost-efficient allocation of natural gas within Europe requires transportation capacities between and within the European countries. In the scenario simulations, there are no supply shortages, and security of supply is guaranteed in every European country. However, some natural gas interconnection pipelines appear to be wholly or almost entirely utilized,[18] which can be a potential risk for security of supply unless alternative pipeline connections to neighboring countries or sufficient storage inventories exist. In particular, some countries or regions, such as Finland, Greece, and Denmark, become largely disconnected from the European natural gas grid. Methane supply in these countries is ensured either by domestic biomethane production or by LNG imports. This could put the countries in a risky situation of dependence on a single supply source. Consequently, the decision to repurpose interconnection pipelines between European countries involves individual and in-depth assessments of country-specific infrastructures, alternative supply sources, and desired resilience levels.

5. Discussion

The following section summarizes structural findings from the scenario simulation and compares the results on a high level with other publications on the development of a European hydrogen infrastructure. Also, the assumptions and results are critically discussed, and further ideas for future research are suggested.

5.1. Comparison of Results with Other Studies

In Section 2, studies and research papers with similar objectives have been introduced. The wide variety of numerical and methodological assumptions makes it challenging to make an unambiguous comparison

[17] Route definition: Baltics - Baltic states: Finland, Estonia, Lithuania; MED - Mediterranean: Italy, Croatia, Greece; NWE - Northwest Europe: Great Britain, France, Belgium, the Netherlands, Germany, Poland; IB - Iberian peninsula: Spain, Portugal; NO: Norway; DZ/LY: Algeria, Libya; SGC - Southern Gas Corridor: Azerbaijan, Turkey.

[18] For instance, interconnectors between the following countries: Spain-France, France-Germany, France-Switzerland, Belgium-Germany, Hungary-Austria, or Hungary-Slovakia.

between the results of previous work and this paper. Still, some findings from different studies can be compared at a high level.

The European Hydrogen Backbone (EHB) initiative (van Rossum et al., 2022) regularly updates its report on a European hydrogen grid for the years 2030 and 2040. A detailed methodology report is unavailable, but the results allow for some comparisons. The EHB consists of 69% repurposed pipelines for a European hydrogen grid in 2040, which is at the same level of maximum repurposed pipelines in this work, however, the EHB also covers domestic pipelines. The load factor of the pipeline grid is an exogenous assumption in the report and is estimated at 5,000 hours per year in 2040 (57% utilization rate) for large pipelines with a maximum capacity of 13 GW. The endogenously determined capacity factor from the simulation varies between the scenarios, resulting in 76 to 81% over the entire pipeline grid in 2050. The largest pipelines in the model have a total capacity of up to 47 GW between Italy and Austria. This significant difference is also the result of varying import corridors. While some of the supply corridors from the report are similar to this work's results (e.g., Northwest Europe, North Africa, Southeast Europe), supply from Spain and the Baltic States to Central Europe has yet to be found as major corridors in the analysis.

Another work from Neumann et al. (2023) results in a similar pipeline utilization rate of 78% with storage capacities between 26 and 43 TWh (compared to 87 and 197 TWh in this work). One reason for the comparably lower storage capacities is the reduced hydrogen utilization for heating and power generation. This work assumes a strong seasonality of hydrogen demand in the heating and power sector, pushing for a higher capacity expansion of hydrogen storage. Similarly, the authors find primary import corridors from the British Isles and Southern Europe (North African countries are excluded in the analysis) and the most extensive hydrogen network expansion in Northwestern Europe. The share of repurposed gas pipelines is between 64 and 69% and the largest hydrogen pipelines have capacities of up to 30 GW (compared to 47 GW in this study).

While the studies differ in many detailed results, some key results are very similar and could indicate robust results for planning a hydrogen grid, such as import corridors from the South and North, the relevance of hydrogen storage, and the high shares of repurposed natural gas pipelines. For operational and technical grid planning, the economic simulations would need to incorporate more engineering aspects to correctly reflect the pipeline flows of natural gas and hydrogen and determine the actual costs of each pipeline project.

5.2. Key Findings from the Scenario Analysis

The model simulation provides some strategic insights for the development of a European cross-border infrastructure. First, it shows the dominance of RE potentials in shaping the hydrogen supply side and determining the supply corridors for hydrogen trade and imports. While technical potentials are widespread across the continent, acquiring knowledge on the realistically exploitable RE potentials becomes crucial, e.g., due to land eligibility, acceptance issues among the local population, or economically unreasonable greenfield investments. The scenario comparison has shown that high utilization of available RE potentials can decrease the total supply cost for hydrogen. However, this could lead to a high concentration of hydrogen production in a few countries with adverse effects on the security of supply and risk exposure due to one-sided dependencies. This result implies the importance of an accelerated expansion of RE capacities since electricity for hydrogen production will compete with other electricity consumers from the household, industry, and mobility sectors. The model results imply a cost-optimal allocation of RE sources across European countries according to country-specific generation and capacity potentials. This leads to a concentration of RE for hydrogen generation in Italy, Greece, Spain, and Portugal for Solar PV, and in Nordic countries, Denmark, France, the Netherlands, the British Isles, and Germany for wind resources. However, the trajectory of RE capacities in reality partially differs from the cost-optimal distribution, as shown by a comparison of the model results' capacity shares with the capacity expansion in the TYNDP National Trends scenario[19] (see Appendix C). The diverging allocation of RE resources from the cost-optimal pathway could increase the need for infrastructure and generation assets, potentially leading to higher supply costs. However, quantifying the loss in welfare requires an integrated simulation of hydrogen and electricity markets and is out of the scope of this paper. Also, the availability of RE generation crucially impacts the output of hydrogen producers. In the scenario simulations, average RE capacity factors over the past 37 years have been used as a representative generation profile (see Section 3.2). However, RE supply is much more volatile with extreme weather events at both ends; hence, for the reason of hydrogen security of supply, it can be reasonable to design the supply chain along a year with below-average RE feed-in in order to reflect different climatic conditions better.

Second, the simulation results indicate the relevance of flexibility in the hydrogen supply system. While hydrogen is commonly considered an enabler to provide flexibility and backup energy for a RE dominated electricity system, the flexibility of hydrogen is not inherent. It must instead be provided by an accordingly designed infrastructure and supply system. Unlike natural gas, where production is mostly constant throughout the year and demand is characterized by a strong seasonality, hydrogen will have both unsteady demand and supply. Production will primarily dependent on volatile RE and demand will depend on both seasonality and short-term fluctuations in demand from the power sector. In the simulation, hydrogen storage, imports, and blue hydrogen from SMR provided (seasonal) flexibility to the system. The load factor of these assets could be comparably low, making them potentially unprofitable business cases, and it is thus unclear whether market prices (and, in particular, price spreads) will set sufficient incentives for the investments.

[19] The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have been adjusted since then.

Third, the results show that repurposing natural gas pipelines has a cost advantage over greenfield pipeline investments in every scenario. Repurposing of cross-border pipelines was found to take place between 2030 and 2040 primarily, but this will require substantial coordination between transmission system operators in order to guarantee security of supply for natural gas during the transition period. Recent publications have suggested different import corridors for hydrogen; however, the identified import routes and exporting countries differ. The capacity and direction of import routes highly depend on the economic and technical parameter choices. Thus, they are less robust against varying assumptions and would need more in-depth analysis of whether they are cost-efficient import corridors. On the other hand, the cross-border pipelines within Europe have appeared in every scenario, showing the potential benefits of trade within the continent and neighboring regions. Many stakeholders consider seaborne imports an essential contribution to hydrogen supply in Europe, but the simulation results could not prove a high-cost efficiency for imports of hydrogen derivatives. While the hydrogen production costs in exporting countries are substantially lower in some cases, the costs for ammonia synthesis, shipping, and reconversion to hydrogen almost double the total import costs. However, these results should be carefully interpreted against the chosen input parameters and the high uncertainty of technology cost development, particularly for hydrogen (derivatives) shipping. This great uncertainty challenges today's planning of trade partnerships with overseas countries. It bears the risk of stranded assets if the technology costs are not decreasing as often projected.

5.3. Limitations and Future Research

The model and the analysis presented in this work contribute to the ongoing discussion on introducing hydrogen as a climate-neutral energy commodity, which could be traded across borders in the future. While proposing new methods to allow integrated assessments of natural gas and hydrogen supplies and showing new insights into drivers of a European hydrogen infrastructure, the results should be interpreted against important limitations and shortcomings of the model.

A central assumption of the model and the scenario analysis is dedicated electricity supply for electrolysers from RE without using electricity markets and transmission. While direct coupling of RE and hydrogen production might be applied in some remote areas, e.g., for offshore wind parks or large-scale solar PV in sparsely populated areas, the majority of electrolysers in Europe will most probably be connected to the public electricity grid and thus use electricity markets to optimize dispatch. Trading electricity instead of hydrogen would become relevant opportunity costs when electricity transmission and markets are included in the model. This missing link in the model raises significant changes in electrolyzers' investment and dispatch decisions. First, operating hours would be less dependent on the sole availability of RE and rather on supply and demand and, consequently, on the electricity price in the equilibrium. The presented model overestimates the operating hours because hours with low RE generation might have uneconomically high electricity prices. Second, the oversupply of RE is currently discarded in the model and cannot be used to supply electricity demand for other purposes. As stated in the results (Section 4), costs for RE represent the highest single cost component, and thus, the model keeps the oversupply of RE small. Adding opportunities for RE generators to the model could lead to a decrease in costs for electricity supply and a varying capacity ratio of RE generators and electrolysers. Moreover, hydrogen demand is entirely exogenous to the model. Many energy consumers have different options to decarbonize, with hydrogen being one option. The cost-efficient use of hydrogen in integrated energy systems becomes a function of relative price differences between hydrogen imports, domestic hydrogen production, and electricity prices, which is out of the scope of this paper. These limitations could be partially solved through integrated optimization of electricity markets and networks for gaseous energy carriers, e.g., similar to Frischmuth et al. (2022) and Neumann et al. (2023). The limitations of these integrated models often lie either in the temporal or spatial resolution or in covering electricity, hydrogen, and natural gas supply. An alternative to this could be a coupling of the integrated hydrogen and natural gas infrastructure model with an electricity market model, e.g., as suggested in Schlund and Schönfisch (2021), and iteratively simulating the development of natural gas, hydrogen, and electricity supply.

The current model setup allows for integrated assessments of hydrogen and natural gas investments and dispatch of cross-border energy exchange but neglects domestic distribution of hydrogen. The focus on cross-border pipelines in the model is chosen to keep computational burden, temporal, and spatial resolution in balance. Hence, the model provides information on European import corridors and developments of a pan-European hydrogen grid but fails to explain the detailed spatial distribution of hydrogen demand, supply, and infrastructures. While this limitation is not expected to impact the described effects substantially, it could lead to different pipeline investments and cost structures between certain countries. Since the presented model is an extension of the original TIGER model, introduced by Lochner (2011c), it can improve spatial resolution, which could be the subject of future research.

As a partial equilibrium model, assuming perfect competition in the evolving hydrogen market, the applied method neglects some endogenous effects and imperfections during the hydrogen market development. For instance, increasing energy costs due to a more complex energy system could lead to higher investment costs for technologies, particularly those with energy-intensive production, e.g., solar PV or steel pipes. Also, an emerging hydrogen market might suffer from imperfections, like reduced liquidity, oligopolistic market structures, or high transaction costs. Furthermore, emerging trade in hydrogen could also be based on long-term contracts in the early years of the market (see, e.g., Antweiler and Schlund (2023)) before a liquid spot market arises.

6. Conclusions

Developing a European cross-border hydrogen infrastructure is considered an essential contribution to transforming the energy system towards climate neutrality while maintaining security of supply and ensuring efficient energy markets. Different initiatives and researchers have published drafts and potential designs of a hydrogen transmission network for Europe. This paper introduces a novel model to simulate a cost-efficient pathway of integrating a European hydrogen network in the existing natural gas infrastructure through repurposing natural gas and building new dedicated hydrogen pipelines. The model extends an existing natural gas dispatch model through investment decisions for hydrogen import terminals, pipelines, storage, and production assets, as well as dedicated RE generation from solar PV, wind onshore, and wind offshore. The original LP model is formulated as a MILP to correctly reflect the binary choice of repurposing cross-border gas pipelines. It is parameterized, applied to seven scenarios, and simulated with monthly resolution for 2030, 2040, and 2050.

The purpose of the case study is not to forecast a future European hydrogen grid because this would need additional information on the development of electricity markets and more detailed technical modeling of the grid. Instead, the simulation shows critical dependencies between different system elements and provides insights for strategic planning of a hydrogen infrastructure. The results have shown the dominance of RE potentials for developing a European hydrogen infrastructure. The availability and location of installed RE capacities for hydrogen production strongly shape investments in and utilization of cross-border pipelines. Highly concentrated hydrogen production in exporting regions, such as North African countries, Norway, and Denmark, can significantly expand import corridors to Central and Northwest Europe, where most hydrogen demand could be located. The share of repurposed pipelines in a hydrogen network could be between 53% and 68% and is relatively constant over all scenarios. While investment in import routes is somewhat sensitive to varying technical and economic assumptions, developing within-Europe cross-border pipelines is robust against different assumptions. Furthermore, the supply system appeared to need flexible assets. In the simulation, flexibility could be provided by either hydrogen storage, seaborne imports, or blue hydrogen production from SMR with CCS. While it will be crucial for the hydrogen system to provide flexibility and pass this value proposition on to the power sector, it is not inherent to hydrogen. It must be enabled by corresponding infrastructure planning. From an economic perspective, it is still being determined whether price signals (and price spreads) will sufficiently incentivize investments and provide flexibility.

The presented model is one of the first of its kind, allowing for integrated analyses of natural gas and hydrogen infrastructure development. However, it exhibits important limitations with options for future research. The model assumes direct coupling of RE with electrolysers without allowing outside options to sell electricity at wholesale markets. For most of the hydrogen production plants, this will most likely not be the case; instead, electrolysers will be dispatched according to price signals from the electricity market. This limitation could be solved by, e.g., coupling the model with an electricity market model. Further, improving the temporal and spatial resolution of the simulation could allow for more detailed insights into the security of supply for hydrogen and natural gas as well as more detailed dispatch strategies of infrastructure assets. Overall, the model uses many numerical and conceptual assumptions characterized by high uncertainty by nature; thus, updated analyses using state-of-the-art data in the future could provide more insights and implications of changing market conditions.

Acknowledgements

The author would like to thank Marc Oliver Bettzüge, Werner Antweiler, Julian Keutz, and Jan Kopp for their valuable feedback. Support in the preparation of illustrations by Erik Schrader, Meike Vey, and Baha Isikdogan is gratefully acknowledged. This research was funded by the German Federal Ministry for Economic Affairs and Climate Action within the research project H2-Ready (grant number 03EI1038B).

References

ACER, 2021. Key facts about gas in the EU. Technical Report. European Union Agency for the Cooperation of Energy Regulators (ACER). Ljubljana. URL: https://acer.europa.eu/en/Gas/Documents/ACER_FACT-SHEETS_2021-07_02.pdf. accessed: 2023-08-02.

Alsulaiman, A., 2023. Renewable Hydrogen Import Routes into the EU. Technical Report. The Oxford Institute for Energy Studies (OIES).

André, J., Auray, S., De Wolf, D., Memmah, M.M., Simonnet, A., 2014. Time development of new hydrogen transmission pipeline networks for france. International Journal of Hydrogen Energy 39, 10323–10337.

Antweiler, W., Schlund, D., 2023. The emerging international trade in hydrogen and the role of environmental, innovation, and trade policies, in: USAEE Working Paper.

Bai, F., Zhao, F., Liu, X., Mu, Z., Hao, H., Liu, Z., 2023. A techno-economic analysis of cross-regional renewable hydrogen supply routes in china. International Journal of Hydrogen Energy (in press), 1–14.

Ball, M., Wietschel, M., 2009. The hydrogen economy: opportunities and challenges. Cambridge University Press, Cambridge.

Baufumé, S., Grüger, F., Grube, T., Krieg, D., Linssen, J., Weber, M., Hake, J.F., Stolten, D., 2013. Gis-based scenario calculations for a nationwide german hydrogen pipeline infrastructure. International Journal of Hydrogen Energy 38, 3813–3829.

Bosch, J., Staffell, I., Hawkes, A.D., 2017. Temporally-explicit and spatially-resolved global onshore wind energy potentials. Energy 131, 207–217.

Bosch, J., Staffell, I., Hawkes, A.D., 2019. Global levelised cost of electricity from offshore wind. Energy 189, 116357.

Brändle, G., Schönfisch, M., Schulte, S., 2021. Estimating long-term global supply costs for low-carbon hydrogen. Applied Energy 302, 117481.

DBI, 2022. Wasserstoff speichern - so viel ist sicher. Technical Report. DBI Gas- und Umwelltechnik GmbH. In German.

DEA, 2022. Technology data for generation of electricity and district heating. Technical Report. Danish Energy Agenca (DEA). Esbjerg.

Deloitte, 2023. Study on hydrogen in ports and industrial coastal areas. Technical Report. prepared for the Clean Hydrogen Partnership. Brussels.

Dieckhöner, C., 2012. Simulating security of supply effects of the nabucco and south stream projects for the european natural gas market. The Energy Journal 33.

EC, 2021. Regulation of the European Parliament and the Council on the internal markets for renewable and natural gases and for hydrogen. European Commission (EC). URL: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0804. accessed: 2023-08-02.

EC, 2022. REPowerEU plan. European Commission (EC). URL: https://commission.europa.eu/publications/key-documents-repowereu_en. accessed: 2022-07-26.

EHB, 2023. The European Hydrogen Backbone (EHB) initiative. URL: https://ehb.eu/. accessed: 2023-07-17.

ElSayed, M., Aghahosseini, A., Caldera, U., Breyer, C., 2023. Analysing the techno-economic impact of e-fuels and e-chemicals production for exports and carbon dioxide removal on the energy system of sunbelt countries–case of egypt. Applied Energy 343, 121216.

ENA, 2021. Britain's hydrogen network plan. Energy Networks Association (ENA). URL: https://www.energynetworks.org/industry-hub/resource-library/britains-hydrogen-network-plan.pdf. accessed: 2023-07-17.

ENTSOE, ENTSOG, 2022. TYNDP 2022 scenario report. Technical Report. European Network of Transmission System Operators for Gas (ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ENTSOG, 2018. ENTSOG Ten-Year Network Development Plan 2018. Technical Report. European Network of Transmission System Operators for Gas (ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ENTSOG, 2023. ENTSOG Ten-Year Network Development Plan 2022. Technical Report. European Network of Transmission System Operators for Gas (ENTSOG) and European Network of Transmission System Operators for Electricity (ENTSOE). Brussels.

ESMAP, 2020. Global photovoltaic power potential by country. Technical Report. World Bank. Washingtion, DC.

EUC, 2023. Fit for 55. Council of the European Union (EUC). URL: https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/. accessed: 2023-08-02.

Eurostat, 2023. Supply, transformation and consumption of gas. URL: https://ec.europa.eu/eurostat/web/main/data/database. accessed: 02-08-2023.

FNB, 2023. Hydrogen core network. Vereinigung der Fernleitungsnetzbetreiber Gas e.V. (FNB). URL: https://fnb-gas.de/en/hydrogen-core-network/. accessed: 2023-07-17.

Franzmann, D., Heinrichs, H., Lippkau, F., Addanki, T., Winkler, C., Buchenberg, P., Hamacher, T., Blesl, M., Linßen, J., Stolten, D., 2023. Green hydrogen cost-potentials for global trade. International Journal of Hydrogen Energy (in press).

Frischmuth, F., Schmitz, R., Härtel, P., 2022. Imagine–market-based multi-period planning of european hydrogen and natural gas infrastructure, in: 2022 18th International Conference on the European Energy Market (EEM), IEEE, Ljubljana, Slovenia. pp. 1–11.

Galyas, A.B., Kis, L., Tihanyi, L., Szunyog, I., Vadaszi, M., Koncz, A., 2023. Effect of hydrogen blending on the energy capacity of natural gas transmission networks. International Journal of Hydrogen Energy 48, 14795–14807.

Gasunie, 2023. Hydrogen network Netherlands. URL: https://www.gasunie.nl/en/projects/hydrogen-network-netherlands. accessed: 2023-07-17.

GEM, 2023. GEM wiki global gas infrastructure tracker. Global Energy Monitor (GEM). URL: https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/. accessed: between October 2022 and July 2023.

van Gessel, S., Hajibeygi, H., 2023. Hydrgen TCP-task 42 underground hydrogen storage. Technical Report. International Energy Agency (IEA). Paris.

GIE, 2021. GIE Storage Database. Gas Infrastructure Europe (GIE). URL: https://www.gie.eu/transparency/databases/storage-database/. accessed: 2023-08-10.

GIE, 2022. GIE LNG databse. Gas Infrastructure Europe (GIE). URL: https://www.gie.eu/transparency/databases/lng-database/. accessed: 2023-08-09.

GIE, 2023. GIE aggregated gas storage inventory. Gas Infrastructure Europe (GIE). URL: https://agsi.gie.eu/. accessed: 2023-08-04.

Gierkink, M., Cam, E., Diers, H., Keutz, J., Kopp, J., Lilienkamp, A., Moritz, M., Wiedmann, M., Zinke, J., 2022. Scenarios for the price development of energy commodities. Technical Report. Institute of Energy Economics at the University of Cologne (EWI). Cologne.

Haeseldonckx, D., D haeseleer, W., 2007. The use of the natural gas pipeline infrastructure for hydrogen transport in a changing market structure. International Journal of Hydrogen Energy 32, 1381–1386.

Heuser, P.M., Grube, T., Heinrichs, H., Robinius, M., Stolten, D., 2020. Worldwide hydrogen provision scheme based on renewable energy. Preprints .

IEA, 2021. Global hydrogen review 2021. Technical Report. International Energy Agency (IEA). Paris.

IEA, 2022. Global hydrogen review 2022. Technical Report. International Energy Agency (IEA). Paris.

IEA, 2022. World energy outlook 2022. OECD/IEA, Paris.

IEA, 2023. Global hydrogen review 2022. Technical Report. International Energy Agency (IEA). Paris.

IRENA, 2023. World energy transitions outlook 2023: 1.5° pathway. International Renewable Energy Agency, Abu Dhabi.

Kakoulaki, G., Kougias, I., Taylor, N., Dolci, F., Moya, J., Jäger-Waldau, A., 2021. Green hydrogen in europe–a regional assessment: Substituting existing production with electrolysis powered by renewables. Energy Conversion and Management 228, 113649.

Krieg, D., 2012. Konzept und Kosten eines Pipelinesystems zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff. volume 144. Forschungszentrum Jülich, Jülich.

Lippkau, F., Franzmann, D., Addanki, T., Buchenberg, P., Heinrichs, H., Kuhn, P., Hamacher, T., Blesl, M., 2023. Global hydrogen and synfuel exchanges in an emission-free energy system. Energies 16, 3277.

Lochner, S., 2011a. Identification of congestion and valuation of transport infrastructures in the european natural gas market. Energy 36, 2483–2492.

Lochner, S., 2011b. Modeling the european natural gas market during the 2009 russian–ukrainian gas conflict: Ex-post simulation and analysis. Journal of Natural Gas Science and Engineering 3, 341–348.

Lochner, S., 2011c. The economics of natural gas infrastructure investments theory and model-based analysis for Europe. Ph.D. thesis. University of Cologne. Cologne.

Marinelli, M., Cutululis, N.A., Hahmann, A.N., 2014. Pan European climate data. Technical Report. Technical University of Denmark (DTU). Lyngby.

Moreno-Benito, M., Agnolucci, P., Papageorgiou, L.G., 2017. Towards a sustainable hydrogen economy: Optimisation-based framework for hydrogen infrastructure development. Computers & Chemical Engineering 102, 110–127.

Moritz, M., Schönfisch, M., Schulte, S., 2023. Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities. International Journal of Hydrogen Energy 48, 9139–9154.

Neumann, F., Zeyen, E., Victoria, M., Brown, T., 2023. The potential role of a hydrogen network in europe. Joule 7, 1793–1817.

Nunez-Jimenez, A., De Blasio, N., 2022. Mighty: Model of international green hydrogen trade. Belfer Center for Science and International Affairs, Harvard Kennedy School. Environment and Natural Resources Program Papers , 1–37.

NWR, 2021. Die Rolle der Untergrund-Gasspeicher zur Entwicklung eines Wasserstoffmarktes in Deutschland. Nationaler Wasserstoffrat (NWR). Briefing Paper. In German.

Otsuki, T., Komiyama, R., Fujii, Y., Nakamura, H., 2023. Temporally detailed modeling and analysis of global net zero energy systems focusing on variable renewable energy. Energy and Climate Change 4, 100108.

Panchenko, V., Daus, Y.V., Kovalev, A., Yudaev, I., Litti, Y.V., 2023. Prospects for the production of green hydrogen: Review of countries with high potential. International Journal of Hydrogen Energy 48, 4551–4571.

Pfennig, M., Böttger, D., Häckner, B., Geiger, D., Zink, C., Bisevic, A., Jansen, L., 2023. Global gis-based potential analysis and cost assessment of power-to-x fuels in 2050. Applied Energy 347, 121289.

Pietzcker, R.C., Stetter, D., Manger, S., Luderer, G., 2014. Using the sun to decarbonize the power sector: The economic potential of photovoltaics and concentrating solar power. Applied Energy 135, 704–720.

Robinius, M., 2015. Strom-und Gasmarktdesign zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff. Ph.D. thesis. Dissertation, RWTH Aachen, 2015. Aachen.

van Rossum, R., Jens, J., La Guardia, G., Wang, A., Kühnen, L., Overgaag, M., 2022. European Hydrogen Backbone - A European hydrogen infrastructure vision covering 28 countries. Technical Report. European Hydrogen Backbone (EHB) initiative. Utrecht.

Rystad, 2023. Gas market cube. URL: https://clients.rystadenergy.com/old-corporate-web/energy-themes/commodity-markets/gas-lng/gas-market-cube/. accessed: 2023-07-23.

Salmon, N., Bañares-Alcántara, R., 2021. Green ammonia as a spatial energy vector: a review. Sustainable Energy & Fuels 5, 2814–2839.

Samsatli, S., Staffell, I., Samsatli, N.J., 2016. Optimal design and operation of integrated wind-hydrogen-electricity networks for decarbonising the domestic transport sector in great britain. International Journal of Hydrogen Energy 41, 447–475.

Schlund, D., Gierkink, M., Moritz, M., Kopp, J., Junkermann, J., Diers, H., Vey, M., 2023. Analyse der globalen Gasmärkte bis 2035. URL: https://www.ewi.uni-koeln.de/de/publikationen/analyse-der-globalen-gasmaerkte-2035/. in German language. Accessed: 02-08-2023.

Schlund, D., Schönfisch, M., 2021. Analysing the impact of a renewable hydrogen quota on the european electricity and natural gas markets. Applied Energy 304, 117666.

Schönfisch, M., 2022. Charting the development of a global market for low-carbon hydrogen, in: EWI Working Paper, Cologne.

Sens, L., Piguel, Y., Neuling, U., Timmerberg, S., Wilbrand, K., Kaltschmitt, M., 2022. Cost minimized hydrogen from solar and wind–production and supply in the european catchment area. Energy Conversion and Management 265, 115742.

Staffell, I., Scamman, D., Abad, A.V., Balcombe, P., Dodds, P.E., Ekins, P., Shah, N., Ward, K.R., 2019. The role of hydrogen and fuel cells in the global energy system. Energy & Environmental Science 12, 463–491.

WEC, 2019. World Energy Scenarios 2019. World Energy Council, London.

Welder, L., Ryberg, D.S., Kotzur, L., Grube, T., Robinius, M., Stolten, D., 2018. Spatio-temporal optimization of a future energy system for power-to-hydrogen applications in germany. Energy 158, 1130–1149.

Appendix A. Model formulation

Table A.3: Model indices, parameters, and variables.

Name	Unit	Definition
Sets		
$t \in Time$		Time
$y \in Years$		Years
$i, j \in Nodes$		Nodes
$tech \in Tech$		Investment technologies: solar PV, onshore wind, offshore wind, electrolyser, hydrogen interconnector, hydrogen storage, ammonia import terminal, SMR with CCS, LNG import terminal
$gas \in Gas$		Type of gas: hydrogen, methane
$res \in RES$		Renewable energy technologies: solar PV, onshore wind, offshore wind
$l \in L$		Costlevels
Parameters		
a	-	Capital recovery factor
f	% of *capex*	Fixed operative and maintenance costs
$capex$	EUR/$\mathrm{mcm_{gas}}$pa or EUR/$\mathrm{MW_{el}}$	Capital expenditures
$opex$	EUR/$\mathrm{mcm_{gas}}$ or EUR/$\mathrm{MWh_{el}}$	Operational expenditures
d	$\mathrm{mcm_{gas}}$	Gas demand (hydrogen or methane)
c_{res}	-	Capacity factor of renewable energy technologies
pot_{tech}	$\mathrm{MW_{el}}$	RE capacity and ammonia import potentials
cap	$\mathrm{mcm_{gas}}$pa	Existing annual hydrogen or natural gas pipeline capacity
Variables		
TC	EUR	Total system costs
P	$\mathrm{mcm_{H2}}$ or $\mathrm{MWh_{el}}$	Production quantity
C	$\mathrm{mcm_{gas}}$pa or $\mathrm{MW_{el}}$	Capacity expansion
I	$\mathrm{mcm_{gas}}$	Import quantity
S	$\mathrm{mcm_{gas}}$	Storage flows
T	$\mathrm{mcm_{gas}}$	Transported quantity of gas
$B \in \{0, 1\}$	-	Binary variable to indicate repurposed natural gas pipelines

Appendix B. Model assumption

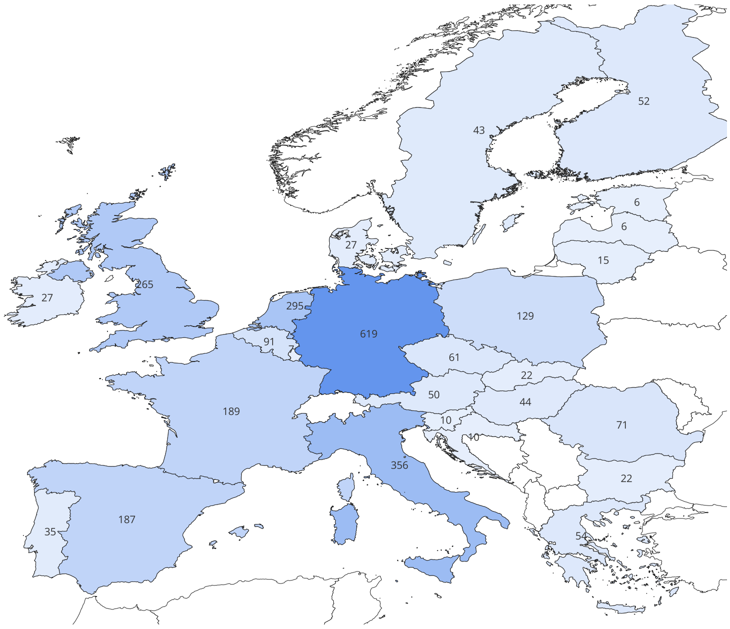

Figure B.9: Country-level hydrogen demand in 2050 in the reference scenario in TWh (own figure based on the Global Ambition scenario in ENTSOE and ENTSOG (2022))

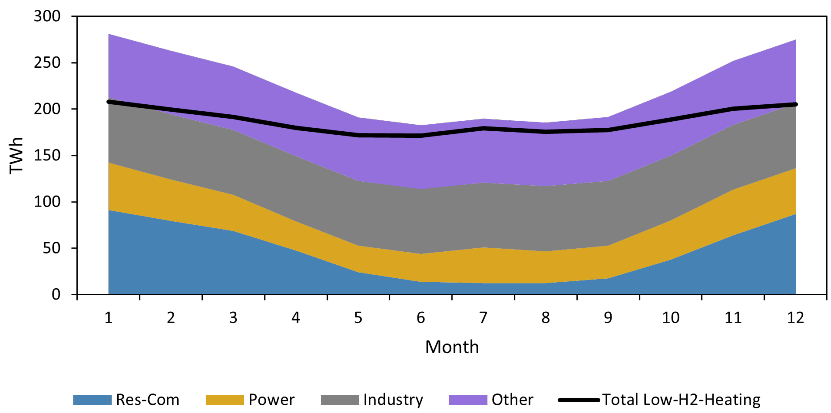

Figure B.10: Temporal hydrogen demand profile per sector in 2050 in the reference scenario and aggregated demand in the low-H2-heating scenario (based on the Global Ambition scenario in ENTSOE and ENTSOG (2022))

Table B.4: Capex data for investment technologies.

Technology	Unit	Capex 2020	Capex 2030	Capex 2040	Capex 2050
LNG regasification terminal	MEUR/bcm$_{ng}$pa	155	155	155	155
Ammonia import terminal	MEUR/bcm$_{H2}$pa	298	231	202	184
Hydrogen pipeline new	EUR/mcm$_{H2}$pa*km	198	198	198	198
Hydrogen pipeline repurposed	EUR/mcm$_{H2}$pa*km	59	59	59	59
Hydrogen cavern storage	MEUR/mcm$_{H2}$	1.71	1.71	1.71	1.71
Electrolysis	EUR/kW$_{el}$	1240	378	338	300
Solar PV utility-scale	EUR/kW$_{el}$	560	380	320	290
Wind onshore	EUR/kW$_{el}$	1120	1040	980	960
Wind offshore	EUR/kW$_{el}$	2120	1800	1680	1640
SMR with CCS	EUR/kW$_{H2}$	1300	1300	1300	1300

Source: Adapted from Brändle et al. (2021); IEA (2021); Moritz et al. (2023); ENTSOG (2018, 2023); van Gessel and Hajibeygi (2023); DEA (2022). Detailed references in Section 3.2.

Table B.5: Fixed O&M, opex, and lifetime data for investment technologies.

Technology	Fixed O&M costs (% of Capex)	Opex (EUR/mcm$_{gas}$)	Lifetime (years)
LNG regasification terminal	1.5	*included in import cost*	25
Ammonia import terminal	4.0	*included in import cost*	25
Hydrogen pipeline	-	1.57 - 6.2 *(depending on electricity price)*	30
Hydrogen cavern storage	3.6	6,750	33
Electrolysis	2.0	-	25
Solar PV	2	-	25
Wind onshore	2	-	25
Wind offshore	2	-	25
SMR with CCS	4	31,035 - 45,060	25

Source: Adapted from IEA (2021); Krieg (2012); Sens et al. (2022); Moritz et al. (2023); van Gessel and Hajibeygi (2023).

Table B.6: Efficiency data for electrolysers and SMR with CCS (lower heating value).

Technology	2020	2030	2040	2050
Electrolysis (kWh$_{H2}$/kWh$_{el}$)	0.64	0.69	0.72	0.74
SMR with CCS (kWh$_{H2}$/kWh$_{th}$)	0.69	0.69	0.69	0.69

Source: Adapted from IEA (2021); Moritz et al. (2023).

Appendix C. Supplementary Results

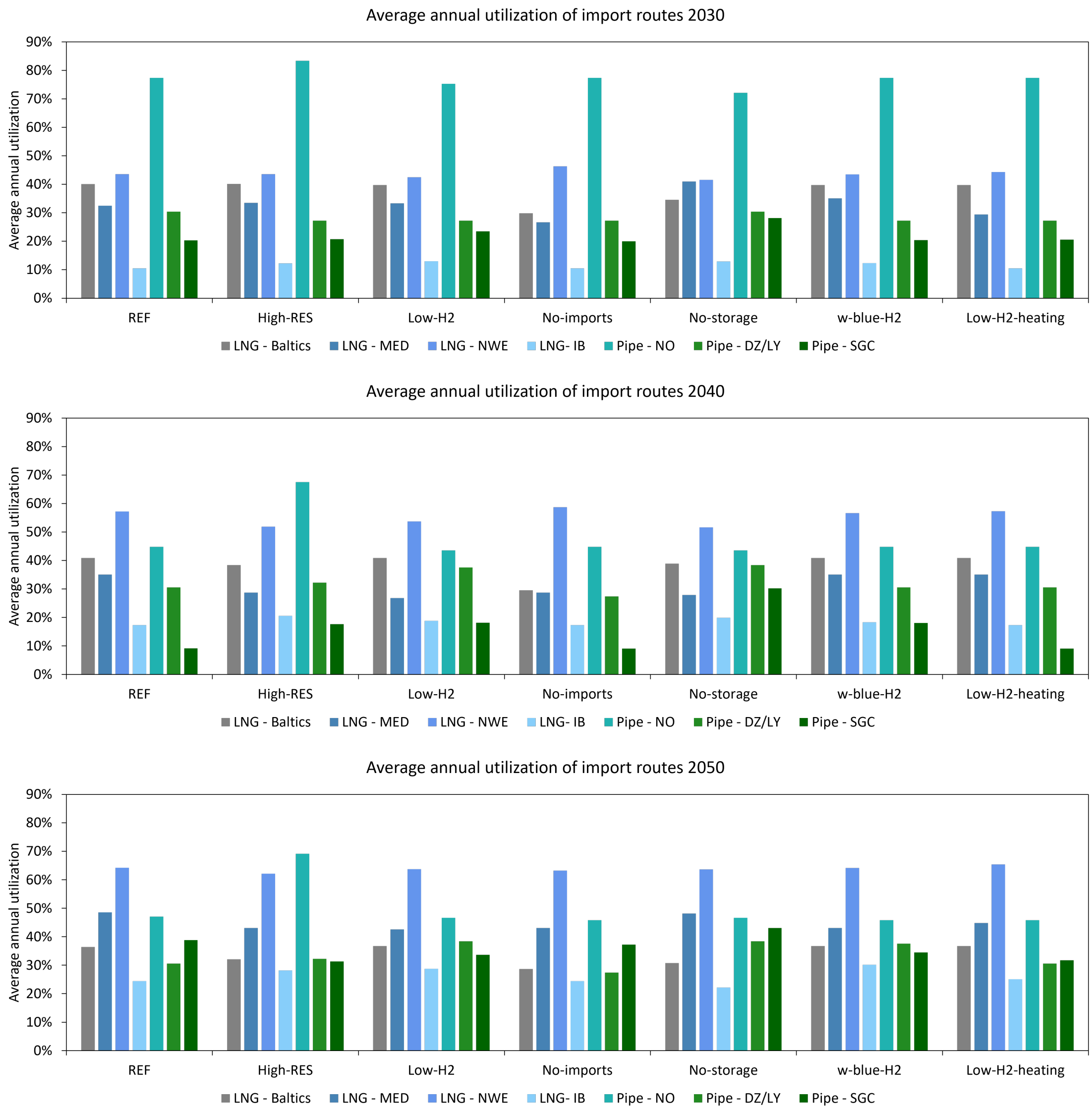

Figure C.11: Average annual utilization of natural gas import routes in different years[20]

[20]Route definition: Baltics - Baltic states: Finland, Estonia, Lithuania; MED - Mediterranean: Italy, Croatia, Greece; NWE - Northwest Europe: Great Britain, France, Belgium, the Netherlands, Germany, Poland; IB - Iberian peninsula: Spain, Portugal; NO: Norway; DZ/LY: Algeria, Libya; SGC - Southern Gas Corridor: Azerbaijan, Turkey.

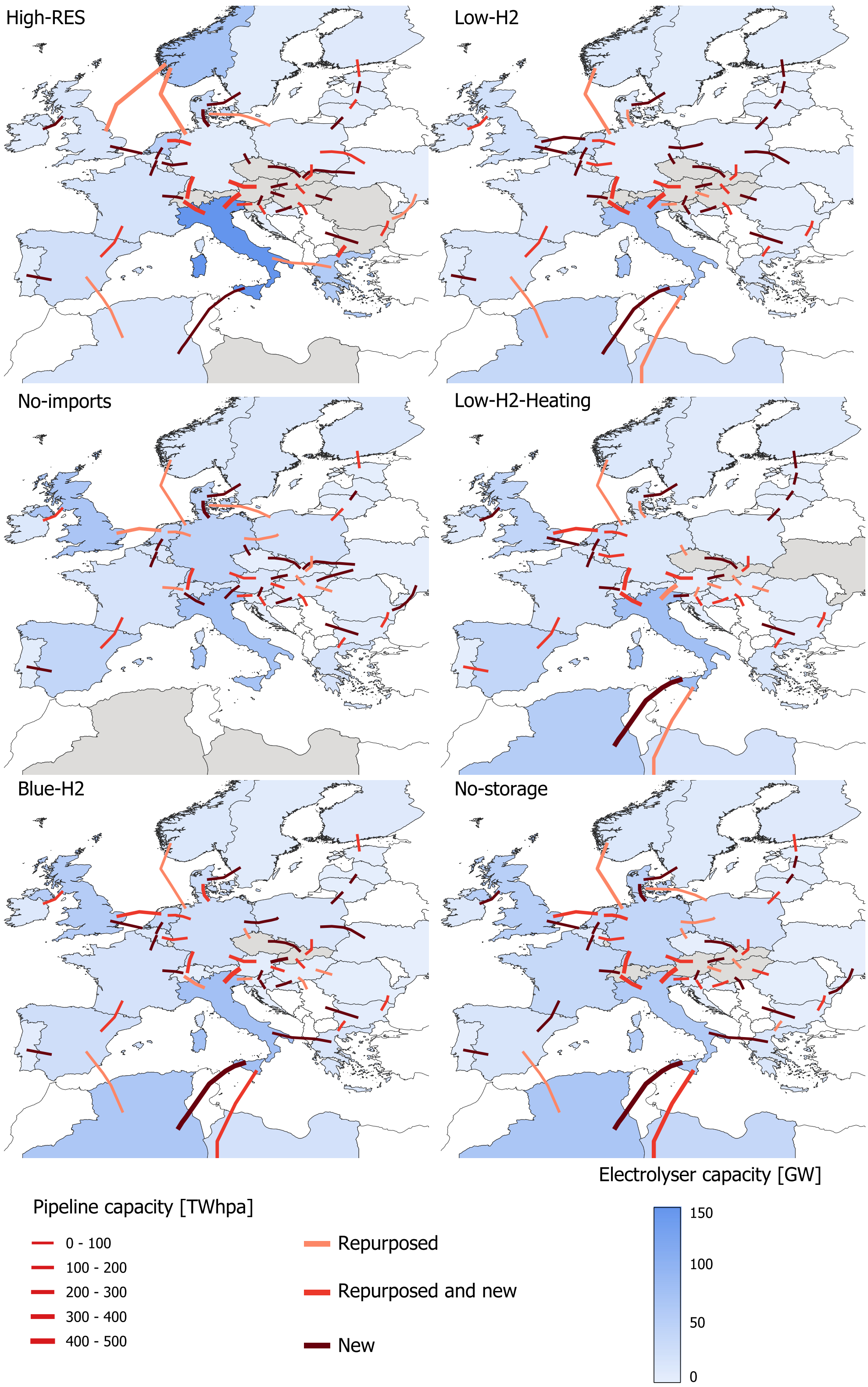

Figure C.12: Hydrogen production and cross-border transportation capacities in 2050 in all scenarios

Table C.7: Relative RE capacity shares per EU country in the year 2030 in the scenarios *REF* and *High-RES* compared to the National Trends scenario in ENTSOE and ENTSOG (2022).

	2030								
	Solar PV			Wind onshore			Wind offshore		
	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends
BG	0.8%	0.0%	0.9%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
EE	0.4%	0.3%	0.1%	0.5%	1.6%	0.3%	1.4%	0.0%	0.3%
FI	2.0%	1.5%	0.4%	6.0%	3.5%	4.0%	0.0%	0.0%	2.1%
GR	15.5%	27.9%	2.0%	0.3%	0.0%	2.2%	0.0%	0.0%	0.1%
HR	0.0%	0.0%	0.2%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%
HU	0.0%	0.0%	1.7%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
IE	0.0%	0.0%	0.2%	6.2%	2.2%	1.9%	7.7%	0.0%	4.8%
LT	0.5%	0.3%	0.3%	1.8%	0.9%	0.7%	0.8%	0.0%	1.9%
LU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LV	0.1%	0.4%	0.0%	0.3%	0.9%	0.1%	2.0%	0.0%	0.7%
PL	0.0%	0.0%	1.4%	15.6%	1.0%	2.8%	5.8%	0.0%	8.1%
PT	4.6%	2.7%	2.1%	0.0%	0.0%	2.9%	0.0%	0.0%	0.4%
RO	1.2%	0.0%	1.3%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%
SE	0.0%	0.0%	2.0%	9.8%	4.5%	5.5%	0.0%	0.0%	6.9%
SI	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
AT	0.0%	0.0%	3.2%	0.0%	0.0%	2.9%	0.0%	0.0%	0.0%
BE	0.0%	0.0%	2.8%	5.3%	1.8%	1.5%	3.6%	0.0%	8.0%
CZ	0.0%	0.0%	2.2%	0.1%	0.0%	0.2%	0.0%	0.0%	0.0%
DE	0.0%	0.0%	25.6%	10.0%	6.4%	24.7%	23.1%	0.0%	32.4%
DK	0.0%	0.0%	1.7%	5.5%	21.9%	2.0%	29.6%	0.0%	9.4%
ES	18.4%	10.0%	12.2%	0.0%	0.0%	15.8%	0.0%	0.0%	0.3%
FR	0.0%	0.1%	11.7%	25.7%	16.4%	11.8%	0.0%	0.0%	7.5%
IT	56.6%	56.8%	13.8%	0.0%	0.0%	6.0%	0.0%	0.0%	1.2%
NL	0.0%	0.0%	7.3%	12.9%	38.8%	2.6%	26.0%	0.0%	15.7%
SK	0.0%	0.0%	0.3%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%

The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have been adjusted since then.

Table C.8: Relative RE capacity shares per EU country in the year 2040 in the scenarios *REF* and *High-RES* compared to the National Trends scenario in ENTSOE and ENTSOG (2022).

	2040								
	Solar PV			Wind onshore			Wind offshore		
	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends	REF	High-RES	TYNDP National trends
BG	3.7%	0.0%	0.6%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
EE	0.1%	0.1%	0.2%	0.6%	0.9%	0.2%	2.1%	0.0%	0.6%
FI	1.4%	1.3%	0.7%	5.3%	3.7%	5.3%	5.9%	13.9%	3.1%
GR	11.4%	35.4%	1.7%	0.1%	0.0%	2.5%	0.0%	0.0%	0.2%
HR	0.0%	0.1%	0.3%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
HU	0.0%	0.0%	2.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
IE	0.0%	0.0%	0.3%	6.3%	3.0%	1.6%	5.7%	0.0%	2.9%
LT	0.2%	0.1%	0.2%	0.9%	0.5%	0.6%	0.6%	0.0%	0.9%
LU	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LV	0.1%	0.2%	0.0%	0.3%	1.3%	0.1%	2.9%	7.4%	0.6%
PL	0.0%	0.0%	1.8%	7.9%	1.8%	1.8%	4.3%	11.2%	6.0%
PT	4.3%	2.0%	2.0%	0.0%	0.0%	3.4%	0.0%	0.0%	0.3%
RO	1.2%	0.0%	1.1%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%
SE	0.0%	0.0%	2.7%	8.5%	5.6%	4.9%	0.0%	0.0%	10.6%
SI	0.0%	0.0%	1.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
AT	0.0%	0.0%	5.5%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%
BE	0.0%	0.0%	3.0%	6.8%	1.3%	1.8%	2.7%	7.0%	3.6%
CZ	0.0%	0.0%	1.9%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
DE	0.0%	0.0%	23.2%	24.2%	3.6%	23.5%	17.1%	10.2%	24.9%
DK	0.0%	0.0%	1.7%	5.6%	32.1%	1.4%	39.5%	0.0%	7.2%
ES	21.8%	4.4%	14.2%	0.0%	0.0%	15.1%	0.0%	0.0%	0.7%
FR	0.0%	0.0%	10.7%	20.2%	13.5%	14.0%	0.0%	0.0%	16.8%
IT	55.8%	56.2%	11.9%	0.0%	0.0%	5.6%	0.0%	0.0%	2.6%
NL	0.0%	0.0%	7.7%	13.1%	32.7%	2.8%	19.2%	50.2%	18.7%
SK	0.0%	0.0%	0.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%

The national trends scenario describes a development of the European energy system until 2040, which aligns with the current national policies (ENTSOE and ENTSOG, 2022). Note that the scenario was published in early 2022, and some national targets have been adjusted since then.