Assessing the benefits of a pan-European hydrogen transmission network

March 2023

GAS FOR CLIMATE
A path to 2050

Guidehouse

Preface

Gas for Climate was initiated in 2017 to analyse and create awareness about the role of renewable and low-carbon gas in the future energy system in full compliance with the Paris Agreement target to limit global temperature increase to well below 2 degrees Celsius. To this end, the entire economy has to become (net) zero carbon by mid-century.

Gas for Climate is a group of eleven leading European gas transport companies (DESFA, Enagás, Energinet, Fluxys, Gasunie, GRTgaz, Nordion, ONTRAS, Open Grid Europe, Snam, and Teréga) and three renewable gas industry associations (Consorzio Italiano Biogas, European Biogas Association and German Biogas Association).

Gas for Climate is committed to achieve net zero greenhouse gas emissions in the EU by 2050 and we are united in our conviction that renewable and low-carbon gas used through existing gas infrastructure will help to deliver this at the lowest possible costs and maximum benefits for the European economy. We aim to assess and create awarenesss about the role of renewable and low-carbon gas in the future energy system. Our group includes leading gas infrastructure companies in seven EU Member States that are collectively responsible for 75% of total natural gas consumption in Europe.

This report on “Assessing the benefits of a Pan-European hydrogen transmission network” has been established by Gas for Climate members together with the contribution of five additional European TSOs. These are Creos Luxembourg, Gasgrid Finland, Gassco (Norway), National Gas Transmission (United Kingdom) and NET4GAS (Czech Republic).

We look forward to discussing the content of report and recommendations with you in the coming weeks and months.

Imprint

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Executive summary

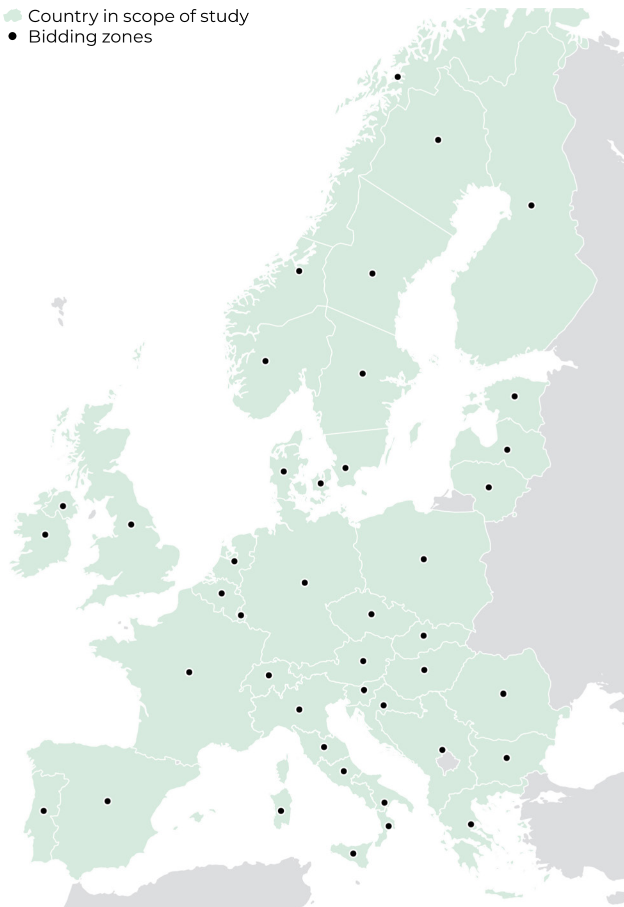
Introduction

Renewable and low-carbon gases are expected to play a key role, alongside other technology and policy options, towards achieving climate neutrality along the goals set forth by the European Green Deal and the interim goals for 2030 expressed by the Fit-for-55 Package. The European Union (EU) strategy on hydrogen, adopted in 2020, put forward a vision for the creation of a European hydrogen ecosystem, in line with the European Green Deal. The REPowerEU plan, established by the European Commission (EC) as a reaction to the Russian invasion into Ukraine, further emphasised the important role of hydrogen and biomethane not only for the energy transition but also to reduce dependency on Russian natural gas imports. Achieving the REPowerEU targets by 2030 and a fully decarbonised European energy system at the latest by 2050 is ambitious. It will require a rapid scale-up of renewable and low-carbon electricity generation, deployment of domestic hydrogen and biomethane production capacities, hydrogen storage and import infrastructure as well as a pan-European hydrogen transmission network (pan-European H_2 network).

The present study assesses the potential benefits of realising a pan-European H_2 network instead of pursuing a regional expansion dedicated to serve demand clusters, at national level. The analysis indicates that the development of a pan-European H_2 network is a key element for the European energy transition, contributing significantly towards an affordable, secure, and sustainable energy supply. The study also found that the pan-European H_2 network can present benefits to the energy system as early as 2030, making a strong case for pursuing an early deployment.

Methodology

The analysis was conducted by means of an energy system model that solely focuses on minimising the total system costs to supply demand for hydrogen, electricity, and methane over the timeframe 2030 – 2050 from a "whole-system perspective" while achieving net zero CO_2 emissions by 2050. The geographic scope of the study is the interconnected EU and neighbouring energy systems (25 EU countries and 9 non-EU countries), see figure below. Scenario input assumptions are largely aligned to the TYNDP 2022 scenarios developed jointly by ENTSOG and ENTSO-E and published before the Russian invasion into Ukraine. Therefore, for the year 2030, assumptions are adjusted with the REPowerEU targets in terms of an accelerated hydrogen and biomethane uptake.



	S1 H_2-Clustered	S1 H_2-Interconnected	S2 H_2-Clustered	S2 H_2-Interconnected
Hydrogen demand 2030 values adjusted for REPowerEU plan	Scenario group 1 **Higher H_2 demand** Demand based on TYNDP 2022 GA		Scenario group 2 **Lower H_2 demand** Demand based on TYNDP 2022 DE	
Investments in H_2 cross-border capacity	✗	✓	✗	✓

The benefits and role of a pan-European H_2 network are assessed by comparing results (in terms of total system costs and other key performance indicators) of the model when this network is expanded (H_2-Interconnected scenario) along a least-cost path, with its counterfactual scenario (H_2-Clustered scenario), that excludes this infrastructure option (see figure above). To test the robustness of the results, this comparison is conducted for a higher[1] and lower[2] evolution of future hydrogen demand, represented in the S1 and S2 scenarios respectively (S1: ~30% higher H_2 demand in 2050).

Results of the study should be interpreted in view of the considered scenario assumptions and the applied modelling approach with its limitations. Since the applied model focuses solely on minimising total system costs, other important considerations such as security of supply or non-economic aspects that might affect the volume and timing of hydrogen production in the various European countries and imports via pipelines and ships are not considered.

A pan-European H_2 network is a cornerstone of the future integrated European energy system

In the H_2-Interconnected scenarios, a full pan-European H_2 network is built out as it is identified by the applied model as part of the cost optimal solution to supply demand for hydrogen, electricity, and methane until 2050. A significant part of the pan-European H_2 network is already in place by 2030, consisting of up to 145 GW cross-border transmission capacity and about 100 TWh storage. This expands to about 475 GW of cross-border transmission and 500 TWh of storage capacity by 2050.[3]

The figure below presents the annual hydrogen net flows across the modelled European energy system for the H_2-Interconnected scenario in 2050 for the higher and lower hydrogen demand projection. In the resulting network of this modelling analysis[4], the **five corridors** identified by the EHB initiative, are clearly visible:

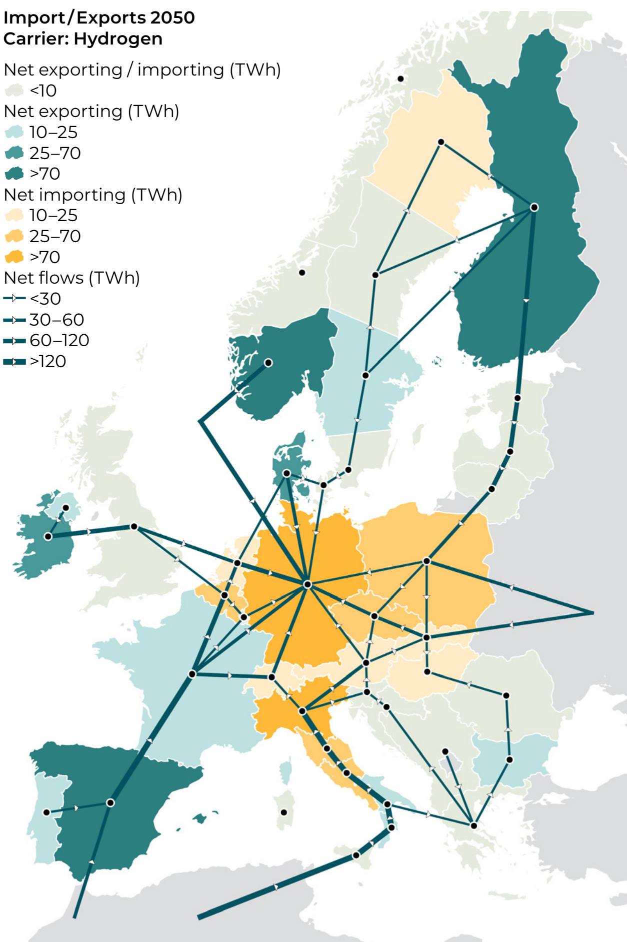
- **Two supply corridors from the south of Europe via Italy and the Iberian Peninsula**, where domestic hydrogen produced mainly from solar power is complemented by renewable hydrogen imports from North Africa supplying countries along the pipeline as well as southern parts of Central Europe,
- a **North Sea supply corridor** that makes use of the vast offshore wind resource potentials for renewable hydrogen production complemented by some low-carbon hydrogen produced in Norway and the UK and supplying Central European countries,
- a **Nordic supply corridor** which transports renewable hydrogen produced from onshore and offshore wind installed in countries surrounding the Baltic Sea,
- a **supply corridor from East and South-East Europe** that taps renewable hydrogen potentials in South-East Europe and Ukraine and supplies the Eastern part of Europe.[5]

1 Based on Global Ambition scenario published in TYNDP 2022
2 Based on Distributed Energy scenario published in TYNDP 2022
3 Specified cross-border transmission capacities include capacities between subnational bidding zones of Denmark, Italy, and Sweden.
4 The EHB vision is built up from the aspirations and network development plans of each of the EHB members, combined with the identified hydrogen demand across sectors. As such these can evolve differently from the present study.
5 Ukraine pipeline imports have not been considered as a supply option in scenario group 2.

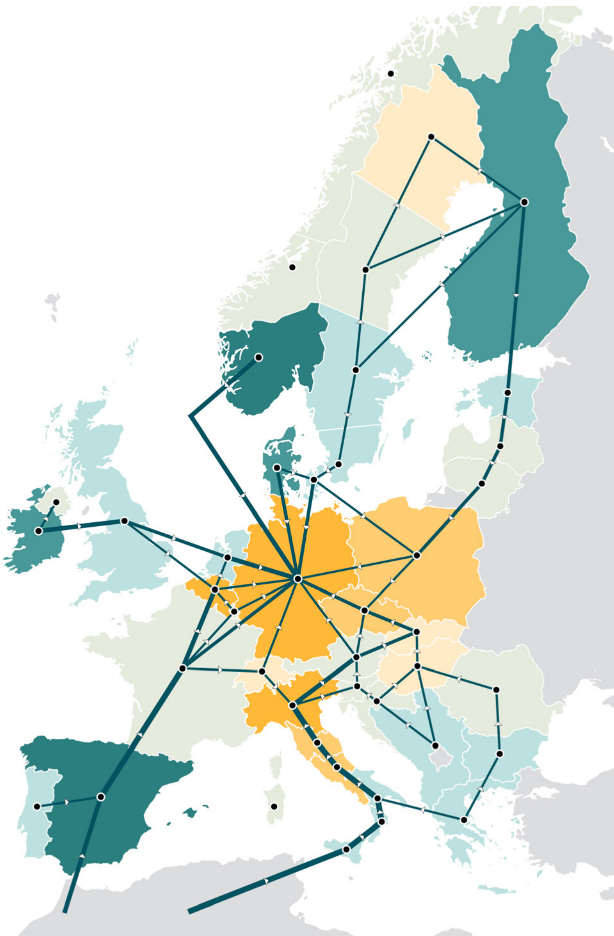
It is important to note that the pan-European H_2 network that develops until 2050 in the H_2-Interconnected scenarios is not predefined as input, but is rather the result of the minimisation of overall system costs carried out by the model. The network develops quite similarly for both high (S1) and low (S2) hydrogen demand scenarios, signalling a robust optimisation result. The scenarios depict infrastructure needed to supply demand for hydrogen, electricity, and methane over the modelled timeframe, while reaching net-zero CO_2 emissions until 2050 at lowest cost.

The full deployment of a pan-European H_2 network as defined in the H_2-Interconnected scenarios would require **investments**[6] **in the order of €70 to €80 billion**[7], for a fully developed network in 2050, depending on the scenario. The model predicts that approximately 55% of the developed pan-European H_2 network could consist of repurposed natural gas transmission pipelines - supporting the findings of the EHB initiative[8].

S1 H_2-INTERCONNECTED



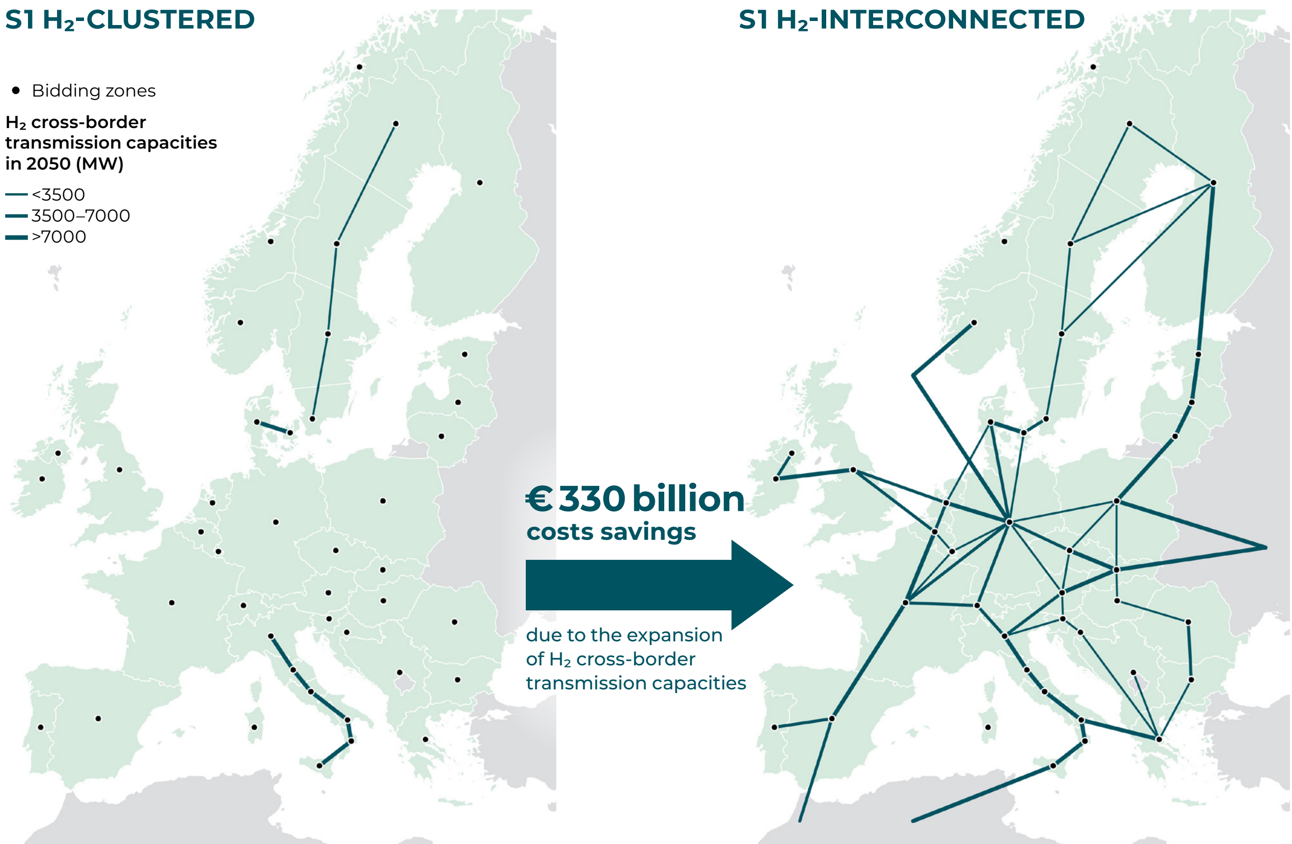
S2 H_2-INTERCONNECTED



6 Total investment cost for new hydrogen transmission and repurposing of existing gas transmission lines based on the model investment decisions.

7 Total investment cost estimated by the EHB initiative ranges between €80 and €143 billion depending on the cost assumptions. Note that values specified by the EHB initiative and this study cannot be compared 1:1 due to the differences in the applied approach, which considers only transmission capacity needed to connect modelled bidding zones and therefore detailed national transmission network costs are not included.

8 European Hydrogen Backbone (2022). A European hydrogen infrastructure vision covering 28 countries Link



When comparing the H_2-Clustered and the H_2-Interconnected scenario (rightmost map in the figure above) of scenario group 1, the latter generates **cost savings of €330 billion** over the timeframe 2030 – 2050 due to the development of a pan-European H_2 network. More than two-thirds of this figure are attributed to reduced cost of the supply mix of hydrogen while the remaining savings are due to lower investment needs into electricity generation, storage and transmission capacities.

A pan-European H_2 network contributes to an affordable energy supply

The quantified cost benefits of €330 billion for S1 H_2-Interconnected mentioned above would rise to €380 billion, if avoided CO_2 emissions costs are factored in. Cost savings are in the same range for the lower H_2 demand scenarios despite hydrogen demand being 30% lower. These cost savings, which significantly outweigh the estimated investment to build the pan-European H_2 network, are possible because the pan-European H_2 network enables the production of hydrogen to take place where it is cheapest. Therefore, compared to the H_2-Clustered scenarios, hydrogen production shifts to regions in Europe with more advantageous renewable resources and, on average, lower electricity prices. The pan-European H_2 network is then used to transport the produced hydrogen where needed and to provide access to large-scale underground storage facilities, for which potentials are not equally distributed across Europe. The study confirms that it is more cost-efficient to install electrolysers close to renewable power generation, and use pipelines to transport hydrogen to the point of consumption than to install electrolysers close to hydrogen demand and supply electrolysers through the electricity grid, a finding coherent with analysis undertaken by the EHB initiative[9] as well as the IEA[10].

9 EHB (2021). Analysing future demand, supply, and transport of hydrogen Link
10 IEA (223). Energy technology perspectives 2023 (page 320) Link

Due to the development of a pan-European H_2 network in the H_2-Interconnected scenarios, investments into electricity cross-border transmission and battery storage capacities are reduced significantly compared to the respective H_2-Clustered scenario (up to 26 GW less transmission and 34 GW/136 GWh storage capacity).

A pan-European H_2 network supports the integration of variable renewable energies and security of supply

The study finds that a pan-European H_2 network also contributes to the integration of intermittent renewable electricity generation by storing excess renewable energy during times of oversupply. Unlike other storage technologies this potential may be provided by the hydrogen supply chain across a wide range of timeframes, from real-time to seasonal balancing. These benefits extend to making energy security more affordable. The study confirms that a pan-European H_2 network can contribute towards a power system with significantly reduced firm capacity needs. The H_2-Interconnected scenarios will require approximately 37 GW less dispatchable capacity in 2030, rising to 43 GW less in 2050 compared to the H_2-Clustered scenario. This is a clear benefit of sectoral integration, enabled through a pan-European H_2 network.

Both the integration of intermittent renewables and enhanced security of supply are achieved through cheaper and wider access to large-scale energy storage made possible by the presence of a pan-European H_2 network. These benefits are of high importance for countries with limited potential to repurpose existing natural gas or build new hydrogen storage facilities. While not a direct result of the analysis, it is worth noting that a pan-European H_2 network will also provide wider access to other critical infrastructure, such as H_2 import terminals, thereby allowing the benefits associated with such infrastructure (supply diversification, competition) to spread across more regions and countries in Europe.

A pan-European H_2 network and biomethane scale-up foster a sustainable energy supply

All scenarios assessed in this study need to reach net zero CO_2 emissions by 2050. The analysis shows that renewable hydrogen and biomethane are the main sources to decarbonise gas supply until 2050. By 2050, renewable hydrogen covers 92-98% of hydrogen demand in the assessed scenarios. Low-carbon hydrogen assets (steam and autothermal reformers with carbon capture) complement the hydrogen supply mix and can generate in the long-term negative CO_2 emissions when using biomethane instead of natural gas in combination with carbon capture and storage. Biomethane is the main source for the decarbonisation of the methane system (3425 Mt of direct CO_2 emissions are avoided through substituting natural gas with biomethane) and reduces energy import dependency at the same time. Results of this study indicate that due to the development of a pan-European H_2 network, direct CO_2 emissions can be further reduced by 10% over the timeframe 2030 – 2050 compared to scenarios in the absence of this network.

Immediate actions needed

The study identified concrete benefits provided by a pan-European hydrogen system as early as 2030. This makes a strong case for immediate actions on the critical path towards ensuring that the required infrastructure will be in place at the end of the current decade.

On the supply side, large-scale deployment of renewable electricity and hydrogen production is needed. Ramping up electrolyser manufacturing capacity and supply chains are also perceived as critical, as is the rapid finalisation of policy and market design frameworks necessary to scale up the installed capacity of electrolysers towards 80 GWe.

Some topics requiring more attention in the upcoming years would be the feasibility and suitability of new hydrogen storage sites, the suitability and availability of existing pipeline segments and storage assets for repurposing, and the feasibility and associated costs of converting existing LNG or oil import terminals versus new-build assets to handle ammonia or liquid hydrogen.

Finally, with respect to policy, the development of national biomethane strategies by EU member states and clarity on the availability of sufficient hydrogen infrastructure-earmarked funds within the context of the 6th PCI list are of utmost importance for the realisation of investments on hydrogen and biomethane infrastructure.

Policies, economic considerations, and technical constraints will shape the concrete layout of the pan-European H_2 network

As mentioned previously, commodity price and other scenario assumptions used in the present analysis were developed prior to the onset of the Russian invasion in Ukraine. The continuously evolving energy landscape has led to the sharp increase of near-term energy prices and increased the uncertainty over the medium and longer term. It has also accelerated the development of renewables and hydrogen projects and increased the urgency with which EU and national energy policies are developed and updated. Within this context, it was assessed how the S1 H_2-Interconnected scenario would differ under sustained high gas prices. In order to assess the impact of further uncertainties, the sensitivity of the results of S1 H_2-Interconnected to lower than required wind and solar deployment across the countries in scope and to a different climatic dataset were also analysed.

While in these three variations the energy system expands differently along a different set of input assumptions, this is not significantly different, proving the robustness of the results. A pan-European H_2 network is a key element in all the assessed sensitivities as well, and is part of the identified cost-optimal solution to achieve an affordable, secure, and sustainable energy supply. The following additional insights emerged:

1. In the higher natural gas prices scenario low-carbon hydrogen maintains a complementary role, in the short term. By 2030 electricity production will not yet be sufficiently decarbonised to supply both demand electrification and renewable hydrogen production. This gradually changes after 2030 and by 2050 renewable hydrogen will have fully displaced low-carbon hydrogen. Low-carbon hydrogen may be important in helping the hydrogen market grow but in the long term should be seen as a transition fuel that will be replaced by renewable hydrogen.
2. Hydrogen import terminals can foster competition and supply diversification similarly to what LNG terminals do today with their inherent sourcing flexibility and openness to global supplies, though they may play a less pronounced role in a low gas price scenario. Import terminals also provide a hedging or backup option in case domestic hydrogen production projects (including renewable generation capacity build out) are delayed or constrained. Thus, shipped hydrogen imports contribute to energy security and enable alternative sourcing strategies.
3. The European renewable hydrogen production across Europe as identified by the model, depends on the considered climate year. Therefore, the base climate year was selected as the most representative for the total renewable energy resources of the countries in scope. However, since every climate year leads to a different regional distribution of renewable hydrogen, even in that average year some regions produce more and others less than their local inter-annual average. A notable example is the Nordic and Baltic Sea region, where significantly more renewable electricity and hydrogen can be produced in years other than the base climatic year used in the current analysis.

The real-world version of the pan-European hydrogen system will materialise based on how individual projects achieve a higher or lower status of competitiveness compared to the level playing field perspective considered in this study. In particular, the concrete development of the pan-European H_2 network will depend on various aspects inter alia where hydrogen can be produced cheapest and where future hydrogen demand is located, but also on non-economic factors (i.e. security of supply, regulatory aspects and societal acceptance) and concrete initiatives from market participants. The non-economic factors mentioned above are beyond the scope of the present study.

Policy recommendations

This study demonstrates that substantial benefits stemming from the realisation of a pan-European hydrogen system are expected. However, there is much uncertainty for the investors and operators of such a system positioned between nascent markets and technologies. The following policy actions are needed at EU level to realise the full potential of renewable and low-carbon gases and its infrastructures:

- **Approve and implement key EU legislative proposals pertaining to renewable and low-carbon gas infrastructure as soon as possible**. Clarity on the hydrogen and decarbonised gas market package and the RED II recast including the associated Delegated Acts defining hydrogen standards, is crucial to allow the hydrogen and biomethane industries to develop. To meet the REPowerEU ambition, these targets should be translated into binding legislation to give a strong market signal.
- **Increase funding and financing mechanisms for early-stage hydrogen infrastructure development**. While there is funding available for cross-border energy infrastructure, e.g., through Connecting Europe Facility - Energy (CEF-E), this is not sufficient. Additional financial aid is needed to kick-start hydrogen infrastructure deployment, for instance through CAPEX funding or subsidies tariffs. To realise favourable financing conditions, the approach of taxonomy to infrastructure should be streamlined and revised to ensure that repurposing of gas infrastructure to enable that the pan-European H_2 network is considered taxonomy aligned.
- **Ensure rapid development and appropriate remuneration of underground hydrogen storage**. Hydrogen storage capacities need to start being developed as soon as possible. In early phase of this market, strong incentives for commercial flexibility are needed in the regulatory framework to scale up prospective hydrogen storage projects for different types of clients. Currently, there is no financing and remuneration model for hydrogen storage in place. Without, it is unlikely that greenfield developments or repurposing of natural gas storage assets will take place at the scale required.
- **Update the natural gas quality standard to ensure more biomethane integration into the gas network**. The Commission should task the European Committee for Standardisation to assess and, if necessary, update the quality standard for cross-border gas to facilitate the greening of the gas system (i.e. if it allows for a twelvefold increase of biomethane injection to the grid in a cost-effective manner). Furthermore, it should be stipulated that Member States must not restrict cross-border flows of biomethane and other green gases.
- **Establish the certification and trading framework for renewable and low-carbon gases as soon as possible**. The implementation of the Union Database and gas guarantees of origin (GO) systems are crucial to enable the development of a transparent and liquid renewable and low-carbon gas market. When implementing these systems, it is crucial to i) streamline the Union database and gas GO systems to work together[11], ii) allow renewable gases injected into the gas grid to be withdrawn flexibly in the EU if the grid is physically interconnected,[12] and iii) extend the Union database to cover renewable fuels used in all energy sectors.[13]
- **Facilitate the scale-up of hydrogen imports to meet REPowerEU targets and support supply diversification**. Import considerations should be included in long-term (hydrogen) infrastructure planning (as part of the TYNDP), covering both pipeline connections, as well as hydrogen (carrier) import terminals. To support this, PCI and PMI decisions would need to be timely to accelerate implementation of projects. Policies should encourage international cooperation and partnershps in the field of renewable and low-carbon gas.
- **Consider benefits across sectors in the PCI CBA assessment methodology for candidate hydrogen projects to foster sector integration**. The present study has identified substantial benefits for the electricity system, due to the realisation of a pan-European H_2 network. The cost benefit analysis (CBA) methodology for assessing hydrogen projects should be updated in order to allow the quantification and monetisation of such benefits from an integrated system perspective.

11 In practical terms, the transfer of gas GO from a Member State registry into the Union database should be allowed, at which point a tradeable Union database GO (or equivalent) is created. The original gas GO should be cancelled from the Member State registry upon registration in the Union database to avoid double counting.

12 The system must also allow for the use of imports of renewable gases produced outside the EU. This recommendation is similar to the Parliament's proposal in the Gas Directive on Certification of renewable and low-carbon fuels certification of renewable and low-carbon fuels (Article 8). Committee on Industry, Research and Energy (2022). DRAFT REPORT on the proposal for a directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) (COM(2021)0803 – C9-0468/2021 – 2021/0425(COD)) Link.

13 An extension of the Union database to cover all end-use sectors (not just transport) was proposed in the RED II revision. As renewable gases injected into the grid are used in all sectors, it is critical this extension is implemented for gases from the start of the database.

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ATR	Autothermal reformer
CCGT	Combined-cycle gas turbine
CAPEX	Capital expense
CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
DE	Distributed Energy
DSR	Demand-side Response
EHB	European Hydrogen Backbone
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for GAS
ESM	Energy system model
EU	European Union
FF55	Fit for 55
GA	Global Ambition
GHG	Greenhouse gases
H_2	Hydrogen
LCP	Guidehouse's Low Carbon Pathways model
LNG	Liquefied Natural Gas
NCV	Net caloric value
NIMBY	Not in my backyard
OCGT	Open-cycle gas turbine
OPEX	Operating expense
PECD	Pan European Climate Database
PEMMDB	Pan-European Market Modelling Database
PV	Photovoltaic
RES	Renewable energy resources
RFNBO	Renewable fuel of non-biological origin
S1	Scenario 1
S2	Scenario 2
SMR	Steam methane reforming
TYNDP	Ten-Year Network Development Plan
UGS	Underground gas storage
VRE	Variable renewable energy
WEPP Database	World Electric Power Plant Database

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Glossary

Bidding zone	Bidding zone: A bidding zone is the largest geographical area within which market participants can exchange energy without capacity allocation. Currently, bidding zones in Europe are mostly defined by national borders. In this study considered bidding zones are aligned to bidding zones used within the TYNDP 2022 developed jointly by ENTSOG and ENTSO-E.
Biomethane	Methane produced from sustainable biomass, typically by upgrading biogas. Biogas and biomethane can be produced via different production routes using a range of feedstocks, including animal manure, agricultural residues, or wood wastes. Biomethane can be used as a direct replacement of natural gas.
Cross-border transmission capacity	Cross-border transmission capacity determines the maximum exchange between two connected bidding zones. In this study, cross-border transmission capacity for electricity, hydrogen, and methane are considered.
European Hydrogen Backbone (EHB)	The EHB initiative consists of a group of thirty-one energy infrastructure operators, united through a shared vision of a climate-neutral Europe enabled by a thriving renewable and low-carbon hydrogen market.
Fit for 55 (FF55)	The Fit for 55 package is a comprehensive set of updates to existing laws and new legislative proposals from the European Commission to help achieve the European Union (EU) target of 55% greenhouse gas (GHG) emissions reduction by 2030 compared to 1990.
Green Deal	A set of proposals from the European Commission to make the EU's climate, energy, transport, and taxation policies fit for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels.
Grid-connected and off-grid electrolysers	Grid-connected electrolysers are connected to the electricity grid and produce hydrogen exclusively from grid-based electricity. Off-grid electrolysers in this study are directly and solely connected to a utility scale solar PV, onshore or offshore wind generation. Therefore, hydrogen production from off-grid electrolysers is directly linked to the temporal availability of solar and wind energy respectively. Potential hybrid solutions and off-grid variants are not considered in this study.
Integrated energy system modelling	Approach applied in this study for simultaneous optimizing the supply of electricity, hydrogen, and methane demand while considering interdependencies between the three systems and related generation, storage, and transmission assets.
Low carbon fuels	A variety of synthetic fuels with a lower GHG emissions footprint than their fossil equivalent. The Gas Directive establishes that the GHG emissions savings are at least 70% compared to a fossil counterpart. The Delegated Act on Article 83 of the Gas Directive should establish the methodology for assessing GHG emissions savings from low-carbon fuels (by December 2024).[14]

14 European Commission (2021). Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen Link

Low-carbon hydrogen	Hydrogen produced from non-renewable sources with GHG savings of at least 70% compared to the fossil benchmark of 94.1 $gCO_2eq/MJ\ H_2$ (across the full lifecycle).[15] An example would be the production of hydrogen via steam methane or autothermal reforming in combination with high carbon capture rates.
Methane	Main component of natural gas. Methane demand is currently supplied mainly by natural gas and transported by gas pipelines. Methane demand can also be supplied by biomethane and synthetic methane using the same transmission and distribution infrastructure developed for natural gas.
Natural gas	Natural gas comprises gases, occurring in underground deposits, whether liquefied or gaseous, consisting mainly of methane.
NIMBY	An acronym for the phrase "not in my backyard", a characterization of opposition by residents to proposed developments in their local area.
Pan-European hydrogen network	In this study a pan-European hydrogen network refers to hydrogen cross-border transmission capacities between countries in scope of this study.
Renewable hydrogen	Hydrogen produced from renewable electricity (e.g. electrolysis) or from renewable energy (e.g. steam reforming of biomethane). “Renewable hydrogen” will be defined in the Delegated Act on Article 27 of the Renewable Energy Directive II (RED II) as Renewable fuel of non-biological origin (RFNBO).
REPowerEU	European Commission plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition in Europe with measures in energy saving, diversification of energy supply and accelerated roll-out of renewable energy to replace fossil fuels in homes, industry, and power generation.
Synthetic methane	Methane produced by synthetising hydrogen and CO_2. In the EU, synthetic methane is in the category of low-carbon fuels and thus must achieve at least 70% GHG emissions reduction compared to a fossil counterpart.

15 European Commission (2021). Directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen Link

1. Background and objectives

In 2021, the European Commission (Commission) announced the Fit for 55 (FF55) package as a comprehensive set of updates to existing laws and new legislative proposals to help achieve the European Union (EU) target of 55% greenhouse gas (GHG) emissions reduction by 2030 compared to 1990 (the previous target was 40%) and a net zero emission energy system latest until 2050. When consented (most of the legislative proposals are still in the approval process as of February 2023), this package will have an immense impact on the decarbonisation of the EU economy.[16]

While most of the FF55 proposals are still being negotiated, 2022 has been a year of major disruptions in the European energy system, with skyrocketing prices and concerns about energy security. Following the Russian invasion of Ukraine, the immediate focus turned to diversification away from Russian energy imports between now and 2030. Similarly, the United Kingdom (UK) government has announced the British energy security strategy as a reaction to the war.[17]

In 2021, EU imported 155 bcm of natural gas from Russia. The REPowerEU plan sets the ambition to replace 35 bcm(~370 TWh, LHV) of this natural gas with biomethane. At the same time, 10 Mt/y (333 TWh/y, LHV) of renewable hydrogen should be produced domestically and 10 Mt/y imported by 2030.[18,19] Besides these more immediate energy security and diversification concerns, achieving the EU's net-zero GHG emission target by 2050 as outlined in the European Green Deal[20] and the FF55 package requires full speed ahead with the energy transition.

It is apparent from the FF55 updates that renewable and low-carbon gases and gas infrastructure will have a pivotal role in cost-effectively achieving EU's 2030 goals and the ultimate pursuit of climate neutrality. They help to achieve GHG emission reductions targets, contribute to energy security (lower import dependence), and affordability to consumers.

To reap the full benefits of renewable and low-carbon gases, infrastructure is a crucial component. Infrastructure is required to transport and store hydrogen across the continent, while current natural gas grids can facilitate the scale up of biomethane.

Renewable and low carbon gases play a key role in the energy transition

Hydrogen is rapidly growing attention in Europe and around the world. In its European hydrogen strategy, the Commission refers to hydrogen as "essential to support the EU's commitment to reach carbon neutrality by 2050 and for the global effort to implement the Paris Agreement while working towards zero pollution."[21] As per a Gas for Climate estimation the FF55 package could result in up to 193 TWh of renewable hydrogen consumption in the EU by 2030, with largest utilization in industry (89 TWh), road transport (51 TWh) and maritime transport (29 TWh).[22] In REPowerEU, the role of renewable hydrogen is further emphasised by targeting up to 10 Mt/y (333 TWh/y) of domestic renewable hydrogen production, as well as 10 Mt/y on hydrogen (carrier) imports by 2030.

16 For an overview of the FF55 proposals and comparison of the underlying energy system modelling perfomed by the Commission to Gas for Climate decarbonisation scenarios, see Gas for Climate (2021). Fit for 55 Package and Gas for Climate Link
17 The Strategy aims to reduce UK's natural gas consumption by 40% by 2030 with substantially increased targets for offshore wind, nuclear energy, hydrogen (both renewable and low-carbon) and possibly also domestic natural gas production. It targets 50 GW of installed offshore wind capacity by 2030, 10 GW of installed hydrogen production capacity (at least 50% renewable) by 2030, 24 GW of nuclear power by 2050, a new licensing round for North Sea fossil fuel production, and a commitment to 4 carbon capture and storage clusters. Department for Business, Energy & Industrial Strategy (2022). British energy security strategy Link.
18 European Commission (2022). Commission Staff Working Document, SWD (2022) 230 final, Implementing the REPowerEU Action Plan: Investment needs, hydrogen accelerator, and achieving the bio-methane targets Link
19 Gas for Climate assessed the options to facilitate the 10 Mt import target by 2030. Gas for Climate (2022). Facilitating hydrogen imports from non-EU countries Link
20 European Commission (n.d.). A European Green Deal - Striving to be the first climate-neutral continent Link
21 European Commission (2020). A hydrogen strategy for a climate-neutral Europe Link
22 Gas for Climate (2021). Fit for 55 Package and Gas for Climate Link.

Hydrogen can be used both as feedstock and fuel. It is storable and has many possible applications across the industry, transport, power, and buildings sectors. Most importantly, hydrogen does not emit CO_2 at the point of use and can be produced with very low GHG emission footprint (renewable or low-carbon hydrogen). Thus, it offers a solution to decarbonise industrial processes and economic sectors where reducing carbon emissions is both urgent and hard to achieve. All this makes hydrogen essential to support the EU's and UK's commitment to reach climate neutrality by 2050 and the global effort to implement the Paris Agreement. To enable the benefits of hydrogen, a hydrogen market needs to be established. The current hydrogen consumption in the EU amounts to 339 TWh,[23] almost of all which is obtained from GHG-intensive production from natural gas (with average GHG intensity of 328 $gCO_2/kWhH_2$).[24] Renewable and low-carbon hydrogen production is at its nascent state today. A rapid scale up of these production technologies is required.

Biomethane is a renewable gas resulting in high GHG savings due to the short carbon cycle of biomass feedstock. It is compatible with the existing gas grids, can improve waste management, supports rural economies, and has the ability to generate negative emissions.[25] Biomethane production through anaerobic digestion is a proven and market-ready technology with little associated technological risks. Thermal gasification, while less mature than anaerobic digestion, has the potential to unlock additional feedstocks for biomethane production. Biomethane is essentially a direct replacement of natural gas that can be produced domestically and used across all sectors of the economy (e.g. building heating, industrial heating, dispatchable electricity generation, transport). The Commission fully recognises these benefits and thus set a target of 35 bcm (371 TWh) of annual biomethane production by 2030. Today, 3.5 bcm (37 TWh) of biomethane and 15 bcm of biogas are produced in the EU27. Gas for Climate recently estimated the sustainable biomethane production potential for each EU member state, with the cumulative potential up to 41 bcm (435 TWh) in 2030 and 151 bcm (1,602 TWh) in 2050.[26]

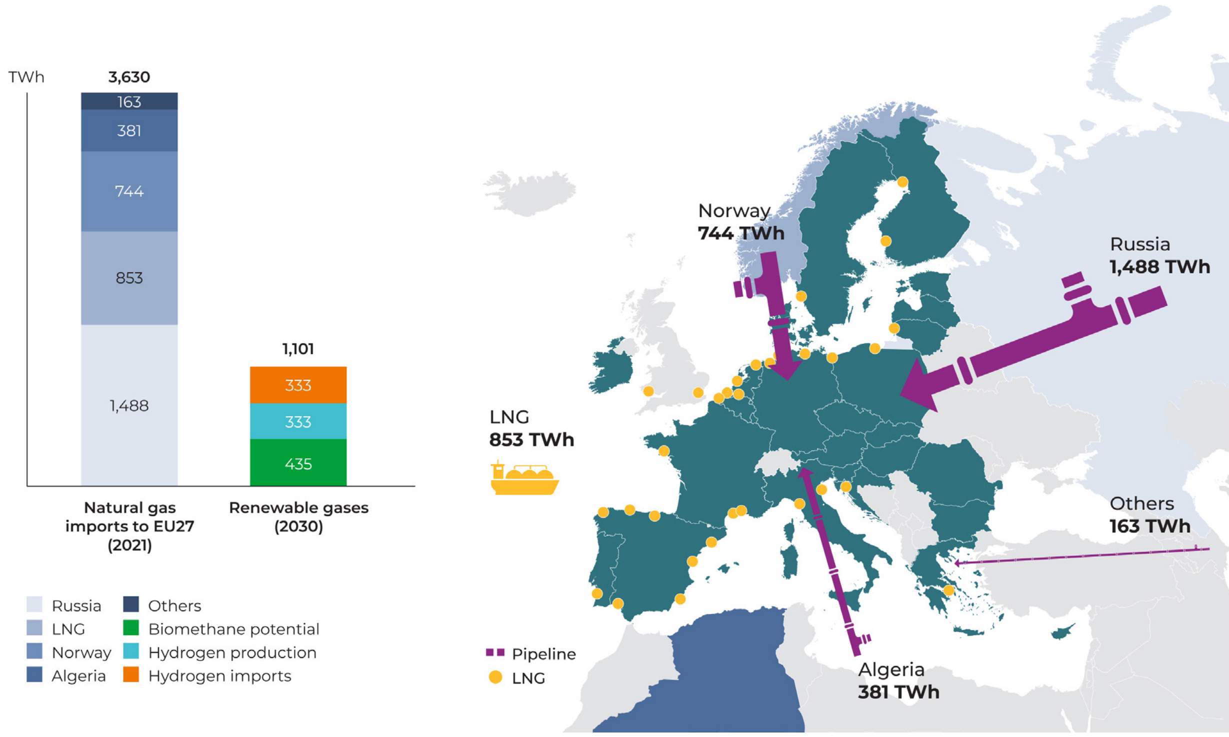
Accelerated deployment of these renewable and low-carbon gases can bring about three main benefits to the energy system and the society:

1. Increase European energy security by reducing dependency on energy imports, in particular from Russia.[27] Figure 1 illustrates gas imports to the EU in 2021, with Russia accounting for 41%, followed by Norway at 23.5%[28], LNG imports at 20.5%, Algeria at 10.5%, and others at 4.5%.[29] The total volume of gas imported was almost 3,580 TWh. Biomethane, used as direct and domestically produced substitute of natural gas, could replace around 12% of the 2021 gas imports by 2030 and almost half of the current gas imports by 2050 (1,602 TWh vs 3,580 TWh).[30] Since the beginning of 2022, the market context has changed radically. From January to November 2022, EU pipeline gas imports from Russia decreased by almost 69 bcm, implying that the total 2022 pipeline imports are around half of the 2021 total pipeline imports of 138 bcm.[31]

If the REPowerEU targets are achieved, the supply of renewable hydrogen by 2030 (666 TWh) could be almost double of the current (non-renewable) hydrogen consumption (339 TWh). Domestic renewable hydrogen production and imports would thus further reduce EU dependency on natural gas imports from Russia by replacing hydrogen produced from natural gas or directly replacing natural gas use.[32] Imports however will stay essential,

23 Fuel Cells and Hydrogen 2 Joint Undertaking (2019). Hydrogen Roadmap Europe Link
24 European Commission (2020). Hydrogen generation in Europe: Overview of key costs and benefits. Link
25 For example, when combined with carbon capture and storage from carbon soil sequestration linked to biomass cultivation intensification.
26 Gas for Climate (2022). Biomethane production potential in the EU Link. Besides estimating production potentials, Gas for Climate also established a Manual for National Biomethane Strategies (2022, Link) which provides step by step instructions on how to develop a national biomethane strategy with best practices collected from around the globe.
27 The natural gas supply to the EU27 are shown for 2021 Link. Biomethane potentials for 2030 and 2050 are from Link. Natural gas and biomethane figures are converted from bcm to TWh using a factor of 10.61 (TWh/bcm). Hydrogen conversion factor is 33.33 MWh/tonne (LHV).
28 Norway agreed to increase its production to help compensate for the decreased imports from Russia. It is estimated that Norway could increase its export to Europe by 8% in 2022. Euronews (2022). Russia's war in Ukraine has forever changed Europe's energy landscape, says Norway minister Link.
29 European Commission (2021). Quarterly report on European gas markets Q4-2021 Link
30 As the natural gas consumption is supposed to significantly decline by 2050, most of natural gas imports could be replaced by domestically produced biomethane.
31 European Commission (2022). Quarterly report on European gas market Q3-2022 Link
32 Part of the 666 TWh could be supplied by low-carbon hydrogen, i.e. by applying carbon capture and storage technologies on hydrogen production from natural gas. Low hydrogen could help to accelerate market and infrastructure development as a complementary measure to renewable hydrogen. However, low hydrogen would not help with reducing natural gas import dependency of the EU.

Figure 1: Natural gas imports to EU27 in 2021, domestic biomethane production potentials in 2030, and hydrogen targets for 2030



highlighting need for reliable import-partners. In total, meeting the REPowerEU targets could reduce EU's dependency on natural gas imports by 30% by 2030 (in other words replacing 73% of 2021's gas imports from Russia, all other things equal).[33]

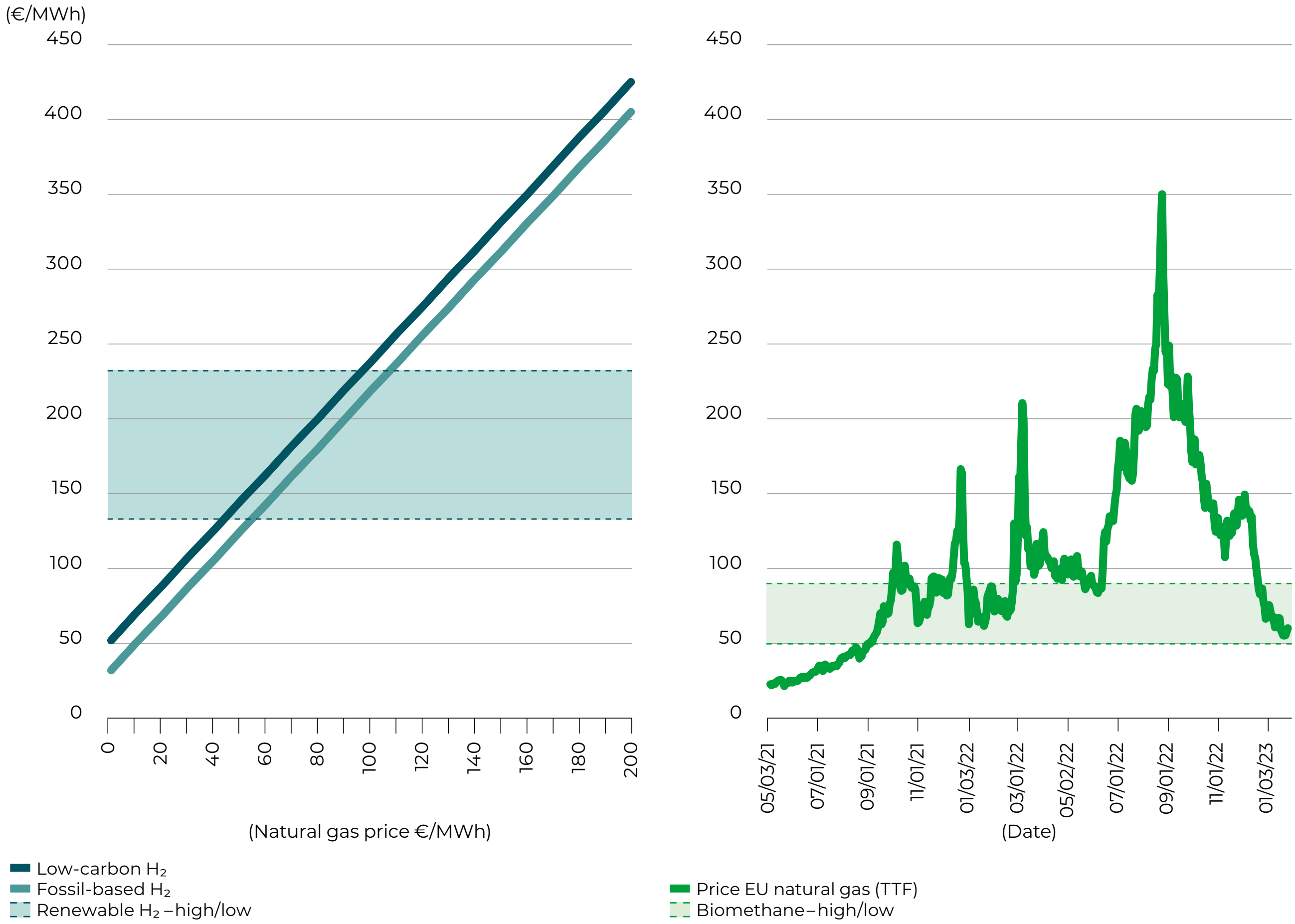
2. Speed up the implementation of climate goals. Renewable and low-carbon gases can significantly contribute to GHG emission reduction. When biomethane from sustainable feedstocks is used instead of natural gas, the overall lifecycle GHG emission reductions are over 80% and some pathways achieve up to 200% emission reduction.[34] This means that displacing natural gas in the grid with biomethane results in large, direct reductions, with only minor infrastructure adaptations.

Today, more than 95% of hydrogen is produced from fossil fuels, resulting in 70 to 100 Mt of CO_2 emissions in the EU.[35] If this hydrogen would be produced with renewable electricity, the GHG emissions would be zero (when excluding scope 3 emissions). Low-carbon hydrogen can also deliver a significant GHG emission reduction in the short term if high CO_2 capture rates (e.g. >90%) and low upstream emissions from natural gas supply can be met.[36]

Renewable and low-carbon gases will therefore play a critical role in meeting the 2030 GHG reduction targets and achieving net-zero emissions by 2050.

33 This is without accounting for additional measures such as energy efficiency and overall demand reduction.
34 This high emission reduction potential (200%) is because, in addition to the emission avoided from replacing a fossil fuel, a similar amount of GHG either is effectively removed from the atmosphere (and stored in the land) or is avoided in adjacent systems (such as avoided methane emissions from agriculture and waste management). The average lifecycle emissions of biomethane are expected to be slightly below zero by 2030, due to a combination of avoiding emissions from alternative waste treatment, soil carbon accumulation, using digestate to replace fossil fertiliser, and applying carbon capture and storage or replacement. Gas for Climate (2021). The Future Role of Biomethane Link
35 European Commission (2020). A hydrogen strategy for a climate-neutral Europe Link
36 Minimal lifecycle 70% reduction compared to the fossil benchmark of 94.1 gCO_2eq/MJ (~3.4 tCO_2/tH_2) is required to qualify as low-carbon. The specific GHG reduction achievable with low-carbon hydrogen depends on several factors, including supply chain emissions of natural gas (direct and indirect via methane leakage), CO_2 capture rate, or the energy source for the carbon capture unit.

Figure 2: Hydrogen production costs (left) and natural gas price developments compared to biomethane production costs (right)



3. Alleviate part of the energy cost pressure on households and companies. The current energy crisis across Europe is associated with high energy bills for both households and companies. In the past two years, the wholesale gas price in Europe has increased from 15 €/MWh in March 2021 to about 70 €/MWh in January 2023, with extreme peaks of up to 350 €/MWh in August 2022.[37] These developments have made the need for diversification away from Russian natural gas even more pressing, but they also increased the competitiveness of renewable and low-carbon gases. Figure 2 (left) illustrates that hydrogen produced from natural gas would be more expensive than renewable hydrogen if the natural gas used is priced between 60-100 €/MWh (with or without carbon capture and storage (CCS)).[38, 39] Figure 2 (right) shows that the average biomethane production cost was lower than the natural gas price between January and October 2022.[40] However, in

37 Data from the Dutch TTF trading point, extracted from Investing.com (2022). Link
38 Grey hydrogen price based on Steam Methane Reforming, analysis by ING (2021). High gas prices triple the cost of hydrogen production Link. Renewable hydrogen production costs are estimated from 4-7 €/kg production cost by Agora Energiewende Link.
39 Additional costs for CCS are based on “Energy Transitions Commission (2021). Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy Link” and is ~0.60 €/kg of hydrogen.
40 Biomethane production cost based on Gas for Climate (2021). The future role of biomethane Link. Natural gas prices from the Dutch TTF trading point, extracted from Investing.com (2022). Link

the coming years, the domestic biomethane and renewable hydrogen production will likely remain small in volume, so this cost savings effect might be rather limited. Conversely, in medium to longer term (e.g. 2025 and after), many analysts expect the natural gas price to stabilise again (although probably not to come back to the levels at the first half of 2021). Regardless of this, domestic renewable gas production should offer a more stable price outlook as these are not linked to the cyclical prices of fossil fuels and thus contribute to a better stability of the European energy markets.

Making the positive contribution of renewable and low-carbon gases a reality will require infrastructure that can transmit, store, and distribute these gases across Europe. While biomethane can use the existing natural gas transmission and distribution infrastructure, hydrogen requires dedicated infrastructure, part of which can be repurposed from unused or underutilised parts of the existing gas network. The vision of dedicated cross-border hydrogen infrastructure spanning across Europe is being illustrated by the European Hydrogen Backbone (EHB) initiative.

A pan-European hydrogen network as a key component of the decarbonised European energy system

The essential role for hydrogen pipeline infrastructure in fostering market competition and security of supply was recognised in the Commission's Hydrogen and decarbonised gas market package, published in December 2021.[41] Following the Russian invasion of Ukraine and the subsequent near halting of natural gas imports from Russia[42], the impetus for a rapid clean energy transition has never been stronger. This position was firmly established already in the FF55 package but got further emphasised in the Commission's REPowerEU plan. Achieving the aforementioned ambitious hydrogen targets by 2030 (10 Mt/y of domestic production +10 Mt/y of imports) will require a rapid acceleration of the development of a dedicated hydrogen pipeline infrastructure, storage facilities, and port infrastructure.

The EHB has been formulating a vision for integrated pan-European hydrogen infrastructure with 31 gas transmission system operators (TSOs) contributing to it. The most recent EHB outline shows that by 2030, five pan-European hydrogen supply and import corridors could emerge, connecting industrial clusters, ports, and hydrogen valleys to regions of abundant hydrogen supply and supporting the Commission's ambition to promote the development of a renewable and low-carbon hydrogen market in Europe. The hydrogen infrastructure could then grow to become a pan-European network, with a length of almost 53,000 km by 2040, largely based on repurposed existing natural gas infrastructure (~60%).[43]

Figure 3 shows how a fully developed European cross-border hydrogen network could ultimately look. It is estimated that the European Hydrogen Backbone for 2040 requires an estimated total investment of €80-143 billion.[43] This investment cost estimate, which is relatively limited in the overall context of the European energy transition, includes cost for interconnectors, compressors, and subsea pipelines, linking countries to offshore energy hubs, and potential export and import regions.[44]

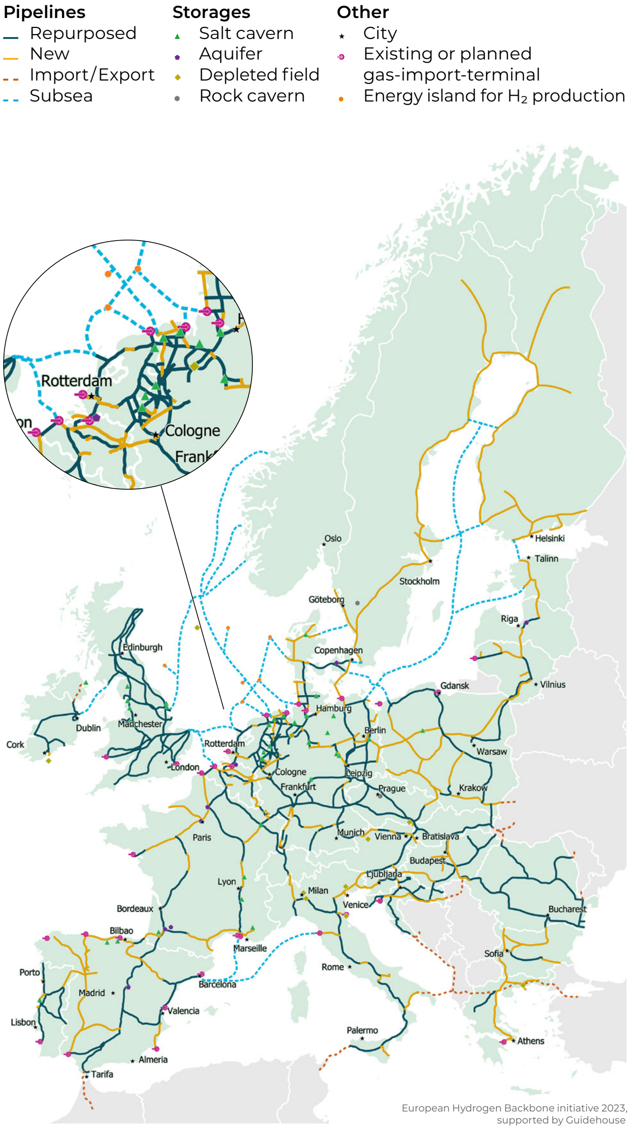
41 The Hydrogen and decarbonised gas market package recasts both the Directive and Regulation on gas markets, reflecting the need to decarbonise the gas networks with biomethane and hydrogen. European Commission (2021) – Proposal for a recast Directive / Regulation on gas markets and hydrogen (COM(2021) 803 final) / (COM(2021) 804 final) Link

42 In week 42 of 2022, the gas imports from Russia to the EU have totalled 536.5 million cubic meters (mcm), compared to 2,580 mcm in week 42 of 2021, which is an 80% decline. EU now imports only about 9% of its gas consumption from Russia. Link

43 European Hydrogen Backbone (2022). A European hydrogen infrastructure vision covering 28 countries Link

44 The estimate does not cover investment costs for local distribution networks.

Figure 3: EHB vision for a fully developed European hydrogen network in 2040[45]



Objective and scope of study

The objective of this study is to assess the benefits and the role of a pan-European hydrogen transmission network (pan-European H_2 network) for the transition towards an affordable, secure, and sustainable energy supply. This is done by applying an integrated energy system model (ESM) that allows to model how demand for hydrogen, electricity, and methane can be supplied in a cost-efficient manner while reaching net zero CO_2 emissions by 2050 under different scenario assumptions. By considering interdependencies between hydrogen, electricity, and methane sectors and respective energy carriers, the ESM identifies the benefits and the role of a pan-European H_2 network from a "whole system perspective". Scenarios with and without giving the ESM the opportunity to invest in hydrogen cross-border transmission capacity between countries are assessed and key performance indicators of the individual scenarios, such as energy supply cost, CO_2 emissions, and capacity needs, are compared.

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The term pan-European H_2 network in this study refers to a pan-European hydrogen transmission network in general and not to a particular hydrogen network with a specific layout.

In particular, the term pan-European H_2 network used in this study does not describe the European Hydrogen Backbone (EHB) developed by the EHB initiative.

While the EHB analysis outlines a strong case for the establishment of this hydrogen infrastructure stretching across Europe, its potential benefits for the transition towards an affordable, secure, and sustainable energy supply has not yet been quantified in detail from a whole system perspective.

The objective of this study is not to add to the debate how end-use sectors should be decarbonised. Therefore, neither own scenarios for future demand for hydrogen, electricity, and methane in the end-use sectors are developed nor scenarios developed by Gas for Climate in the past are used in this study. Instead, demand

45 European Hydrogen Backbone (2023). Link This map is an update of the maps in Link, which means that the amount of kilometres and investments stated above will slightly deviate. These numbers will be updated soon by the EHB initiative.

scenarios based on the Global Ambition (GA) and Distributed Energy (DE) scenario developed jointly by the European Network of Transmission System Operators for Electricity and Gas (ENTSO-E, ENTSOG) are used.[46] In 2050, gaseous hydrogen demand in the end-use sectors is about 30% higher in the GA scenario than in the DE scenarios which allows to assess the benefits of a pan-European H_2 network under a "higher" and "lower" scenario for future hydrogen demand in Europe.

Results of this study must be interpreted in view of the considered scenario assumptions and the applied modelling approach. The landscape of the European energy system changes rapidly since the European energy crisis started. Therefore, especially for the early years of the covered timeframe in this study, results may not be fully in line with the latest plans and developments of individual countries. However, this does not jeopardise the main aim of the study, i.e. to assess the potential benefits of a pan-European H_2 network in general. Results of this study do not signify a particular need for a specific hydrogen, electricity, or methane transmission infrastructure asset for a future time horizon. Instead, cross-border transmission capacities and observed energy flows are a result of the applied modelling approach and scenario assumptions which have the sole aim to assess the benefits and role of a pan-European H_2 network irrespective of its concrete design.

How a future pan-European H_2 network will develop over time depends on various aspects and concrete measures of involved stakeholders. Especially in view of the current European energy crisis, security of supply considerations of policy decision makers, such as diversify of supply and energy independency, will certainly have a stronger impact on the development of the European energy system infrastructure than in the past. Such considerations are difficult to monetarise and are not considered by the applied ESM as it is solely driven by the applied cost minimisation criterion to meet future energy demand while achieving defined CO_2 emission reduction targets. Nevertheless, findings of this study in terms of the benefits of a pan-European H_2 network are robust across the different investigated scenarios.

In the following chapters, an overview of the applied methodology is provided before the key findings of the assessment are presented and insights from assessing the impact of some alternative developments than assumed in the main scenarios are highlighted. Finally, policy recommendations to accelerate the development of a pan-European hydrogen system and biomethane uptake are specified. The appendix covers the major modelling assumptions and input parameters used for the assessment.

46 ENTSO-E&G (2022). TYNDP 2022. Link; Regulation (EU) 347/2013 requires that ENTSOG and ENTSO-E use scenarios for their respective Ten-Year Network Development Plans (TYNDPs). Since 2018, ENTSO-E and ENTSOG develop TYNDPs jointly together. TYNDP scenario reports are published every two years. Scenarios are used by ENTSO-E and ENTSOG to test electricity and gas transmission needs and projects.

2. Methodology

Applied methodology and investigated scenarios

An integrated ESM is used to assess the role and benefits of a pan-European H_2 network to supply European demand for hydrogen, electricity, and methane over the timeframe 2030 – 2050. The applied methodology is composed of three major steps as shown in Figure 4.

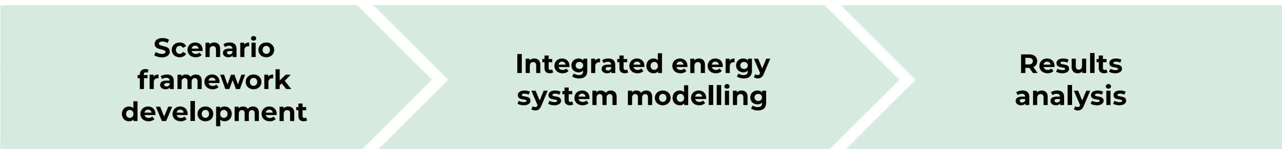
In the first step, the scenario framework is developed under which the potential benefits of a pan-European H_2 network are assessed. This includes the definition of the geographical and temporal scope and granularity of the analysis, the selection of scenarios that are assessed, and the development of the scenario-specific input datasets for the ESM.

The assessed scenarios cover the timeframe 2030 – 2050 and consider 34 countries (see Figure 5). 25 countries of the EU, Norway, Switzerland, the UK, and the non-EU countries of the Balkan region.[47]

The spatial granularity for the countries in scope is aligned to the existing bidding zones of the European electricity market. Most countries are represented by one bidding zone.[48] Denmark, Italy, Norway, and Sweden have multiple bidding zones due transmission constraints of their national electricity grid. The considered bidding zones for the countries in scope are the same as used in TYNDP 2022 with the exception that the non-EU countries of the Balkan region are considered in an aggregated way in this study.

Figure 5: Countries in scope of the study and considered bidding zones

Figure 4: High-level overview of applied methodology to assess the benefits of the pan-European H_2 network



47 Cyprus and Malta are the two EU countries that are not included in the study. The non-EU countries of the Balkan region are Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, and Serbia.
48 A bidding zone is the largest geographical area within which market participants can exchange energy without capacity allocation. In this study supply and demand for hydrogen, electricity, and methane for each bidding zone needs to be balanced using domestic supply sources and imports from and exports to neighbouring bidding zones.

In the second step, the ESM is used to optimise from a whole system perspective the supply of hydrogen, electricity, and methane demand for the countries in scope over the timeframe 2030 – 2050 based on a cost minimisation criterion and the requirement to reach net-zero CO_2 emissions until 2050.

Hydrogen demand can be supplied by grid-connected electrolysers, off-grid electrolysers, steam methane reformers (SMRs) or autothermal reformers (ATRs). While grid-connected electrolysers consume electricity from the grid to produce hydrogen, off-grid electrolysers are connected directly to a dedicated solar PV, onshore or offshore wind power plant to produce renewable hydrogen. All SMRs and ATRs are equipped with CCS, meaning that only low-carbon hydrogen production is considered in this study. So-called "Grey Hydrogen" produced from natural gas or coal without CCS is not considered as a supply option. Blending hydrogen in the existing gas grid is often considered as a transitional way to quickly scale-up hydrogen supply. However, hydrogen blending is not considered in this analysis.[49] Natural gas, biomethane, and synthetic methane are considered supply options to meet methane demand while taking into account the net-zero CO_2 emissions target by 2050.[50]

Four different scenarios are assessed. The four scenarios are categorised into two scenario groups: Scenario Group 1 (Higher H_2 demand) and Scenario Group 2 (Lower H_2 demand), see Figure 6. Each scenario group is composed of a "H_2-Clustered Scenario" (S1/S2 H_2-Clustered) and a "H_2-Interconnected Scenario" (S1/S2 H_2-Interconnected). **The only difference between the H_2-Interconnected scenarios and the counterfactual scenarios, i.e. the H_2-Clustered scenarios, is that in the former the ESM can invest in hydrogen cross-border transmission capacities between countries, while this is not possible in the latter scenarios**.

In the H_2-Clustered scenarios, hydrogen cross-border transmission capacity can only be installed between domestic bidding zones of countries that are represented by multiple bidding zones. All other input parameters are kept the same for the H_2-Clustered and the respective H_2-Interconnected scenario. This allows to trace back the difference between the scenarios to the investments into hydrogen cross-border transmission infrastructure. It is important to note that investments in **hydrogen cross-border transmission capacity is not exogenously predefined in any of the scenarios but optimised endogenously** by the ESM and therefore only deployed when contributing to the cost optimal solution to supply demand for hydrogen, electricity, and methane over the timeframe 2030 – 2050.

In the third step, results for the individual scenarios are analysed and compared with each other. Based on the comparison of key performance indicators of the individual scenarios, conclusions about the benefits of a pan-European H_2 network and its role for the transition towards an affordable, secure, and sustainable European energy supply are drawn.

Figure 6: Investigated scenarios to assess the benefits of a pan-European H_2 network

	S1 H_2-Clustered	S1 H_2-Interconnected	S2 H_2-Clustered	S2 H_2-Interconnected
Hydrogen demand 2030 values adjusted for REPowerEU plan	Scenario group 1 **Higher H_2 demand** Demand based on TYNDP 2022 GA		Scenario group 2 **Lower H_2 demand** Demand based on TYNDP 2022 DE	
Investments in H_2 cross-border capacity	✗	✓	✗	✓

49 The strategic value of hydrogen blending to the development of large-scale national markets greatly depends on Member States country specifics, including the underlying national natural resources endowments, the location of demand and supply centres and the existing infrastructure underpin. In this perspective, EU rules should be flexible enough to allow optimising national energy policy decisions without prejudice to cross border interoperability.

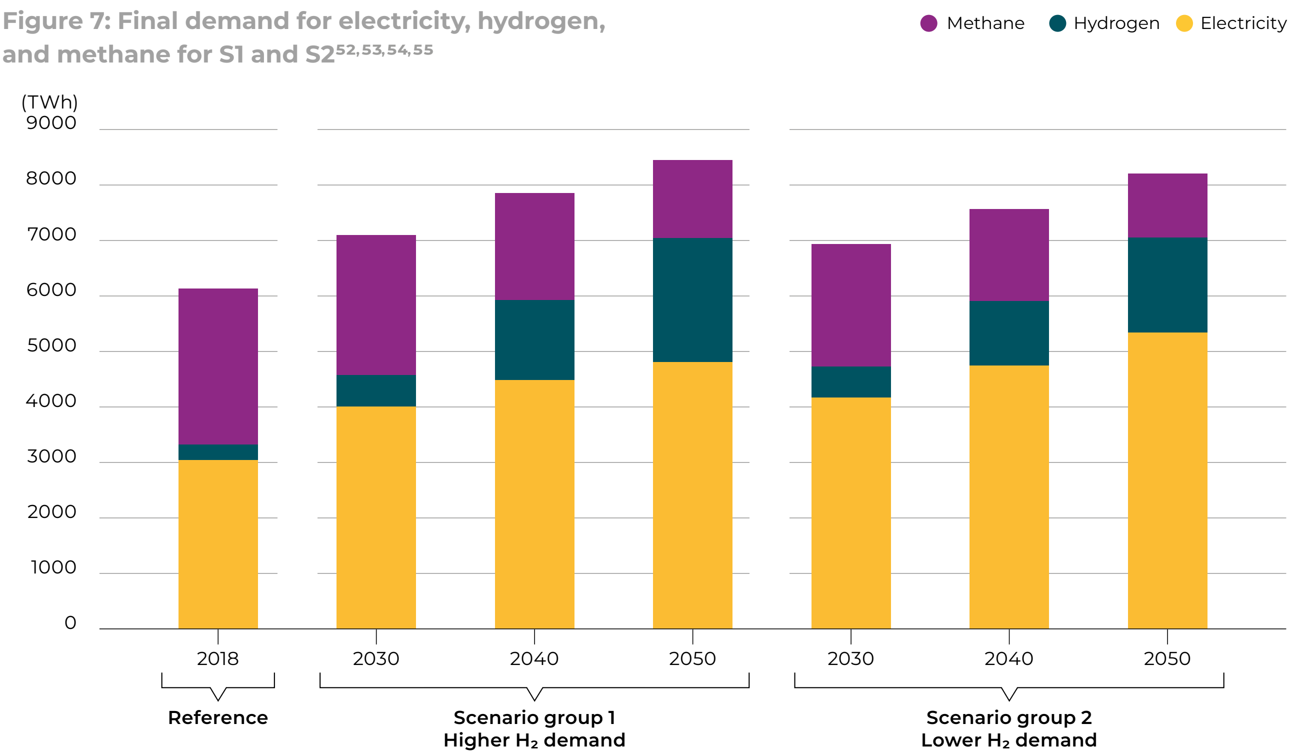
50 See glossary for a definition of renewable and low-carbon hydrogen, synthetic methane, grid-connected and off-grid electrolysers.

Scenarios describing the possible future of the European energy system are a prerequisite when aiming to analyse the benefits of a pan-European H_2 network. It is important to recognise that scenarios are not forecasts. Instead, they describe a range of possible futures which can be used as a framework to analyse the role and benefits of a pan-European H_2 network or any other infrastructure/technology. In the following paragraph, the scenarios used in this study are introduced in some more detail.

Final demand scenarios

Figure 7 shows the development of the final demand, i.e. demand in the end-use sectors, for hydrogen, electricity, and methane of the analysed system over the timeframe 2030 – 2050 for Scenario group 1 (S1) and Group 2 (S2). **In 2050, final hydrogen demand is about 30% higher in S1**. For the years 2040 and 2050, final demand for hydrogen, electricity, and methane in S1 and S2 is directly taken from TYNDP 2022 GA and DE respectively.[51] For the year 2030, TYNDP 2022 values for hydrogen and methane demand for the EU countries in scope are adjusted to consider REPowerEU targets in terms of reducing natural gas consumption and accelerating hydrogen uptake. The adjustments done to align with REPowerEU targets leads to a higher hydrogen demand and a lower methane demand in 2030 across the EU countries in scope compared to the TYNDP 2022 GA and DE scenario data.

Figure 7: Final demand for electricity, hydrogen, and methane for S1 and S2[52,53,54,55]



51 Final demand for hydrogen and methane in Switzerland is based on Swiss Federal Office of Energy (2021). Energieperspektiven 2050+ Link as data for Switzerland is not published in the TYNDP scenarios. In the case of Norway and the non-EU countries of the Balkan region, only final electricity demand is considered in the analysis as hydrogen and methane demand scenarios for these countries is not published in the TYNDP scenarios. Not considering hydrogen and methane demand in the end-use sectors in Norway can be considered to have no impact on the results of this study due to the abundant Norwegian domestic supply potentials. Not considering hydrogen and methane demand in the end-use sectors of the non-EU countries of the Balkan region has a marginal impact on the findings of this study due to the expected limited demand in these countries compared to the overall demand of the analysed system.

52 Reference year (2018) data source: Eurostat (2022). Data Browser – Energy – Energy statistics – Energy balances. Link

53 For the reference year, 2018, hydrogen is assumed to be produced from methane with a 70% conversion efficiency. The methane required to produce hydrogen is subtracted from the final consumption of methane.

54 Hydrogen demand figures do not include demand supplied via by-products and demand to produce synthetic fuels (liquids).

55 ENTSO-E&G (2022). TYNDP 2022. Link. The demand data for S1 and S2, displayed in the graph, is adapted from TYNDP 2022 Global Ambitions and Distributed Energy scenarios respectively and REPowerEU targets. Hydrogen and methane demand values are adjusted in 2030 to align with REPowerEU targets

Demand figures do not include i) indirect electricity demand to produce hydrogen through grid-connected electrolysers, ii) methane demand for electricity generation and hydrogen production through SMRs and ATRs, and iii) hydrogen demand for electricity generation and synthetic methane production. These demands are modelled endogenously and are therefore an output of the applied ESM.

Final demand for liquids and solids is out of scope of the study due to the assumed limited impact on hydrogen, electricity, and methane cross-border transmission infrastructure. This also means that hydrogen demand to produce synthetic fuels (liquids) is not considered in the analysis. Synthetic fuels to supply and decarbonise demand for liquids could be produced domestically or imported by ships. Importing hydrogen via ships in the form of ammonia or other derivatives such as methanol or synthetic kerosene to supply demand for liquids has the advantage that losses due to re-conversion into gaseous hydrogen are avoided.

Final electricity demand increases in both scenarios significantly until 2050, mainly driven by the electrification in the transport sector but also due to increased use of electricity for heating. In S1, final electricity demand increases from about 4000 TWh in 2030 to more than 4800 TWh in 2050, an increase of 20% over the timeframe. Electricity demand increases even stronger in S2 due to a higher direct electrification rate and reaches more than 5300 TWh in 2050 (28% increase).

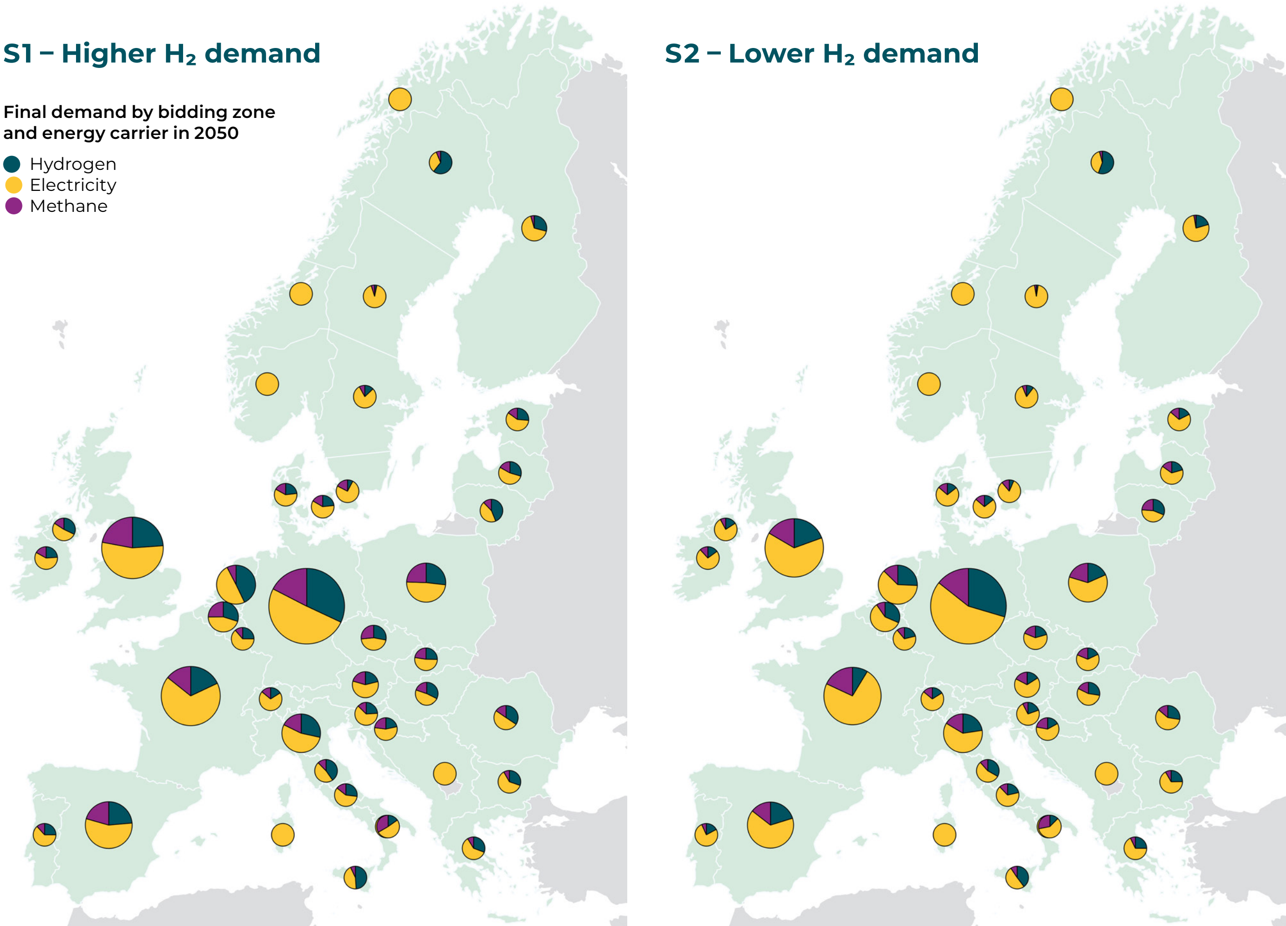
To get independent from Russian natural gas imports, the REPowerEU plan sets inter alia target to produce 333 TWh/y (10 Mt/y) of renewable hydrogen domestically by 2030. Furthermore, up to 333 TWh/y (10 Mt/y) of hydrogen from outside of the EU27 shall be imported, of which 133 TWh/y (4 Mt/y) as ammonia and other hydrogen derivatives such as methanol via ships. To account for this uptake of domestically produced and imported hydrogen, final hydrogen demand of the EU countries in scope is set to 533 TWh/y in 2030 for S1 and S2. The targeted 133 TWh/y of shipped hydrogen imports are neglected in this context as it is assumed that these imports are consumed directly at industrial clusters located at importing ports or used as liquid fuels for maritime shipping and therefore have no impact on hydrogen cross-border transmission capacities.

Final demand for gaseous hydrogen in the end-use sectors increases strongly after 2030 and becomes the main gas energy carrier until 2050 in both scenarios. In contrast, final methane demand decreases significantly until 2050, as it is replaced to a large extent by electricity in the residential/tertiary sector and by hydrogen in the industry sector. However, even methane demand decreases, biomethane and eventually also synthetic methane supply needs to be increased significantly until 2050 to replace natural gas, which is currently the primary source to supply methane demand. In S1, final hydrogen demand increases almost fourfold from about 570 TWh in 2030 to 2230 TWh in 2050. At the same time, final methane demand decreases from about 2500 TWh to 1400 TWh. Due to a higher direct electrification of the end-use sectors final hydrogen and methane demand in 2050 is significantly lower in S2.

> !
>
> Final demand for hydrogen assumed in this study, i.e. gaseous hydrogen demand in the end-use sectors, is based on TYNDP 2022.
>
> Final demand figures do not include hydrogen demand to produce synthetic fuels such as ammonia, methanol, synthetic kerosene or diesel.

The distribution of final demand for hydrogen, electricity, and methane in 2050 across the considered bidding zones is shown in Figure 8. In both scenarios, hydrogen demand is highest in Germany, the UK, the Netherlands, Poland, Northern Italy, France, and Spain. About 70% of the total hydrogen demand in 2050 occurs in Central Europe (incl. UK).

Figure 8: Final demand for electricity, hydrogen, and methane by bidding zone in 2050 for S1 (left) and S2 (right)



Supply side scenarios

While investments and the dispatch of the system to supply hydrogen, electricity, and methane demand is optimised for the individual scenarios, some parts of the supply side capacity installed over the timeframe 2030 – 2050 are exogenously defined and therefore not optimised endogenously. Similar to the final demand scenarios, the exogenously defined capacities of the electricity sector for S1 and S2 are based to a large extent on TYNDP 2022 GA and DE respectively.

Figure 9 presents the exogenously defined capacities of the electricity sector aggregated by fuel type for the entire system in S1 and S2. In line with TYNDP 2022 GA and DE, the major difference between S1 and S2 is the development of the installed capacity of the nuclear power plant fleet until 2050 (102 GW vs. 24 GW in 2050).

!

Upper bounds for investments in solar PV, onshore wind, and offshore wind power in this study are based on the maximum values reported for the respective technology in TYNDP 2022 in each country/bidding zone.

These upper bounds do not represent the technical potential for solar and wind power in Europe.

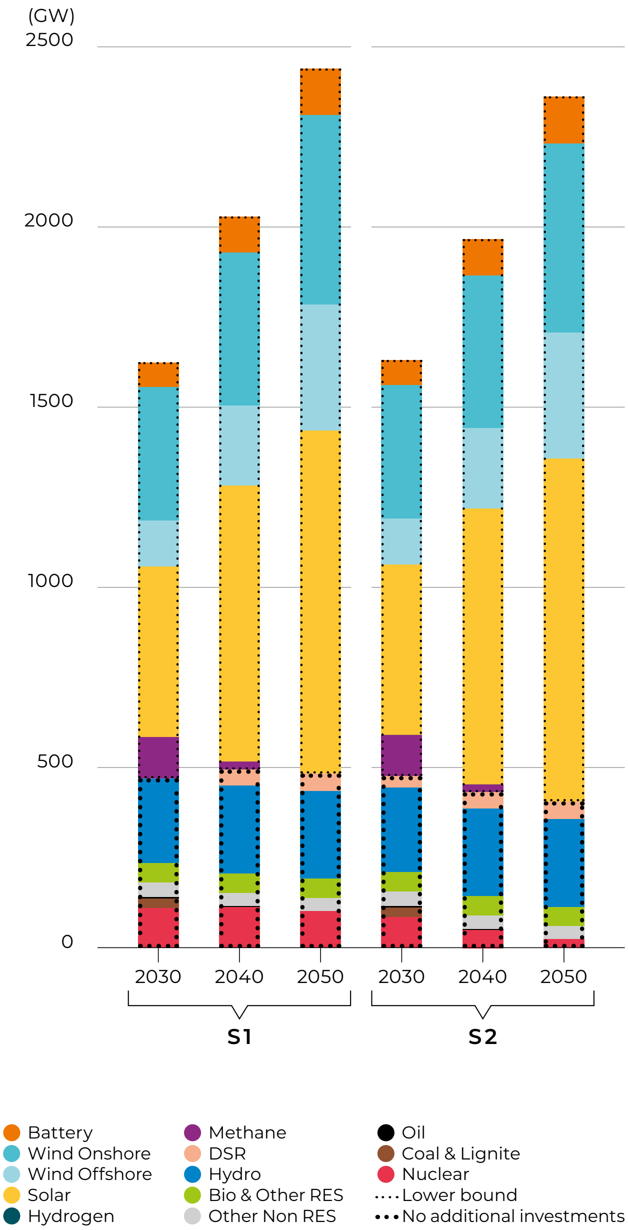
Upper bounds in 2030 allow to achieve solar and wind targets specified in REPowerEU.

The installed capacity of the nuclear power plant fleet in S1 and S2 over the timeframe 2030 – 2050 is based on TYNDP 2022 GA and DE respectively, with the exception that some of the nuclear power plants in Belgium are assumed to still be in operation in 2030.[56] Installed capacities under the categories hydro power, bio and other renewable energy resources (RES), other non RES, and demand side response (DSR) in S1 and S2 are equal to the respective TYNDP 2022 scenario. Like it is the case for nuclear power plants, additional investments in these technologies are not optimised when using the ESM to model the different scenarios.

The exogenously defined installed capacity of coal (hard-coal and lignite), methane, and oil-fired power plants over the timeframe 2030 – 2050 is based on the World Electric Power Plant (WEPP) database which is maintained and updated by S&P Global Market Intelligence.[57] In the case of hard-coal and lignite fired power plants, the decommissioning date of individual units was further refined to ensure total installed capacities match TYNDP 2022 GA and DE scenarios. In line with TYNDP 2022, by 2040 all coal fired power plants are decommissioned. No capacity for hydrogen fired power plants was exogenously predefined. Instead, investments in open-cycle gas turbine (OCGT) and combined-cycle gas turbine (CCGT) power plants fired by hydrogen over the timeframe 2030 – 2050 are optimised endogenously by the ESM. This is also the case for additional investments for OCGT and CCGT power plants fired by methane beyond what is exogenously predefined.

For onshore and offshore wind power, solar PV, and batteries the exogenously defined capacity over the timeframe is determined by using, for the year 2030, the minimum value for the respective technology given in the TYNDP 2022 GA and DE scenarios. For the years 2040 and 2050 for the respective technology the exogenously defined capacity is determined by assuming 85% of the minimum value of TYNDP 2022 GA and DE. Additional investments beyond the predefined capacities for solar PV, wind and batteries are optimised endogenously by the ESM for all model years. The upper bound for investments in solar, wind and batteries in each bidding zone and year is defined by using the maximum value for the respective technology of the TYNDP 2022 GA and DE scenarios. The applied lower and upper bounds ensure that on the one hand results of the ESM in terms of installed capacities in each bidding zone deviate only to a limited extent from the TYNDP 2022 scenarios while on the other hand providing some flexibility to its distribution across Europe when modelling the individual scenarios.

Figure 9: Exogenously defined capacity of the electricity sector in S1 (left) and S2 (right)



56 Euronews (2022). Nuclear energy Belgium postpones phase out by 10 years due to Ukraine war Link
57 S&P Global Link

Additional hydrogen supply potentials

Renewable hydrogen imports via pipelines and ships from outside the countries in scope of this study are considered as a potential supply source to meet demand for gaseous hydrogen. The investment in and use of these additional supply sources is optimised endogenously by the ESM for the individual scenarios.

While shipped hydrogen import potentials are available in all scenarios and are only constrained by geographical availability of port infrastructure, hydrogen pipeline import potentials are only available in the H_2-Interconnected scenarios. Hydrogen pipeline imports are available from North Africa and Ukraine (see Table 1).

> Hydrogen and methane imports from Russia are excluded as a potential supply source for future European energy demand in this study.
>
> In TYNDP 2022, the Russian low carbon hydrogen supply potential in 2050 was estimated to be up to 400 TWh. Making use of these potentials would impact results for the assessed scenarios considerably.

Upper bounds for hydrogen pipeline imports from North Africa and Ukraine in S1 H_2-Interconnected and S2 H_2-Interconnected are based on TYNDP 2022 GA and DE respectively.[58] Hydrogen imports from Russia are – like methane imports – not considered as supply option in this study.

Hydrogen supply potentials from Norway and the UK, which are specified in the TYNDP 2022 as additional supply potentials to meet hydrogen demand of EU27, are not included in the table above as the two countries are part of the countries in scope of this study. How this study treats low-carbon hydrogen supply potentials from Norway and the UK is described in the following paragraph.

Table 1: Additional hydrogen pipeline import potentials considered in the H_2-Interconnected scenarios

		S1 H_2-Interconnected			S2 H_2-Interconnected		
		2030	2040	2050	2030	2040	2050
North Africa	[TWh]	86	259	317	0	259	259
Ukraine	[TWh]	0	114	228	0	0	0

Role of low-carbon hydrogen

Low-carbon hydrogen was commonly seen as a complementary solution to renewable hydrogen.[59,60] Retrofit of existing hydrogen production facilities[61] using natural gas as feedstock with CCS or greenfield development[62] of new ones was seen as a way to quickly scale up the hydrogen market, before renewable hydrogen can be deployed at scale. However, this was prior to the significant increase in wholesale natural gas market prices in Europe observed since 2021. Within this new market environment, the role of low-carbon hydrogen in this analysis needs to be clarified.

The total low-carbon hydrogen production in all scenarios is capped at 150 TWh for 2030, 2040 and 2050 based on the current Norwegian and UK plans. The 150 TWh of low-carbon hydrogen production is composed of about 50 TWh from the UK and 100 TWh from Norway. The upper bound of low-carbon hydrogen production in the UK and Norway used in the scenarios is based on and intended to reflect existing plans and government targets for 2030.[63,64] It is not intended to be a technical potential of low-carbon hydrogen, which is significantly higher in particular in the case of Norway.

58 Note that in updated ENTOSG draft scenarios (not published yet), hydrogen imports from Ukraine are assumed to be available already in 2030. However, in S2 H_2-Interconnected no hydrogen imports from Ukraine are considered, deviating from TYNDP DE.
59 See e.g. Gas for Climate (2020). Gas decarbonization pathways 2020 – 2050 Link
60 Pettersen et al. (2022). Blue hydrogen must be done properly Link
61 Mostly SMR.
62 Besides SMR, ATR or partial oxidation reactors (PoX) are commonly used.
63 S&P Global (2022, May 05). UK must remove barriers to green hydrogen to meet 5-GW 2030 target.
64 Gassco (2021). Norwegian Perspectives – ENTSOG and ENTSO-E’s Workshop On The Extra Eu Supply Potentials For TYNDP 2022. Link

The main reason for including low-carbon hydrogen in the analysis (besides it being in Norwegian and UK plans) is its potential role in diversification of supply (from a technology perspective) and ability to be more rapidly deployed at scale than renewable hydrogen. Hydrogen supply and demand balancing, especially at the early stages of the market and infrastructure development, will be challenging. This is due to limited linepack and storage capacities and especially if electrolysers are required to follow electricity production from variable renewable energy (VRE) sources like solar PV or wind power. This would create intermittent hydrogen supply, while the hydrogen demand is relatively constant, for instance due to large industrial facilities. Low-carbon hydrogen supply could help alleviate part of this problem by operating (relatively) flexibly to bridge this supply and demand mismatch.[65]

Seemingly, low-carbon hydrogen production would not make economic sense with current natural gas wholesale prices in Europe (fluctuating commonly between 120 – 200 EUR/MWh, with spikes even higher, in 2022). However, the production cost of natural gas remained largely unchanged in 2022. This means producers of natural gas can produce low-carbon hydrogen using natural production cost rather than wholesale prices. The decision to sell natural gas directly or to produce low-carbon hydrogen is then driven by opportunity cost of the decision to pursue either of these options. Ultimately, this depends on the margins natural gas producers believe they can earn on the hydrogen versus natural gas market. To remain neutral to which of these two options will be preferred, the ESM applied in this study can decide to invest in low-carbon hydrogen production in countries outside of the EU that produce natural gas, i.e. the UK and Norway.

For low-carbon hydrogen to have any positive effect on GHG emissions reduction, the lifecycle emissions (direct and indirect) have to be carefully assessed and monitored. The proposed *Hydrogen and decarbonised gas market package* recognises this and establishes a minimal lifecycle 70% GHG emission reduction compared to the fossil benchmark of 94.1 gCO_2eq/MJ (~3.4 tCO_2/tH_2) to qualify as low-carbon. This includes all direct emissions from combustion and reforming of natural gas, energy source for the CCS and hydrogen transport, but also indirect emissions, from methane and hydrogen leakage. Finally, all the existing low-carbon hydrogen assets can later be fed with part of the available biomethane to create much-needed negative CO_2 emissions. Such installations could be relevant even beyond 2050.

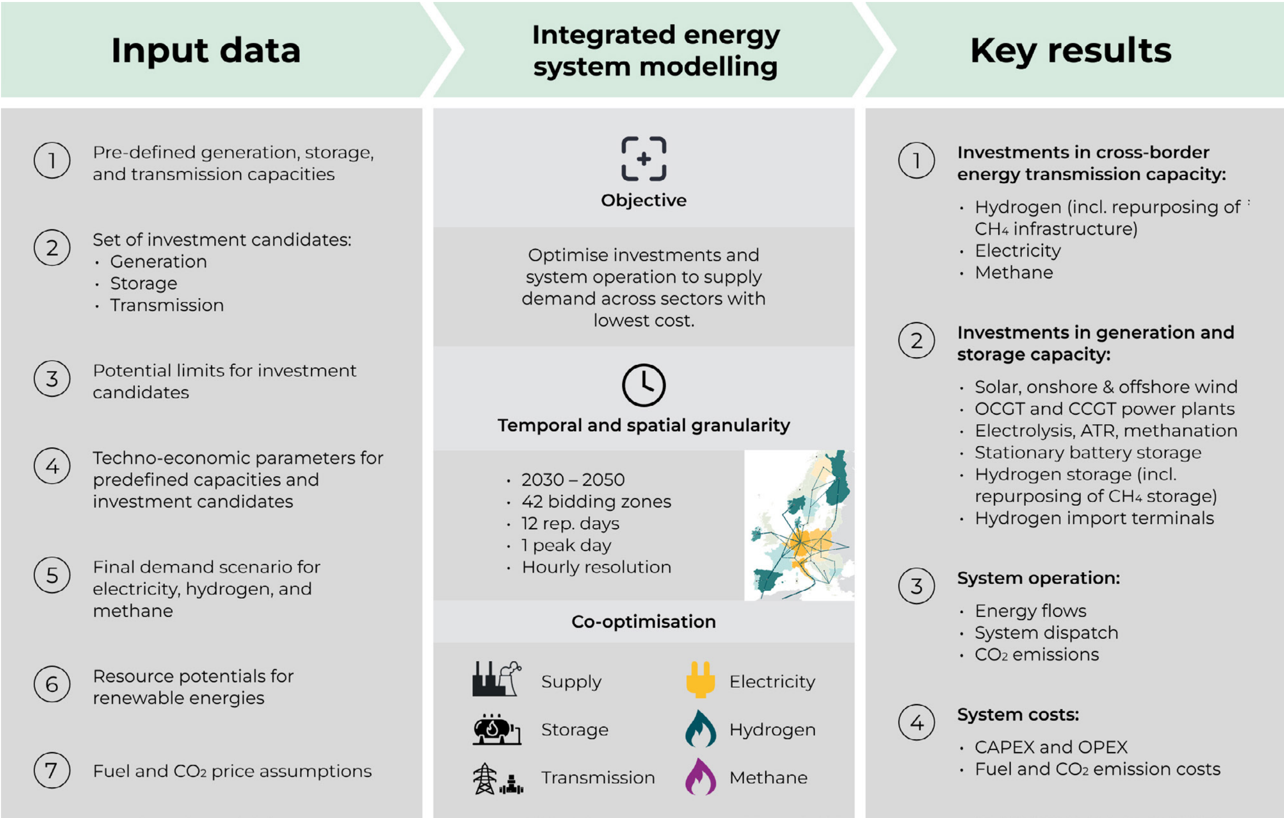
An integrated ESM to quantify benefits of a pan-European hydrogen network

Guidehouse's Low-carbon Pathways (LCP) model is used to model the four scenarios introduced in the previous section. The LCP model is a 'bottom-up' integrated ESM that allows for simultaneous investment and dispatch optimisation to supply the demand for various energy carriers over a multi-annual timeframe. From a whole system central planning perspective, the ESM minimises the net present value of capital expenditures (CAPEX) as well as fixed and variable operational expenditures (OPEX) over the modelled timeframe to supply the demand for the considered energy carriers. Within the optimisation, interdependencies between sectors and related assets are considered. Figure 10 provides an overview of the LCP model and how it is configurated for this study.

The ESM is used to minimise for the individual scenarios the total system costs to supply the demand for hydrogen, electricity, and methane for the country in scope over the timeframe 2030 – 2050. Major input parameters for the model are the existing and exogenously predefined generation, storage, and transmission capacities over the timeframe, a set of investment candidates that can be installed additionally to the predefined capacities, techno-economic parameters for all considered assets, a projection for final demand for hydrogen, electricity, and methane, resource potentials for renewable energies as well as fuel and CO_2 price assumptions.

65 Specific minimum operating capacity for SMR, ATR, or PoX differs per technology and is further influenced by the inclusion of CCS. In general, operating at 20%-40% of the nominal capacity should be possible for a period of time (depending on technology), hower this comes at and efficiency loss and thus increases costs. Guidehouse own research (not public).

Figure 10: Overview of Guidehouse's LCP model and its configuration for the study



Considered investment candidates are hydrogen and electricity cross-border transmission capacities, utility-scale solar PV, onshore wind and offshore wind power, hydrogen and methane fired OCGT and CCGT power plants, stationary batteries, different hydrogen storage options, grid connected electrolysers, electrolysers connected directly to wind or solar power plants, autothermal reformers (ATR)[66] equipped with CCS, methanation plants for synthetic methane production, and hydrogen import terminals. Repurposing of existing methane cross-border transmission and storage capacity to transport and store hydrogen respectively is optimised endogenously.[67] Cost assumptions for solar and wind power investment candidates differ between S1 and S2 in line with the storylines of TYNDP 2022 GA and DE respectively (see Appendix).[68]

Key results of the ESM are investments in cross-border energy transmission infrastructure between bidding zones as well as generation and storage capacities in each bidding zone, the hourly system dispatch with related energy flows and CO_2 emissions, and CAPEX and OPEX over the timeframe.

66 Existing steam methane reformers (SMRs) were modelled as part of the existing system but were not considered as investment candidates due to the limited carbon capture rate for SMRs equipped with CCS compared to ATRs.
67 Analyses by the EHB initiative showed that repurposed hydrogen pipelines can have a capacity of 80% of the initial capacity of the methane pipeline that has been repurposed.
68 Investment costs of the distributed electricity generation technologies solar PV and onshore wind are significantly cheaper in TYNDP 2022 DE. This is due to the fact that in the TYNDP DE scenario storyline a much higher deployment of distributed energy technologies is assumed, which leads – due to learning curve and utility of scale effects - to lower investment costs than considered in the TYNDP 2022 GA scenario. For offshore wind farms it is vice versa, as these assets are considered as centralised electricity generation technology.

The countries in scope are represented by 42 bidding zones. To ensure fast computation time, the modelled timeframe is represented by three years (2030, 2040, and 2050). Each of the years is approximated by 13 representative days (one per month plus one 'peak day'). The representative days consists of 24 hourly timesteps and aim to approximate seasonal and diurnal variability of the availability of solar, wind and hydro resources as well as demand for hydrogen, electricity, and methane. The 'peak day' describes a situation where the system is stressed due to very low availability of VRE, i.e. solar and wind, and a simultaneous peak demand for hydrogen, electricity, and methane. The representative days are linked to allow modelling of seasonal storage assets.

The climatic year 2009 is used in this study to describe seasonal and diurnal variability of solar, wind, and hydro potentials and demand for hydrogen, electricity, and methane in the end-use sectors (see Appendix). The year 2009 can be considered on the one hand as the most representative year in terms of resource availability of renewable energy resources but at the same time represents, after the climatic year 2012, the second most stressful climatic year in terms of a 2-week Dunkelflaute situation at the European aggregated level.[69]

Limitations of study

The applied methodology has limitations that must be considered when interpreting the results of this study. Some of these limitations are listed below:

- **Spatial granularity:** The analysed system is represented by 42 bidding zones. Each bidding zone is treated as "copper plate", meaning that no transmission and distribution infrastructure is modelled within a bidding zone and consequently any potential grid congestion within a bidding zone is not captured in the analysis. Therefore, the study does not allow to identify the benefits of domestic hydrogen pipelines or any other energy transmission infrastructure within a bidding zone.
- **Transmission infrastructure modelling:** All cross-border transmission capacity is modelled on an aggregated level using the transport model approach. In the transport model approach energy transmission between bidding zones is only constrained by the installed transmission capacity between bidding zones, which is subject to optimisation. Furthermore, some hurdle costs (like a small fee) to prevent unrealistic long energy flows and to facilitate the convergence of the optimisation models are applied. Due to the applied simplifications, no details for individual transmission assets can be derived from the analysis.
- **Final demand scenarios:** Final demand for hydrogen, electricity, and methane in the end-use sectors in each bidding zone over the modelled timeframe is defined exogenously and is not optimised endogenously within the applied ESM. This means, self- and cross-price elasticities across energy carriers in the end-use sectors are not modelled. In other words, by adopting predefined end-use demand scenarios, it is not modelled how energy carrier prices may impact their own demand across different regions nor how the price of one energy carrier may impact demand for another carrier in the end use sector.
- **Temporal resolution and VRE availability:** To limit computational time of the applied ESM when modelling the cost-optimal pathway to meet demand for hydrogen, electricity, and methane over the timeframe 2030 – 2050 from a whole system perspective, only the years 2030, 2040, and 2050 are explicitly modelled and each year is represented in terms of temporal variability of VRE and demand by 13 representative days. This means, not all 8760 hours of a year are considered when modelling supply and demand for the three energy carriers. This likely underestimates the flexibility challenges caused by the transition towards an energy system dominated by VRE and the role for renewable gases in the power sector. Furthermore, only the climatic year 2009 is considered to approximate seasonal and diurnal variability of solar, wind, and hydro resources when modelling the four

69 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines. Link

main scenarios. Even though the climatic year 2009 is a very representative year in terms of VRE availability it should be noted that considering a different climatic year impacts to some extent the results of the applied ESM. The impact of considering a different climatic year on results is presented in Chapter 4.

- **Investment, cost of capital, and competitive energy market assumptions:** Cost assumptions for investment candidates and the cost of capital (expressed by the weighted average of cost of capital) are not differentiated by country in the applied ESM. In real life, these parameters differ across countries, e.g. due to differences in the cost for land required for onshore wind and utility-scale PV power plants or due to the sea-depth in the case of offshore wind farms. Furthermore, the ESM assumes a competitive energy market characterised by atomic agents and perfect information over the entire modelled timeframe. These assumptions preclude any market participant (agent) from exercising market power and making supernormal profits. How energy markets in the real-world may deviate from this assumption can be currently experienced painfully in Europe. In this context special attention should be paid on the just emerging hydrogen market, which will be in the near-term future characterised by a limited number of suppliers and off-takers.

- **Policy targets, national initiatives, and industry projects:** The applied scenario assumptions that serve as input to the ESM do not necessarily cover all established policy targets, national initiatives, and industry projects that have been established since the European energy crisis started. Therefore, especially for the early years of the modelled timeframe 2030 – 2050, results of this study may not be fully in line with the plans and developments of individual countries. However, this does not jeopardise the main aim of the study, i.e. to assess the potential benefits of a pan-European H_2 network in general.

- **Environmental concerns and public acceptance:** This study considers competing infrastructure on an equal basis in terms of public acceptance, licensing lead times etc. However, in real projects this may not always be the case.

All of the above do not reduce the value of this modelling exercise which is meant to assess the benefits of a pan-European H_2 network to foster the transition towards an affordable, secure, and sustainable European energy system. The real-world version of the pan-European H_2 network would materialise based on how individual projects achieve a higher or lower status of competitiveness compared to the level playing field perspective considered in this study.

3. Key findings

In the following sections, the key findings related to the benefits and role of a pan-European H_2 network for the transition towards an affordable, secure, and sustainable European energy supply derived from modelling the future integrated European energy system under the different scenarios are presented.

3.1. A pan-European H_2 network contributes to an affordable energy supply

SUMMARY

- A pan-European H_2 network is part of the least-cost system to supply demand for hydrogen, electricity, and methane over the timeframe 2030 – 2050. Cost savings of about €330 and €325 billion are generated in S1 H_2-Interconnected and S2 H_2-Interconnected respectively due to the development of a pan-European H_2 network over the 21-year timeframe. If costs for avoided CO_2 emissions are included, cost savings increase to about €380 billion.
- Cost savings are generated mainly by an optimal allocation of hydrogen production across Europe and by making use of cost-competitive hydrogen pipeline imports from neighbouring regions. Both are possible due to the development of a pan-European H_2 network. The pan-European H_2 networks provides cost savings related to hydrogen imports and supply capacities as well as due to lower investment needs into electricity cross-border transmission capacities, stationary battery storages, and peaking power plants. Even though reconversion of shipped hydrogen derivatives plays a minor role in the H_2 interconnected scenarios, hydrogen import terminals have an important role to ensure security of supply and sufficient market competition.
- Several supply corridors are visible that supply hydrogen demand in Central Europe in the scenarios where a pan-European H_2 network develops. These corridors are in line with the potential hydrogen supply corridors identified by the EHB initiative.

About €325 - €380 billion cost savings over the timeframe 2030-2050

Investments and dispatch decisions of the applied ESM to optimise the supply of hydrogen, electricity, and methane demand over the timeframe 2030–2050 are based on a cost minimisation criterion. As the only difference between the clustered (S1 H_2-Clustered, S2 H_2-Clustered) and the interconnected (S1 H_2-Interconnected, S2 H_2-Interconnected) scenarios is the opportunity to invest in hydrogen cross-border transmission capacity between countries in scope, cost differences between the scenarios can be traced back to the deployment of such infrastructure.

Cost savings of €330 billion are generated due to the development of a pan-European H_2 network in S1 H_2-Interconnected compared to its counterfactual scenario S1 H_2-Clustered. Cost savings are quantified by comparing the CAPEX and OPEX of the entire system to supply the demand for hydrogen, electricity, and methane over the 21-year timeframe in the respective scenarios. **Cost savings would increase to €380 billion** if costs for avoided CO_2 emissions are included in the comparison.[70]

70 Costs for direct CO_2 emissions are included in the objective function of the optimisation model by multiplying the total direct CO_2 emissions caused by the system dispatch when supplying demand for hydrogen, electricity, and methane with the assumed CO_2 emission price assumed over the modelled timeframe.

The development of a pan-European H_2 network also provides significant cost savings when hydrogen demand increases more moderately after 2030. **Cost savings of about €325 billion**[71] are generated in S2 H_2-Interconnected compared to S2 H_2-Clustered, meaning that cost savings are almost the same even though demand for hydrogen is about 30% lower in 2050 compared to S1 scenarios. The cost savings achieved in the interconnected scenarios indicate that the development of a pan-European H_2 network contributes significantly to an affordable European energy supply.

Figure 11 shows the installed hydrogen cross-border transmission capacities by 2050 in S1 H_2-Interconnected and S1 H_2-Clustered (top) and S2 H_2-Interconnected and S2 H_2-Clustered (bottom) respectively and related cost savings over the timeframe 2030 - 2050. In the scenarios where possible, i.e. in the interconnected scenarios, a full pan-European H_2 network is installed until 2050 following the applied cost minimisation algorithm. Total hydrogen cross-border transmission capacity of the pan-European H_2 network in 2050 is about 475 GW and 465 GW in S1 H_2-Interconnected and S2 H_2-Interconnected respectively.[72] Also, in the H_2-Clustered scenarios, where hydrogen transmission capacity can only be installed between domestic bidding zones of countries that are represented by more than one bidding zone, hydrogen transmission capacities are developed (case of Denmark, Italy and Sweden) as such infrastructure contributes to the cost optimal solution under this constraint scenario as well.

When optimising the expansion of hydrogen transmission capacities between bidding zones existing methane transmission capacity can be repurposed if deemed by the ESM to be not needed to balance methane supply and demand across Europe. Further, the ESM can invest in entirely new hydrogen pipelines to expand hydrogen cross-border transmission capacity between bidding zones (see the Appendix for the detailed economic assumptions for both options).

The full build out of a pan-European H_2 network until 2050 as defined in S1 H_2-Interconnected and S2 H_2-Interconnected by the ESM leads to investment costs[73] of about €80 and €70 billion respectively. In both scenarios, approximately 55% of the developed pan-European H_2 network is composed of repurposed methane transmission capacities that are currently used to transport natural gas and biomethane. These results supporting the findings of the EHB initiative which specified total investment costs of about €80 billion[74] for the envisaged European Hydrogen Backbone and that approximately 60% of the network could be based on repurposed natural gas transmission pipelines.[75]

The benefits of repurposing existing gas pipelines for transporting hydrogen extend beyond project costs. Since they may be considered brownfield projects, repurposing works will face significantly shorter and simpler permitting processes, even if they entail replacing pipework, and can therefore be delivered quicker. This is a big advantage compared to greenfield projects (i.e. new pipelines or new overhead transmission lines) which will certainly face larger scrutiny to address stakeholder concerns related to the impact on the environment or the vicinity to individual properties or dwellings (NIMBY objections).

It is important to note that identified cost savings are due to the expansion of cross-border hydrogen transmission capacity between countries. The applied spatial granularity of the study does not allow to quantify cost savings due to the development of hydrogen pipelines within a country. This is because most of the countries that are in the scope of the study are represented by only one bidding zone and a bidding zone is treated as “copper plate” for domestic energy flows.

71 € 370 billion if avoided costs for CO_2 emissions are factored in.

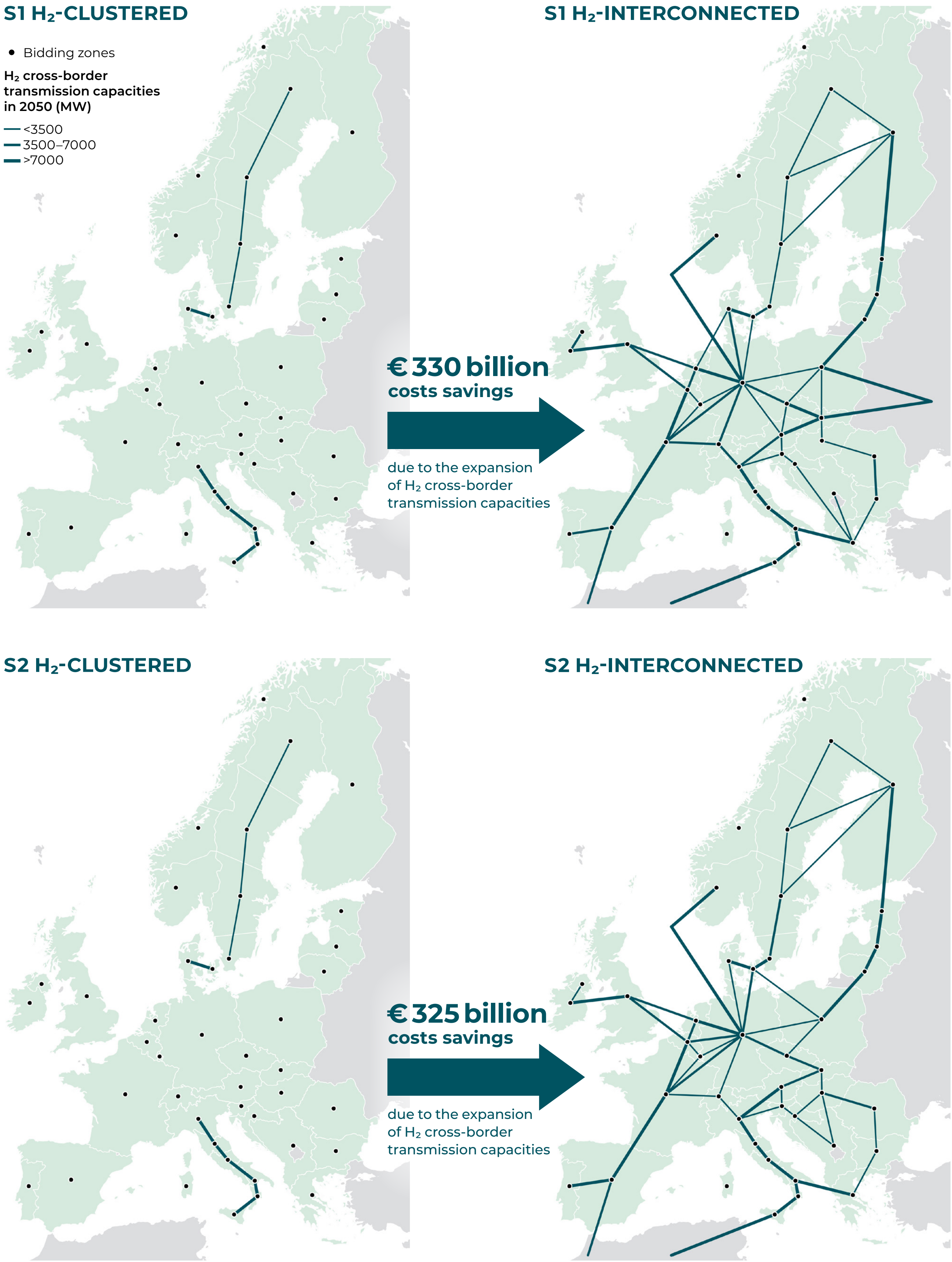
72 Specified cross-border transmission capacities include capacities between subnational bidding zones of Denmark, Italy, and Sweden.

73 Investment cost for new hydrogen transmission and repurposing of existing gas transmission capacities based on the model investment decisions.

74 Total investment cost ranges from €80 – €143 billion depending on the cost assumptions. The main reason for the relatively large band-width is the uncertainty and variability concerning compression system design and costs. In particular, compression system investment costs depend heavily on the underlying concept design; including whether the project is greenfield or brownfield, the design operating pressure range, n+1 rule implementation, and compressor technology choice (centrifugal or reciprocating). Note that values specified by the EHB initiative and this study cannot be compared 1:1 due to the differences in the applied approach, which considers only transmission capacity needed to connect modelled bidding zones and therefore detailed national transmission network costs are not included.

75 European Hydrogen Backbone (2022). A European hydrogen infrastructure vision covering 28 countries Link

Figure 11: Installed hydrogen cross-border transmission capacity in 2050 and related cost savings

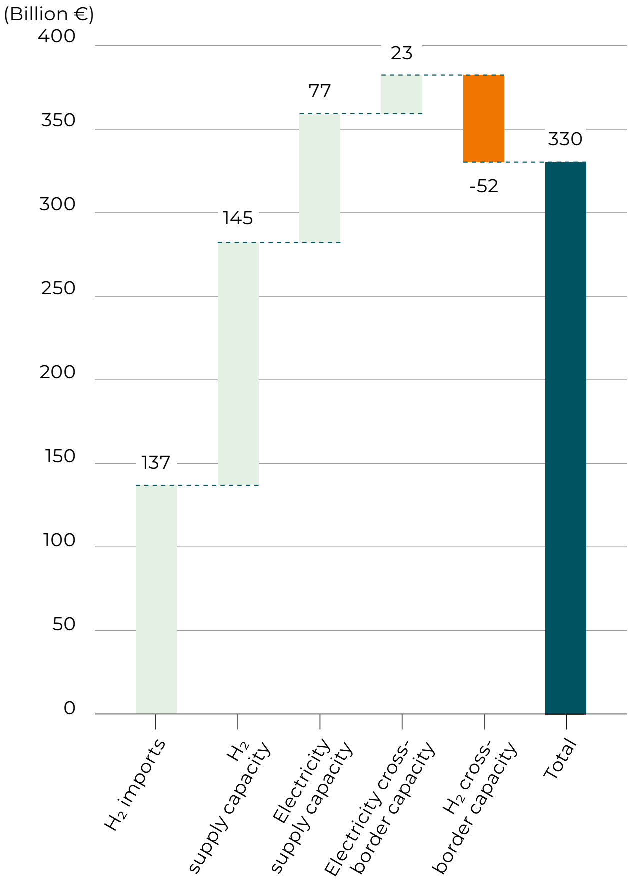


Extending this analysis within national boundaries would involve building a H_2-Clustered scenario with electrolysers near hydrogen demand centres, instead of near major electricity generation sites, and comparing it to an H_2-Interconnected scenario with optimally derived national hydrogen transmission infrastructure.[76] Cost savings in favour of the latter would be expected to increase further because:

- In most cases it is much more cost efficient to install electrolysers in areas of major electricity generation, i.e. in areas with bulk solar and wind power generation which dominates the future energy system, and use pipelines to transport the produced hydrogen to the demand than installing electrolysers next to hydrogen demand and transmitting required electricity through the electricity grid. Previous analyses showed that for high-volume transport of energy when the desired end-product is hydrogen, 48-inch and 36-inch pipelines – both newly built and repurposed ones and excluding storage costs – are 2 to 4 times more cost-effective than the most cost-effective electricity transmission options.[77, 78]
- Without hydrogen pipelines, also hydrogen storage capacities would need to be installed next to hydrogen demand which would mean in most cases that hydrogen would need to be stored in comparable expensive aboveground storage devices instead of making use of low-cost underground storage options, such as salt caverns or depleted gas fields. Furthermore, the inherent storage capacity offered by hydrogen pipelines due to line-packing would not be available.

The H_2-Interconnected scenarios entail larger investments and therefore higher costs for hydrogen cross-border transmission capacity compared to the H_2-Clustered scenarios. However, these costs are overcompensated due to i) lower costs for hydrogen imports, ii) lower investment needs for hydrogen supply capacities, iii) reduced need for electricity generation and storage capacities, and iv) less requirements for electricity cross-border transmission capacities. Figure 12 shows the cost savings by category exemplarily for S1 H_2-Interconnected compared to S1 H_2-Clustered.

Figure 12: Composition of cost savings of S1 H_2-Interconnected compared to S1 H_2-Clustered due to the installation of hydrogen cross-border transmission capacity



Major cost differences between the H_2-Interconnected and the respective H_2-Clustered scenario occur due to the differences in the supply for gaseous hydrogen demand over the modelled timeframe. Figure 13 presents the development of the annual supply for gaseous hydrogen demand for the entire modelled system. **Domestic hydrogen production from electrolysers**, both from grid-connected and off-grid electrolysers directly connected to offshore wind, onshore wind, and solar PV power plants, **is by far the major supply source in all scenarios**. Low-carbon hydrogen produced from ATRs and SMRs equipped with CCS and hydrogen imports through

76 For example, in the case of Germany the major share of the electrolyser fleet would be installed in the North of the country where most of the electricity is generated due to the strong deployment of onshore and offshore wind power until 2050 and hydrogen pipelines are used to transport hydrogen from the North to demand centres in the West and South of the country.

77 European Hydrogen Backbone (2021). Analysing future demand, supply, and transport of hydrogen Link

78 IEA (2022). Global Hydrogen Review 2022 Link

pipelines and shipping play a limited role to supply the gaseous hydrogen demand of the modelled system, especially in the long-term. The high share of domestic hydrogen production contributes considerably to the energy security of the system. However, hydrogen imports play a key role to diversify supply which further adds to the security of supply but also market competition.

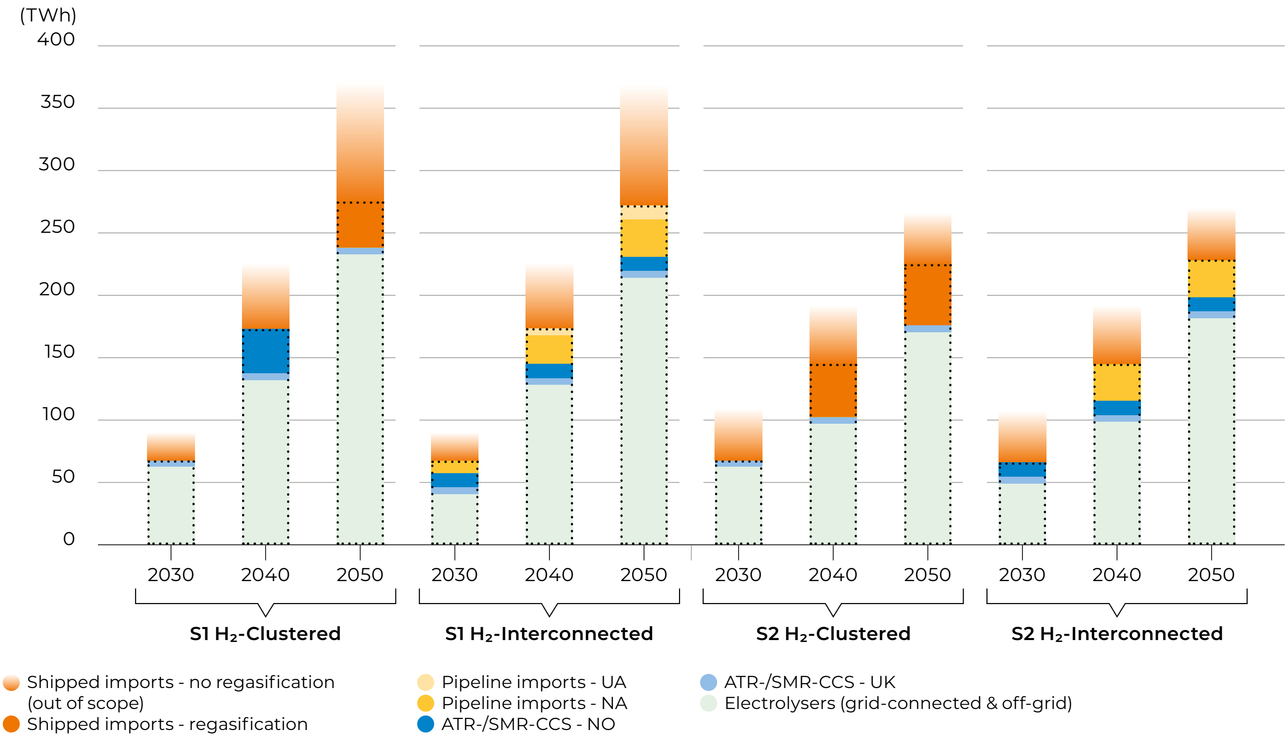
In S1 H_2-Interconnected, hydrogen production directly at solar and wind power plants through off-grid electrolysers and from grid-connected electrolysers increase from about 360 TWh in 2030 to almost 1900 TWh in 2050. In 2050, renewable hydrogen produced from electrolysers represents about 80% of the total gaseous hydrogen supply. Due to the development of hydrogen cross-border transmission infrastructure Norwegian low-carbon hydrogen supply potentials can be used to complement the supply of hydrogen demand in central Europe. Low-carbon hydrogen produced in Norway (~ 100 TWh) and the UK (~ 50 TWh) represents about 5% of the total gaseous hydrogen supply in 2050. Note that low-carbon hydrogen could be also just a transition fuel and be replaced by renewable hydrogen in the long-term (see Chapter 4). Pipeline imports from North Africa increase from about 85 TWh in 2030 to about 260 TWh in 2050. Ukraine pipeline imports are part of the optimal supply mix from 2040 onwards and increase from 50 TWh to 100 TWh until 2050. By 2050, pipeline imports from North Africa and Ukraine supply about 15% of the total gaseous hydrogen demand. The hydrogen supply mix in S2 H_2-Interconnected is very similar to S1 H_2-Interconnected with the major difference that – in line with the scenario assumptions – pipeline imports from North Africa are only available by 2040 and imports from Ukraine are not available at all.

Import terminals provide the opportunity to diversify supply and therefore contribute not only to the security of supply but also to foster market competition which has a positive effect on consumer prices. However, due to the rigorous cost optimisation approach applied in the ESM, shipped hydrogen imports have a limited role to supply gaseous hydrogen demand in the H_2-Interconnected scenarios. The ESM identifies a combination of an optimal allocation of domestic hydrogen production across the countries in scope and hydrogen imports via pipelines, both enabled through a pan-European H_2 network, as more cost competitive. In real life, the development of the European energy system will also be driven by factors that go beyond pure economic considerations especially when it comes to the topic of security of supply.

Import terminals play a comparable strong role to supply gaseous hydrogen demand in the H_2-Clustered scenarios, as in these scenarios each country must supply its hydrogen demand with its limited domestic resources or, if port infrastructure allows, through shipped hydrogen imports. In 2050, 13% and 22% of the gaseous hydrogen demand is supplied by shipped imports in S1 H_2-Clustered and S2 H_2-Clustered respectively. Due to its low energy density, transporting hydrogen via ships is economically challenging as it requires converting produced hydrogen into a more energy dense liquid (e.g. ammonia, liquid hydrogen, or liquid organic hydrogen carriers) so that more energy can be transported. As this conversion step is not needed for imports via pipelines, hydrogen pipeline import prices are considered cheaper than the price for shipped imports. This leads to significant cost savings related to hydrogen imports in the H_2-Interconnected scenarios (refer to the Appendix for assumed hydrogen import prices). Furthermore, to enable hydrogen imports by ships, large investments in import terminals are required where shipped hydrogen imports are reconverted into gaseous hydrogen and fed into the hydrogen network. These investments cause additional costs in the H_2-Clustered scenarios compared to the H_2-Interconnected scenarios.

Import terminals will likely play an important role in supplying Europe with hydrogen derivatives and synthetic fuels produced from renewable hydrogen to fully decarbonise the chemical and the transport sectors (maritime shipping, aviation, long-distance road transport). Therefore, potential shipped imports of hydrogen derivatives that are not reconverted into gaseous hydrogen and shipped imports of renewable hydrogen-based fuels (e.g. synthetic kerosine or diesel) are also visualised in Figure 13. However, note that visualised imports are only indicative, as demand and supply for non-gaseous hydrogen demand is beyond the scope of this study.

Figure 13: Annual hydrogen supply over the timeframe 2030–2050[79]



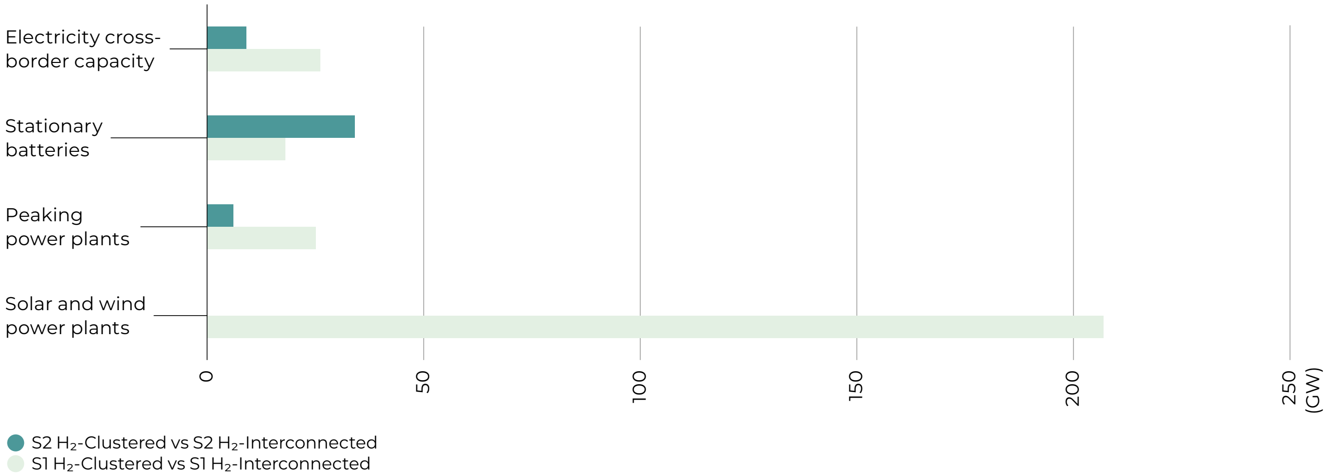
The pan-European H_2 network which is built out in the H_2-Interconnected scenarios allows for an optimal allocation of hydrogen production across the countries in scope (see the following sub-chapter for more details). As major parts of the electrolyser fleet are shifted to countries/bidding zones with better renewable energy resource potentials and, on average, lower electricity prices, the electrolyser fleet operates with a higher average annual capacity factor. Therefore, more hydrogen is produced per installed MW of electrolyser capacity, leading to less investments into electrolysers in the H_2-Interconnected scenarios compared to the H_2-Clustered scenarios. The reduced investments into electrolyser capacity generates additional cost savings in the scenarios where a pan-European H_2 network is developed. The difference in installed electrolyser capacity over the 21-year timeframe is especially high between S1 H_2-Interconnected and S1 H_2-Clustered (143 GWH_2). The pan-European H_2 network does not only allow to operate electrolysers with a higher capacity factor but also to make use of low-carbon hydrogen from Norway and renewable pipeline imports from North Africa and the Ukraine. This reduces the need of domestic production of renewable hydrogen from electrolysers compared to the H_2-Clustered scenario.[80]

The development of a pan-European H_2 network in the H_2-Interconnected scenarios generates significant cost savings also due to lower investments needs for cross-border electricity transmission capacity, stationary battery storage, and peaking power plants. In the case of S1 H_2-Interconnected cost savings are also generated in terms of investments into solar and wind power plants (see Figure 14). The avoided investments result from the simultaneous optimisation of the ESM for generation, storage, and cross-border transmission capacity across the hydrogen, electricity, and methane sectors, and in particular from the optimisation of electrolyser locations. These findings confirm the high importance of an integrated planning for the future pan-European energy transmission system infrastructure.

79 Shipped imports that are not reconverted into gaseous hydrogen only indicative as supply for hydrogen derivatives and synthetic fuels is out of scope of this study. Visualised values based on imported decarbonised liquids into EU27 according to TYNDP 2022 GA and DE respectively.

80 Installed electrolyser capacity in 2050 is 25% lower in S1 H_2-Interconnected compared to S1 H_2-Clustered while annual hydrogen production of the electrolyser fleet is only 8% lower.

Figure 14: Reduced capacity needs over timeframe 2030-2050 due to the development of a pan-European H_2 network



Investments into electricity cross-border transmission capacities are reduced by 26 GW and 9 GW in S1 H_2-Interconnected and S2 H_2-Interconnected compared to their respective counterfactual scenario. The reduced investments in S1 H_2-Interconnected represents more than 30% of the total investments in electricity cross-border transmission capacity in S1 H_2-Clustered over the 21-year timeframe. Lower investments into electricity cross-border transmission capacity are caused mainly by the fact that large parts of the grid-connected electrolyser fleet are shifted to countries/bidding zones with, on average, lower electricity prices and higher renewable energy resources. Additionally, after domestic demand has been met hydrogen produced in these countries/ bidding zones is then transported by the pan-European H_2 network where it is needed. As this strategy is not possible in the H_2-Clustered scenarios, larger investments in electricity cross-border transmission capacity take place to be able to transport surplus electricity to countries/bidding zones with major hydrogen demand, where it is converted into hydrogen through grid-connected electrolysers. Savings of S2 H_2-Interconnected compared to S2 H_2-Clustered are lower because the higher electricity demand in the end-use sectors in the S2 scenarios requires also in the scenario where a pan-European H_2 network is installed a strong build out of electricity cross-border transmission capacity.

Investments into stationary battery capacities are reduced significantly as well due to the development of a pan-European H_2 network in the H_2-Interconnected scenarios. Batteries, or other electricity storage and flexibility options like demand response, can lower the need for electricity transmission capacity as grid congestion and curtailment of electricity generation from VRE can be reduced. Large investments into stationary batteries take place in the H_2-Clustered scenarios to limit the need for further investments in electricity cross-border transmission capacity. While in S1 H_2-Clustered and S2 H_2-Clustered the cumulative installed battery storage capacity reaches 149 GW and 174 GW respectively in 2050, in S1 H_2-Interconnected and S2 H_2-Interconnected only 131 GW and 140 GW respectively of battery storage capacity is installed until 2050. This means a differences of 18 GW (73 GWh) and 34 GW (136 GWh) respectively to S1 H_2-Clustered and S2 H_2-Clustered.[81]

81 Stationary batteries installed until 2030 are assumed to have a storage capacity equivalent to 2 full load hours of discharging. Stationary batteries installed afterwards are assumed to have storage capacity equivalent to 4 full load hours.

The installation of a pan-European H_2 network also reduces the investments in methane and hydrogen fired peaking power plants. Over the 21-year timeframe 25 GW and 6 GW less peaking power plant capacity is installed in S1 H_2-Interconnected and S2 H_2-Interconnected respectively compared to their respective counterfactual scenario. This is because electricity peak demands (composed of demand in the end-use sectors and indirect demand from electrolysers) can be reduced in the H_2-Interconnected scenarios due to the optimal allocation of hydrogen production across the pan-European energy system enabled through a pan-European H_2 network.

Finally, about 200 GW less solar and wind power capacity is installed in S1 H_2-Interconnected compared to S1 H_2-Clustered over the timeframe 2030 – 2050. This is mainly because less renewable electricity is needed for renewable hydrogen production as low-carbon hydrogen and imported hydrogen supply larger parts of the hydrogen demand. Furthermore, due to the development of the pan-European H_2 network some parts of the solar and wind power fleets are reallocated to regions with higher resource availability which allows to produce more electricity per installed capacity. Installed solar and wind power capacity is about the same in S2 H_2-Interconnected and S2 H_2-Clustered. However, thanks to the build out of a pan-European H_2 network, with the same amount of installed solar and wind power capacity significantly more renewable hydrogen is produced due to the optimal allocation of solar and wind capacities across Europe.

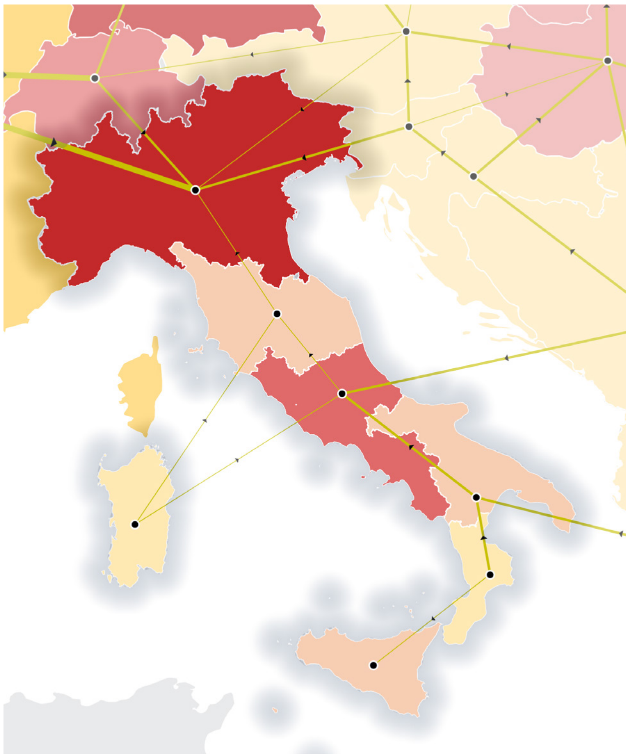
Hydrogen is produced where it is cheapest

It is more cost efficient to co-locate electrolysers next to renewable power generation and use pipelines to transport hydrogen to demand centres than co-locating electrolysers at hydrogen demand centres and transmitting required electricity to run the electrolysers through the electricity grid. This finding is confirmed from the integrated energy system modelling conducted for the different scenarios in this study.

For illustration of this point, Figure 15 (left) shows hydrogen supply and demand for the Italian bidding zones and resulting net hydrogen flows in 2050 (S1 H_2-Clustered). Although hydrogen demand is significantly higher in northern Italy, electrolysers are installed mainly in the south of Italy and hydrogen pipelines are used to transport the produced hydrogen to the north. The location of electrolysers and the expansion of hydrogen transmission capacity between the domestic Italian bidding zones is a result of co-optimising supply and transmission capacities across the hydrogen, electricity, and methane system. The ESM identifies the optimal trade-off between lower cost for hydrogen production through electrolysers in the southern bidding zones, necessary investments in hydrogen transmission capacities to transport hydrogen up to the north and avoided expansion of the electricity grid.

Figure 15 (right) shows which of the Italian bidding zones are annual net electricity importers (red) and exporters (yellow) in 2050 according to S1 H_2-Clustered. Bidding zones that are annual net importers have on average a higher electricity price than their neighbouring bidding zones. Even though electricity demand in the southern bidding zones is significantly increased through the dispatch of grid-connected electrolysers in those areas, the southern bidding zones are still exporting electricity to the north, indicating that electricity prices in the south are on average lower than in the north of the country. The bidding zones of northern and central Italy are major electricity importers. Installing grid-connected electrolysers in these bidding zones to supply domestic demand would further increase demand for electricity and therefore the need for electricity imports (requiring an expansion of the cross-border transmission capacity to connected bidding zones) or investments in domestic electricity generation capacities. Both would cause additional costs and therefore deviate from the cost optimal solutions. As resource potentials for solar and wind power are higher in the south, electrolysers directly connected to solar and wind power plants are also more competitive in the south of Italy. In sum, electrolysers, both grid-connected and off-grid electrolysers connected directly to solar and wind power plants, are mainly installed in the south of Italy and a hydrogen transmission system is built out to transport hydrogen from the south to central and northern Italy.

Figure 15: Hydrogen supply and demand (left) and electricity net importing/exporting bidding zones (right) across Italy in 2050 according to S1 H_2-Clustered



S1 H_2-CLUSTERED

Import/Exports 2050 (Carrier: Hydrogen) (TWh)

Net importing/exporting
- <10

Net exporting
- 10–25
- 25–70
- >70

Net importing
- 10–25
- 25–70
- >70

Demand/Supply
- Ship imports
- Electrolysers
- Demand
- 125
- 100
- 75
- 50

Net flows
- 25–50
- 50–100

S1 H_2-CLUSTERED

Import/Exports 2050 (Carrier: Electricity) (TWh)

Net importing/exporting
- <10

Net exporting
- 10–25
- 25–70
- >70

Net importing
- 10–25
- 25–70
- >70

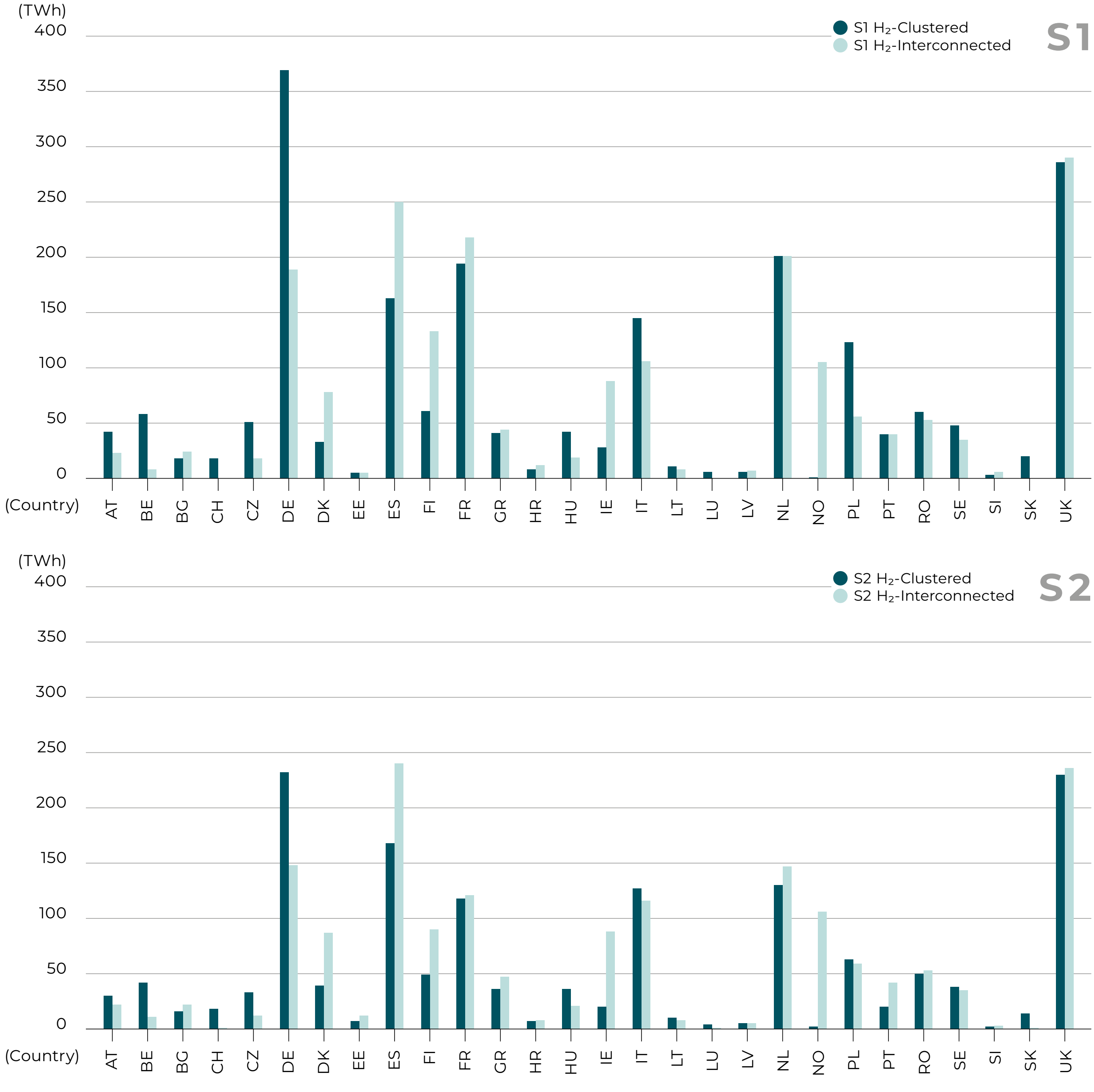
Net flows
- <10
- 10–20
- 20–30
- 30–40
- 40–50
- >50

The fact that it is more cost efficient and reduces the need for electricity grid expansion installing grid-connected electrolysers next to electricity generation and using pipelines to transport hydrogen to where it is needed is in line with findings of other studies.[82-88]

The observations for S1 H_2-Clustered in Italy on a country level can also be generalised to the entire pan-European level when comparing S1 H_2-Clustered with S1 H_2-Interconnected. Due to the expansion of a pan-European H_2 network in the H_2-Interconnected scenarios, hydrogen production is shifted to countries/bidding zones that have excellent solar and wind resources and, on average, lower electricity prices (see Figure 16).[89]

82 Sameraro, M.A. (2021). Renewable energy transport via hydrogen pipelines and HVDC transmission lines Link
83 DeSantis et al. (2021). Cost of long-distance energy transmission by different carriers Link
84 Miao, B., Giordano, L., Chan, S. H. (2021). Long-distance renewable hydrogen transmission via cables and pipelines Link
85 Gasunie, TenneT (2019). Infrastructure Outlook 2050 Link
86 Guidehouse (2020). Integration routes North Sea offshore wind 2050 Link
87 Gasunie, TenneT (2020). Infrastructure Outlook 2050 – Phase II – Pathways to 2050 Link
88 IEA (2023). Energy Technology Perspectives 2023 Link
89 Annual capacity factors by bidding zones for solar, wind and hydro power are specified in the Appendix.

Figure 16: Hydrogen production by country in 2050 for S1 scenarios (top) and S2 scenarios (bottom)[90]



In the H_2-Clustered scenarios, Germany (DE) is the largest hydrogen producer, because it is the country with the highest hydrogen demand. As in the H_2-Clustered scenarios, no hydrogen cross-border transmission capacity can be installed between countries, Germany needs to – same as all other countries – supply its hydrogen demand with domestic resources and/or shipped hydrogen imports. In contrast, the build out of a pan-European H_2 network in the H_2-Interconnected scenarios allows for shifting hydrogen production to countries/bidding zones with lower hydrogen production cost. The lower hydrogen production cost is due to, on average, lower electricity prices (relevant for grid-connected electrolysers) and higher resource potentials for renewable energies (relevant for off-grid electrolysers directly connected to solar or wind power plants).

90 Hydrogen production figures do not include pipeline or shipped imports from outside the countries in scope.

In the H_2-Interconnected scenarios hydrogen production is shifted to countries with excellent solar and wind potentials, in particular Denmark, Finland, Ireland, and Spain which is the largest producer of hydrogen in the EU27 in both H_2-Interconnected scenarios. In S2 H_2-Interconnected, also hydrogen production in Portugal and the Netherlands is increased significantly compared to the counterfactual scenario. In France, hydrogen production also increases significantly between S1 H_2-Clustered and S1 H_2-Interconnected because of competitive hydrogen production thanks to high renewable energy resource potentials and a large nuclear generation fleet operating in 2050. Since in the S2 scenarios final electricity demand in France is considerably higher and the capacity of the installed nuclear fleet in 2050 is significantly lower (15 GW vs 52 GW), hydrogen production increases only slightly in S2 H_2-Inteconnected compared to S2 H_2-Clustered. The lower hydrogen exports from France in S2 H_2-Clustered compared to S1 H_2-Interconnected are replaced to a large extent by higher hydrogen exports from the Iberian Peninsula and the Netherlands. The UK is a major hydrogen producer in all scenarios. Hydrogen production in the UK does not differ considerably between the H_2-Clustered scenarios and the H_2-Interconnected scenarios since the considered upper limits for solar and wind potentials are maxed out. In the H_2-Interconnected scenarios, some of the hydrogen demand in Central Europe is supplied by low-carbon hydrogen produced in Norway transported through repurposed natural gas pipelines.

Hydrogen production is reduced significantly in Austria, Belgium, Switzerland, the Czech Republic, Germany, Hungary, Italy, and Poland in the H_2-Interconnected scenarios. As hydrogen pipeline imports from Ukraine are only available in S1 H_2-Interconnected, hydrogen production in Poland is reduced more in S1 H_2-Interconnected than in S2 H_2-Interconnected. The availability of pipeline imports from Ukraine also impacts hydrogen production in other Eastern European countries. In Italy, despite its excellent solar resources in the south, domestic hydrogen production is complemented with hydrogen imports from North Africa in the H_2-Interconnected scenarios. Hydrogen production in Sweden is reduced in the scenarios where a pan-European H_2 network is built out because some of the Swedish hydrogen demand is supplied by imports from Denmark and Finland. In this context it must be noted that the climatic year 2009, which was used to determine solar and wind resource availability by bidding zone in this study, represents a year where annual capacity factors for on- and offshore wind power for Sweden, Finland, and the Baltic regions are below the long-term average.[91]

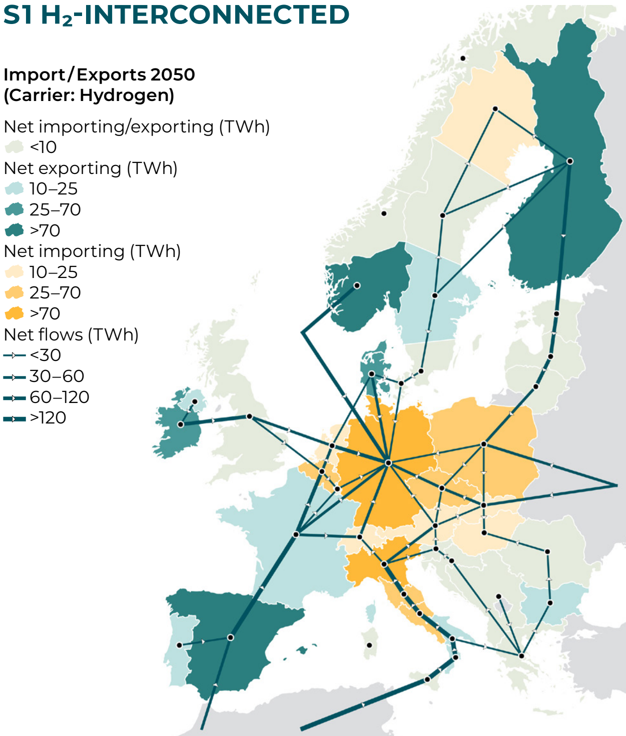
Figure 17 shows the annual net exporting/importing bidding zones in 2050 for hydrogen (left) and electricity (right) and associated net flows across Europe for S1 H_2-Interconnected. Figure 18 shows the same for S2 H_2-Interconnected. **Several supply corridors are visible that supply hydrogen demand in Central Europe**, namely a North Sea supply corridor, two supply corridors from the south of Europe via Italy and the Iberian Peninsula, which both make use of renewable hydrogen imports from North Africa in addition to domestic production, a Nordic supply corridor exporting hydrogen produced from countries around the Baltic Sea, and a supply corridor from Eastern/South-Eastern Europe that taps renewable hydrogen potentials in Ukraine and South-Eastern Europe. These supply corridors are in line with the potential hydrogen supply corridors that have been identified by the EHB initiative.[92]

91 The concrete development of a pan-European H_2 network will depend on various aspects, inter alia on the cost of hydrogen production in different regions of Europe. The availability of solar and wind resources has a strong impact on costs for renewable hydrogen production. The impact of renewable resource availability on hydrogen production and flows across Europe is described in Chapter 4, section 3.

92 European Hydrogen Backbone (2022). A European hydrogen infrastructure vision covering 28 countries Link

Figure 17: S1 H_2-Interconnected: Hydrogen (left) and electricity (right) net importing/exporting bidding zones and annual net flows

S1 H_2-INTERCONNECTED



S1 H_2-INTERCONNECTED

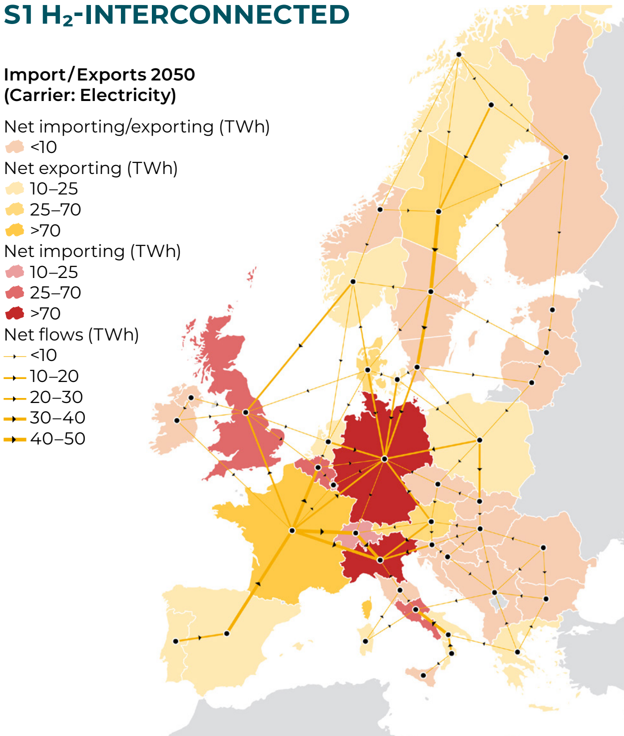
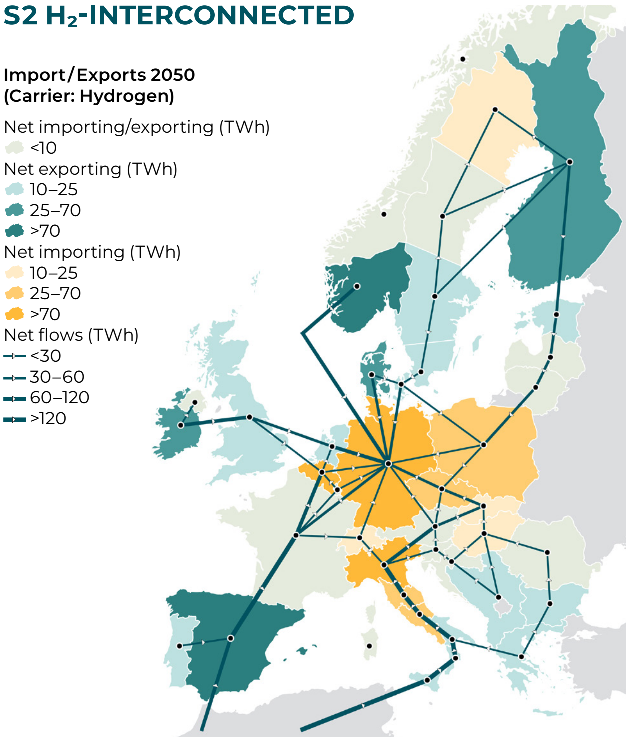
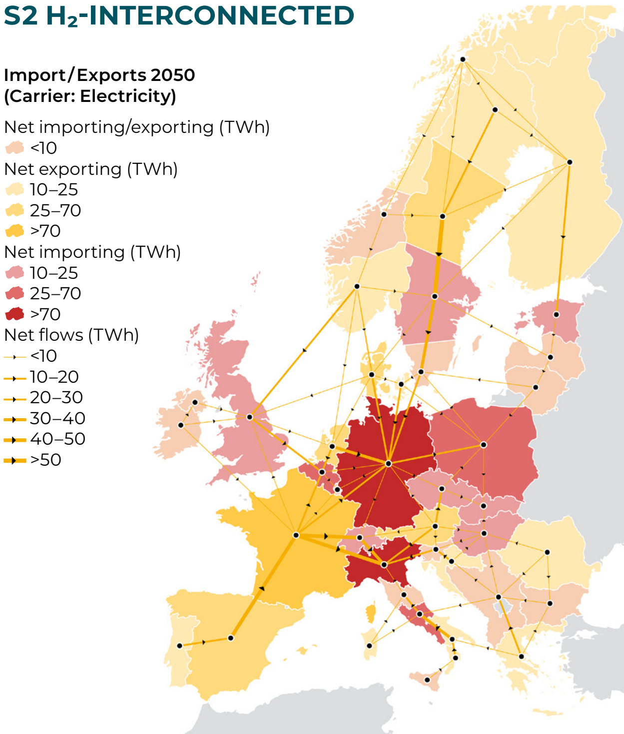


Figure 18: S2 H_2-Interconnected: Hydrogen (left) and electricity (right) net importing/exporting bidding zones and annual net flows

S2 H_2-INTERCONNECTED



S2 H_2-INTERCONNECTED



3.2. A pan-European H_2 network supports the integration of variable renewable energies and security of supply

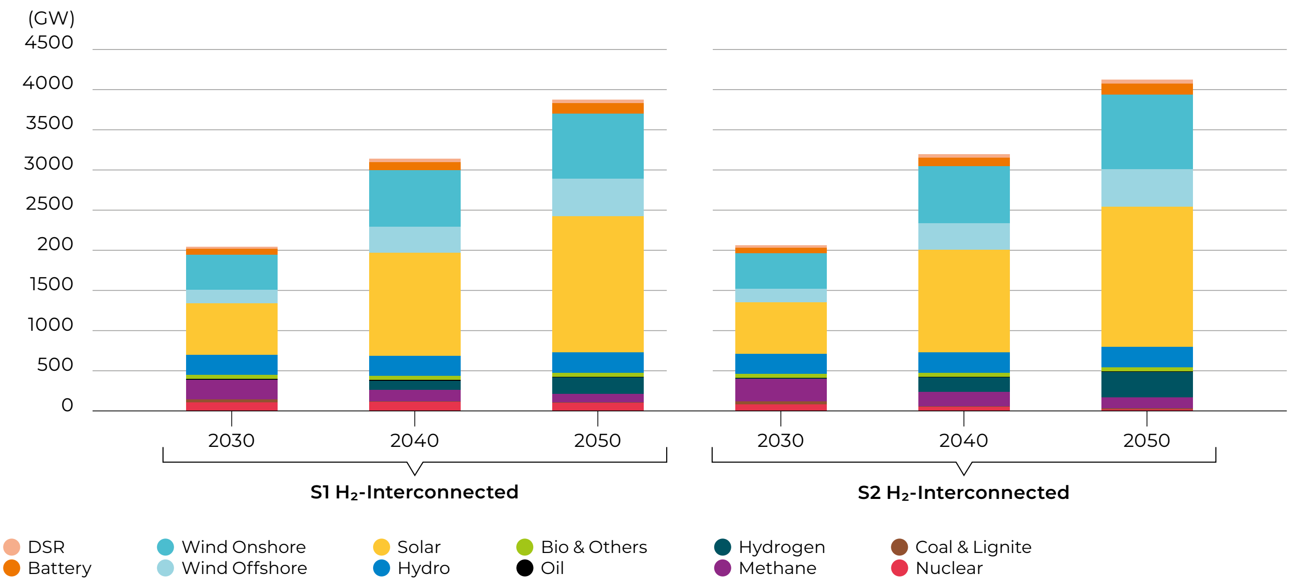
SUMMARY

- Hydrogen and related infrastructure can provide substantial storage potential to balance the energy system at a time scale ranging from intra-day to across seasons. A pan-European H_2 network can provide continent-wide access to large-scale energy storage. This is of particular interest for countries where such potential is limited.
- An integrated network development process would render the energy system more resilient and energy security more affordable. A pan-European H_2 network developed from such a process can deliver an energy system with significantly less firm capacity needs. This is largely due to continent-wide access to hydrogen storages which in turn allow shutting down electrolyser production without shedding hydrogen load.

Hydrogen and related infrastructure contribute to balancing the electricity system across a wide range of time frames

The future European energy system will experience larger variability on the supply side, driven by power generation from non-dispatchable VRE sources. Similarly, continuous electrification of demand will create higher electricity demand peaks, especially during cold weather (due to electrification of heating). Figure 19 shows the development of the cumulative installed capacity in the electricity sector over the timeframe 2030 – 2050 according to S1 H_2-Interconnected and S2 H_2-Interconnected. It is clearly visible that the future electricity supply will be dominated by the VRE, i.e. solar and wind power. In 2050, electricity generation from VRE represents about 80% of the total electricity supply. Intermittent electricity generation from VRE is complemented mainly by hydro, nuclear and biomass power plants but also by flexible methane- and hydrogen-fired power plants which are supplied by the pan-European H_2 network and ensure system adequacy.

Figure 19: Cumulative installed capacity in the electricity sector over the timeframe 2030 - 2050

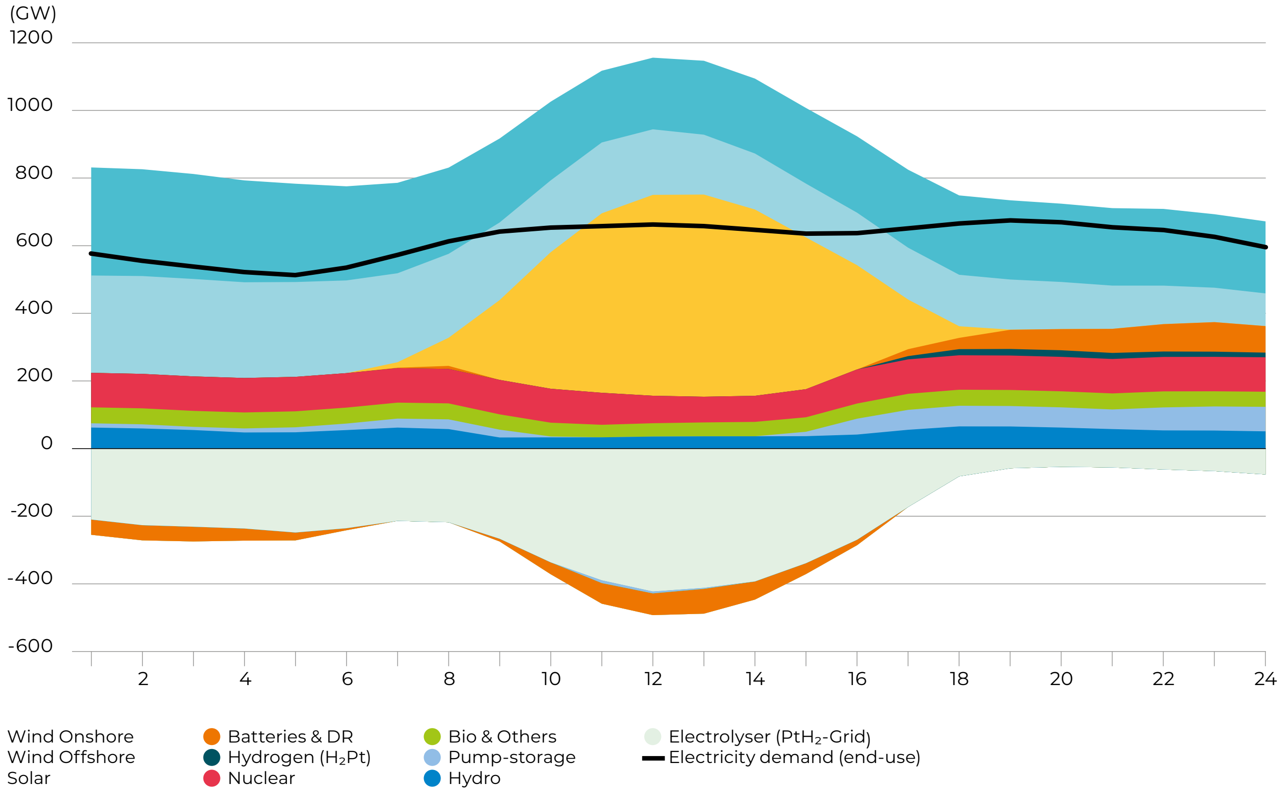


Hydrogen storage and transmission infrastructure can play a key role towards integrating VRE and balancing the future energy system, both from a short-term and a long-term perspective. During times of oversupply from VRE generation surplus electricity can be stored in the form of hydrogen at relatively low cost and at large volumes, compared to other storage options like batteries or hydro pump storage.[93] During times of electricity undersupply, which in particular occur when VRE availability is low and electricity demand is high[94] stored hydrogen can be converted back to electricity through hydrogen-fired dispatch-able power plants.[95] Furthermore, the hydrogen storage and transmission infrastructure allows the decoupling of hydrogen demand from production which will be increasingly reliant on VRE generation, that is both for grid-connected electrolysers and electrolysers directly supplied by solar and wind power plants.

Unlike other storage technologies, this potential may be provided by the hydrogen supply chain across a wide range of timeframes. Real-time balancing can be provided by grid connected electrolysers that modulate their output based on signals received from the electricity system operator.[96] Intra-day balancing is possible if several hours of buffer storage are present, thereby decoupling hydrogen supply and demand and enabling the flexible operation of grid-connected electrolysers. Seasonal balancing is possible by accessing larger scale storage sites (salt, rock cavern or depleted gas) connected to the hydrogen transmission network.

Figure 20 illustrates the hourly system dispatch to supply electricity demand across the modelled area for a representative day in February 2050. The end-use electricity demand is oversupplied, primarily due to excess VRE generation. This excess

Figure 20: Hourly system dispatch to supply electricity demand during a representative day in February in 2050 (S1 H_2-Interconnected)



93 Zhang et al (2022). The role of hydrogen in decarbonizing a coupled energy system Link
94 Sometimes referred to as “Dunkelflaute” or “Windless Winter Week”.
95 Ruhnau et al (2022). Storage requirements in a 100% renewable electricity system: extreme events and inter-annual variability Link
96 Since the model used in this analysis solves on an hourly time step the capacity of PtH_2 to provide reserves is not analysed.

electricity is fed to electrolysers, which operate at continuously varying load during the day, hence adapting their electricity consumption/dispatch in a flexible manner to the availability of VRE. In this example it is noteworthy that the intra-day load variability of electrolysers is higher than any of the dispatchable generation fleets.

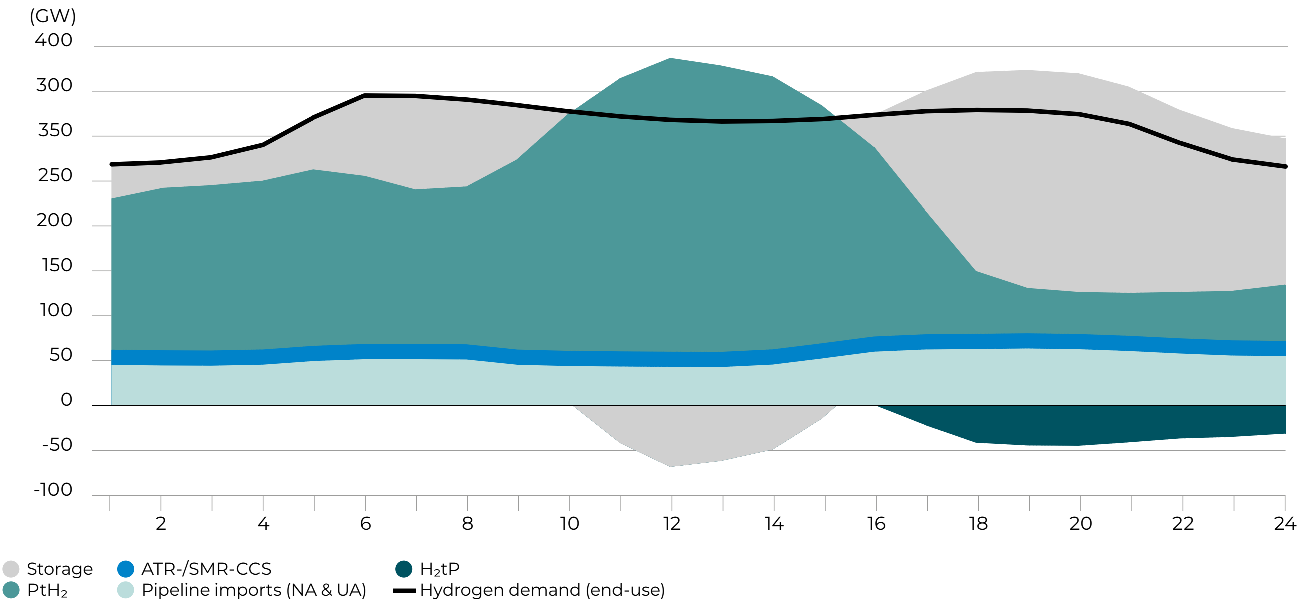
Figure 21 below provides further insight on the operation of the integrated electricity and hydrogen systems by showing the hourly supply of hydrogen over the same representative day in February 2050. Electrolysers provide the bulk of hydrogen supply to meet hydrogen demand in the end-use sectors and from hydrogen fired power plants (H_2tP), but their variable generation profile requires the presence of a hydrogen daily buffer storage to balance hourly supply demand. This is provided in the short-term by system linepack and in the longer term also by salt cavern storage capacities.

One further interesting result from the above figures relates to the operation of a few GW of power plants fired with hydrogen (H_2tP), despite that the entire aggregated modelled area has a surplus of VRE generation. Due to the limited electricity cross-border transmission capacity, it is not possible to transport all the excess electricity to some regions experiencing a supply deficit. Local hydrogen-based dispatchable power generation, which is supplied by a pan-European H_2 network, is instead used in these regions to meet electricity demand.

Linepack storage was introduced in the applied ESM as storage volume equivalent to three hours of annual end-use peak demand for each of the modelled bidding zones.[97] Based on this simplified approach, the inherent storage capacity of the hydrogen network in S1 H_2-Clustered and S1 H_2-Interconnected in 2050 is approximately 1.7 TWh, roughly 4 times higher than the (optimal) total storage capacity of batteries in 2050 determined by the ESM.

Salt caverns, depleted fields, and rock caverns were considered as seasonal/long-term hydrogen storage options. Figure 22 illustrates the seasonal operating pattern of hydrogen storages in 2050 according to S1 H_2-Interconnected as calculated by the ESM. The pattern resembles that of existing natural gas storages, with filling taking place during the summer and withdrawal in the winter, aligned with the availability of VRE, in particular of solar resources. This pattern allows to store excess electricity generated by the VRE generation fleets during the spring and summer seasons.

Figure 21: Hourly system dispatch to supply hydrogen demand during a representative day in February in 2050 (S1 H_2-Interconnected)



97 This assumption was made based on the input of technial experts from the members of this study.

The development of a pan-European H_2 network provides access to large-scale energy storage even for countries which have no, or only very limited potential to repurpose existing salt caverns or depleted fields to store hydrogen, or to construct new salt caverns (such as Sweden, Finland, or the Baltic countries). This provides considerable cost benefits as the need for more expensive hydrogen storage options such as above ground storage is reduced. Figure 23 shows the installed storage capacity in 2050 in H_2-Interconnected by bidding zone.

In total hydrogen storage with a capacity of about 500 TWh is installed until 2050.[98] These storage requirements are in line with GIE estimates, which place hydrogen storage demand for EU27 + UK in 2050 at the level of 466 TWh.[99] According to the analysis countries with the highest installed hydrogen storage capacity will be Germany, the Netherlands, France, Spain, Italy, Poland, the UK, and Romania. About 40% of the storage capacity installed until 2050 can be based on repurposed salt caverns and depleted fields that are currently used as natural gas storages. The remaining 60% of the storage capacity would have to be provided by newly developed salt caverns.

Figure 22: Net hydrogen discharging (positive) and charging (negative) values by month in 2050 in S1 H_2-Interconnected

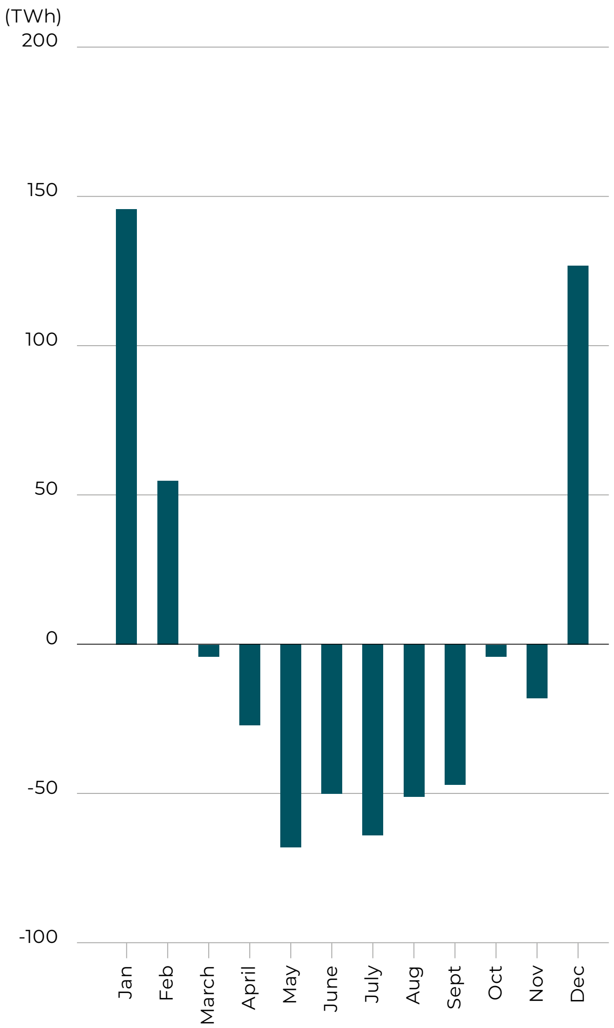
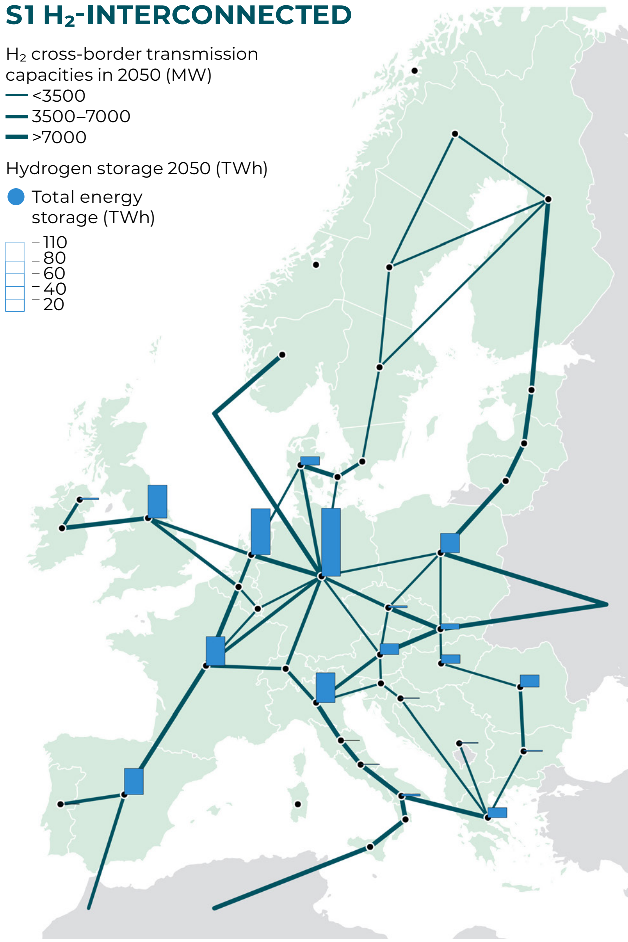


Figure 23: Hydrogen cross-border transmission and storage capacity by 2050 in S1 H_2-Interconnected



98 Hydrogen storage capacity installed until 2050 in S2 H_2-Interconnected is the same range.
99 GIE (2021). Picturing the value of underground gas storage to the European hydrogen system Link; Total hydrogen demand assumed in 2050 in the GIE study is 1968 TWh which is about 15% lower compared to S1 OPT.

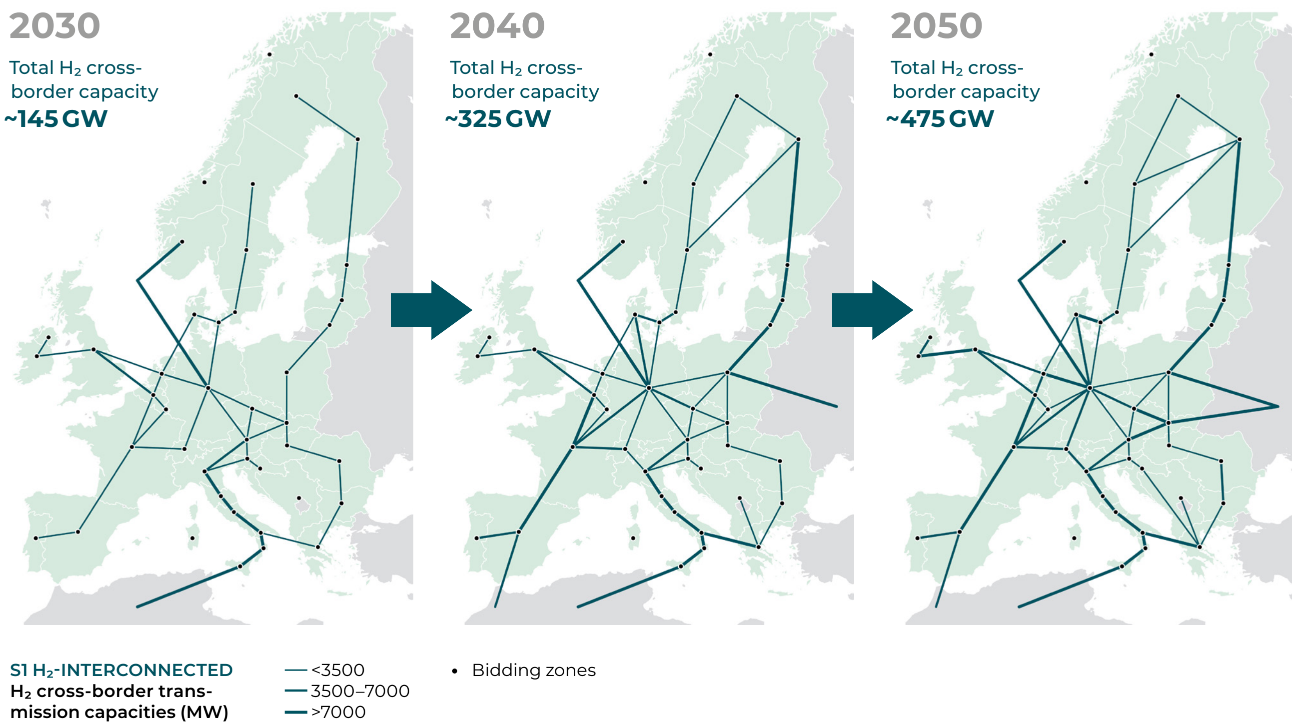
The energy system is more resilient and energy security more affordable

Figure 24 shows the development of the pan-European H_2 network over the timeframe 2030 – 2050 according to S1 H_2-Interconnected. Total hydrogen cross-border transmission capacity increases from about 145 GW in 2030 to about 325 GW in 2040 and reaches about 475 GW in 2050.[100] Almost all interconnections that are developed until 2050 are already part of the pan-European H_2 network in 2040, as observed from the pathway optimisation over the timeframe 2030 – 2050. After 2040, only a few entirely new interconnections are developed. Major investments after 2040 are focused on expanding the capacity of previously developed hydrogen transmission corridors.

A mature pan-European H_2 network is already developed by 2040 enabling an integrated European hydrogen market. Investments into hydrogen cross-border transmission capacity are a result of the applied cost optimisation algorithm. This consists of optimising the supply for hydrogen, electricity, and methane in an integrated way considering interdependencies between the three sectors and related assets from a whole system perspective. Therefore, the development of a pan-European H_2 network does not only allow hydrogen to be supplied in the most cost-efficient way, by interconnecting European hydrogen markets, but is also a key cornerstone for the full integration of the entire European energy market.

The expansion of a pan-European H_2 network can offer significant benefits in terms of network resilience and security of supply by i) providing network access to seasonal storage for countries without suitable geological formations, ii) increasing system flexibility through additional short term hydrogen storage (linepack) and iii) helping achieve power system adequacy with significantly lower dispatchable resources (backup power plants and batteries).

Figure 24: Development of a pan-European H_2 network in S1 H_2-Interconnected between 2030 and 2050



100 Hydrogen cross-border transmission capacity increases from about 100 GW in 2030 to 465 GW in 2050.

The role of gas storage is *"instrumental to security of supply as it provides an additional reserve in a case of strong demand or supply disruptions"*[101]. Amid the 2022 gas crisis the European Commission, acknowledging the critical nature of storage infrastructure, proposed legislation that defines storage facilities as "critical infrastructure" and imposes obligations on their operators aiming to reduce risks to security of supply of natural gas.[100] Hydrogen storage will likely have a similarly important role beyond 2030 in reducing risks to security of supply but from a somewhat altered perspective. In S1 H_2-Interconnected almost 80% of hydrogen delivered in the EU by 2050 will be indigenously sourced. Therefore, the exposure to geopolitical or other risks that could lead to supply disruptions is greatly reduced, compared to today's gas supply situation. However, the linkage of green hydrogen production to VRE sources increases the supply risk because of weather variability which will become the primary risk source. This risk can be mitigated by energy storage in all forms.

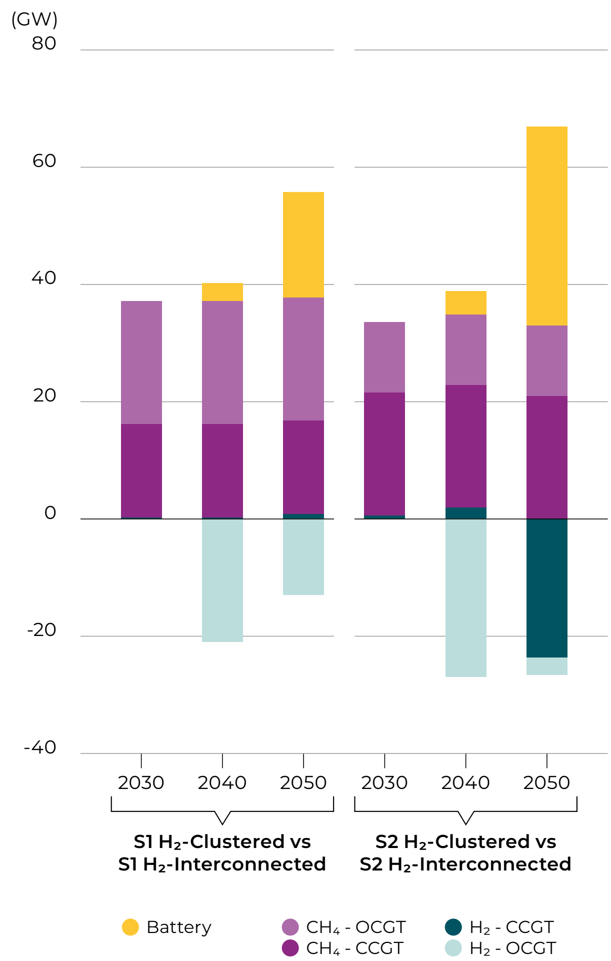
Seasonal/long-term storage requirements are quite significant for the future European energy system, as illustrated in Figure 22 and explained in the previous paragraph. Excess VRE generation during spring and summer can be converted to hydrogen and then transported towards major demand centers, where most of the hydrogen storage capacity is located (see Figure 23). This can be particularly beneficial for countries which have little or no hydrogen storage potential on their territory, particularly during stress moments for the energy system.

Short term storage is important for enabling the flexible operation of electrolysers during intra-day and for ensuring the availability of hydrogen for dispatchable power plants for the brief intervals that they will be required to generate to cover peak electricity demand. While a future hydrogen system focusing on national expansion, similar to the H_2-Clustered scenarios, will include a national hydrogen network which will provide this flexibility, it is certain that a pan-European H_2 network will provide significantly more linepack. However, due to the uncertainties over the physical network configuration and the fact that a hydraulic model is required to accurately assess linepack, the potential benefits of an expanded hydrogen network have not been fully accounted for in the present study.

101 European Commission (2022). New rules in gas storage Link

Results of the applied ESM indicate that an integrated network development process leading to **a pan-European H_2 network can deliver an energy system with significantly less firm capacity** compared to a system comprising of nationally developed networks. Figure 25 provides the installed capacity difference of peaking technologies between the H_2-Clustered and H_2-Interconnected scenarios. S1 H_2-Interconnected will require approximately 37 GW less dispatchable capacity in 2030, rising to 43 GW in 2050 compared to S1 H_2-Clustered. This capacity represents 10-13% of the total hydrogen, methane, and battery fleets. In the S2 scenarios the numbers are slightly different, but the trend is the same with 40 GW less dispatchable assets in 2050. In both cases we notice that the H_2-Interconnected scenarios contain more investment in hydrogen-fired capacity (negative bars) instead of methane-fired capacity.

Figure 25: Additional thermal and battery installed capacity in the S1/S2 H_2-Clustered scenarios compared to S1/S2 H_2-Interconnected scenarios



Since all the above technologies directly contribute to achieving the required power system adequacy standards (here achieved by being able to supply peak winter demand), it can be concluded that in the H_2-Interconnected scenarios, where a pan-European H_2 network is installed, the required system adequacy level can be achieved with significantly less backup generation and electricity storage capacity.

This result is a nice example of how optimising the energy system across sectors can help achieve the same levels of system resilience at a lower cost. The installed capacity needs are defined by the ESM during the January peak day, when electricity demand is at its highest and VRE generation is at its lowest. A comparison between S1 H_2-Interconnected and S1 H_2-Clustered dispatching on that day reveals substantially less electrolytic production of hydrogen across the modelled system in the H_2-Interconnected scenario. Hydrogen demand is served by H_2 storages. By contrast, in the H_2-Clustered scenario some hydrogen production must be maintained to avoid hydrogen load shedding. This is an outcome of the ESM which should be interpreted with some caution in terms of absolute numbers, given the simplified representation of a full year by means of representative days and the way storage is operated across days. However, it is a clear indication of how in the future power generation adequacy will need to be assessed across energy systems and vectors and a demonstration of the benefits provided by a pan-European H_2 network in that respect.

3.3. A pan-European H_2 network and biomethane scale-up foster a sustainable energy supply

SUMMARY

- A pan-European hydrogen network allows hydrogen to be produced in regions with the best renewable energy potential in Europe and helps utilise cost-competitive renewable hydrogen from outside of Europe. This reduces the direct CO_2 emissions over the timeframe 2030 – 2050 by 10% compared to scenarios without a pan-European hydrogen network.
- Renewable hydrogen and biomethane are the main sources to decarbonise the gas supply until 2050 in all scenarios. Renewable hydrogen covers 92-98% of hydrogen demand in 2050, while low-carbon hydrogen develops from a transition fuel to carbon-negative fuel due to the utilisation of biomethane instead of natural gas after 2040. Biomethane supports the decarbonisation of the methane system (3425 Mt of direct CO_2 emissions from natural gas are avoided over the timeframe 2030 – 2050) and reduces energy import dependency at the same time.

10% reduction of direct CO_2 emissions can be realised over the timeframe 2030 – 2050

All assessed scenarios within this study are required to reach net zero CO_2 emissions by 2050. **Electricity generation from VRE, renewable hydrogen, and biomethane are the main supply side decarbonisation options** in all analysed scenarios following the applied cost minimisation criterion. Comparing the total direct CO_2 emissions of the modelled system when supplying demand for hydrogen, electricity, and methane under the different scenarios indicates that the development of a pan-European H_2 network could further accelerate the transition towards a sustainable energy supply.

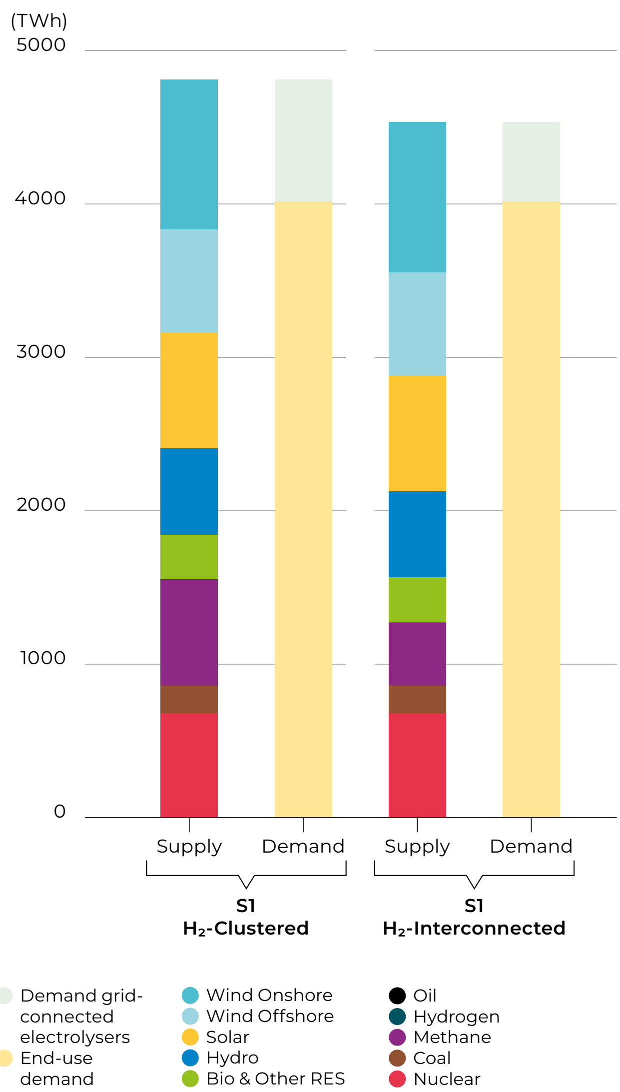
Due to the development of a pan-European H_2 network in the H_2-Interconnected scenarios that allows hydrogen to be produced in areas with best renewable energy potentials across Europe and tap cost competitive renewable hydrogen potentials from neighbouring regions (North Africa and the Ukraine), **direct CO_2 emissions over the timeframe 2030 – 2050 are reduced by almost 10%** compared to the scenarios where no hydrogen transmission network is developed (S1 H_2-Clustered and S2 H_2-Clustered). As all scenarios must reach net zero CO_2 emissions by 2050, savings in direct CO_2 emissions in S1 H_2-Interconnected and S2 H_2-Interconnected therefore occur rather in the beginning of the modelled timeframe. The main reason for the reduced CO_2 emissions in the H_2-Interconnected scenarios is the lower use of natural gas in the power sector. Figure 26 compares the electricity supply and demand in the year 2030 under S1 H_2-Clustered and S1 H_2-Interconnected.

In S1 H_2-Interconnected, the investments in hydrogen cross-border transmission infrastructure until 2030 allows hydrogen production locations across Europe to be optimised and enables imported renewable hydrogen from North Africa and low-carbon hydrogen supply potentials from Norway and UK to be tapped into. This reduces the domestic electricity demand caused by electrolysers in 2030 significantly. Electricity demand for grid-connected electrolysers is 278 TWh lower in S1 H_2-Interconnected than in S1 H_2-Clustered (792 TWh vs 515 TWh). Due to this lower total electricity demand (including demand for hydrogen production), electricity production from methane-fired power plants in 2030 is only 413 TWh in S1 H_2-Interconnected compared to almost 691 TWh in S1 H_2-Clustered. As methane-fired power plants in 2030 are mainly fired by natural gas, the lower electricity generation from methane power plants leads to about 480 TWh (-40%) less natural gas burned for electricity generation in S1 H_2-Interconnected compared to S1 H_2-Clustered. **The reduced natural gas consumption in the power sector leads to direct CO_2 emission savings of about 110 Mt in 2030**.

When further focusing on the difference in electricity demand for hydrogen production, Figure 26 shows that in S1 H_2-Clustered, electrolysers consume more electricity in 2030 in comparison to S1 H_2-Interconnected. This increased electricity demand may result from natural gas fired CCGTs, as electricity generation from methane increases simultaneously. This indicates that under S1 H_2-Clustered, a share of hydrogen produced with grid-based electrolysis faces the risk of not complying with rules governing the production of RFNBOs.[102] These results are the consequence of an optimal unconstrained least-cost solution identified by the ESM.

However, in the S1 H_2-Clustered scenario, the CO_2 emissions could significantly be reduced by 2030 if this hydrogen would be replaced with certified, shipped renewable hydrogen imports. In an alternative development scenario where domestic hydrogen production in the S1 H_2-Clustered scenario is limited to 333 TWh/y (10 Mt/y) for the EU countries in scope, direct CO_2 emissions are on par with S1 H_2-Interconnected. However, since more expensive hydrogen imports via terminals fill the supply gap, as upper limits for solar and wind potentials in 2030

Figure 26: Electricity supply and demand in 2030



102 The RFNBO criteria will be set to ensure that hydrogen and its derivatives are produced in a sustainable matter. The criteria are yet to be finalised by the European Commission.

are already fully deployed, the total annual system costs in 2030 increase by 13 B€. These additional costs would further increase the cost difference between S1 H_2-Clustered and S1 H_2-Interconnected, further highlighting the cost benefits of a pan-European H_2 network.

Renewable hydrogen and biomethane are the main sources to decarbonise future gas supply

Renewable hydrogen and biomethane are the main sources to decarbonise the gas supply until 2050 in all investigated scenarios. As described in key findings 1, a pan-European H_2 network provides significant cost benefits to supply future demand for hydrogen, electricity, and methane. Assuming that hydrogen pipeline and shipped imports from outside the countries in scope are produced from renewable energies, **renewable hydrogen supplies 92-98% of the gaseous hydrogen demand in 2050** in the individual scenarios. This renewable hydrogen is complemented by some low-carbon hydrogen produced by SMRs and ATRs which are equipped with CCS.

In S1 H_2-Interconnected and S2 H_2-Interconnected, the ESM identified a consistent production of 145 TWh for low-carbon hydrogen supply (from the UK and NO) between 2030–2050.[103] However, the gas composition feeding into the low-carbon hydrogen production units changes significantly (virtually and physically). This is most apparent in the UK where the share of the biomethane on the gas supply changes from 8% in 2030, to 17% in 2040, and 80% in 2050.[104]

Assuming that biomethane and natural gas have a consistent distribution across the methane infrastructure, the combined biomethane and natural gas feed into **low-carbon hydrogen production units starts creating essential negative GHG emission in the system**. At assumed 90% CO_2 capture rate, the share of biomethane could be as low at 10% to start creating net negative GHG emissions.[105] This also makes all the low-carbon hydrogen production units potentially relevant beyond 2050. These assets would continue creating negative emissions in the system as the biomethane share on total gas supply expectedly increases even further (due to additional biomethane production and/or further decrease in natural gas production), avoiding stranded assets in the transition.

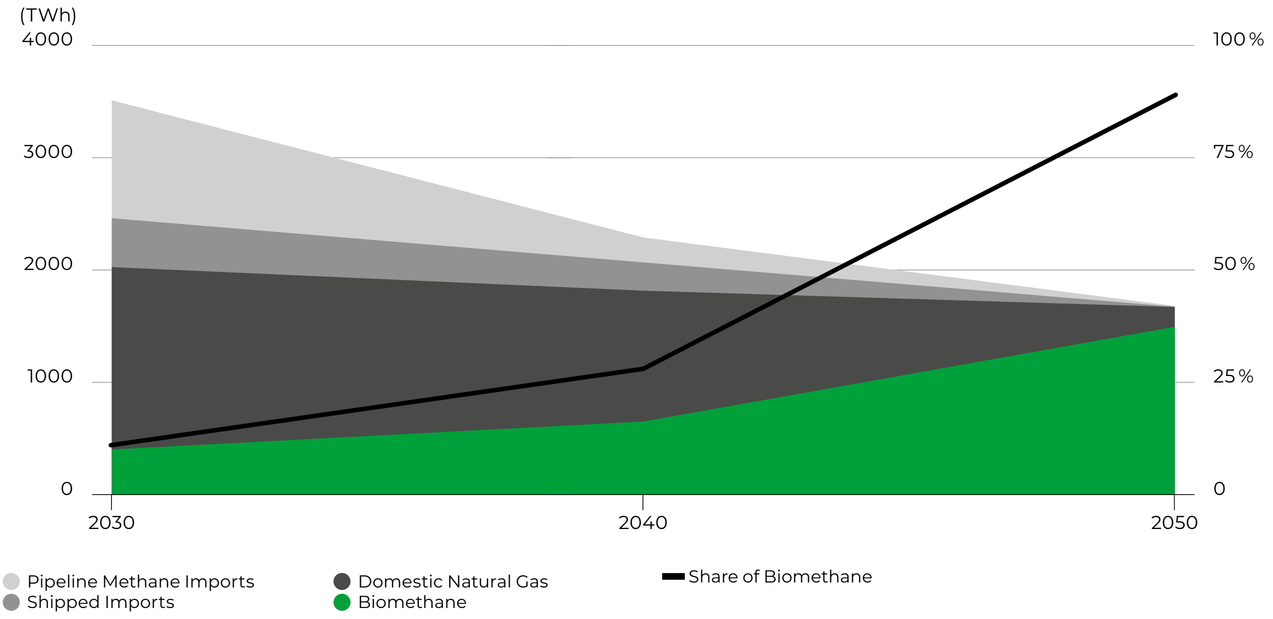
Figure 27 presents the composition of the methane supply over the timeframe 2030 – 2050 for S1 H_2-Interconnected. Based on the applied cost optimisation approach domestically produced biomethane becomes the main supply source after 2040.[106] Biomethane production in the countries in scope increases from about 400 TWh in 2030 to 1500 TWh in 2050.[107] By 2050, biomethane supplies about 90% of the total methane demand of the analysed system. The remaining 10% of natural gas consumption in 2050 are solely used in combination with CCS to produce low-carbon hydrogen. **Due to the use of biomethane more than 3425 Mt of direct CO_2 emissions from natural gas are avoided over the timeframe 2030 – 2050**.

The strong biomethane scale up across Europe replaces domestic natural gas that mainly originates from Norway and UK as well as methane imports from outside the countries in scope via ships and pipelines. Consequently, the increased use of **biomethane does support the decarbonisation of the methane system and reduces energy import dependency at the same time**.

Importantly, the increase in biomethane can be transported by existing natural gas infrastructure. Between 2030 and 2050, methane flows between countries are decreasing due to the shift from natural gas to biomethane. This is the result of the distributed production of biomethane across Europe, while natural gas is domestically produced or imported from countries with large production, and then distributed across Europe. With the uptake of hydrogen supply and demand, **coordinated planning between hydrogen and methane networks will be required** to determine which pipelines would still be used for (bio)methane, considering in particular security of supply aspects, and which pipelines could be repurposed for hydrogen transport.

103 Upper limits of 100 TWh and 50 TWh for low-carbon hydrogen production in Norway and the UK respectively have been included in the model.
104 Norway remains one of the last natural gas production countries even in 2050 and thus low-carbon hydrogen production is still fully based on natural gas.
105 The exact figure is depending on many factors such as methane leakage of biomethane vs natural gas production, SMR/ATR efficiency and CO_2 vs CO formation due to larger biomethane share in the feedstock.
106 The applied cost optimisation approach and defined upper bounds for installed solar and wind power capacities results in a minimal role for synthetic methane.
107 For 2030 and minimum biomethane uptake of 370 TWh was considered for the EU countries in scope in alignment with REPowerEU targets.

Figure 27: Development of methane supply and share of biomethane over the timeframe 2030–2050 in S1 H_2-Interconnected



3.4. Immediate actions are needed

SUMMARY

- A pan-European hydrogen system composed of up to 145 GW cross-border transmission, about 100 TWh storage, and 80 GWe electrolyser capacity was identified within the analysed scenarios as part of the cost-optimal European energy system in 2030.
- To reach REPowerEU targets in terms of domestic hydrogen and biomethane production as well as in terms of hydrogen imports, immediate actions are needed given the long lead times for required assets.
- The pan-European H_2 network will be the basis for the nascent hydrogen market across the EU, while contributing significantly towards achieving the REPowerEU targets in a cost-efficient manner. It is therefore important to earmark sufficient funds for hydrogen infrastructure projects to ensure funding is available as the market develops.

The results of the analysed scenarios indicate that **a pan-European H_2 network and an accelerated biomethane uptake** are key elements for the transition towards an affordable, secure, and sustainable European energy supply and **provide significant benefits already in the short-term**. In the scenarios where a pan-European H_2 network can be developed, i.e. in S1 H_2-Interconnected and S2 H_2-Interconnected, the applied ESM identified a pan-European hydrogen system that is composed of up to 145 GW cross-border transmission capacity, about 100 TWh storage[108], and 80 GWe electrolyser capacity, as part of the cost-optimal European energy system in 2030.

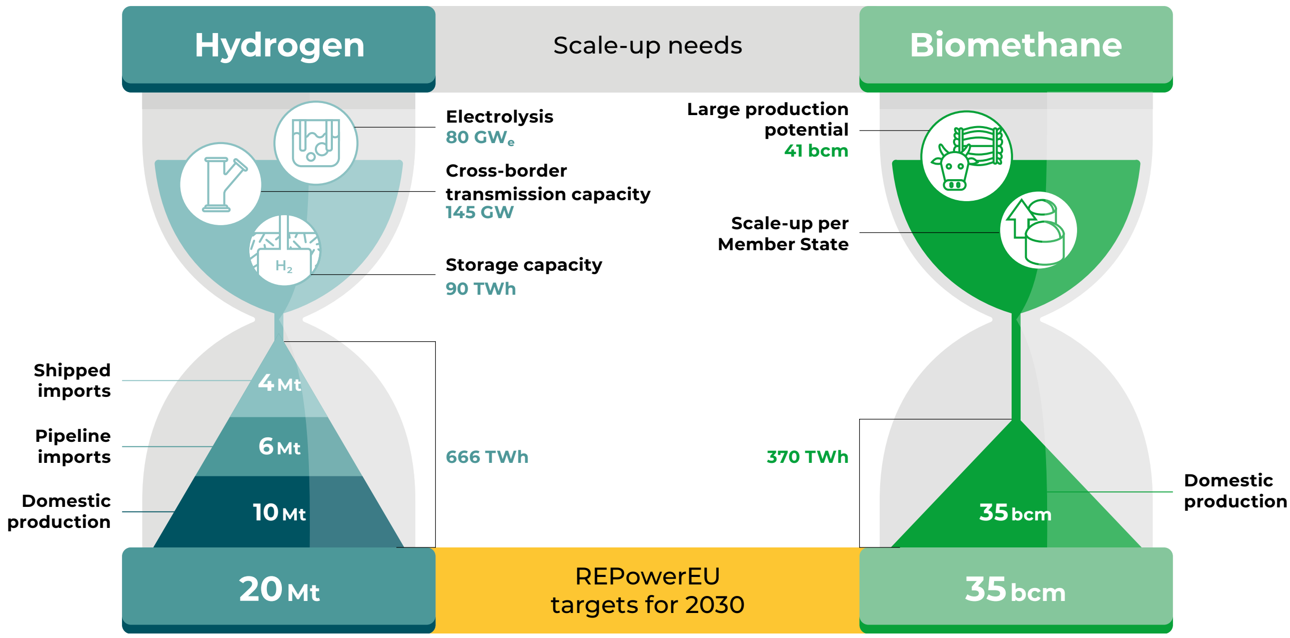
108 About 90 TWh in S1 H_2-Interconnected and 110 TWh in S2 H_2-Interconnected

From an EU perspective, this pan-European hydrogen system includes pipeline interconnections to North Africa as well as to the non-EU countries Norway and the UK to make use of cost competitive renewable and low-carbon hydrogen supply potentials in these neighbouring regions/countries. Pipeline imports from these regions (~6 Mt/y) will be crucial to complement domestic hydrogen production (~10 Mt/y) to achieve REPowerEU targets in terms of hydrogen uptake in a cost-efficient manner. In accordance with REPowerEU, hydrogen import terminals allowing the import of up to 4 Mt/y of hydrogen in the form of ammonia, or as any other hydrogen-based product via ships, need to be in operation by 2030. Import terminals are an important source for diversifying supply, which will increase market competition and security of supply. However, shipped hydrogen should be imported in the form required by the end use to minimise conversion losses. Furthermore, a strong ramp up of biomethane production capacity is needed to tap into the high domestic supply potential of EU member countries to produce at least 35 bcm in 2030 (see Figure 28). To ensure the required infrastructure is in place when needed, immediate actions from all involved stakeholders are needed given the long lead times (3-10 years) for hydrogen and biomethane infrastructure assets).

Below key areas are listed that will require coordinated and immediate efforts between governments, regulators, and industry to ensure targets can be achieved and required infrastructure is in place when needed:

- Electrolyser manufacturing capacity and supply chains will need to ramp up. The current capacity of electrolyser manufacturers in Europe is estimated at 2.5 GWe per year, a fraction of what is needed to achieve the REPowerEU targets. The urgency has been acknowledged as an unprecedented challenge and a significant industrial opportunity by European electrolyser manufacturers who committed to a tenfold increase of electrolyser manufacturing output by 2025[109]. This buildout depends on government

Figure 28: REPowerEU targets for hydrogen and biomethane uptake and infrastructure scale up needs by 2030



109 European Commission (2022). Electrolyser summit joint declaration 04/05/2022 Link

targets translating into real-world projects and can be catalytic in making hydrogen more competitive. According to the IEA, if electrolyser projects in the pipeline are realised and the planned scale-up in manufacturing capacities takes place, costs for electrolysers could fall by 70% by 2030 compared to today[110].

- Access to hydrogen storage across Europe was identified by the present study as one of the most important drivers behind developing a pan-European H_2 network. An estimate of the required storage volume was based on optimal send-in and send-out capacities determined by the ESM. Further analysis is needed to quantify the required hydrogen storage capacity needs based on country granularity. This would enable storage operators to prepare for a potential transition to hydrogen. However, given the current energy crisis and the storage filling requirements, existing assets may not be available for repurposing by 2030. Therefore, the attention of the "hydrogen community" should also steer in the direction of identifying suitable sites for developing new salt caverns for hydrogen storage in the near term.

- The pan-European H_2 network is meant to efficiently connect the supply and demand of hydrogen, both of which currently do not exist. In doing so this infrastructure will be the basis for the nascent hydrogen market across the EU, while contributing significantly towards achieving the REPowerEU target in a cost-efficient manner. However current funding mechanisms are limited and may not be sufficient for developing a pan European H_2 infrastructure. It is therefore important to earmark funds that will be made available for hydrogen infrastructure as the market develops.

- The repurposing of natural gas pipelines is a no-regret option and contributes enormously towards making energy more affordable and sustainable and the energy system more resilient in 2030. Based on the results from the analysed scenarios it is estimated that 10% of the existing natural gas transmission network is repurposed by 2030 and approximately 27% by 2050 in the S1 H_2-Interconnected scenario. The cost of repurposing existing natural gas pipelines is estimated at 10-25% of the CAPEX of new hydrogen pipelines[111] with benefits extending to easier licensing reduced environmental impact and public acceptance. However, while the actual works related to repurposing may be much swifter, the repurposing decision process consists of several steps of non-insignificant uncertainty or complexity[112]. The first, and perhaps most challenging step consists of defining which segments of the gas transmission network may be repurposed to hydrogen. During this process the actual need, the technical feasibility, and the operational possibility to proceed with the asset repurposing must be acknowledged by multiple actors. This process will likely take place at a national level, based on joint scenarios on gas and electricity aligned with the TYNDP developed jointly by ENTSOG and ENTSO-E.[113]

- Although the present analysis did not identify shipped hydrogen as a major part of the cost-optimal supply mix to supply gaseous hydrogen demand, import terminals have an important role to play in terms of security of supply and market competition - as they allow to diversify supply - and for the delivery of hydrogen carriers or derivative products such as renewable ammonia and methanol. These products will be supplied to various end-users in industry or be the basis for other renewable fuels for shipping and aviation. However, further research is needed to gain a better understanding of the technical feasibility and implications of converting LNG or oil terminals to handle ammonia or other hydrogen-based products.[114, 115] The topic is of high interest, given the current importance of LNG terminals for diversifying supplies and contributing to energy security. Repurposing LNG and oil terminals would limit to some extent the need to build entirely new hydrogen import terminals.

110 IEA (2022). Global Hydrogen Review Link
111 European Hydrogen Backbone (2020). How a dedicated hydrogen infrastructure can be created Link
112 ACER – DNV study on Future regulatory decisions on natural gas networks
113 EC Proposal on common rules for the internal markets in renewable and natural gases and in hydrogen COM 2021/803
114 Gas for Climate (2022). Facilitating hydrogen imports from non-EU countries Link
115 Fraunhofer ISI (2022) Conversion of LNG Terminlas for Liquid Hydrogen or Ammonia Link

- the soonest possible

- Biomethane production needs to be scale up to reach the REPowerEU target of 35 bcm in 2030. As can be seen on the right-hand side of Figure 28, there is a large production potential of 41 bcm in EU-27 for 2030, because there are enough sustainable feedstocks available to meet the REPowerEU target.[116] However, to scale up, this EU target has to be translated into individual contribution by all member states. To assist with this, the EC published a Biomethane Action Plan[117], setting out measures to be taken at both national and European levels to scale up biomethane production and consumption. The plan includes a recommendation to member states to develop a national biomethane strategy as soon as possible.[118] In 2022, Gas for Climate has compiled a 10-step manual to support member states in developing and implementing their national biomethane strategies. These range from developing a national biomethane vision and setting initial targets to having a fully implemented national biomethane strategy. Action is needed on all these steps in all members states to meet the REPowerEU target by 2030.[119]

- Across all required infrastructure development priorities listed, it is essential that developers are enabled to create bankable projects this year (2023) already. Since the hydrogen market is still nascent, the deployment of market mechanisms that create certainties to market actors about prices and volumes will be important. Next to this, public funding to support asset developments will be required to accelerate the market. As an example, the 6th PCI list that will be evaluated this year will provide project owners with benefits regarding regulatory and permitting priority, and financial support. While the resulting access to public funding will remain a competitive process, it is important to have clarity the soonest possible about the amounts and whereabouts of hydrogen-earmarked funds that are becoming available, and by when.

- The above areas require immediate attention from various stakeholders across the energy system value chain. However, for some of these key areas, there is no proper regulatory framework in place to facilitate action, scale-up, or even acceleration. In the policy recommendation (see Chapter 5), a more elaborate description is provided of what is needed as soon as possible to meet REPowerEU targets and ensure that the significant benefits provided by the development of a pan-European H_2 network and accelerated biomethane supply can be achieved in 2030.

116 Gas for Climate (2022). Biomethane production potentials in the EU Link
117 Chapter 5 of European Commission (2022). Commission Staff Working Document, SWD (2022) 230 final, Implementing the REPowerEU Action Plan: Investment needs, hydrogen accelerator, and achieving the bio-methane targets Link
118 European Commission (2022). Biomethane action plan, Action 1.2: Develop national strategies on sustainable biogas and biomethane production and use or integrate a biogas and biomethane component in the National Energy and Climate Plans (NECPs) Link
119 Gas for Climate (2022). Manual for National Biomethane Strategies Link

4. Insights from assessing alternative developments

The ESM used in this study applies a rigorous cost optimisation approach when modelling the future integrated European energy system. Results of the ESM are driven heavily by the assumptions used in each scenario. However, given the long-term horizon of the study, these assumptions are uncertain by definition. Furthermore, the development of the European energy system will also be driven by factors which go beyond pure economic considerations. In the following sections, three sensitivities are conducted in order to validate the robustness of the results under alternative developments and to gain further insights into the potential role of low-carbon hydrogen, hydrogen import terminals, and hydrogen production across Europe.

SUMMARY

- → A pan-European H_2 network and the five supply corridors are also part of the cost-optimal solution identified by the ESM in all three assessed alternative developments.
- → In 2030 renewable electricity will still be a bottleneck for renewable hydrogen production, more present under high gas prices. Low-carbon hydrogen will complement renewable hydrogen supply, primarily in the early years even under higher natural gas price assumptions. However, low-carbon hydrogen will gradually phase-out beyond 2040 as renewable hydrogen becomes cheaper. As we approach 2050 renewable hydrogen will have fully displaced low-carbon hydrogen.
- → Shipped hydrogen imports can foster competition and supply diversification like LNG today with its inherent sourcing flexibility, and grant access to global supplies. Thus, hydrogen import terminals help contribute to energy security and enable alternative sourcing strategies.
- → Distribution of renewable hydrogen production across Europe as identified by the ESM depends on the considered climate year. Therefore, the base climate year (2009) was selected as the most representative for the total renewable energy resources of the countries in scope. However, since every climate year leads to a different regional distribution of renewable hydrogen, even in the average year some regions produce more and others less than their local inter-annual average. A notable example is the Nordic and Baltic Sea region, which in other climate years can produce significantly more renewable electricity and hydrogen compared to the base climatic year used in the current analysis.

The complementary role of low-carbon hydrogen

In the main scenarios S1 H_2-Interconnectedand S2 H_2-Interconnected of this analysis, the exogenously defined low-carbon hydrogen supply potential of 150 TWh is fully deployed over the modelled timeframe and complements domestic hydrogen production from electrolysers and pipeline imports from North Africa and Ukraine. The full deployment of the low-carbon hydrogen potential is a result of the applied techno-economic assumptions for ATRs and SMRs equipped with CCS and especially the price assumptions for natural gas. Natural gas prices used in the scenarios presented so far are based on TYNDP 2022 assumptions, which have been developed well before the current and ongoing European energy crisis.[120] Current natural gas price projections[121] for the mid-term are significantly higher than the considered TYNDP 2022 assumptions. Therefore, an additional scenario (S1 H_2-Interconnected-HighNGprice) to assess the sensitivity of the results to higher gas prices, and in particular its impact on the role of low-carbon hydrogen, was deemed useful. Table 2 presents natural gas price assumptions for S1 H_2-Interconnected and S1 H_2-Interconnected-HighNGprice. All other input assumptions were kept the same for the two scenarios.

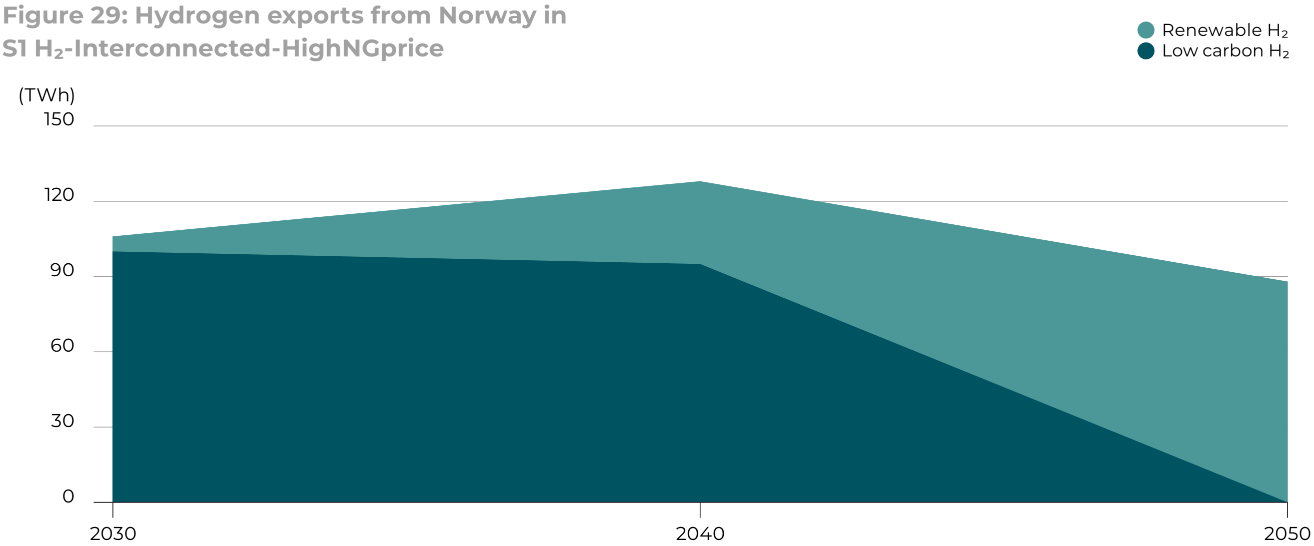
The higher natural gas price assumed in S1 H_2-Interconnected-HighNGprice has a major impact on the use of low-carbon hydrogen over the timeframe 2030 – 2050. Since demand for hydrogen in the end-use sectors is exogenously defined and therefore fixed in the ESM, the full 150 TWh of low-carbon hydrogen is still deployed in 2030 despite the high natural gas price. This is because upper limits for domestic renewable hydrogen production and pipeline imports from North Africa are reached and low-carbon hydrogen produced in Norway and the UK is still competitive (at 88€/MWh), compared to shipped hydrogen imports (at 95 €/MWh).

Table 2: Natural gas price assumption for S1 H_2-Interconnected and S1 H_2-Interconnected-HighNGprice

		2030	2040	2050
S1 H_2-Interconnected	(€/MWh)	20	15	15
S1 H_2-Interconnected-HighNGprice	(€/MWh)	70	50	50

However, under the higher gas price assumption, the deployment of low-carbon hydrogen potential is changing over the modelled timeframe. After 2030, low-carbon hydrogen produced in Norway is increasingly replaced by renewable hydrogen as shown in Figure 29. By 2050 all Norwegian hydrogen imports to Central Europe are renewable hydrogen. In the case of UK, the high natural gas price has a smaller impact on low-carbon hydrogen production because already in S1 H_2-Interconnected, i.e. in the scenario with low natural gas prices, natural gas consumed by ATRs and SMRs equipped with CCS is gradually replaced with biomethane from 2040 onwards to generate negative CO_2 emissions (see key findings 3).

Figure 29: Hydrogen exports from Norway in S1 H_2-Interconnected-HighNGprice



120 The natural gas price in 2030 specified in TYNDP 2022 was increased from 14.5 €/MWh to 20.3 €/MWh (+40%) also in the main scenarios to acknowledge the impact of the current European energy crisis on natural gas prices in the upcoming years. Natural gas prices for 2040 and 2050 assumed in the main scenarios are directly taken from TYNDP 2022 (15 €/MWh in 2040 and 2050).
121 Dutch TTF gas Futures prices Link

The results of the S1 H_2-Interconnected-HighNGprice highlight the potential role for low-carbon hydrogen as a transition fuel which eventually will be replaced by renewable hydrogen in the medium- to long-term, as renewable electricity becomes increasingly more available. Given the climate targets, renewable hydrogen should be the prevalent option to supply future hydrogen demand. **Low-carbon hydrogen can act as a hydrogen market facilitator and enabler to start the development of a pan-European H_2 network** as the case of a recently announced pipeline linking Norway and Germany shows.[122]

Hydrogen import terminals increase security of supply

Shipped hydrogen imports are not identified as a major part of the optimal supply mix to meet gaseous hydrogen demand until 2050 in the scenarios where a pan-European H_2 network is developed (S1 H_2-Interconnected, S2 H_2-Interconnected) due to the rigorous cost optimisation approach applied in the ESM. Demand for gaseous hydrogen in these scenarios is met mainly by domestic hydrogen production through electrolysers complemented by renewable pipeline imports from North Africa and Ukraine, and low-carbon hydrogen produced in Norway and the UK.

However, hydrogen import terminals will play a key role for Europe to achieve an affordable, secure, and sustainable energy supply. Various parties along the value chain, including governments, are currently working on agreements for shipped hydrogen imports from outside Europe.[123] For multiple European countries, shipped hydrogen imports will be valuable to diversify the supply of gaseous hydrogen and to supply the chemical industry and refineries with renewable or low-carbon hydrogen derivatives such as ammonia or methanol located near ports. These imports can also supply hydrogen for synthetic fuels in the transport sector, especially for long-distance freight transport, maritime shipping, and aviation.[124, 125]

If the scale-up of renewable electricity generation in Europe is lower than expected, this would impact the security of supply and need for shipped hydrogen imports. To identify what the value and role of shipped hydrogen imports could be in such a constrained scenario, the applied upper limits of the ESM for solar and wind power investments were reduced by 10% in 2030, 2040, and 2050 (Table 3). This reduction mimics a scenario where the deployment of renewable energies stays behind targets, for instance due to the "not in my backyard" (NIMBY) public acceptance issues. This occurs where local communities are opposed to the building of, for example, wind turbines in their local area.

Table 3: Upper limits for onshore, offshore, and solar PV capacity considered in S1 H_2-Interconnected and S1 H_2-Interconnected -LowRES

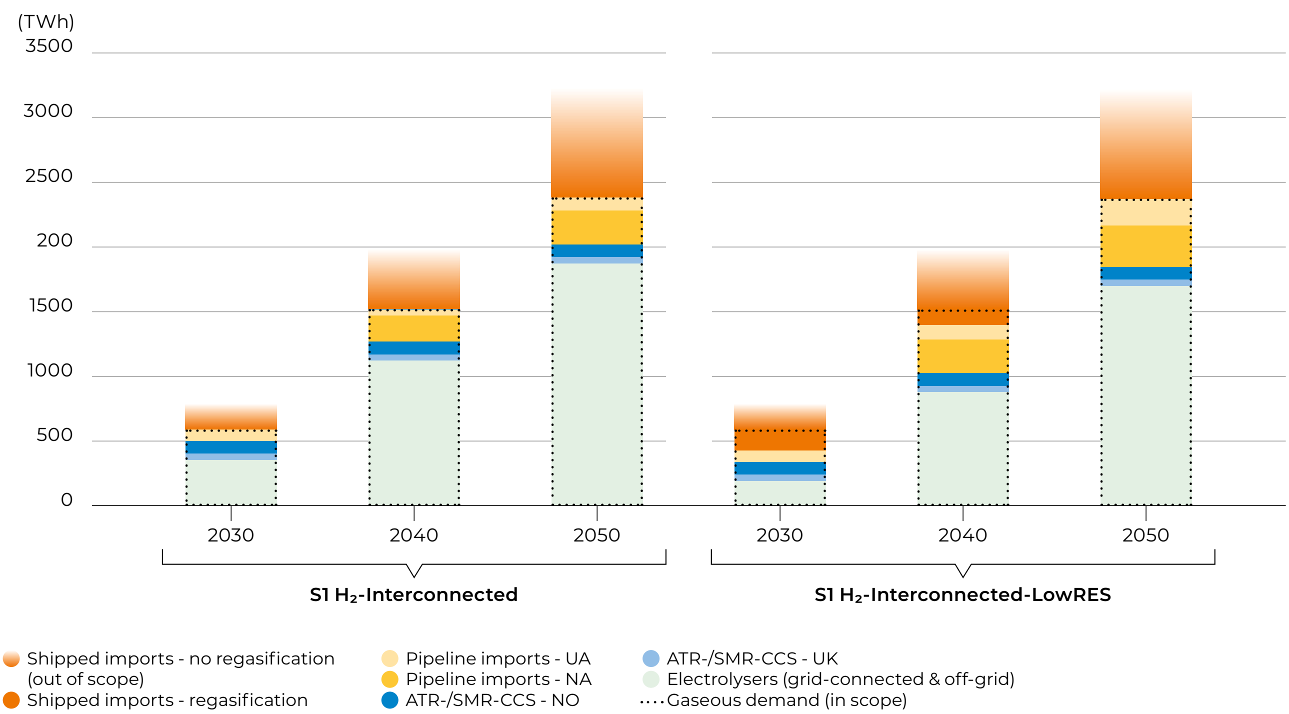
	2030	2040	2050
Onshore wind (S1 H_2-Interconnected / S1 H_2-Interconnected -LowRES)	439 / 396 GW	716 / 644 GW	927 / 834 GW
Offshore wind (S1 H_2-Interconnected / S1 H_2-Interconnected -LowRES)	174 / 157 GW	332 / 300 GW	473 / 426 GW
Solar PV (S1 H_2-Interconnected / S1 H_2-Interconnected -LowRES)	638 / 574 GW	1287 / 1158 GW	1764 / 1587 GW

122 Equinor announced plans to send an initial 2 GW of low-carbon hydrogen to Germany through a new hydrogen pipeline by 2030 Link
123 Gas for Climate (2022). Facilitating hydrogen imports from non-EU countries Link
124 IEA (2019). The future of hydrogen Link
125 Gas for Climate (2020). Gas decarbonization pathways 2020 – 2050 Link

The impact of such an upper bound can be seen in Figure 30 below which compares the development of the annual supply for gaseous hydrogen between the S1 H_2-Interconnected and S1 H_2-Interconnected-LowRES. It can be observed that a reduced deployment of solar and wind power capacity results in the need to supply parts of the gaseous hydrogen demand by shipped imports in 2030 and 2040 and import more renewable hydrogen via pipelines from neighbouring regions, as there is a lower potential to produce renewable hydrogen domestically. In the long run, the ESM shows that with a reduced upper bound of only 10% for solar and wind power, regasification of shipped hydrogen imports would no longer be needed in 2050 because the domestic renewable hydrogen production together with pipeline imports would still be high enough to meet demand. It is, however, hard to predict whether in 30 years developments like for instance the NIMBY effect would still hamper the production of renewable hydrogen. Furthermore, by then only the marginal costs for shipped hydrogen will be relevant, as liquefaction and regasification terminals do already exist. Nevertheless, even though they are not utilised in 2050 for regasification according to the rigorous cost optimisation approach applied, the import terminals play an important role also in the long-term to ensure sufficient market competition and provide back-up capacity in the case of any supply interruption from the other resources.

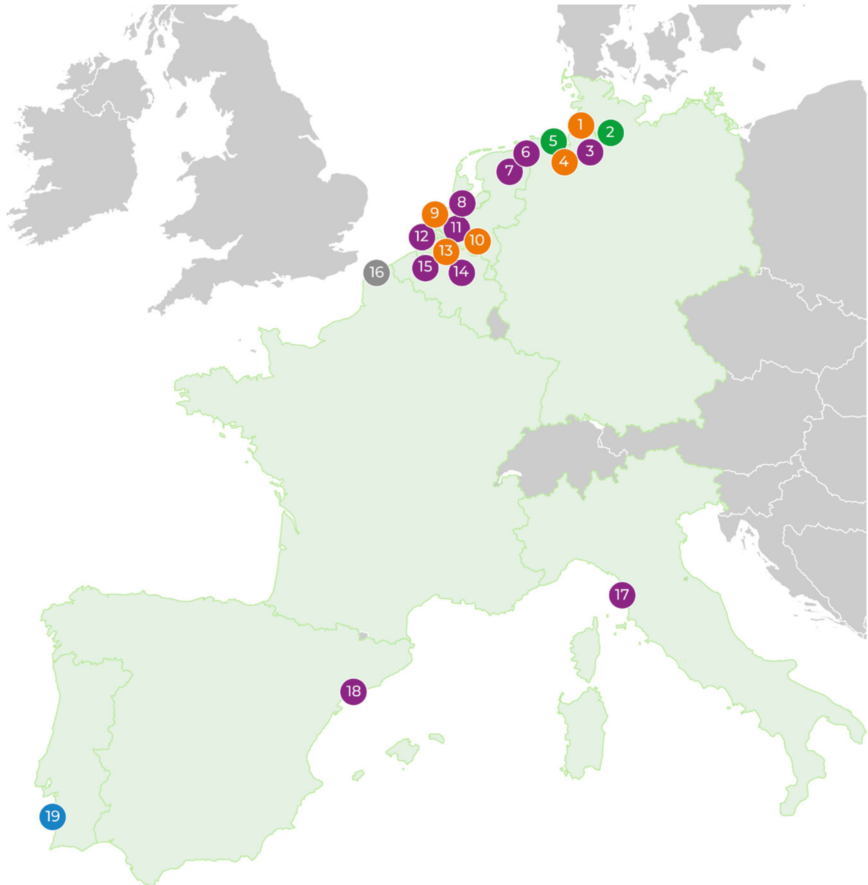
The biggest cost-driver for hydrogen transport via ships are conversion losses.[127] Hydrogen can be imported via ships as a liquid or as various energy carriers, such as ammonia, liquid organic hydrogen carriers (LOHCs), methanol or synthetic methane. These carriers have similar value chains including hydrogen production, conversion, storage, shipping and, if needed, reconversion.

Figure 30: Annual supply of gaseous hydrogen demand over timeframe 2030 - 2050[126]



126 Shipped imports that are not reconverted into gaseous hydrogen only indicative as supply for hydrogen derivatives and synthetic fuels is out of scope of this study. Visualised values based on imported decarbonised liquids into EU27 according to TYNDP 2022 GA.
127 Guidehouse (2022). Covering Germany's green hydrogen demand: Transport options for enabling imports Link

Figure 31: Overview of existing plans for hydrogen import terminals across Europe[129]



Depending on transport conditions and final utilisation of the carriers, different conversion and/or reconversion losses apply. Therefore, it may be desirable to transport hydrogen and its derivatives in the form required by the end use to minimise conversion losses. In the short term, ammonia, methanol, and synthetic methane could offer competitive options as potential hydrogen shipping carriers. Currently, there are already several plans for import terminals of these carriers in western Europe, adding up to 4.4 Mt/y of hydrogen (see Figure 31).[128]

Based on the assumptions used, this study shows that where feasible, pipelines are the most cost-efficient way to transport large volumes of hydrogen. However, decisions for hydrogen imports will not solely be determined based on cost considerations, as security of supply aspects and market competition are equally important. Therefore, irrespective of the potentially higher costs, shipped hydrogen imports are not only an option where pipelines are not present or available but also represent in general an important element for the future European energy system when aiming for an affordable, secure, and sustainable energy supply.

128 Gas for Climate (2022). Facilitating hydrogen imports from non-EU countries Link
129 Gas for Climate (2022). Facilitating hydrogen imports from non-EU countries Link

Availability of renewable energy resources impacts location of hydrogen production

The aim of this study is to provide an overall quantitative assessment about the benefits of a pan-European H_2 network to foster the transition towards an affordable, secure, and sustainable European energy system as envisioned by the Green Deal.[130] The real-world version of the pan-European hydrogen system would materialise based on how individual projects achieve a higher or lower status of competitiveness compared to the level playing field perspective considered in this study. In particular, the concrete development of pan-European H_2 network will depend on various aspects inter alia where hydrogen can be produced cheapest and where future hydrogen demand is located, but also on non-economic factors (security of supply, regulatory aspects) and concrete actions of market participants.

ESMs, like the one used on the present study, provide guidance to system planners in identifying least cost system development pathways. These ESMs are fed by an extensive set of input parameters, some of which affect directly, or indirectly the cost competitiveness of alternative model choices and therefore the prediction of the future least cost expansion pathway. This least-cost solution can be very sensitive to some of these input parameters.

Climate variability is one example illustrating the sensitivity of results to factors indirectly driving the least cost solution. All scenarios in the present analysis point to renewable hydrogen produced via electrolysis in Europe as the dominant supply of hydrogen demand in all time frames analysed in the present study (2030-2050). This means that renewable hydrogen production will vary, not only from hour to hour and season to season but also between years. In all main scenarios of the present study the climatic year 2009 was used to determine solar, wind, and hydro resource availability. It was chosen as it is a representative year in terms of overall availability of renewable energy resources from an entire European perspective.[131] However, it also represents a year where annual capacity factors for on- and offshore wind power for the Baltic Sea countries[132] are between 4% and 16% respectively below the long-term average. Figure 32 compares the annual capacity factors for onshore wind for the individual bidding zones considered in this study based on the climatic year 2009 and 1995 with min./max. and long-term average values (1982-2019). The climatic year 1995 is significantly more favourable for the countries around the Baltic Sea in terms of wind availability.

Given that CAPEX for investment candidates (solar, wind, electrolysers, etc) and financial conditions (WACC) are the same for all considered bidding zones, the inter annual variability of the renewable resource and the proximity to hydrogen demand are the main competitiveness drivers for hydrogen production in each bidding zone. This means that the cost-optimal energy system, including the pan-European H_2 network, specified by the ESM will depend on the climatic year chosen for the analysis.

In order to explicitly quantify the effect of climatic variability on the results, a sensitivity run on scenario S1 H_2-Interconnected, using the climatic year 1995 to describe diurnal and seasonal variability of VRE availability was executed (S1 H_2-Interconnected-CY1995). This sensitivity gives insight into how the competitiveness of hydrogen production changes in different regions of Europe and consequently it's production. Figure 33 below provides the relative difference in hydrogen production between S1 H_2-Interconnected and S1 H_2-Interconnected-CY1995 for six regions.

130 European Commission (n.d.). A European Green Deal - Striving to be the first climate-neutral continent Link
131 The climatic year 2009 was also used in TYNDP 2022 within capacity expansion optimisation modelling.
132 Baltic Sea countries: Estonia, Finland, Latvia, Lithuania, Poland, Sweden.

Figure 32: Annual capacity factor of onshore wind power by bidding zone for climatic years 1995 and 2009[133]

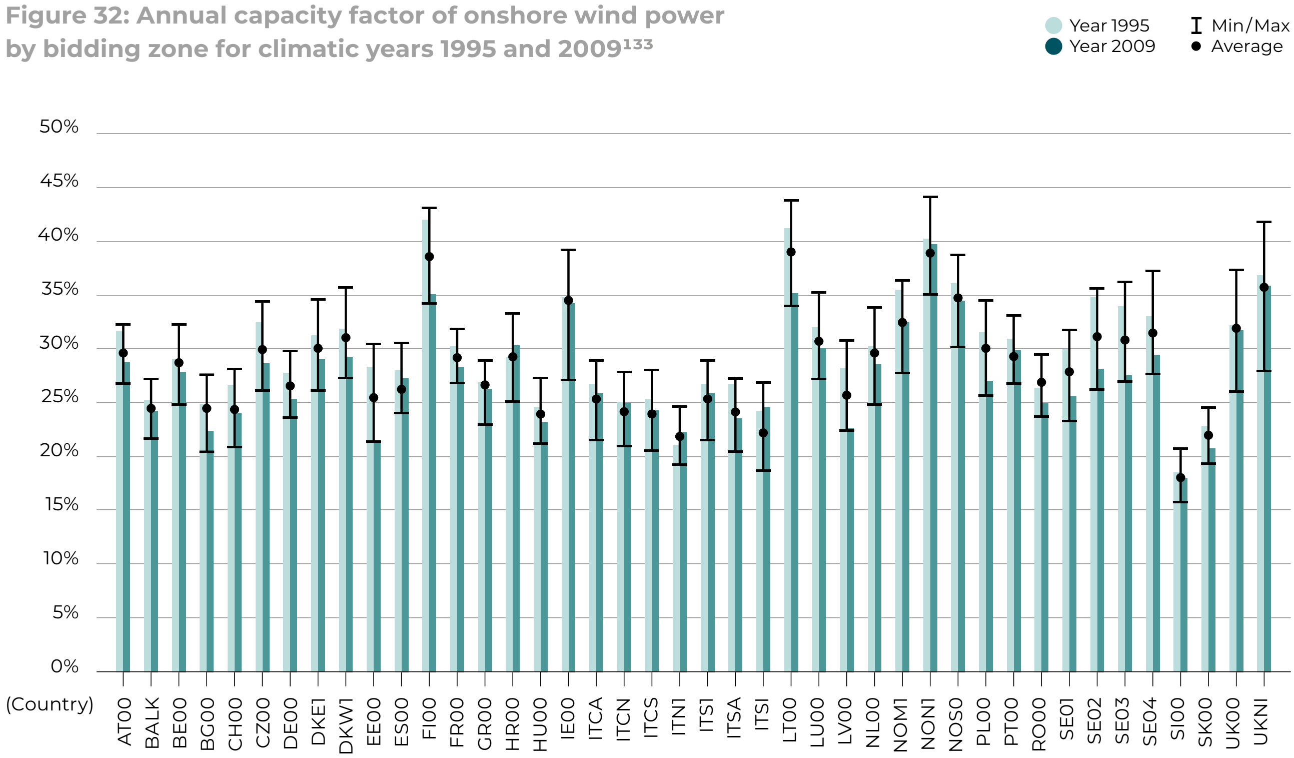
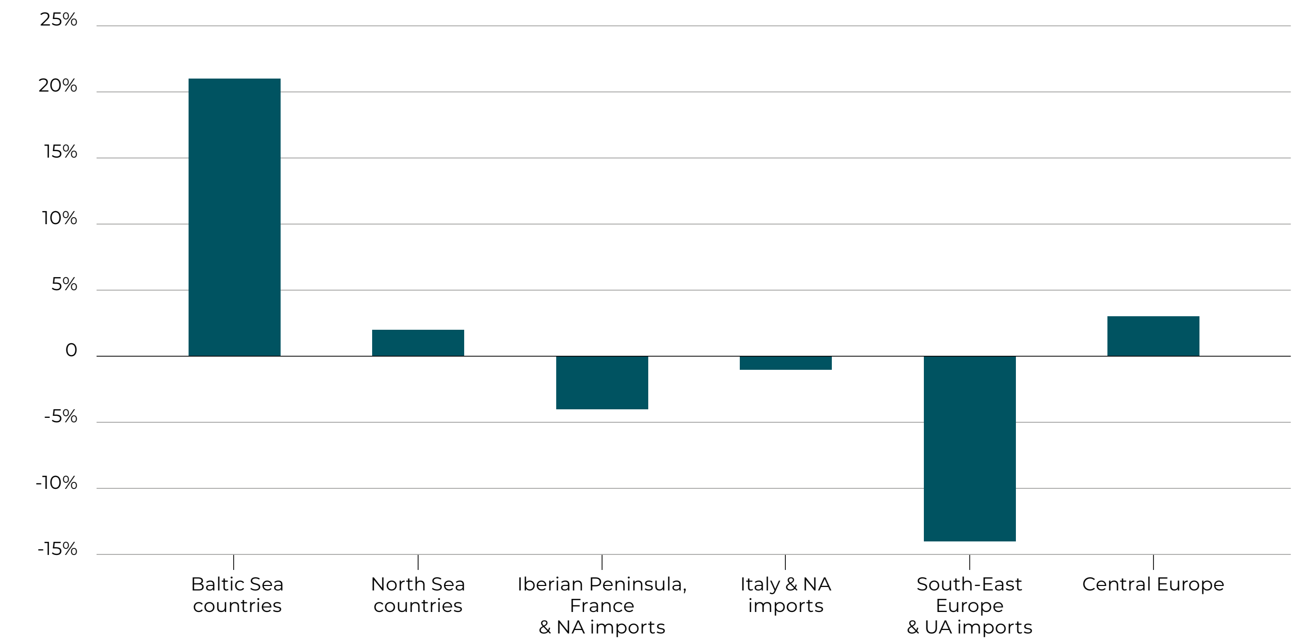


Figure 33: Change in hydrogen production by region in 2050 based on climatic year 1995 compared to climatic year 2009 (S1 H_2-Interconnected)



133 Capacity factors based on the PECD.

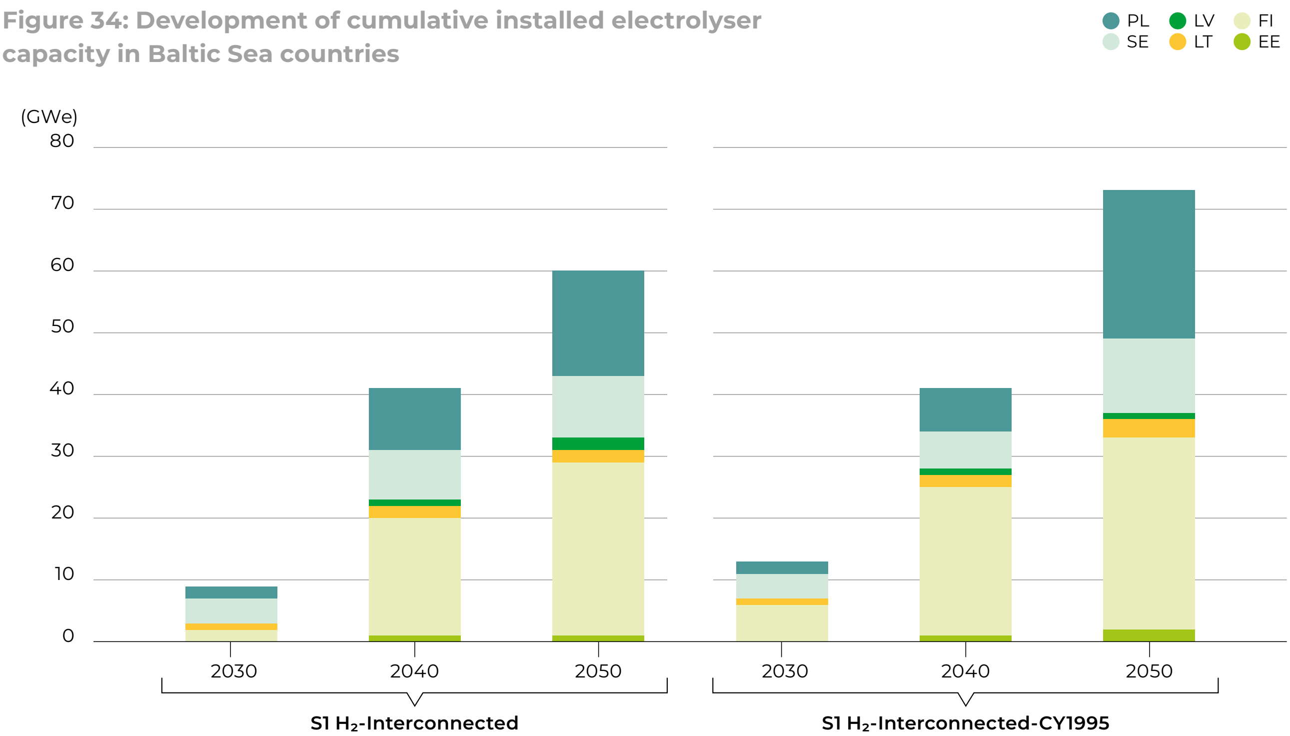
It can be noticed that North-central Europe, in particular the Baltic Sea countries, would produce in excess of 20% more renewable hydrogen in 2050 for the climate year 1995, compared to the base 2009 climatic year used throughout the present study. It should be noted that this result is also affected by an upper limit for solar and wind power investments in each bidding zone using the maximum value for the respective technology from the TYNDP 2022 scenarios. Without such a constraint hydrogen production from the Baltic Sea countries could ultimately contribute with significantly higher hydrogen production to the overall hydrogen supply mix of the modelled system.

This is further evidenced in Figure 34, which provides the cumulative addition of electrolyser capacity in the Baltic Sea countries from 2030 to 2050 for S1 H_2-Interconnected (based on climatic year 2009) and S1 H_2-Interconnected-CY1995 respectively. It can be observed that in 2030 there is a threefold investment in electrolyser capacity in Finland in S1 H_2-Interconnected-CY1995 compared to the base scenario S1 H_2-Interconnected. Subsequently in 2040 and especially in 2050, as the upper capacity constraint for wind and solar power potentials is activated, thereby limiting the further expansion of electrolysers in Finland, the ESM further invests in the region, primarily in Poland and Sweden where constraints still leave room for such investments.

The different timing and distribution of electrolyser investments in the Baltic Sea countries also impacts related investments in hydrogen-cross-border transmission capacity. Total hydrogen cross-border transmission capacity connecting Finland with neighbouring countries in 2050 increases by almost 10% in S1 H_2-Interconnected-CY1995. Due to the accelerated investments into electrolyser capacity, which are also accompanied by larger investments in on- and offshore wind power plants, investments in hydrogen cross-border capacities connecting Finland with its neighbours are preponed and hydrogen exports increase by more than 20 TWh in 2030 compared to the base scenario S1 H_2-Interconnected.

This example provides an indication of how the least-cost expansion of an energy system can diverge from what one cost-optimal solution dictates based on a specific set of input assumptions and how, by implementing policies that facilitate a rapid renewable deployment, countries and regions can have an impact on how the pan-European H_2 network ultimately develops. However, we should stress that in all three sensitivity cases presented here the overall results are robust in terms of how the five supply corridors of the pan-European network develop as a least-cost solution by the ESM.

Figure 34: Development of cumulative installed electrolyser capacity in Baltic Sea countries



5. Policy recommendations

The analysis underpinning this study demonstrates the significant contributions of a pan-European H_2 network and an accelerated biomethane uptake towards an affordable, secure, and sustainable European energy system. To realise these benefits, immediate actions are needed by policy makers. Gas for Climate has been investigating the requirements for both hydrogen infrastructure deployment as well as biomethane integration into the energy system since 2017 in various publications. The policy and regulatory environment can either accelerate or seriously delay relevant developments. This is particularly important as several key pieces of legislation have been proposed by the Commission in recent years and are currently debated in the European Parliament and the Council.[134] The policy recommendations below aim to provide a clear set of actions that can be undertaken on EU level to achieve a rapid deployment of renewable and low-carbon gases.

- **Approve and implement key EU legislative proposals pertaining to renewable and low-carbon gas infrastructure as soon as possible**. Clarity on the hydrogen and decarbonised gas market package, RED II recast and RED II Delegated Act on Article 27 (RFNBO) is crucial to allow the hydrogen and biomethane industries to develop. To meet the REPowerEU ambition of 10 Mt/y of domestic production, 10 Mt/y of hydrogen imports and 35 bcm of biomethane by 2030, these targets should be translated to binding legislation to give a strong market signal.
  a. **Hydrogen**. Gas TSOs are the operator of choice for hydrogen infrastructure given their long-standing experience in transporting gas. It is important to ensure that the skills and knowledge developed through the years are best used in the development of a Pan-European H_2 network. Furthermore, when developing the necessary network development plans, the acquired competences shall be duly used whilst safeguarding the flexibility and versatility required in the ramp-up phase of a nascent market. On the national level, a legally binding integrated network development planning process for gas (methane and hydrogen) should be introduced. We also fully support the proposal of the European Parliament to remove horizontal unbundling from the recast Directive on gas markets and hydrogen.[135]
  b. **Biomethane**. The European Parliament's proposal also indicates progress on biomethane. Facilitating the scale-up of biomethane in the current natural gas system, e.g., through regional feedstock potential mapping, is a priority.[136] In terms of feedstock potentials, Gas for Climate scenarios show a significant role for sequential cropping.[137] To unlock this, silage crops grown in a sequential cropping system should be included in Annex IX Part A of the RED II (advanced biofuel and biogas feedstocks; without production cap).[138]
- **Increase funding and financing mechanisms for early-stage hydrogen infrastructure development**. Our analysis shows an investment need of €70 to €80 billion for cross-border hydrogen connection[139]. In the current early market phase of the hydrogen economy, the existing infrastructure re-financing model using tariffs is not fit for purpose as the few offtakers would have to bear the full costs. While there is funding available for cross-border energy infrastructure, e.g., through Connecting Europe Facility - Energy (CEF-E), this is not sufficient. Additional financial aid is needed to kick-start hydrogen infrastructure deployment, for instance through CAPEX funding or subsidies tariffs. To realise favourable financing conditions, the approach of taxonomy to infrastructure

134 Hydrogen and decarbonised gas market package, recast of the Renewable Energy Directive, Delegated Acts on Renewable Fuels of Non-Biological Origin, update of the EU Emission Trading System and introduction of the Carbon Border Adjustment Mechanism, amongst other.
135 Committee on Industry, Research and Energy (2023) Compromise amendments on the proposal for a regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (recast) (COM(2021)0804 - 2021/0424(COD)) Link
136 Ibid.
137 Gas for Climate (2022). Biomethane Production Potentials in the EU Link.
138 Gas for Climate analysis further eleborates the justfification for sequantial cropping to be included in RED II Annex IX Part A feedstocks. See Gas for Climate (2021). Sequential Silage Crops as Advanced Feedstock under the EU RED II. Link.
139 These costs are only referring to the transmission capacity needed to connect modelled bidding zones and do not reflect detailed national transmission network cost.

should be streamlined and revised to ensure that repurposing of gas infrastructure to enable that the pan-European hydrogen network is considered taxonomy aligned.

- **Ensure rapid development and appropriate remuneration of underground hydrogen storage**. This report shows that large-scale hydrogen storage will be a core component of the pan-European H_2 network. It will play a key role in balancing energy supply and demand (especially longer-term) and provide energy security services. Storage should become a competitive market across Europe. In early phase of this market, strong incentives for commercial flexibility are needed in the regulatory framework to scale up prospective hydrogen storage projects for different types of clients. However, the lead times for underground storage are long (3-10 years), while this report already shows the need for 90-110 TWh of large-scale hydrogen storage in 2030 and between 450-500 TWh in 2050. Thus, storage capacities need to start being developed as soon as possible. Currently, there is no financing and remuneration model for hydrogen storage in place. Without, it is unlikely that greenfield developments or repurposing of natural gas storage assets will take place at the scale required.[140]
- **Update the natural gas quality standard to ensure more biomethane integration into the gas network**. The Commission should task the European Committee for Standardisation to assess and, if necessary, update the quality standard for cross-border gas to facilitate the greening of the gas system (i.e. if it allows for a twelvefold increase of biomethane injection to the grid in a cost-effective manner). Furthermore, it should be stipulated that Member States must not restrict cross-border flows of biomethane and other green gases.
- **Establish the certification and trading framework for renewable and low-carbon gases as soon as possible**.[141] The Union Database and gas guarantees of origin (GO) systems are crucial to enable the development of a transparent and liquid renewable and low-carbon gas market. When implementing these systems, three key recommendations should be considered. First, streamline the Union database and gas GO systems to work together to enable tracing of sustainability information, trade of gases, and to provide a robust accounting mechanism that can be applied for Member State target accounting and voluntary disclosure purposes.[142] Second, allow renewable gases injected into the gas grid to be withdrawn flexibly in the EU if the grid is physically interconnected.[143] Third, extend the Union database to cover renewable fuels used in all energy sectors.[144]
- **Facilitate the scale-up of hydrogen imports to meet REPowerEU targets and support supply diversification**. More in-depth understanding of the integration of hydrogen import infrastructure in the energy system is needed. Import considerations should be included in long-term (hydrogen) infrastructure planning (as part of the TYNDP), covering both pipeline connections, as well as hydrogen (carrier) import terminals. To support this, PCI and PMI decisions would need to be made timely to accelerate implementation of projects. Policies should encourage international cooperation and partnerships in the field of renewable and low-carbon gas.
- **Consider benefits across sectors in the PCI CBA assessment methodology for candidate hydrogen projects to foster sector integration**. The present study has identified substantial benefits for the electricity system, due to the realisation of a pan-European hydrogen system. The cost benefit analysis (CBA) methodology for assessing hydrogen projects should be updated in order to allow the quantification and monetisation of such benefits from an integrated system perspective.

140 The current model for natural gas storage cannot be transferred 1:1 to hydrogen storage. First, seasonal price spreads are likely to be much lower for hydrogen than for natural gas, minimising the revenues of hydrogen storage operators. Second, the security (of supply) value of hydrogen storage assets needs to be recognised and properly monetised to create a viable business model.

141 Detailed recommendations on this point can be found in section 2.4.5 in Gas for Climate (2021). Fit for 55 Package and Gas for Climate Link.

142 In practical terms, the transfer of gas GO from a Member State registry into the Union database should be allowed, at which point a tradeable Union database GO (or equivalent) is created. The original gas GO should be cancelled from the Member State registry upon registration in the Union database to avoid double counting.

143 The system must also allow for the use of imports of renewable gases produced outside the EU. This recommendation is similar to the Parliament's proposal in the Gas Directive on Certification of renewable and low-carbon fuels certification of renewable and low-carbon fuels (Article 8). Committee on Industry, Research and Energy (2022). DRAFT REPORT on the proposal for a directive of the European Parliament and of the Council on common rules for the internal markets in renewable and natural gases and in hydrogen (recast) (COM(2021)0803 – C9-0468/2021 – 2021/0425(COD)) Link.

144 An extension of the Union database to cover all end-use sectors (not just transport) was proposed in the RED II revision. As renewable gases injected into the grid are used in all sectors, it is critical this extension is implemented for gases from the start of the database.

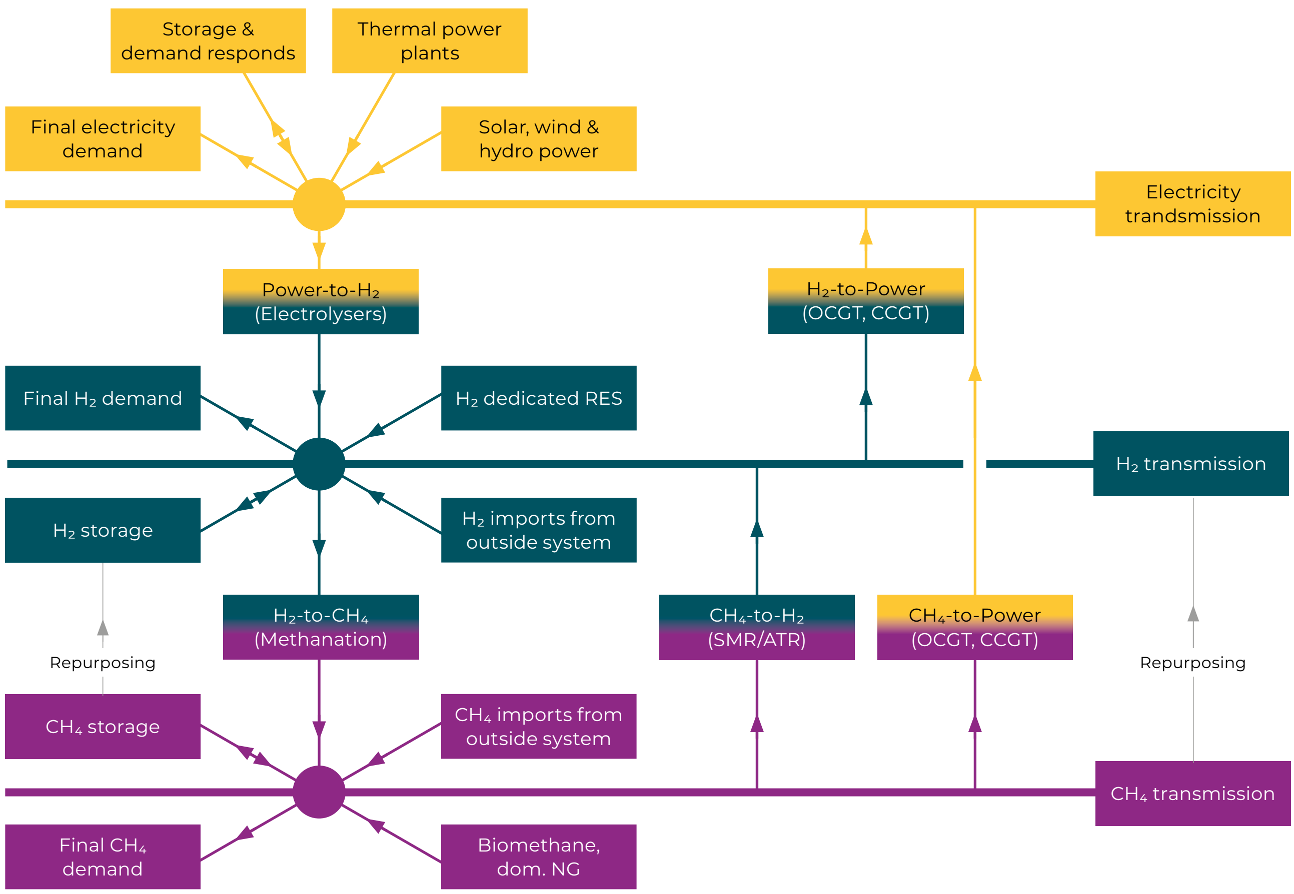
Appendix: Major modelling assumptions

Integrated energy system modelling approach

The applied ESM in this study considers interdepenencies between electricity, hydrogen, and methane systems when optimizing the supply of future energy demand. Figure 35 shows how the electricity, hydrogen, and methane systems are coupled in the ESM. For each of the three energy carriers a final demand is exogenously. The final demand for electricity, hydrogen, and methane needs to be supplied by domestic resources, imports from other bidding zones or imports from outside the modelled system.

The electricity system is coupled with the hydrogen system through grid connected electrolysers and hydrogen fired OCGT and CCGT power plants. The electricity and methane system are linked through OCGTs and CCGTs supplied by natural gas and/or biomethane. The hydrogen and methane system are coupled through methanation plants and SMRs/ ATRs. The methane and hydrogen system are further linked as existing methane transmission and storage capacity can be repurposed for hydrogen usage which is optimised endogenously.

Figure 35: Integrated modelling across electricity, hydrogen, and methane sectors



The additional demand through the conversion of one energy carrier to the other and related losses is modeled endogenously. For example if an electrolyser is dispatched to produce hydrogen this leads to an additional electricity demand that needs to be supplied. Based on how the systems are coupled in the ESM the following demands are modelled endogenously:

- Hydrogen and methane demand for electricity generation,
- Electricity demand for hydrogen generation through electrolysers,
- Hydrogen demand to produce synthetic methane, and
- Methane demand to produce hydrogen through SMRs/ATRs

The integrated modelling across the three systems ensures that investment and dispatch decission are optimised from a whole system perspective considering the interdependencies between the individual energy carriers and related systems.

Final demand scenario

The final annual demand for electricity, hydrogen, and methane in the end-use sectors over the timeframe 2030 – 2050 considered in this study is based to a large extent on the TYNDP 2022 GA and DE scenarios.[145] In the case of hydrogen and methane, final demand figures for the year 2030 were adjusted based on the REPowerEU plan.[146]

To become independent from Russian natural gas imports, the REPowerEU plan sets inter alia a target to produce 333 TWh (10 Mton) of renewable hydrogen domestically by 2030. Furthermore, up to 333 TWh (10 Mton) of hydrogen from outside of the EU27 shall be imported in 2030, of which 133 TWh (4 Mton) as ammonia. To account for this uptake of domestically produced and imported hydrogen, final hydrogen demand of the EU countries in scope of this study is set to 533 TWh in 2030 for S1 and S2. The targeted 133 TWh of ammonia imports are neglected in this context as it is assumed the imported ammonia is used to supply the demand for liquids/e-fuels.[147]

The additional hydrogen uptake in 2030 is distributed proportional to the final hydrogen demand of the individual countries according to the TYNDP 2022 GA and DE. It is assumed that the increased availability of hydrogen is taken up by the industrial and transport sector and replaces final methane demand in these sectors accordingly. Figure 36 – Figure 41 present the annual final demand for electricity, hydrogen, and methane by country for the years 2030, 2040, and 2050 for both S1 and S2.

Annual final demand per country or bidding zone for electricity, hydrogen, and methane was specified and converted into hourly demand time-series based on the climate year 2009. The hourly final electricity demand time-series are directly taken from TYNDP 2022. As hourly final demand time-series for hydrogen and methane are not published in TYNDP 2022, the respective time-series were developed using data published by the When2Heat project and information about demand for hydrogen and methane in the individual end-use sectors specified in TYNDP 2022.[148]

145 Final demand for electricity and methane in Switzerland and Northern Ireland is based on Swiss Federal Office of Energy (2021). Energieperspektiven 2050+ Link and Department for the Economy (2021). Future energy decarbonization scenarios – Northern Ireland Link respectively as such data is part of the TYNDP scenarios. In the case of Norway and the non-EU countries of the Balkan region, demand for hydrogen and methane in the end-use sectors is not considered within the analysis.
146 European Commission (2022). REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition. Link
147 Final demand for solids and liquids are out of scope of the analysis due to the limited impact on energy cross-border infrastructure.
148 Ruhnau, O., Muessel, J. (2022). When2Heat Heating Profiles. Open Power System Data Link

Figure 36: Annual final electricity demand by country in 2030, 2040, and 2050 (S1)

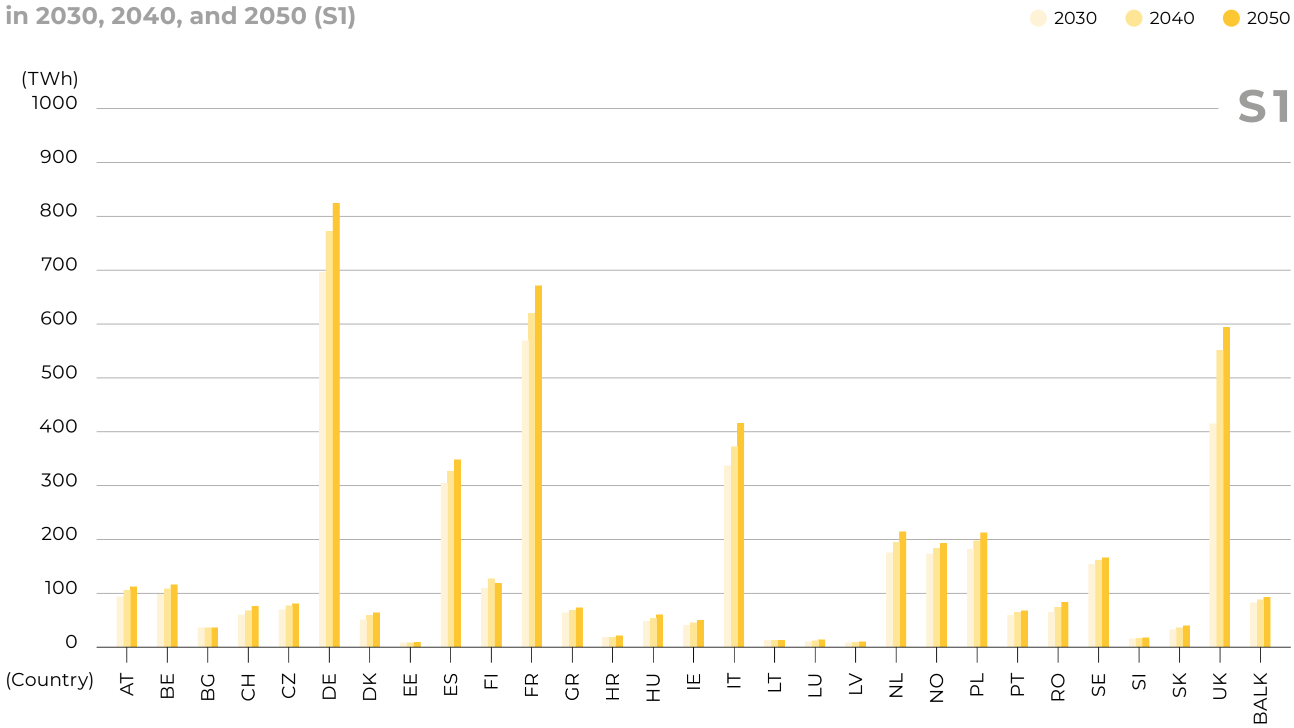


Figure 37: Annual final electricity demand by country in 2030, 2040, and 2050 (S2)

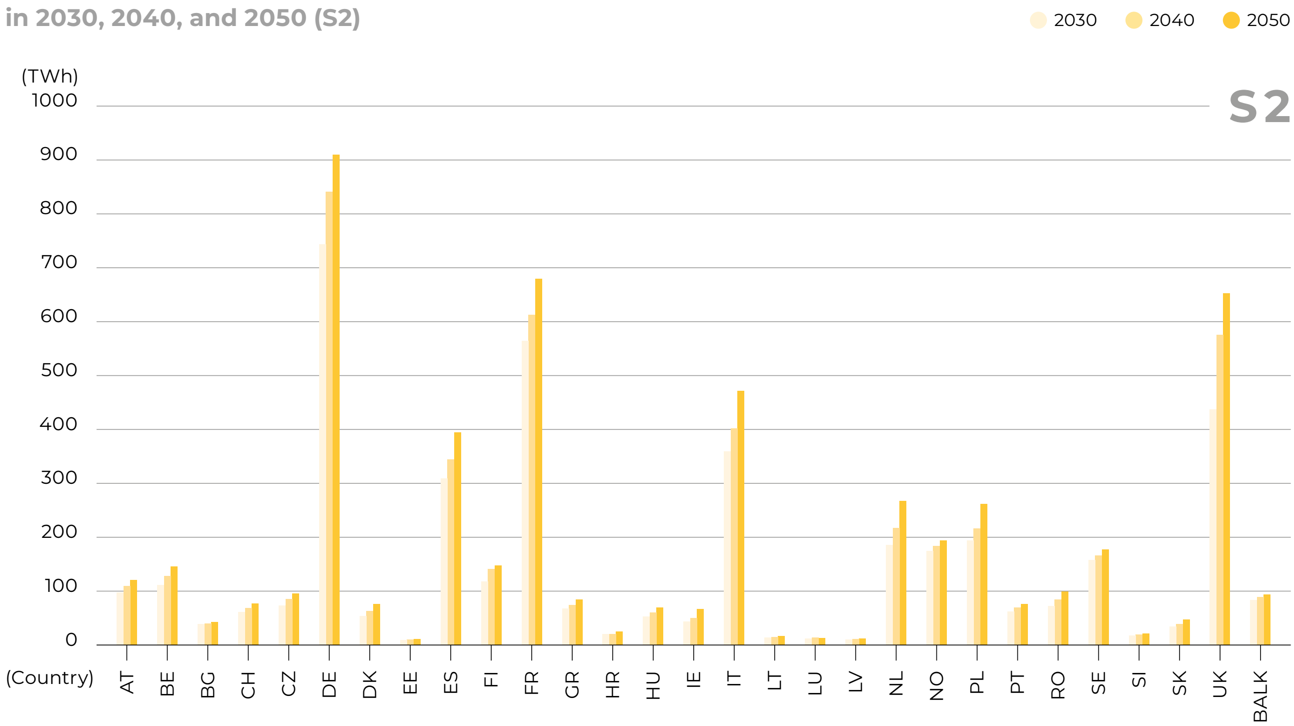


Figure 38: Annual final demand for hydrogen by country in 2030, 2040, and 2050 (S1)

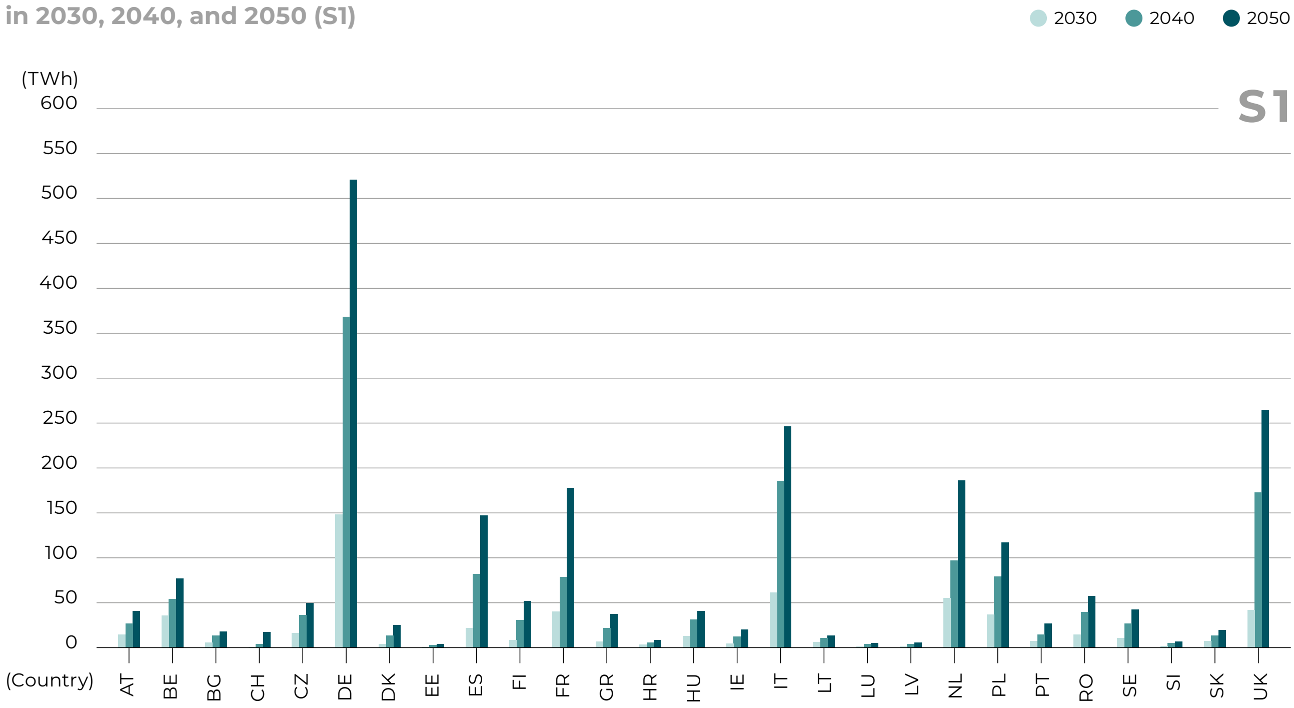


Figure 39: Annual final demand for hydrogen by country in 2030, 2040, and 2050 (S2)

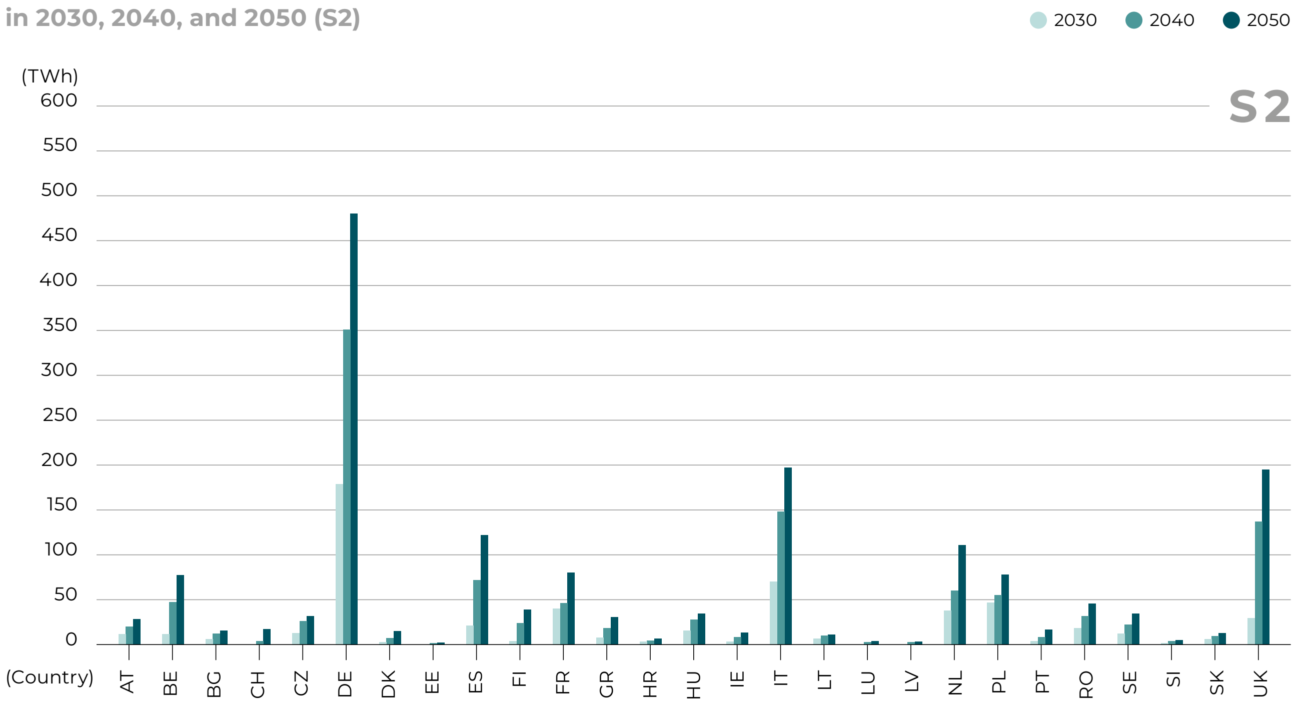


Figure 40: Annual final demand for methane by country in 2030, 2040, and 2050 (S1)

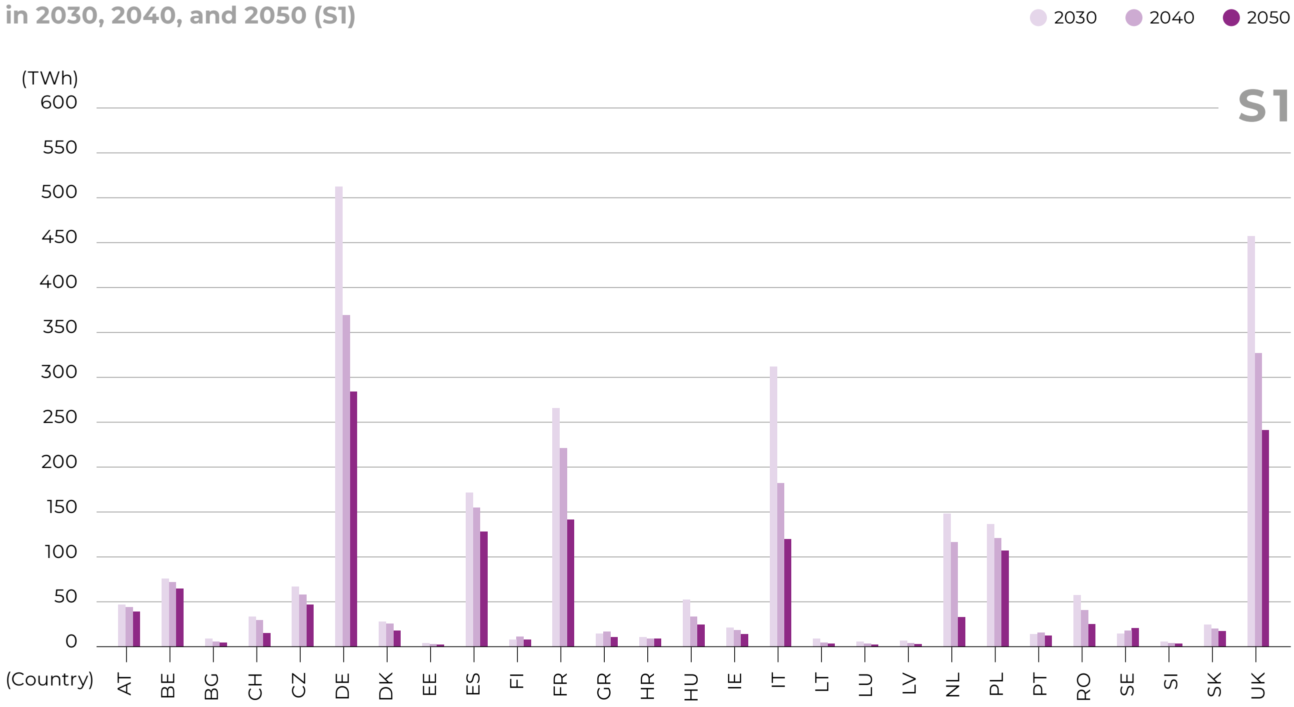


Figure 41: Annual final demand for methane by country in 2030, 2040, and 2050 (S2)

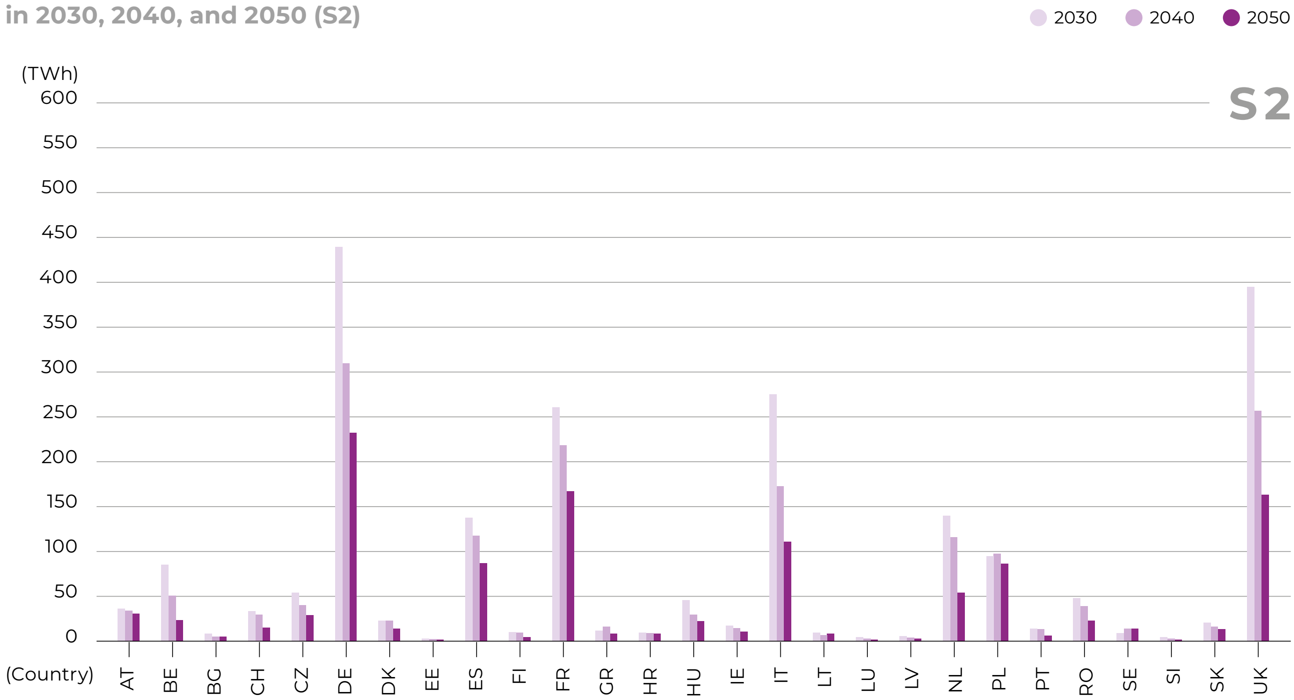
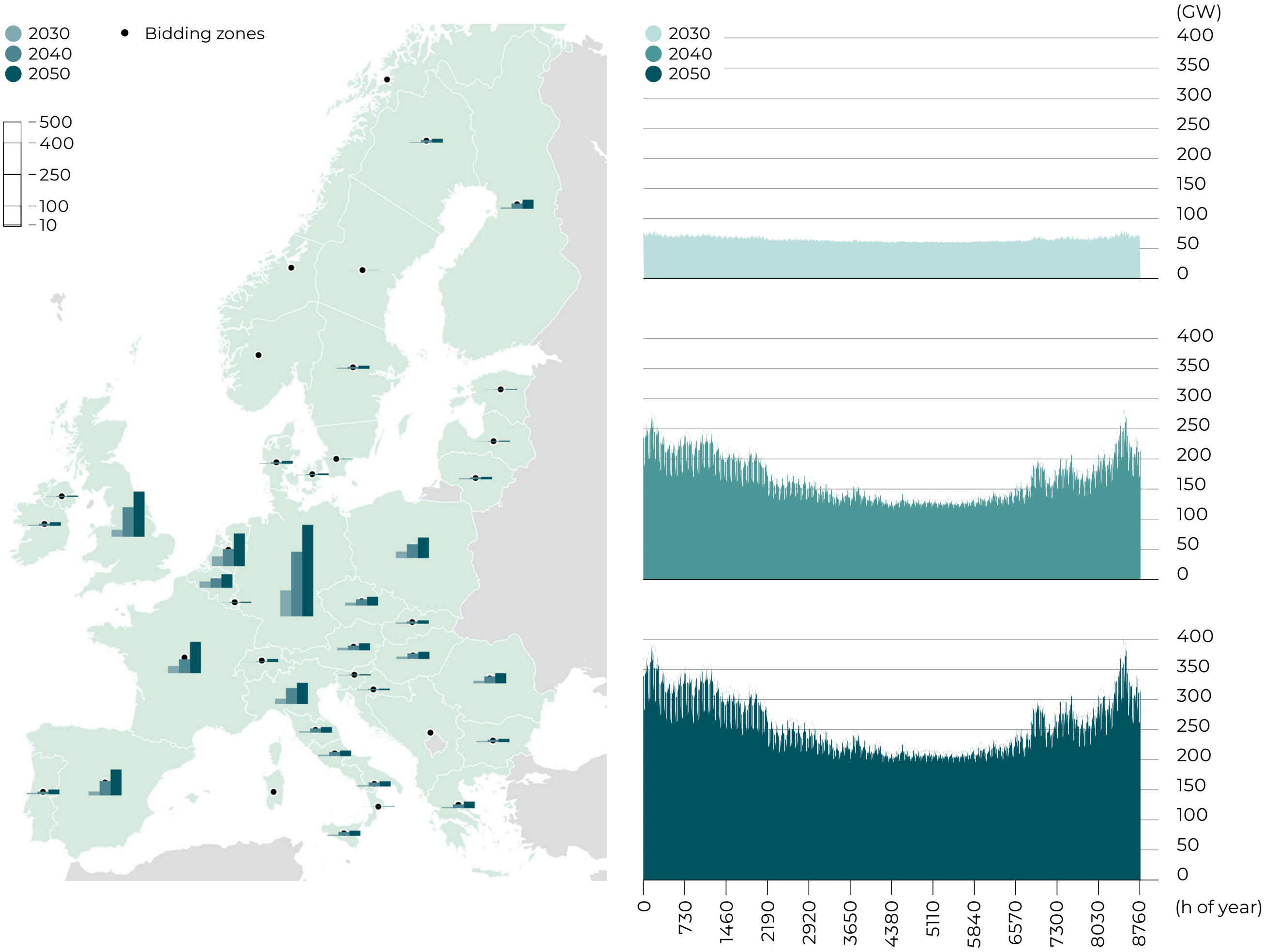


Figure 42: Annual final demand for hydrogen by bidding zone (left) and hourly hydrogen demand of the entire system (right), both for S1



When developing the hourly final hydrogen and methane demand time-series, the annual demand for space and water heating according to TYNDP 2022 was distributed over the year based on the hourly When2Heat profiles for the climate 2009. A flat profile was assumed for hydrogen and methane usage in all other sectors (industry, transport, etc.). The end-use sector specific hourly final demand time-series were stacked to quantify the total final hourly demand time-series for the respective energy carrier in each bidding zone. Figure 42 presents exemplarily the annual final demand for hydrogen by bidding zone (left) and the hourly final hydrogen demand for the entire system for S1.

Exogenously defined capacities

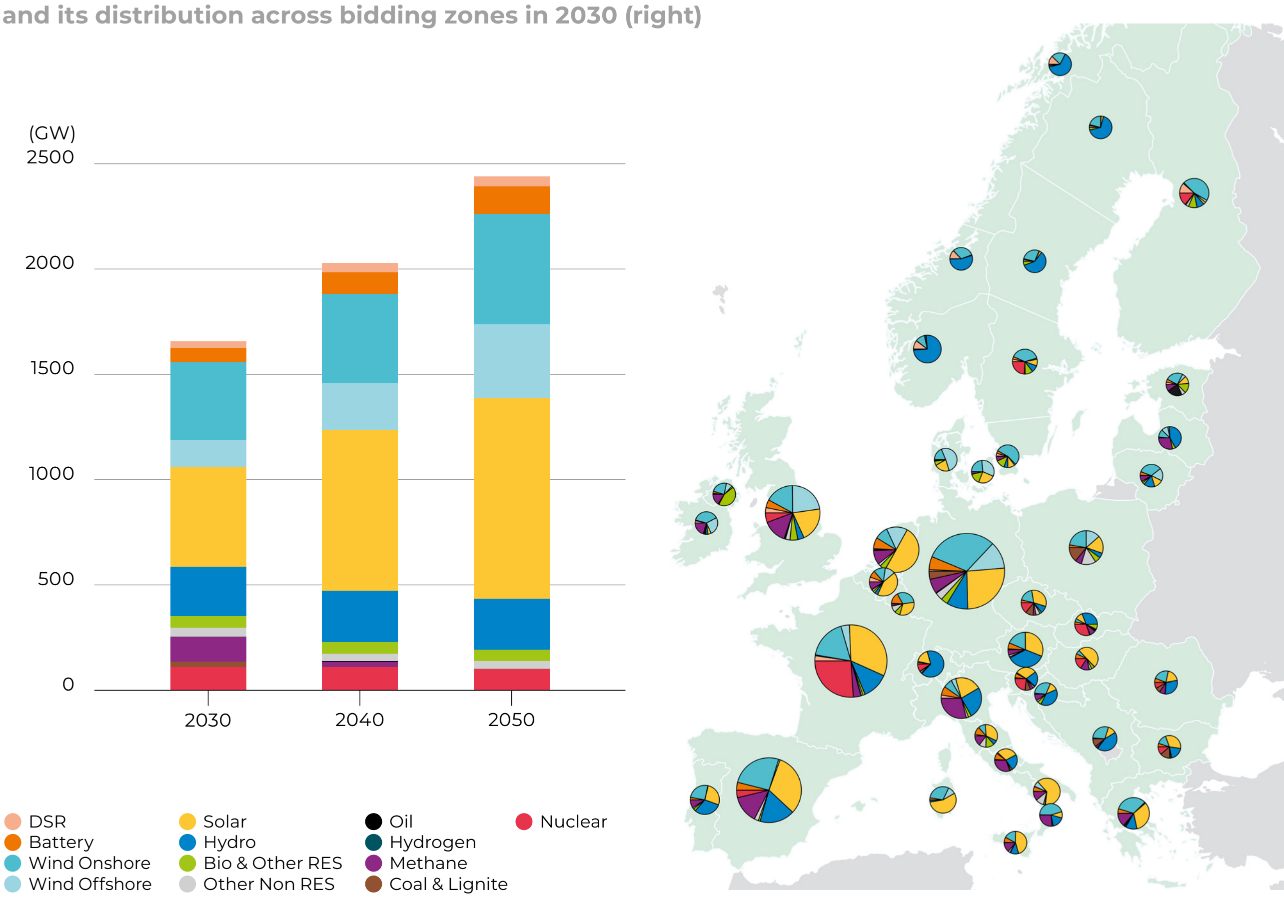
Some of the installed capacity is exogenously defined over the timeframe 2030–2050, i.e. scenario defined and not optimised by the ESM for the individual scenarios. Figure 43 shows the predefined capacity of the entire electricity system aggregated by fuel type over the timeframe 2030 – 2050 as well as its distribution across the considered bidding zones in 2030.

The installed capacity of the nuclear power plant fleet is based on TYNDP 2022 GA and DE, with the exception that some of the nuclear power plants in Belgium are assumed to still be in operation in 2030.[149] Installed capacities under the categories hydro power, Bio and other RES, other Non RES, and DSR are based on TYNDP 2022 GA and DE.

For onshore and offshore wind power, solar power, and batteries the predefined capacity over the timeframe is determined by using, for the year 2030, the minimum value for the respective technology given in the TYNDP 2022 GA and DE scenarios. For the years 2040 and 2050 for the respective technology the predefine capacity is determined by assuming 85% of the minimum value of the TYNDP 2022 GA and DE scenarios. Additional investments beyond the predefined capacities for solar, wind, and batteries in each bidding zone over the timeframe 2030 – 2050 is optimised endogenously. The upper bound for investments in solar, wind and batteries in each bidding zone and year is defined by using the maximum value for the respective technology of the TYNDP 2022 GA and DE scenarios.

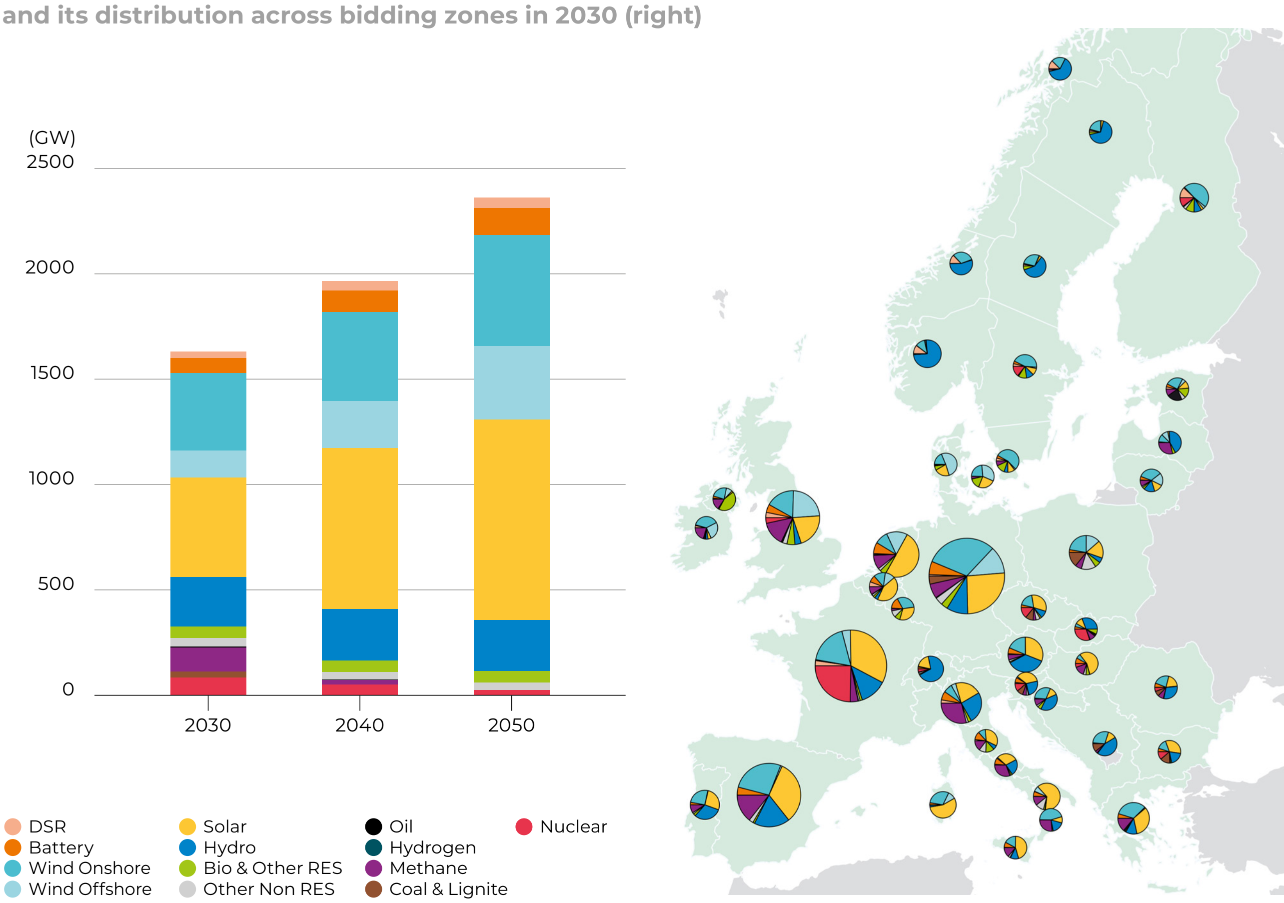
Exogenously defined installed capacity of hard-coal, lignite, methane, and oil-fired power plants over the timeframe 2030 – 2050 is based on the World Electric Power Plant (WEPP) database which is maintained and updated by S&P Global Market Intelligence.[150] In the case of hard-coal and lignite fired power plants, the decommissioning date of individual units was further refined to ensure installed capacity matches TYNDP 2022 GA and DE scenarios. In line with TYNDP 2022, until 2040 all coal fired power plants are decommissioned. No capacity for hydrogen fired power plants is predefined. Instead, installed capacity of OCGTs and CCGTs fired by hydrogen is optimised endogenously, as it is the case for additional methane fired power plants.

Figure 43: Predefined capacity of the electricity system (S1) for 2030 – 2050 (left) and its distribution across bidding zones in 2030 (right)



149 Euronews (2022). Nuclear energy Belgium postpones phase out by 10 years due to Ukraine war Link
150 S&P Global Link

Figure 44: Predefined capacity of the electricity system (S2) for 2030 – 2050 (left) and its distribution across bidding zones in 2030 (right)



Liquefied natural gas (LNG) import terminal capacities by bidding zone in 2030 are based on GIE's "LNG Import Terminals Map Database April 2022" and considers all existing, under construction, and planned projects until 2030.[151] Methane underground storage (UGS) capacity existing in 2030 in each bidding zone is based on GIE's "Storage Map 2021.[152] If not repurposed to be operated with hydrogen, which is optimised endogenously within the ESM, it is assumed that all methane storage capacity existing in 2030 is available until 2050.

Predefined electrolyser capacity is based on the respective hydrogen strategies of the countries in scope of this study. For countries which do not have an electrolyser target in place yet, the 'Hydrogen Electrolyzer Tracker' of Guidehouse Insights was used to determine installed electrolyser capacity in 2030.[153] The generation of the electrolysers, and therefore the load factor of the electrolyser is optimised endogenously in the model. The existing SMR capacity in 2030 is based on an internal low-carbon hydrogen supply projects database developed by Guidehouse and the Fuel Cells and Hydrogen Observatory (FCHO) database.[154] For countries that are represented by multiple bidding zones within the assessment, input from TSOs, TYNDP 2022 scenario data and own assumptions were applied to distribute the predefined capacities in 2030 across the respective bidding zones. All SMR units in 2030 are assumed to be equipped with carbon capture and storage (CCS) units. No hydrogen storage capacity was predefined, meaning that hydrogen storage capacities are optimised endogenously by the ESM for the respective scenario.

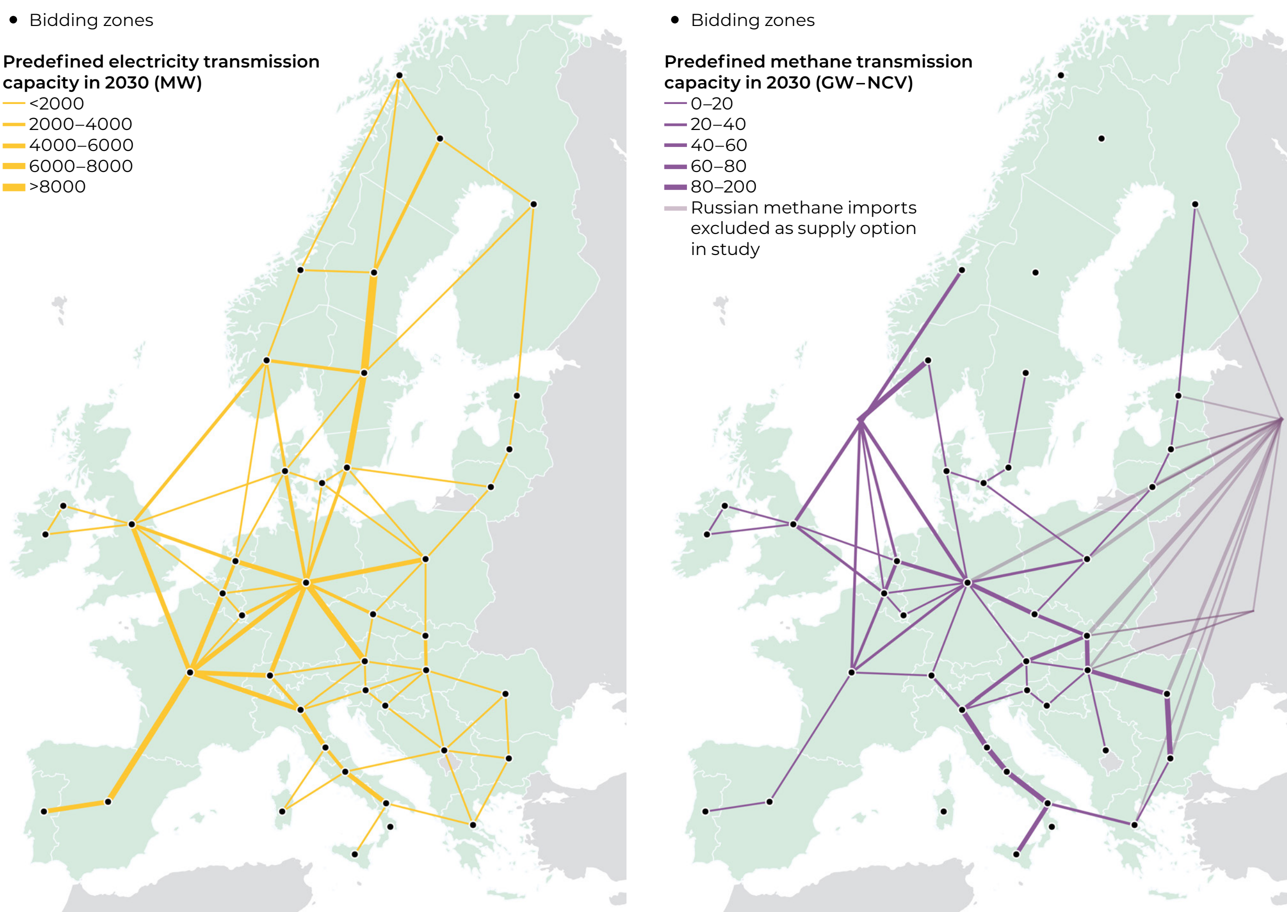
151 GIE LNG Database Link
152 GIE Storage Database Link
153 Guidehouse Insights (2021). Hydrogen Electrolyzer Tracker Link
154 Fuel Cells and Hydrogen Observatory database Link

Starting grid

Figure 45 presents starting infrastructure for the electricity and methane system in 2030. The electricity cross-border transmission capacity between bidding zones in 2030 is defined by using the minimum value of the TYNDP 2022 GA and DE scenario for the respective interconnection. Further expansion of electricity cross-border capacity over the timeframe 2030–2050 is optimised endogenously by the ESM.

The methane cross-border transmission capacity in 2030 is based on the ENTSOG/GIE "System Development Map 2020/2021" and its associated dataset as well as input provided by TSOs about currently under construction and planned projects.[155] Figure 45 (right) shows the methane cross-border starting grid. If not repurposed to be operated with hydrogen, which is optimised endogenously by the ESM, it is assumed that methane cross-border transmission capacity is available until 2050. No hydrogen cross-border transmission capacity is exogenously defined in the analysis. Instead, all hydrogen interconnections between bidding zones are optimised endogenously.

Figure 45: Starting electricity and methane transmission grid in 2030



155 ENTSOG / GIE (2021). System Development Map 2020/2021 Link

Investment candidates

Several investment candidates are available that can be installed in addition to the predefined capacities:[156]

- Onshore wind, offshore wind, and utility-scale solar PV
- OCGT and CCGT power plants fired by methane or hydrogen and stationary batteries
- Electricity and hydrogen cross-border transmission capacity (new and repurposed)
- Grid-connected electrolysers and electrolysers connected directly to renewable energies
- ATRs equipped with CCS
- Methanation plants for synthetic methane production
- Hydrogen import terminals and hydrogen storage (new and repurposed)

Table 4 and Table 5 presents the cost assumptions for the investment candidates for electricity generation and storage for S1 and S2 scenarios. In line with TYNDP 2022 GA and DE, investment costs for solar, onshore wind, and offshore wind power differs between the two scenarios. The ESM can invest in onshore and offshore wind, utility-scale solar PV, hydrogen and methane fired open-cycle and combined-cycle gas turbines (OCGT, CCGT), and stationary batteries. Cost assumptions for these investment candidates are mainly based on TYNDP 2022 GA and DE.[157] In the case of batteries, assumptions are based on the Danish Energy Agency Technology Catalogue, which is also one of the main source for TYNDP cost assumptions.[158] For investments in utility-scale solar PV, onshore wind, and offshore wind power capacity an upper bound in each bidding zone is defined using the maximum value of TYNDP 2022 GA and DE for that bidding zone.

Table 4: Cost assumptions for electricity generation and storage investment candidates (S1)

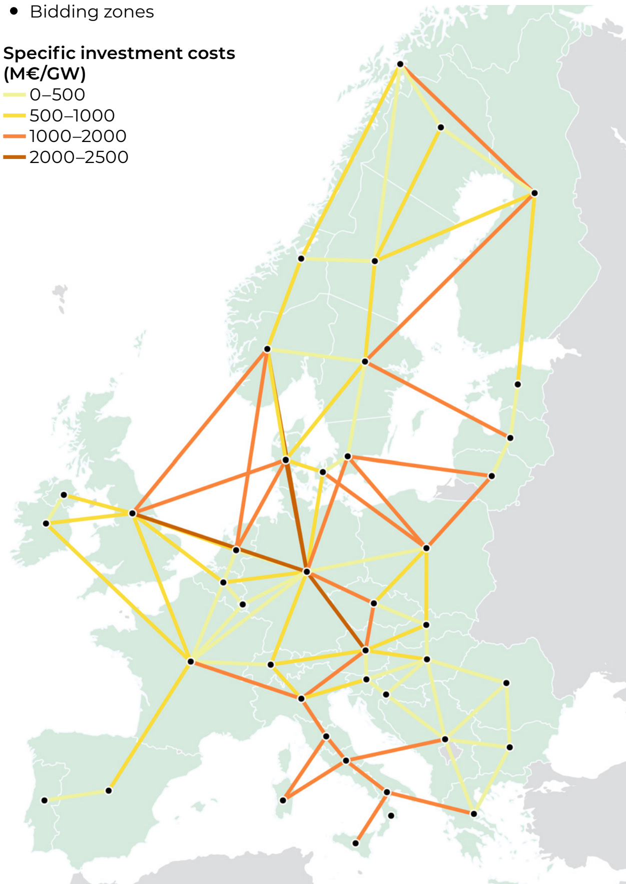
			2030	2040	2050	Lifetime (years)
Onshore wind	Investment costs	(€/kW)	1220	1166	1127	30
	Fixed O&M costs	(€/kW/a)	14.7	13.4	12.9	
Offshore wind	Investment costs	(€/kW)	1620	1444	1348	30
	Fixed O&M costs	(€/kW/a)	30.5	26.6	24.7	
Solar PV (utility-scale)	Investment costs	(€/kW)	444	385	350	40
	Fixed O&M costs	(€/kW/a)	8.3	7.9	7.6	
CCGT	Investment costs	(€/kW)	830	800	800	25
	Fixed O&M costs	(€/kW/a)	27.8	26.9	26.0	
OCGT	Investment costs	(€/kW)	435	424	412	25
	Fixed O&M costs	(€/kW/a)	7.7	7.6	7.4	
Batteries (4h)	Investment costs	(€/kW)	764	500	380	25
	Fixed O&M costs	(€/kW/a)	5.7	5.7	5.7	

156 A weighted average cost of capital (WACC) of 5% is assumed for all investment candidates.
157 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines – Version April 2022 Link
158 Danish Energy Agency (2022). Technology Catalogue for Energy Storage Link

Table 5: Cost assumptions for electricity generation and storage investment candidates (S2)

			2030	2040	2050	Lifetime (years)
Onshore wind	Investment costs	(€/kW)	915	817	758	30
	Fixed O&M costs	(€/kW/a)	10.5	9.1	8.6	
Offshore wind	Investment costs	(€/kW)	2076	1954	1851	30
	Fixed O&M costs	(€/kW/a)	38.8	35.9	33.9	
Solar PV (utility-scale)	Investment costs	(€/kW)	333	281	250	40
	Fixed O&M costs	(€/kW/a)	6.0	5.4	5.0	
CCGT	Investment costs	(€/kW)	830	800	800	25
	Fixed O&M costs	(€/kW/a)	27.8	26.9	26.0	
OCGT	Investment costs	(€/kW)	435	424	412	25
	Fixed O&M costs	(€/kW/a)	7.7	7.6	7.4	
Batteries (4h)	Investment costs	(€/kW)	764	500	380	25
	Fixed O&M costs	(€/kW/a)	5.7	5.7	5.7	

Figure 46: Specific investment costs to increase electricity cross-border capacity



Besides investing in electricity generation and storage capacity beyond the predefined capacities, the ESM can invest in additional electricity cross-border transmission capacity. Investment cost assumptions are based on ENTSO-E and presented in Figure 46.[159]

Table 6 presents the applied cost assumptions for investment candidates for hydrogen and synthetic methane production. The ESM can invest in grid-connected electrolysers and electrolysers directly connected to offshore wind, onshore wind, and utility-scale PV, ATRs equipped with CCS, hydrogen import terminals and methanation plants. Cost assumptions of electrolysers are based on TYNDP 2022.[160] For electrolysers directly fed by renewable electricity, investment costs for offshore wind, onshore wind and PV have been reduced by 360 €/kW, 50 €/kW, and 10 €/kW to consider cost savings on electricity grid connections in line with TYNDP 2022 assumptions. Economic assumptions for ATRs equipped with CCS are based on Oni et al (2022)[161], and for methanation

159 ENTSO-E (2019). European Power System 2040 - Completing the Map – Technical Appendix, p. 36. Link
160 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines – Version April 2022 Link
161 Oni et al. (2022). Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions Link

Table 6: Cost assumptions for hydrogen supply investment candidates

			2030	2040	2050	Lifetime (years)
Electrolyser	Investment costs	(€/kW_{H_2})	493	380	270	25
	Annual O&M costs	(of invest. cost)	4%	4.5%	5%	
ATR with CCS (91% CR)	Investment costs	(€/kW_{H_2})	1275	1275	1275	25
	Annual O&M costs	(of invest. cost)	2.5%	2.5%	2.5%	
Methanation plant	Investment costs	(€/kW_{CH_4})	450	350	250	25
	Annual O&M costs	(of invest. cost)	5%	5%	5%	
Hydrogen import terminal	Investment costs	(€/kW_{H_2})	432	353	273	30
	Annual O&M costs	(of invest. cost)	2.5%	2.5%	2.5%	

plants on Böhm et al. (2020)[162]. Cost assumptions for hydrogen import terminals are taken from DNV GL[163]. Investments in ATRs are only considered as investment options in Norway and the UK.

Table 7 presents the efficiencies of electrolysers, ATRs-CCS, CCGTs, and OCGTs assumed within the study. Efficiency assumptions for electrolysers are taken from TYNDP 2022 and are based on a scenario for market shares of alkaline and PEM electrolysers as assumed in TYNDP 2022.[164] Efficiency and carbon capture rates for ATRs equipped with CCS are based on Oni et al.[165] Efficiencies for CCGTs and OCGTs are based, like for all other thermal power plants, on ENTSO-E's Pan-European Market Modelling Database (PEMMDB).

Table 8 presents the cost assumptions for different hydrogen storage technologies. It is difficult to generalise storage costs because of the wide variety in sizes, operating conditions, and the number of injection and withdrawal cycles. Investment costs for hydrogen storage are based on GIE (2021)[166]. Investment costs for repurposed salt caverns are estimated to be 33% lower than for new salt caverns. Cost assumptions for above ground storage are taken from STOR&GO (2018)[167]. Provided cost figures should not be seen as a comparison between different types of storage (that is too premature), but rather as an indication of the order of magnitude of the investment cost. The potential to repurpose existing methane underground storages for hydrogen storage in each bidding zone depends on the existing capacities and its need for methane storage. The total hydrogen storage potential in existing salt caverns is about 45 TWh. For depleted gas fields it is about 160 TWh.[168] The technical potential of new salt caverns is with more than 7,500 TWh abundant yet concentrated to only a few countries.[169, 170]

Table 7: Efficiency (NCV) of electrolysers, ATRs, CCGTs, and OCGTs

	2030	2040	2050
Electrolyser	69%	71%	74%
ATR with CCS (91% CR)	80%	80%	80%
CCGT	60%	60%	60%
OCGT	44%	44%	44%

162 Böhm et al (2020). Projecting cost development for future large-scale power-to-gas implementations by scaling effects Link
163 DNV GL (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment Link
164 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines – Version April 2022, p.34. Link
165 Oni et al. (2022). Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions Link
166 GIE (2021). Picturing the value of underground gas storage to the European hydrogen system Link
167 STOR&GO (2018). Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimisation - D8.6 Link
168 GIE (2021). Picturing the value of underground gas storage to the European hydrogen system Link
169 Caglayan, et al (2020). Technical potential of salt caverns for hydrogen storage in Europe Link
170 For the technical potential for new salt caverns only sites within 50 km from shore were considered.

Table 8: Economic assumptions of hydrogen storage investment candidates

			2030	2040	2050	Lifetime (years)
Salt cavern (new)	Investment costs	(€/kWh)	0.9	0.9	0.9	50
	Annual O&M costs	(of invest. cost)	4%	4%	4%	
Salt cavern (repurposed)	Investment costs	(€/kWh)	0.6	0.6	0.6	50
	Annual O&M costs	(of invest. cost)	4%	4%	4%	
Depleted gas field (repurposed)	Investment costs	(€/kWh)	N/a	0.45	0.45	50
	Annual O&M costs	(of invest. cost)	N/a	4%	4%	
Hard rock cavern (new)	Investment costs	(€/kWh)	1.2	1.2	1.2	50
	Annual O&M costs	(of invest. cost)	4%	4%	4%	
Above ground storage (new)	Investment costs	(€/kWh)	33	33	33	30
	Annual O&M costs	(of invest. cost)	2%	2%	2%	

Cost assumptions for hydrogen cross-border capacity

Investment costs for hydrogen transmission pipelines and compressors depend on their size, their location (onshore vs offshore), and if pipelines are new or repurposed. Table 9 presents the specific investment costs for different hydrogen transmission pipeline types and compressors considered in this study. The hydrogen pipeline and compressor OPEX are assumed to be 0.9% and 1.7% of the investment costs of pipelines and compressors, respectively. Cost assumptions are taken from the EHB (2022) report.[171]

Table 9: Investment costs for hydrogen pipelines and compressors assumed in study

Pipeline type		Pipeline: Investment costs (M€/km)	Compressor: Investment costs (M€/km)	Assumed pipeline capacity (GW)
Onshore small (20 inch)	Repurposed	0.3	0.09	1.2
	New	1.5	0.09	1.2
Onshore medium (36 inch)	Repurposed	0.4	0.14	3.6
	New	2.2	0.32	4.7
Onshore large (48 inch)	Repurposed	0.5	0.62	13
	New	2.8	0.62	13
Offshore medium (36 inch)	Repurposed	0.4	0.23	3.6
	New	3.7	0.54	4.7
Offshore large (48 inch)	Repurposed	0.5	1.06	13
	New	4.8	1.06	13

171 EHB (2022). European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 28 Countries Link

The specific investment cost to increase hydrogen cross-border transmission capacity between bidding zones include investment costs for pipelines and compressors and were determined by making use of the EHB (2022) maps and the underlying dataset.[172] Specific investment costs are provided for two types:

Type 1 – repurposing: Specific investment costs to repurpose existing methane cross-border transmission capacity. Note that repurposing existing methane transmission capacity still require, in some cases, the construction of some new hydrogen transmission pipelines within a bidding zone as described in the paragraph below. Therefore, presented cost figures are a mixture of costs due to repurposing and construction of new pipelines. As type 1 cost category provides only specific investment costs for bidding zones that are already connected through natural gas pipelines, cost figures for type 1 do not exist for all potential hydrogen interconnections (e.g. between Finland and Sweden).

Type 2 – new: Specific investment costs to increase hydrogen cross-border transmission capacity beyond the transmission capacity potential which exist due to repurposing existing methane transmission capacity. Presented specific investment costs are based therefore exclusively on cost assumptions for new hydrogen transmission pipelines.

The approach to determine the specific investment costs for Type 1 (repurposing) and Type 2 (new) is as follow:

- In a first step, the distance between each bidding zone is determined by calculating the straight-line distance between the centre coordinate location of each bidding zone. The distance is increased by 25% to account for deviation of the real-world construction of pipelines from the shortest distance between the centre points of bidding zones.
- As a second step, the fraction of offshore versus onshore pipelines and their respective sizes (small, medium, or large) per bidding zone are determined using the EHB 2022 map and the underlying dataset. The total breakdown of pipeline type and size between two model regions is determined using a weighted average based on the distance of pipelines within each of the bidding zones.
- In a third step, conducted only to determine specific investment costs for Type 1 (repurposing), the ratio of repurposed to new pipelines is determined to consider that even if natural gas pipelines between two bidding zones exist that can be repurposed, additional, new pipelines might be required within each of the respective bidding zone to allow cross-border flows. To account for this, Type 1 (repurposing) specific investment costs are composed of a combination of new and repurposed pipelines, proportional to the ratio of new versus repurposed pipelines in each bidding zone according to the EHB 2022 map and related dataset.
- In a last step, the breakdown of pipeline type (onshore vs. offshore, new vs. repurposed (for Type 1)), size, and distance between connected bidding zones, is used to determine the specific investment costs to increase hydrogen cross-border transmission capacity between two bidding zones for Type 1 and Type 2.

Hydrogen and methane import supply potential

Renewable hydrogen imports through pipelines from North Africa and the Ukraine as well as hydrogen imports through shipping are considered as a potential supply option to meet hydrogen demand of the countries in scope of this study. While shipped hydrogen import potentials are available in all scenarios, pipeline imports are only available in S1 H_2-Interconnectedand S2 H_2-Interconnected as a potential supply source. Maximum hydrogen pipeline import potentials are based on TYNDP 2022 and are presented in Table 10.[173] Hydrogen import potentials from Russia are not considered in this study. The actual use of hydrogen pipeline and shipped imports is optimised endogenously by the applied ESM.

172 EHB (2022). European Hydrogen Backbone Maps Link
173 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines – Version April 2022 Link

Table 10: Maximum hydrogen pipeline supply potential

		S1 H_2-Interconnected			S2 H_2-Interconnected		
		2030	2040	2050	2030	2040	2050
North Africa	(TWh)	86	259	317	0	259	259
Ukraine	(TWh)	0	114	228	0	0	0

Maximum annual methane pipeline and LNG import potentials assumed in the study are presented in Table 11. Maximum pipeline import potentials for North Africa and the Middle East are based on TYNDP 2022.[173] Maximum shipping imports are calculated based on the total installed import terminal capacity (technical physical capacity) assumed to be available in 2030 in the countries in scope of the study. Methane pipeline imports from Russia are not considered as a supply option to meet methane demand in the countries in scope of the study. The maximum annual methane pipeline and LNG import potentials are the same for S1 and S2. The actual use of methane pipeline and LNG imports is optimised endogenously by the applied ESM.

Table 11: Maximum methane pipeline and LNG imports

		2030	2040	2050
North Africa	(TWh)	516	516	516
Middle East	(TWh)	329	338	338
LNG	(TWh)	3200	3200	3200

Biomethane supply potential

Biomethane supply potential for individual countries in scope of this study is based on a recent GfC study.[174] Table 12 shows the total biomethane supply potential for the countries in scope of the study. Figure 47 shows the biomethane supply potential by country. The amount of the biomethane supply potential used is determined by the ESM.

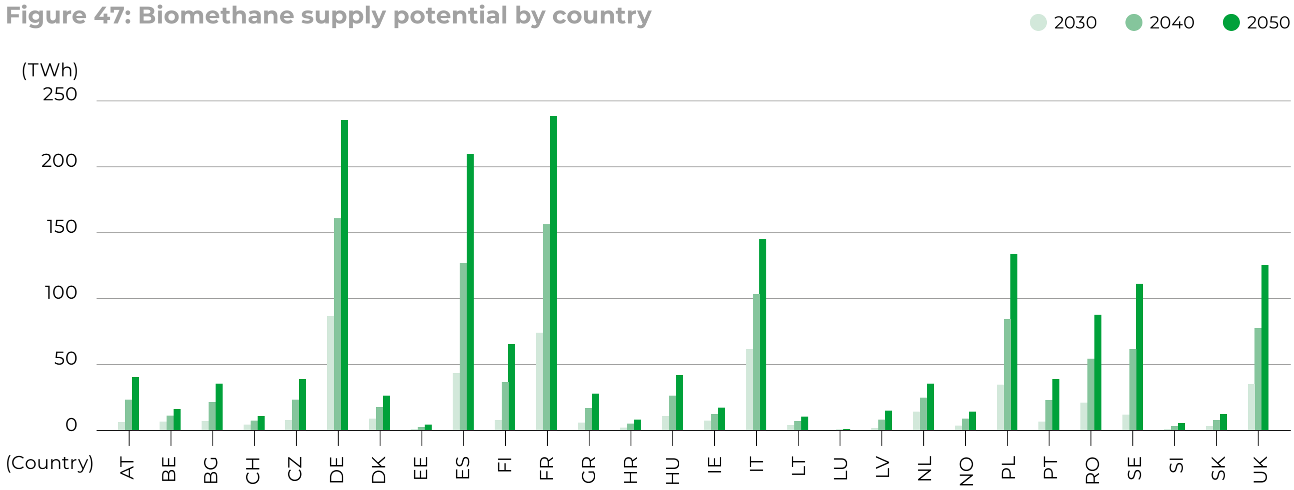
The biomethane supply potential on a national level is based on feedstock type (e.g. manure and municipal solid waste) and production technology (anaerobic digestion and gasification). For countries that are represented by multiple bidding zones in the ESM, the European Biomethane Map by GIE and EBA is used to estimate the number of plants per bidding zone.[175] To calculate the potential per bidding zone, the number of plants in the bidding zone are divided by the number of plants in the country and multiplied by the total national supply potential. For the year 2030, a constraint is included in the applied ESMs to ensure biomethane supply targets as specified in REPowerEU are met (370 TWh in 2030).[176]

Table 12: Total biomethane supply potential for the countries in scope of this study

		2030	2040	2050
Biomethane	(TWh)	481	1160	1839

174 Gas for Climate (2022). Biomethane production potentials in the EU Link
175 EBA/GIE (2021). European Biomethane Map Link
176 European Commission (2022). REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition Link

Figure 47: Biomethane supply potential by country



Availability of solar, wind and hydro power

Temporal availability of wind, solar and hydro power is based on the Pan European Climate Database (PECD), version v3.0.[177] The PECD covers the timeframe 1982 – 2019. The database contains hourly capacity factors for onshore wind, offshore wind, solar PV, and concentrating solar power as well as daily and weekly time-series for different hydro power technologies for each of the bidding zones considered this study.

In this study the climatic year 2009 is used to consider the seasonal and diurnal variability of renewable energy resources. The year 2009 can be considered on the one hand as the most representative year in terms of resource availability of renewable energy resources but at the same time represents, after the climatic year 2012, the second most stressful climatic year in terms of 2-week Dunkelflaute situation at the European aggregated level.[178] Figure 48 – Figure 50 present the annual capacity factors for onshore wind, offshore wind and solar PV for the climatic year 2009.

Figure 48: Annual capacity factors of onshore wind power by bidding zone

177 ENTSO-E (2021). ERAA 2021 Link
178 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines Link

Figure 49: Annual capacity factors of offshore wind power by bidding zone

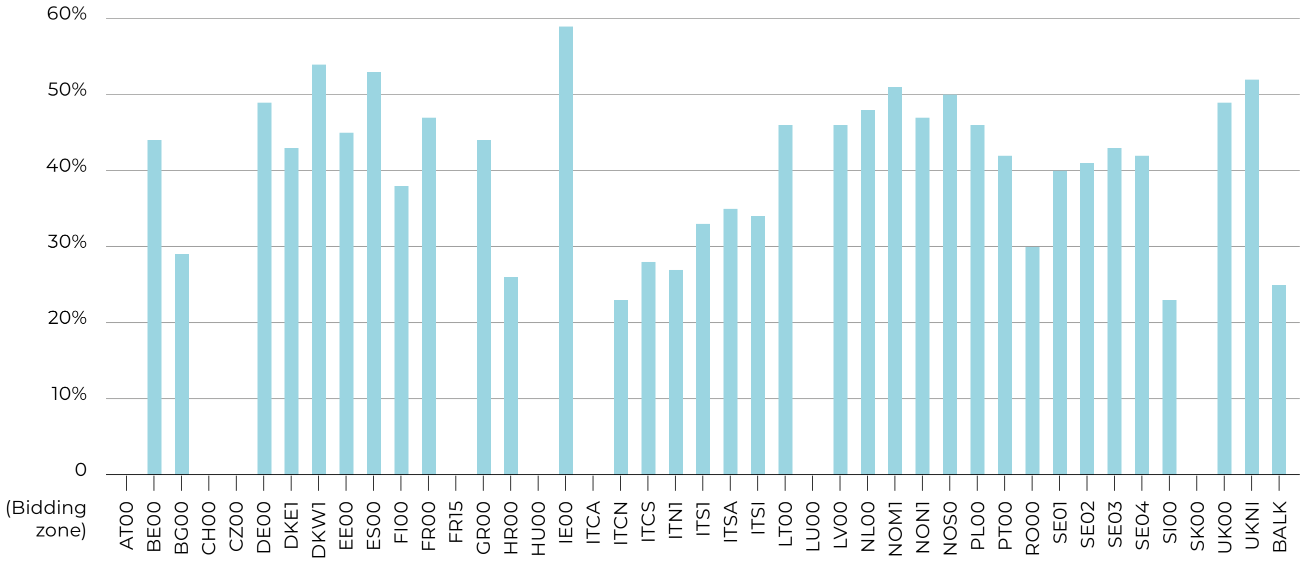
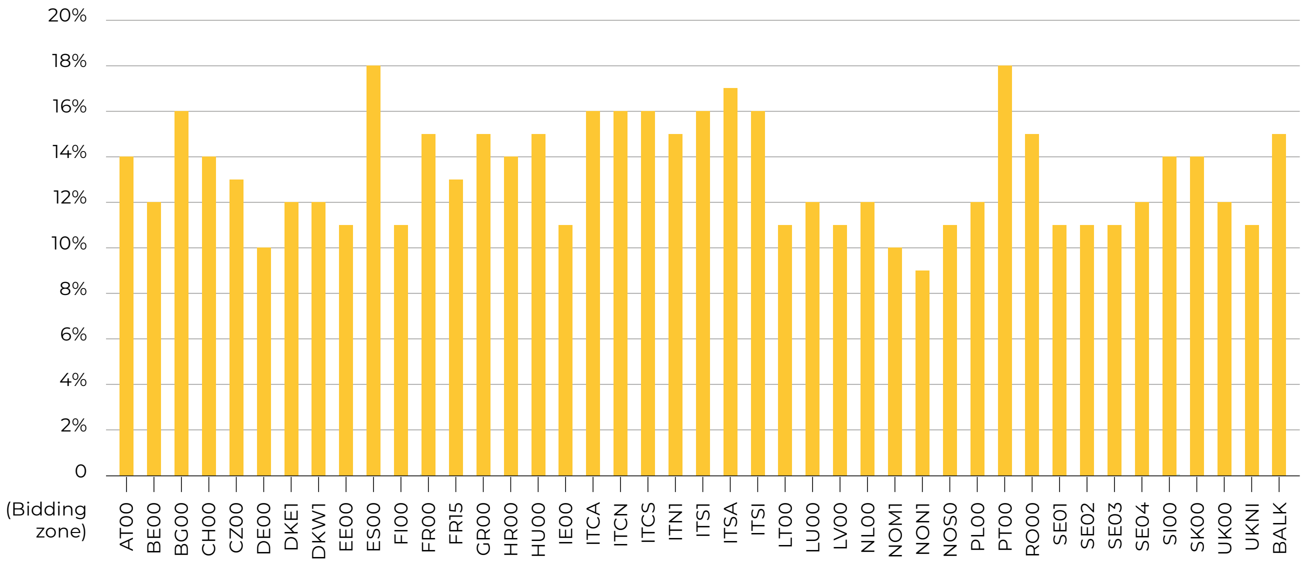


Figure 50: Annual capacity factors of solar PV by bidding zone



Representative days selection

For the ESM, 13 representative days are used (one for each month and one peak day). The representative days consist of 24 hourly timesteps. The selection of representative days aims to approximate the seasonal and diurnal variability of variable renewable energies (VREs) and energy demands, while allowing the model to optimise within a reasonable amount of time and with reasonable computational efforts. To determine the representative days for each VRE, each bidding zone is assigned to a group (North, North-west, North-east, Central, Central-west, Central-east, South-west, and South-east). A combination of the hourly (difference in capacity factors between each hour in the day) and daily (difference between the minimum and maximum capacity factor over the course of a day) fluctuation for the capacity factors for each bidding zone and the bidding zone group are used to select the representative day. For each of the groups and each of the VREs, a number of steps are followed to select the representative days used in the model:

1. The daily and hourly fluctuation for each bidding zone and each group are calculated. Weighted averages of these values are calculated and assigned to each day. The day with the largest value is selected as representative day for the respective group. This ensures that the selected representative day has sufficient fluctuation between each hour in the day, has a sufficient range of capacity factors, and that bidding zones within the same region, assumed to have similar weather patterns, have the same representative day selected.
2. The capacity factors for the selected representative day are then scaled to the yearly average capacity factor for each bidding zone.

The peak day is selected as the day with the lowest average capacity factors in January, February, or December for each respective VRE and bidding zone. The peak day gas and hydrogen demand values are based on the peak gas demand daily values provided in TYNDP 2022.

Emission factors and commodity prices

Table 13 presents the considered CO_2 emission factors in this study. With the exception for methane imports, emission factors are based on JRC.[179] CO_2 emission factors for methane imports are based on the composition of methane imports assumed over the timeframe 2030 - 2050 (see Table 14). We only consider direct CO_2 emissions in the analysis, as they only have impact on the short-run marginal cost of assets and therefore impact the investment and dispatch decisions of the applied energy system model.

Table 13: CO_2 emission factors

		2030	2040	2050
Biomass	(t/MWh)	0	0	0
Biomethane	(t/MWh)	0	0	0
Hard Coal[180]	(t/MWh)	0.347	0.347	0.347
Heavy Oil[181]	(t/MWh)	0.267	0.267	0.267
Hydrogen imports	(t/MWh)	0	0	0
Light Oil[182]	(t/MWh)	0.249	0.249	0.249
Lignite	(t/MWh)	0.364	0.364	0.364
Natural Gas	(t/MWh)	0.202	0.202	0.202
Nuclear	(t/MWh)	0	0	0
Methane imports	(t/MWh)	0.202	0.182	0
Oil Shale[183]	(t/MWh)	0.267	0.267	0.267
Synthetic Methane (imported)	(t/MWh)	0	0	0

Table 14: Composition of methane imports from outside modelled system

		2030	2040	2050
Natural gas	(%)	100	85	0
Biomethane	(%)	0	7.5	25
Synthetic methane	(%)	0	7.5	75
Resulting CO_2-free share of imports	**(%)**	**0**	**15**	**100**

Table 15: CO_2 emission price

		2030	2040	2050
CO_2 emission price	(€/t)	78	123	168

179 JRC (2017). Covenant of Mayors for Climate and Energy: Default emission factors for local emission inventories Link
180 Average emission factor for coal types of anthracite, other bituminous coal, and sub-bituminous coal
181 Values for heating oil used as no data provided for heavy oil
182 Values for gasoline used as no data provided for light oil
183 Values for heating oil used as no data provided for oil shale

Table 15 and Table 16 respectively show the CO_2 emission and fuel prices considered in this study. The CO_2 emission price and most fuel prices are based on TYNDP 2022.[184] Compared to TYNDP 2022 assumptions, the natural gas price in 2030 is increased from 14.5 €/MWh to 20.3 €/MWh (+40%) to acknowledge the impact of the current European energy crisis and its impact on natural gas prices in the upcoming years. For the years 2040 and 2050, the original TYNDP 2022 assumptions are used.

Prices for methane imports from outside the modelled system are based on the applied assumption for the composition of methane imports over the timeframe 2030 – 2050 (see Table 14) and the assumed prices for natural gas, biomethane, and imported synthetic methane.

Renewable hydrogen import prices via pipelines from North Africa and Ukraine are aligned to TYNDP 2022 but differentiated by origin. Pipeline imports from Ukraine are set equal to the import price assumed in TYNDP 2022. Renewable hydrogen pipeline imports from North Africa are assumed to be 20% cheaper due to better renewable energy resource potentials than in Ukraine. The shipped hydrogen costs are calculated based on an average price for hydrogen conversion, storage, and shipping from Oxford (2022), Ronald Berger (2021), IRENA (2022), and KRB (2021).[185] To avoid double-counting, costs for reconversion into gaseous hydrogen are not included in the shipped hydrogen import price as costs for import terminals are quantified separately. This results in a shipped hydrogen price of 45, 40, and 35 €/MWh for 2030, 2040, and 2050 respectively. The hydrogen production cost used to calculate the shipped renewable hydrogen import prices are assumed to be produced from solar PV and electrolysers, resulting in production costs of 50, 40, and 30 €/MWh.[186] The total shipped renewable hydrogen import price is the sum of the hydrogen conversion, storage, and shipping and the hydrogen production cost. The cost for reconversion and storage of the shipped hydrogen is calculated separately in the model, using the cost assumptions for hydrogen import terminals given in Table 6. Biomass price assumptions are not specified in TYNDP 2022 and are therefore based on biofuel price assumptions specified in detail in TYNDP 2018.[187]

Table 16: Fuel price assumptions

		2030	2040	2050
Biomass–DK	(t/MWh)	34	35	35
Biomass–FI	(€/MWh)	29	36	36
Biomass	(€/MWh)	22	22	22
Biomass–IE	(€/MWh)	11	12	12
Biomass–PL	(€/MWh)	20	20	20
Biomass–SK	(€/MWh)	6	6	6
Biomethane	(€/MWh)	75	61	50
Hard Coal	(€/MWh)	9	9	9
Heavy Oil	(€/MWh)	31	29	28
Hydrogen–Pipeline imports North Africa	(€/MWh)	60	45	35
Hydrogen–Pipeline imports Ukraine	(€/MWh)	n/a	60	45
Hydrogen–Shipped imports	(€/MWh)	95	80	65
Light Oil	(€/MWh)	36	35	33
Lignite–Group 1 (BG, MK, CZ)	(€/MWh)	5	5	5
Lignite–Group 2 (SK, DE, PL, UK, IE)	(€/MWh)	7	7	7
Lignite–Group 3 (SI, RO, HU)	(€/MWh)	9	9	9
Lignite–Group 4 (GR)	(€/MWh)	11	11	11
Natural Gas	(t/MWh)	20	15	15
Nuclear	(t/MWh)	2	2	2
Methane–Pipeline and shipped imports	(t/MWh)	20	20	61
Oil Shale	(t/MWh)	7	10	14

184 ENTSO-E&G (2022). TYNDP 2022 Scenario Building Guidelines Link
185 KRB (2021). Hydrogen imports and downstream applications Link
Roland Berger (2021). Hydrogen transportation | The key to unlocking the clean hydrogen economy Link
IRENA (2022). Global Hydrogen Trade to Meet the 1.5°C Climate Goal, Part II Link
For detailed analysis see: Gas for Climate (2022). Facilitating Hydrogen Transports from non-EU countries Link
186 The technology costs for solar PV and electrolysers are based on the costs provided in Table 4, Table 5, and Table 6 above. A solar capacity factor of 23% is assumed.
187 ENTSO-E&G (2018). TYNDP 2018 Scenario Report - Methodology Report Annex II Link

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