

Lenivova, Veronika

Working Paper

Potential development of renewable hydrogen imports to European markets until 2030

OIES Paper: ET, No. 08

Provided in Cooperation with:

The Oxford Institute for Energy Studies, Oxford

Suggested Citation: Lenivova, Veronika (2022) : Potential development of renewable hydrogen imports to European markets until 2030, OIES Paper: ET, No. 08, ISBN 978-1-78467-195-2, The Oxford Institute for Energy Studies, Oxford

This Version is available at:

<https://hdl.handle.net/10419/253282>

Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

Terms of use:

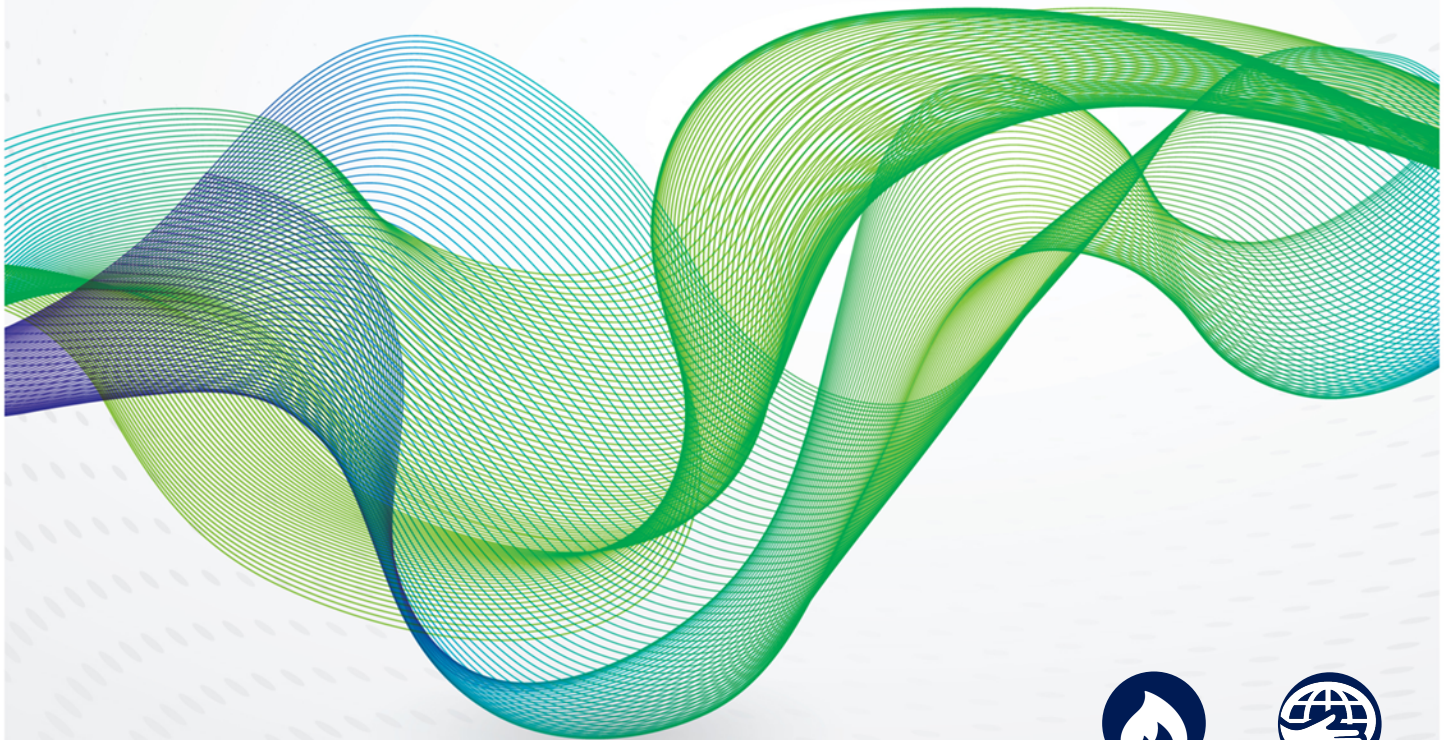
Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.

March 2022

Potential development of renewable hydrogen imports to European markets until 2030



GAS



ENERGY TRANSITION



The contents of this paper are the author's sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its members.

Copyright © 2022

Oxford Institute for Energy Studies

(Registered Charity, No. 286084)

This publication may be reproduced in part for educational or non-profit purposes without special permission from the copyright holder, provided acknowledgment of the source is made. No use of this publication may be made for resale or for any other commercial purpose whatsoever without prior permission in writing from the Oxford Institute for Energy Studies.

ISBN 978-1-78467-195-2



Preface

Veronika Lenivova recently completed her Master's dissertation at Brandenburg University of Technology Cottbus-Senftenberg, co-supervised by Tatiana Mitrova and Martin Lambert from OIES. Currently she is a research fellow at the Fraunhofer Research Institution for Energy Infrastructures and Geothermal Energy (IEG). Following her Master's dissertation, she has written this, her first, paper for OIES considering potential import routes for low-carbon and renewable hydrogen (H₂) to main European markets like Germany. In particular, she has made an assessment of the robustness of claims made by Hydrogen Europe and subsequently picked up by the European Commission in its Hydrogen Strategy that there will be 40GW of electrolyser capacity in countries like Morocco and Ukraine providing hydrogen imports to Europe by 2030.

The paper provides considerable detail regarding the background to the potential use of low carbon hydrogen in the energy transition, the development of European hydrogen strategies, as well as details of the energy systems in the potential exporting countries of Morocco, Ukraine, Norway, and Western Russia. Some readers may wish to skip this detail. It is also important to note that this research pre-dates recent political and military tensions between Russia and Ukraine which is likely to influence future development pathways.

By 2030, potential demand for H₂ could be high enough to initiate some limited international hydrogen trade, most likely between European countries initially, rather than from outside Europe. Low carbon/renewable hydrogen demand will initially come from sectors that are currently utilizing conventional hydrogen for industrial purposes, such as oil refineries, ammonia and methanol industries, plus some new industrial demand in the steel sector. Additional demand could come from the transportation and heating sectors, although this is more uncertain. Geographically, a northern hydrogen cluster around Netherlands and NW Germany will be more significant for hydrogen demand than southern Europe. With more abundant renewable energy (RE) resources in southern Europe some trade may take place between, say, Spain and Germany, although this may be limited by available capacity to transport hydrogen across Europe.

The paper goes on to consider potential H₂ exporters to Europe, including Ukraine and North African countries (in line with the proposal from Hydrogen Europe) and Norway and Russia. Ukraine and North Africa have advantages in terms of RE potential and cost, as well as mature natural gas (NG) infrastructure. It also identifies several criteria which should be considered when assessing the feasibility of such imports, including:

- extent of decarbonization of domestic energy system;
- water availability;
- proximity to H₂ demand centres;
- state of development of the infrastructure and readiness for H₂ injection;
- history of bilateral relationships and security of supply.

To the extent that there is a case for hydrogen imports from outside Europe, the paper concludes that Norway and Russia, currently the two main natural gas providers to the EU, could provide hydrogen sooner and at a lower cost, most likely starting with blue and, perhaps, turquoise hydrogen. On the other hand, a greater diversity of H₂ exporters may be preferred politically to increase security of supply and promote competition.



The supply cost of hydrogen in 2030 is predicted to be in a reasonably (and perhaps surprisingly) narrow band around €3/kg from various sources and supply chains. Based on certain assumptions, natural gas-based hydrogen shows the lowest total cost. However, in the long run, as natural gas and carbon dioxide (CO₂) prices increase and the cost of green hydrogen decreases, green hydrogen may become more competitive. The speed of this transition is difficult to predict with reasonable certainty. Key factors in green H₂ production costs are the electricity price, operating hours and capital expenditure for electrolyser equipment. In terms of infrastructure, retrofit or construction of new H₂ pipelines are a promising solution for transporting energy over long distances. H₂ transport by ship and electricity transmission is significantly more expensive. For hydrogen storage, the only viable economical solution would be storage in underground geological formations, such as salt caverns and depleted gas fields. Lack of H₂ storage in underground formations, for example in Northern Italy, leads to significant increases in total H₂ cost (approximately by three times). Identification of suitable underground storage could become an important factor in determining the extent of penetration of hydrogen into the energy system.

This paper concludes that overall, while imports of hydrogen to Europe are certainly possible in the longer term, there are many challenges to be addressed and it appears unlikely that they will occur by 2030 in the manner and at the scale envisaged by the Hydrogen Europe study. This conclusion supports the growing consensus that development of low carbon hydrogen, certainly within Europe, is likely to start within relatively local hydrogen clusters, with some limited bilateral trade.

Martin Lambert
Head, Hydrogen Research
Energy Transition Research Initiative, OIES



Contents

Preface	ii
Contents	iv
Figures	v
Tables	vi
Introduction	1
Hydrogen boom in the European Union	1
I. Comparative overview of the hydrogen strategies in the European Union	2
The EU hydrogen strategy	2
II. Hydrogen demand by 2030	6
Existing hydrogen production in Europe	6
Agora Energiewende Study ‘No-regret Hydrogen’	9
III. European low-carbon hydrogen import routes	11
Northern Africa – Morocco	11
Ukraine	14
Norway	20
Russia	25
IV. Economic assessment of European hydrogen supply chains	30
Introduction of supply chains based on the map: blue/turquoise vs. green hydrogen	30
Hydrogen infrastructure costs	32
Hydrogen routes up to 2030	39
Hydrogen routes 2030-2035	40
Conclusion	41



Figures

Figure 1: Current hydrogen demand in the EU	4
Figure 2: Timeline of the acceptance of the national hydrogen strategies within last 4 years	5
Figure 3: Overview of main hydrogen production hubs in EU27 + UK, visual representation of.....	6
two H ₂ clusters.....	6
Figure 4: Local potential of renewable hydrogen production in Europe	7
Figure 5: An ambitious roadmap for the deployment of hydrogen in the European Union.....	9
Figure 6: Projected hydrogen demand in 'no-regret' scenario in 2030.....	10
Figure 7: Trajectory of industrial H ₂ demand 2020-2050 within specific demand sectors	10
Figure 8: Overview of energy sector in Morocco, 2018 (production, imports, total primary energy supply and total final consumption)	12
Figure 9: Moroccan electricity production by source 1990-2019.....	13
Figure 10: Overview of the energy sector in Ukraine (imports, total energy supply and total final consumption).....	15
.....	15
Figure 11: Ukrainian electricity production by source 1990-2019	15
Figure 12: Potential of wind power plant capacity in Ukraine.....	16
Figure 13: Potential of average annual green hydrogen production in Ukraine	17
Figure 14: RE supply in 2007-2016, Ukraine; RE supply as a share of TPES in 2007-2016, Ukraine	18
Figure 15: Prognosis of the Ukrainian biofuel market (per type of biofuel) up to 2050	19
Figure 16: Major natural gas transit pipelines flowing through Ukraine.....	20
Figure 17: Overview of energy production, TES, and TFC in Norway, 2018	21
Figure 18.: Norwegian electricity production by source, 1990-2019	22
Figure 19: Allocation of the wind speed in Norway and average energy production from wind turbines (GWh) - aggregated per year	22
Figure 20: Norwegian greenhouse gas emissions in 2018, million tonnes CO ₂ equivalents and % of the total emissions.....	24
Figure 21: Overview of the Russian energy market, level of exports in 2018	25
Figure 22: Russian electricity production by source 1990-2019.....	26
Figure 23: Map of Russian Federation, North-western federal region	26
Figure 24: New installed capacity of renewable energy facilities (wind) based on the results of competitive selection power wind generators starting in each year from 2015 to 2024, in MW	27
Figure 25: Process supply chains for different types of hydrogen: blue, turquoise and green.....	31
Figure 26: Overview of the possible hydrogen supply routes 2030-2040	31
Figure 27: Hydrogen production cost evolution in the European Union up to 2040	33
Figure 28: Hydrogen production costs via electrolysis, impact of the investment cost for electrolyser equipment and power price (example of French power market)	34
Figure 29: Emerging European Hydrogen Backbone by 2030 and growing network coverage across more countries in 2035.....	36
Figure 30: Economical comparison of hydrogen transport options over different distances	37
Figure 31: Total salt cavern potential in European countries (onshore, offshore and onshore within 50km of shore)	38
Figure 32: Possible hydrogen supply routes to Europe up to 2030.....	40
Figure 33: Development of hydrogen import routes between 2030 and 2035	41



Tables

Table 1: The European hydrogen strategy, phases' analysis	3
Table 2: Summary of EU Member States national hydrogen strategies	5
Table 3: Assessment of the theoretical wind power potential and hydrogen production in Ukraine	17
Table 4: Comparison of case studies for hydrogen import to EU demand centres	30
Table 5: Cost comparison of different types of pipeline transportation for hydrogen	36
Table 6: European regional levelized costs of storage (salt caverns and pressurised tanks).....	38



Introduction

Hydrogen boom in the European Union

With growing awareness of climate change and continuously increasing concentrations of greenhouse gases in the atmosphere, European governments are implementing tighter CO₂ reduction targets. The new climate strategy, the 'European Green Deal' released at the end of 2019, is mainly focused on the decarbonization of the energy sector. The new targets are set for reduction of greenhouse gas (GHG) emissions by at least 55 per cent by 2030, compared to the 1990 levels.¹ Hydrogen is expected to play an important role in helping meet these targets. During the year 2020 a number of policies and strategies were introduced under the policy package 'A European Green Deal'. The most relevant to the hydrogen economy are: The European Hydrogen strategy released 8 July 2020 (as part of an EU Strategy for Energy System Integration), the 2030 Climate Target Plan and the European industrial strategy.² More details on the European Hydrogen Strategy can be found in the paper by Alex Barnes and Katja Yafimava from the OIES.³

In December 2020 the European Commission discussed a proposal to revise the EU rules on Trans-European Networks for Energy (the TEN-E Regulation). Executive Vice-President for the Green Deal, Frans Timmermans, said: 'Now is the time to invest in the energy infrastructure of the future. ... including offshore wind and hydrogen. We need to update and upgrade now to achieve the Green Deal's goal of climate neutrality by 2050.'⁴ Through policy support instruments, for example PCI (Projects of Common Interest), hydrogen infrastructure projects are likely to be supported. Such support is specifically aimed at cross-border hydrogen networks (both retrofit of existing assets for pure H₂ use and construction of new hydrogen only infrastructure). Furthermore, other directives are scheduled to be reviewed.⁵ On the other hand, the EU Commission has reported that there is no need for continuing policy support for cross-border natural gas energy projects.

Hydrogen Europe, one of the biggest hydrogen industry associations, published 'Green Hydrogen for a European Green Deal A 2x40GW Initiative' in the first quarter of 2020. The paper proposed a rather ambitious target of 40GW of installed electrolyser capacity within the EU for domestic purposes, and another 40GW, mainly in Northern Africa and Eastern Europe (Ukraine), for green hydrogen imports. The 2x40GW target was also adopted by the EU hydrogen strategy. The study covers the main components of the hydrogen economy, including production – via water electrolysis, transport and distribution (pipelines, shipment in the form of ammonia), storage (salt caverns and empty gas fields), maturing of hydrogen markets, gradual plan of growth for the electrolysers market in Europe, and potential importers of renewable hydrogen (Northern Africa and Ukraine).⁶

Given that the current capacity does not exceed 1GW in all of Europe, this target of installed electrolyser capacity of at least 40 Gigawatt by 2030, raises many questions.⁷ Several member states have already presented their hydrogen strategies. In Europe, currently, more than 350 clean hydrogen projects are operating, although most at small scale. That includes various projects that are targeting to reduce emissions from conventional hydrogen production in industrial applications as well as enabling

¹ European Commission. (2019). 'What is the European Green Deal? What will we do?'
https://ec.europa.eu/commission/presscorner/detail/en/fs_19_6714

² European Commission. (2020). 'A European Green Deal. Striving to be the first climate-neutral continent'.
https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en

³ Barnes, A. and Yafimava, K. (2020). 'EU Hydrogen Vision: regulatory opportunities and challenges', *Oxford Energy Institute*, 1–17

⁴ European Commission. (2020). 'Revised rules for cross-border energy infrastructure'. Press release.
https://ec.europa.eu/commission/presscorner/detail/en/IP_20_2394

⁵ European Commission. (2020). 'Remarks by Commissioner Simson on Commission's proposal'.
https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_20_2438

⁶ Hydrogen Europe (2020). 'Green Hydrogen for a European Green Deal A 2x40 GW Initiative'

⁷ European Commission. (2020). 'Q&A: A Hydrogen Strategy for a climate neutral Europe'.
https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_1257



hydrogen use (as energy carrier or feedstock) in new sectors, such as transportation and power generation.⁸

To support specific investments and the emergence of a completely new hydrogen industry, the Commission launched the European Clean Hydrogen Alliance in 2020. This is intended to accelerate the development of renewable and low-carbon hydrogen technologies by 2030 and the decarbonization of industry as well as endorse industrial leadership in Europe. In 2020, 500 companies were registered as the members of the EU Clean Hydrogen Alliance, which is targeting to increase to 2000 companies by 2050 and attract investments of €5-9 billion by 2024 and €26-44 billion by 2030. The focus is to increase installed capacities for producing hydrogen by electrolysis, starting from at least 6GW by 2024 and 40GW (EU) + 40GW (non-EU) by 2030.⁹

There are many aspects of potential hydrogen development in Europe. This paper focuses on the Hydrogen Europe 2x40GW report, and analyses the feasibility of the proposed imports considering the likely scale of the hydrogen market and required infrastructure. In Part I, hydrogen strategies of European governments are discussed and compared. Part II analyses the demand of hydrogen in the EU, its demand centres and the resulting need for H₂ imports. Part III assesses the realistic potential of importing hydrogen from countries outside the EU (not just North Africa and Ukraine but also Norway and Russia). This includes consideration of whether such countries should use renewable power generation domestically to decarbonize power generation, rather than for hydrogen exports to Europe. Finally, Part IV provides an overview of the economic factors and costs of different hydrogen import routes. The cost structure will be discussed and categorised based on the design of the supply chains and availability of emerging hydrogen technologies.

I. Comparative overview of the hydrogen strategies in the European Union

Hydrogen, as an energy carrier, has great potential to displace conventional energy commodities, such as oil, coal and gas by mid-century. Large-scale imports and exports of hydrogen are forecast. Stricter climate change targets and dramatically tighter carbon budgets will cause major changes in world energy trading schemes by 2050. Clean hydrogen can contribute various solutions to the challenges in the energy systems:

- integration of more renewables into the energy system, as well as enabling large scale seasonal storage;
- decarbonization of hard-to-electrify sectors (industry and transport – steel, chemicals, trucks, ships, and planes);
- provision of energy security by diversifying the energy mix, introducing flexibility to balance grids, localization and decentralization of the energy supply, increase of system efficiency.

Nevertheless, a number of limitations exist to hinder the immediate roll out of the hydrogen economy in Europe. These include: improvement of electrolyser technology; rapid development of hydrogen infrastructure; establishment of robust supply chains for clean hydrogen, and implementation of a new regulatory framework, including sector coupling. The EU hydrogen strategy aims to overcome these issues and sets ambitious targets for the next decade. One of the main goals of any hydrogen strategy is to repeat the learning curve of photovoltaics (PVs) in 10 years for the water electrolysis technology.¹⁰

The EU hydrogen strategy

The EU hydrogen strategy and the associated European Clean Hydrogen Alliance was launched in 2020. In the strategy, the process of developing the hydrogen economy is divided into three phases:

⁸ Fuel Cells and Hydrogen Joint Undertaking. (2020). 'All H2020 projects'. <https://www.fch.europa.eu/fchju-projects/h2020>

⁹ European Commission. (2020). 'European Clean Hydrogen Alliance'. https://ec.europa.eu/growth/industry/policy/european-clean-hydrogen-alliance_en

¹⁰ European Commission. (2020). 'Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions - Towards a hydrogen economy in Europe: a strategic outlook'. https://www.euractiv.com/wp-content/uploads/sites/2/2020/06/Hydrogen_strategy.pdf



2020-2024, 2025-2030 and 2030-2050. Most relevant to this paper are the first two phases, as they act as the major push or boost for development of new commodities. The first decade up to 2030 will determine if the hydrogen economy will become significant or stay as hype.

According to the strategy, by 2024 a minimum target of 6GW of installed capacity for electrolysis technology, with a total annual production of 1 million tonnes of renewable hydrogen, should be reached. Currently, Europe uses around 8.3 mt or 339 TWh of hydrogen per year. According to Hydrogen Europe, most of the hydrogen (95%) is produced via steam methane reforming (SMR) and to a lesser extent autothermal reforming (ATR), both highly carbon-intensive processes, which correspond to an emission rate of 393gCO₂/kWh. The objective of the first phase is to replace fossil fuel production of hydrogen by low and carbon free energy sources. Both hydrogen from renewable electricity and natural gas small modular reactors (SMR) combined with carbon capture (utilization) and storage (CCS/CCUS) could contribute to decarbonization of existing hydrogen production mainly for refinery, ammonia, steel and chemical industries (Figure 1). Currently, most hydrogen (64%) is produced on-site, so called captive market, followed by 21 per cent as a byproduct (for example chlor-alkali processes) and 15 per cent from central hydrogen production.¹¹

The second phase (2025-2030) of the EU hydrogen strategy envisages rapid growth of installed electrolyser capacity to a minimum of 40GW within the EU, aiming for renewable hydrogen production of 10 million tonnes per year. The stated hydrogen production is rather ambitious, as realistically the output of electrolyser capacity of 40GW could not exceed 4-5 tonnes of H₂ per year from renewable electricity (maximum 4000 operational hours). New hydrogen sectors are planned to be unlocked, starting with steel production, trucks, rail, maritime transport applications, as well heating systems for civil buildings. By 2030 all pilot projects are supposed to be finished and have ready proved business cases for large-scale rollout. The markets are still planned to be either captive or central (close to the end use or to the H₂ production location), as hydrogen infrastructure (pipeline network) will not be mature by this point.

Table 1: The European hydrogen strategy, phases' analysis

Phase	The EU Hydrogen strategy
1. 2020-2024	The objective is to decarbonize existing hydrogen production for current uses such as in the chemical sector, and promote it for new applications. 6 GW of installed electrolysers' capacity With production of H ₂ up to one million tonnes In comparison to the current situation, approximately 1 Gigawatt of electrolysers are installed in the EU today.
2. 2024-2030	Min. 40 Gigawatt of renewable hydrogen electrolysers with the production of up to ten million tonnes of renewable hydrogen for new sectors including steel-making, trucks, rail and some maritime transport applications. It will still mainly be produced close to the user or close to the renewable energy sources, in local ecosystems.
3. 2030-2050	Renewable hydrogen technologies should reach maturity and be deployed at large scale to reach all hard-to-decarbonize sectors where other alternatives might not be feasible or have higher costs.

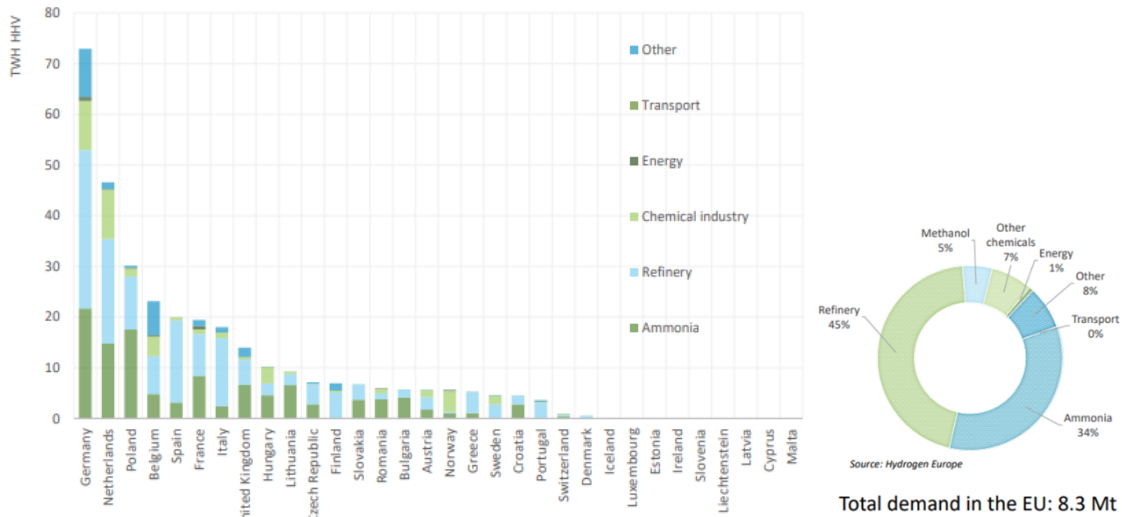
Source: European Commission (2020b) 'Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions - Towards a Hydrogen economy in Europe: a Strategic Outlook'

¹¹ Reigstad, G. A. et al. (2019). 'Hydrogen for Europe. Final report of the pre-study'. https://www.sintef.no/globalassets/sintef-energi/hydrogen-for-europe/hydrogen-for-europe-pre-study-report-version-4_med-omslag-2019-08-23.pdf



Hydrogen technologies are an integral part of the Green Deal and the recently announced green recovery plan of the EU. Some EU Member States (EUMS) have already launched national hydrogen strategies, depending on the economic, industrial, and geographical features of the country. The first of these are the Netherlands, Norway, Germany, France, Portugal, and Spain. All of them are the first EUMS with the highest hydrogen demand for the industrial sector, with a leader – Germany - where H₂ demand corresponds to approximately 72 TWh HHV (higher heating value) (21% of total EU hydrogen demand). (Figure 1). Many other EUMS announced their national strategies will be released by end-2022.¹²

Figure 1: Current hydrogen demand in the EU



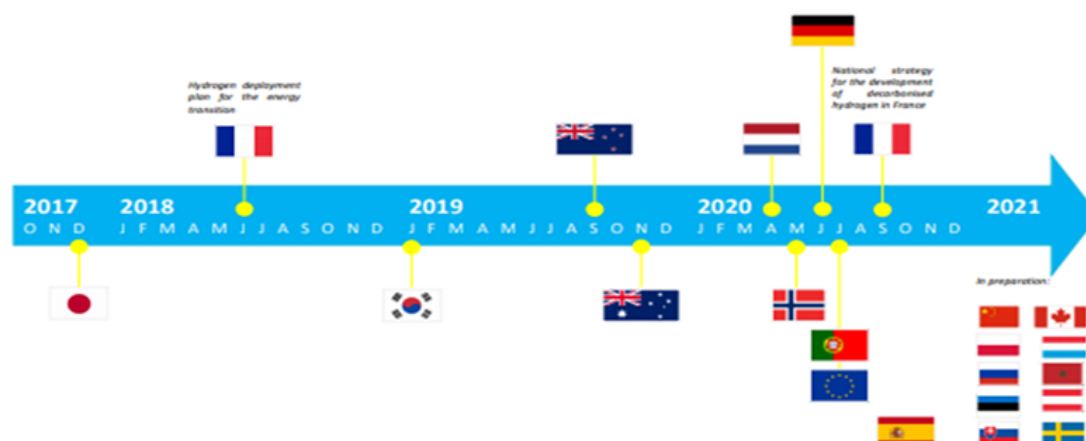
Source: Hydrogen Europe Hydrogen demand per Member State regarding the end use sector

Source: Hydrogen Europe (2020) 'Clean Hydrogen Monitor 2020'

In Figure 2, the timeline illustrates the years and months covering the start of the rush to release hydrogen strategies. In April 2020, Hydrogen Europe published the study 'Green Hydrogen for a European Green Deal A 2x40 GW Initiative', prompting a H₂ strategy race among EUMS. The competition for a higher ranking in the new growing niche of the hydrogen economy has triggered ambitious strategies and targets for hydrogen related technological developments as summarised in Table 2. These ambitious targets raise several questions. For example, are the targets overestimated and excessive? Will EUMS follow the announced clean hydrogen route? Will investment plans be enough? Is it possible for the electrolyser industry to grow so rapidly in a 10-year span? While these questions are certainly valid, they are beyond the scope of this paper which aims to develop a realistic assessment of the potential for hydrogen imports into Europe.

¹² Hydrogen Europe (2020a) 'Clean Hydrogen Monitor 2020', in

Figure 2: Timeline of the acceptance of the national hydrogen strategies within last 4 years



Source: Hydrogen Europe 'Clean Hydrogen Monitor 2020'

Table 2: Summary of EU Member States national hydrogen strategies

National Hydrogen Strategy	Date of Release	Description	Investment plan (in €)
The Netherlands	30 March 2020	3 – 4 GW of electrolysis capacity by 2030; 500 MW by 2025 Roll out of H ₂ transport (50 tank stations, 15,000 FCEVs and 3000 heavy duty vehicles Enable by 2030 heating sector via pilot projects	9 bn (until 2050)
Norway	3 June 2020	Transport Industry	0.4 billion
Germany	10 June 2020	2030: H ₂ demand 90-110 TWH, 6 GW of electrolyzers installed capacity	7 bn + 2bn external partnerships
Portugal	24 May 2020		1 bn
France	14 September 2020	Industry 10% decarbonized H ₂ use in industry by 2023 and 20-40% by 2028	7.2 bn
Spain	Hydrogen Roadmap October 2020	4 GW of electrolyzers installed capacity, 25% decarbonized H ₂ use in industry by 2030	8.9 bn
Italy	Draft, September 2020	5 GW of electrolyzers installed capacity 2% of final energy demand by 2030 from hydrogen	4 bn (€10 bn)

Source: Government of the Netherlands. (2020). Netherlands Government Strategy on Hydrogen, BMWi. (2020). The National Hydrogen Strategy. www.bmw.de, International Trade Administration. (2020). Spain Renewable Hydrogen Roadmap, Watson Farley & Williams. (2021). The Italian Hydrogen Strategy, Bretagne Développement Innovation. (2020). National strategy for the development of decarbonised and renewable hydrogen in France. FCH JU 2. (2020). Portugal. Opportunities for Hydrogen Energy Technologies Considering the National Energy & Climate Plans Table of content., Norwegian Ministry of Petroleum and Energy, & Norwegian Ministry of Climate and Environment. (2020). The Norwegian Government's hydrogen strategy towards a low emission society.

By simply adding the proposed installed capacity of electrolyzers by 2030 of the European countries listed in Table 2, the main target of 40 GW domestic hydrogen production can be achieved. It remains to be seen the extent to which these countries are actually able to deliver on these ambitions.

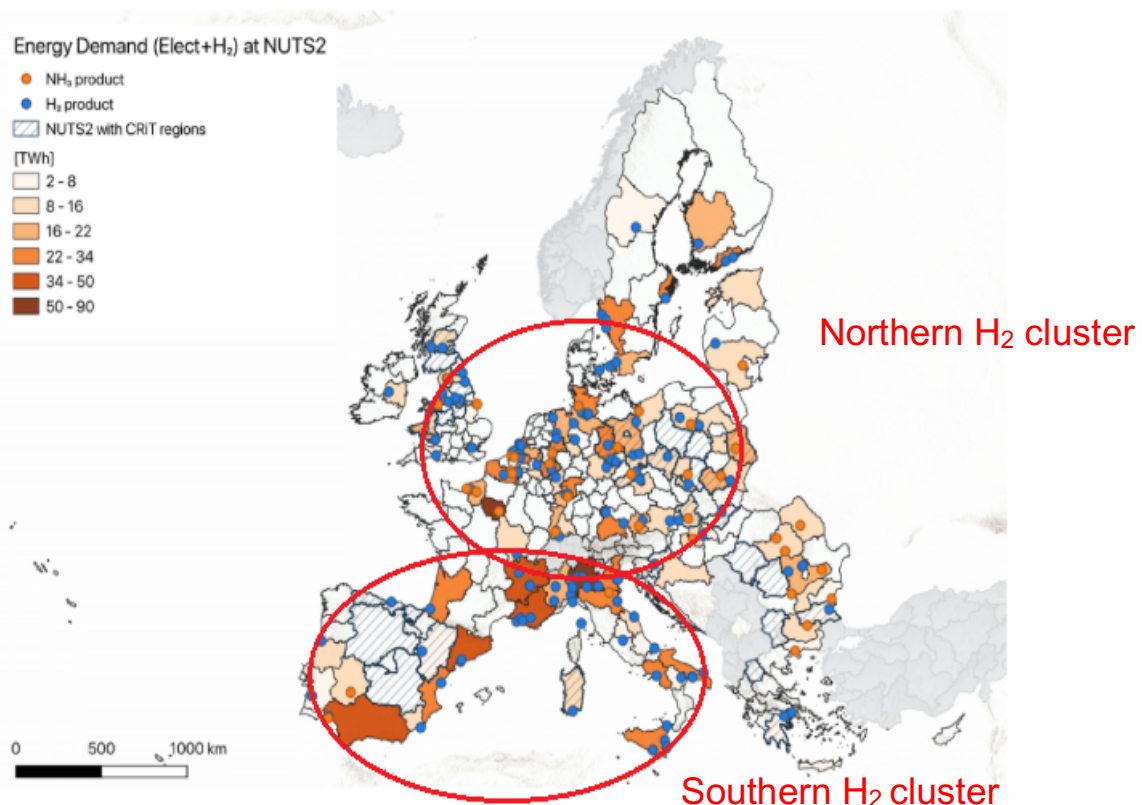
II. Hydrogen demand by 2030

Existing hydrogen production in Europe

To understand the potential size and location of demand for hydrogen imports, this section considers the location of demand and availability of local production which, in most cases, will be more cost effective than long distance imports.

According to the EU hydrogen strategy, the first step on the way to a clean hydrogen economy is to optimize and decarbonize the current hydrogen demand for industrial purposes in the European Union. For this purpose, authors Kakoulaki et al from the EU commission Joint Research centre have released a detailed and first of its kind study on the estimation of the current fossil fuel based hydrogen production on a regional level.¹³ Figure 3 shows the authors results, achieved by collecting and harmonizing open source geospatial data on the location, size and type of hydrogen production (ammonia or hydrogen). The map comprises polygons with different colours, representing the total annual demand for electricity in TWh on a regional level (combining the total electricity consumption and the potential demand for electrolysis to decarbonize fossil based hydrogen) and blue and red dots, which refers to chemical industries with hydrogen and ammonia production respectively.

Figure 3: Overview of main hydrogen production hubs in EU27 + UK, visual representation of two H₂ clusters



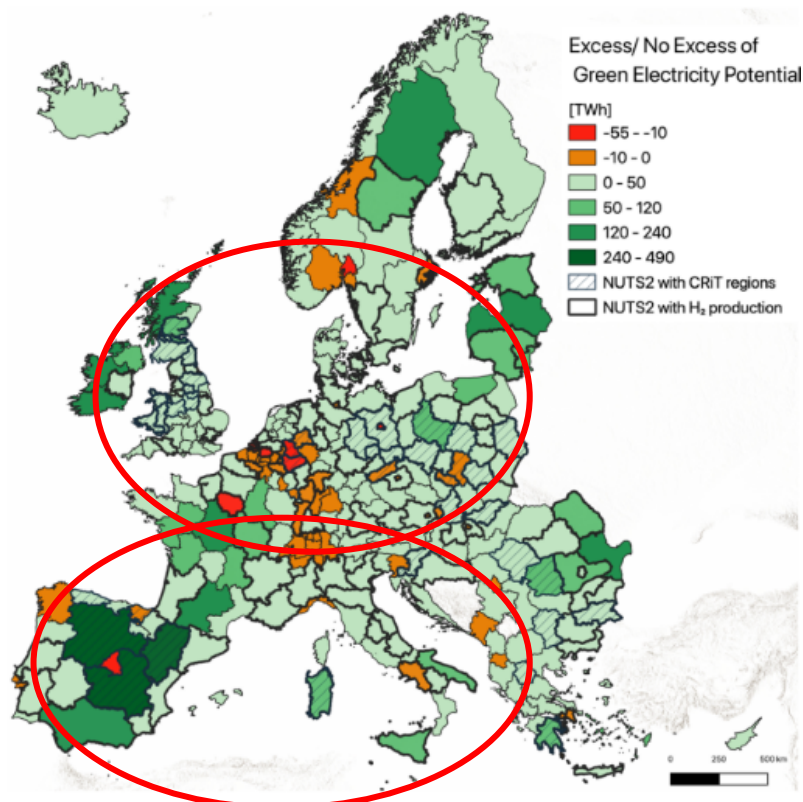
Source: Kakoulaki *et al.*, 2021

¹³ Kakoulaki, G. *et al.* (2021). 'Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables', *Energy Conversion and Management*. Elsevier Ltd, 228 113649. <https://doi.org/10.1016/j.enconman.2020.113649>

Figure 3 gives a good visualization of what is happening in the hydrogen sector in Europe and the UK and which specific locations and countries are the starting points for realising potential hydrogen industry and infrastructure. To estimate the potential domestic H₂ production, volumes for importing and location-related design of the supply chains, the EU plus UK are divided into two hydrogen clusters: Southern and Northern H₂ clusters. According to Figure 3, the Northern H₂ cluster has a higher number of H₂ related industries and more electricity intensive regions. Germany, the Netherlands, United Kingdom, France and Denmark are the focus countries for hydrogen demand and are potential H₂ importers. The southern cluster covers mainly Spain, Italy and Portugal. According to the geographical features of each country from both clusters, there is no general solution for supply chain design. In fact, many different regional features such as existing hydrogen and natural gas infrastructure, availability of underground storage, access to maritime routes, type and requirements of the end product and renewable energy potential are crucial for design of the unique supply chain of each country.

Kakoulaki et al's study provides the technical potential of renewable energy (RE) resources (not including bioenergy sources). In particular, the work identifies the capabilities of RE to cover current electricity demand and replace the fossil fuel-based hydrogen with electrolysis. The result is presented on Figure 4, where the majority of regions present sufficient potential for current electricity needs and H₂ demand (light green colour corresponds to excess of green energy potential of 0-50 TWh per year). The northern hydrogen cluster shows higher deficit of green electricity potential (the Netherlands and Germany) than the southern cluster, signalling a need for hydrogen imports. The southern cluster shows higher potential for domestic renewable energy generation. Therefore, hydrogen imports to the southern cluster are not a high priority for the next decade.

Figure 4: Local potential of renewable hydrogen production in Europe



Source: Kakoulaki *et al.*, 2021

There are a wide range of future hydrogen potential demand forecasts. A report by Aurora Energy Research provides analysis of the overall potential for low carbon hydrogen in Europe, assessing the likely extent of market growth to 2050. Aurora's analysis suggests that hydrogen demand could grow rapidly from 327TWh today up to 2500TWh by 2050 and that there could be significant demand for low



carbon hydrogen in industry which would double current demand to 700TWh by 2050. In the 2030s and 2040s there is high potential for hydrogen use in transportation (particularly in heavy duty vehicles such as buses, trucks, trains and potentially planes) and heating (replacing natural gas).¹⁴

In Hydrogen Europe's 2020 study 'Green Hydrogen for a European Green Deal A 2x40GW Initiative', the demand for renewable hydrogen was presented as a roadmap with two scenarios, business as usual and ambitious. Figure 5 illustrates the following projection of hydrogen demand. In 2030, the demand is assumed to be in a range of 481TWh – 665TWh (427TWh for existing industry feedstock and 54TWh and 238TWh additional depending on the scenario). In the ambitious scenario (Figure 5), the additional demand for hydrogen is divided between the transportation sector (70TWh), power generation (65TWh), new industry feedstock (63TWh) and heating plus power for buildings (33TWh). In the long run up to 2050, hydrogen demand could reach up to 2240TWh, which according to the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), is around 24 per cent of total final energy demand. The rather ambitious target of hydrogen demand in the transportation and heating sectors raises a number of questions. The decarbonization competition in the energy sector between electrification and hydrogen molecules is ongoing. In the case of passenger vehicles and household heating systems, electric solutions such as electric vehicles (EV) and heat pumps will definitely take a leading role, due to costs, energy efficiency and because the level of simplicity and development of these technologies is already available on the market today.¹⁵

Several months after the '2x40GW Initiative' paper, the EU Commission released the EU hydrogen strategy, based on the work of Hydrogen Europe, where the approximate installed capacity for hydrogen production from renewable electricity is 80GW (40GW x 2). According to Figure 5, in order to satisfy the required hydrogen demand for existing industry feedstock (427TWh or 13MM tonnes of H₂), the aforementioned 80 GW electrolyser capacity would not be enough, as it corresponds to around 10MMtonnes of annual H₂ production. Instead, 105GW of electrolyser installed capacity is required for existing industry feedstock demand. Regarding the total hydrogen demand for business as usual, and ambitious scenarios, the targets of roughly 117GW and 160GW of installed electrolyser capacity respectively would be required in 2030.

¹⁴ Aurora Energy Research. (2020). 'Hydrogen in the Northwest European Energy System'

¹⁵ Knobloch, F. *et al.* (2020). 'Net emission reductions from electric cars and heat pumps in 59 world regions over time', *Nature Sustainability*. Nature Research, 3(6), 437–447. <https://doi.org/10.1038/s41893-020-0488-7>

Thomaßen, G., Kavvadias, K. and Jiménez Navarro, J. P. (2021). 'The decarbonisation of the EU heating sector through electrification: A parametric analysis' *Energy Policy*. Elsevier Ltd, 148. <https://publications.jrc.ec.europa.eu/repository/handle/JRC120530>

Figure 5: An ambitious roadmap for the deployment of hydrogen in the European Union



Source: FCH JU (2019)

Agora Energiewende Study 'No-regret Hydrogen'

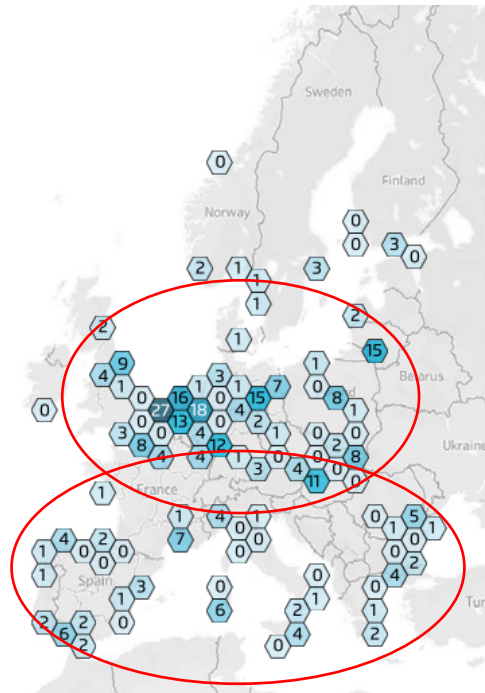
In early 2021 Agora Energiewende released a study 'No-regret hydrogen', providing scenarios for development of hydrogen technologies with 'no-regret', meaning a cost minimisation approach. In this case, demand for hydrogen is derived only from the hard-to-abate energy sectors, such as the iron, steel, and fertiliser production industries, and aviation and maritime transport, where hydrogen is the only solution to move away from the use of fossil fuels. The study focuses on the short-term development of hydrogen sectors in Europe, and thus is suitable for drawing projections by 2030. Agora Energiewende's study can be considered as a base for hydrogen demand in 2030, 2040 and 2050: actual demand may be higher, but with greater uncertainty. Such insight helps in understanding and designing the whole supply chain, where the centre part is assessment of a hydrogen backbone pipeline. According to the authors, it is important to mention that the supply chain system of hydrogen is not integrated with the electricity system, meaning that the production of H₂ is supplied from dedicated RE sources. Figure 6 shows the total 'no-regret' hydrogen demand in 2030. The map is divided into two hydrogen clusters: Northern and Southern, following the same method used in the European Commission Joint Research Centre' study.¹⁶ The main demand centre, according to analysis by Agora Energiewende, is the trilateral region of North Rhine-Westphalia (Germany), Flanders (Belgium), and the Netherlands, due to the location of a high number of industries there.¹⁷

¹⁶ Kakoulaki, G. *et al.* (2021). 'Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables', *Energy Conversion and Management*. Elsevier Ltd, 228. <https://www.sciencedirect.com/science/article/pii/S0196890420311766?via%3Dihub>

¹⁷ Agora Energiewende *et al.* (2021). 'No-regret hydrogen'. https://static.agora-energiewende.de/fileadmin2/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf



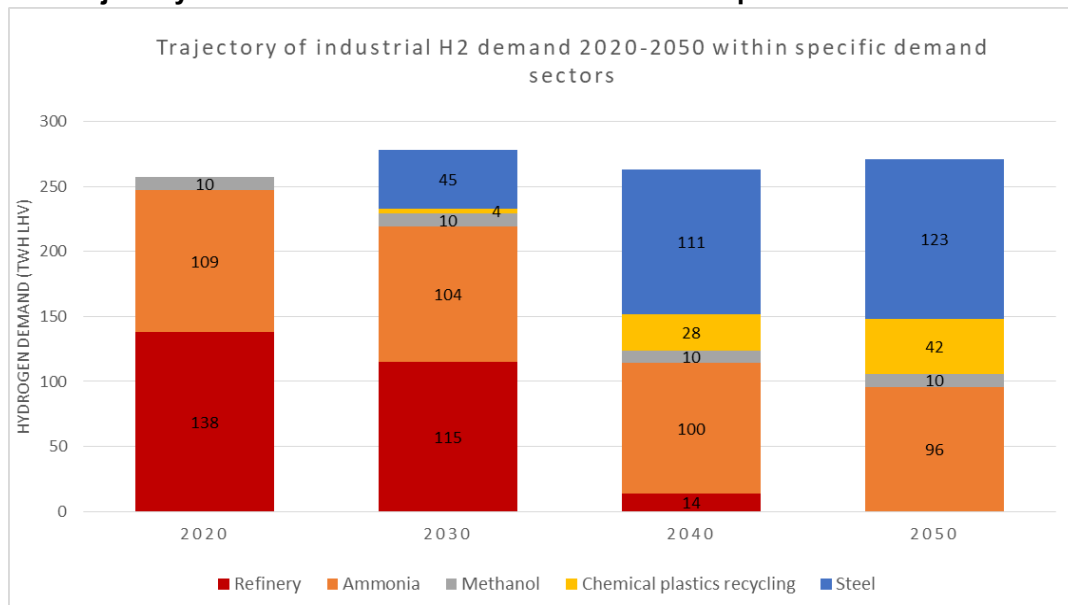
Figure 6: Projected hydrogen demand in ‘no-regret’ scenario in 2030



Source: Agora Energiewende et al. (2021)

Another outcome of the study is the development of forecasts for different industrial hydrogen demands from 2020 to 2050. Figure 7 shows the change of hydrogen demand by sector. In 2020 the total demand is 257TWh nearly all in the refinery and ammonia sectors. By 2030, the reduction of hydrogen utilization in the refinery sector reflects the global trend of minimisation of crude oil and oil products consumption, while growing H₂ demand for steel production compensates, resulting in an increase in total hydrogen demand (278TWh). By 2050 the total hydrogen demand declines slightly to 270TWh. H₂ demand for steel is 123TWh followed by 96 TWh for ammonia, 42 TWh for chemical recycling of plastics, and 10 TWh for methanol.

Figure 7: Trajectory of industrial H₂ demand 2020-2050 within specific demand sectors



Source: Agora Energiewende et al. (2021)



Combining the results of these various studies, it is reasonable to conclude that the largest and earliest potential demand for hydrogen imports will be to meet demand in the northern cluster in the industrial heartlands of the Netherlands and Germany.

III. European low-carbon hydrogen import routes

In Hydrogen Europe's paper '2x40GW', the authors emphasize that 40GW hydrogen import will come from two specific directions: 30GW from North Africa (Morocco, Algeria, Egypt, Tunisia and Libya), and 10GW from Ukraine. North Africa has vast solar and wind resource potential. According to Hydrogen Europe, the Sahara Desert is the sunniest place in the world, with around 3600-4000 operating hours per year, and the level of the solar insolation can reach 2500-3000kWh/m². For comparison, 10 per cent of the Sahara Desert area could satisfy total global energy demand.¹⁸ Regarding the renewable situation in Ukraine, the authors state the high potential for wind energy and biomass. Ukraine has the potential to build 688GW of wind energy capacity on its territory.¹⁹

While the Hydrogen Europe report mentions two sources for hydrogen supply to Europe, it does not go into detail about the logistics of production and transportation, for example:

- how the significant number of electrolyser capacity can be built and by whom,
- how the infrastructure could be designed or optimized,
- is there enough geological storage of hydrogen,
- what is the pipeline transmission capacity,
- and who is going to initiate the investment and financial support needed to start the hydrogen economy.

The selection of countries is limited, and this paper aims to provide a wider look at the feasibility of a range of different hydrogen import routes that the European Union could consider. It starts by considering the above questions regarding the two main hydrogen export candidates – Morocco and Ukraine. For simplicity, Morocco is a representative from northern Africa. Apart from the exporters suggested in the paper by Hydrogen Europe, two other candidates for low carbon hydrogen export, Norway and Russia, are considered in this study. An overview of potential exporters starts by considering the country's energy mix, and assessing the following key criteria as they are likely to evolve between now and 2030:

- limited decarbonization of domestic energy system,
- water availability,
- proximity to H₂ demand centres,
- state of development of the infrastructure and readiness for H₂ injection,
- history of bilateral relationships and security of supply.

Northern Africa – Morocco

Most of the energy consumed in Morocco (up to 80% in 2017) is imported fossil fuels, see Figure 8. The share of domestic production contains mostly biofuels and other renewable energy sources. In particular, in 2018, the total energy supply constituted 61 per cent oil, 24 per cent coal, 5 per cent natural gas, and the remaining 10 per cent was a combination of renewable energy (mostly bioenergy and waste, then wind and solar energy and hydro).

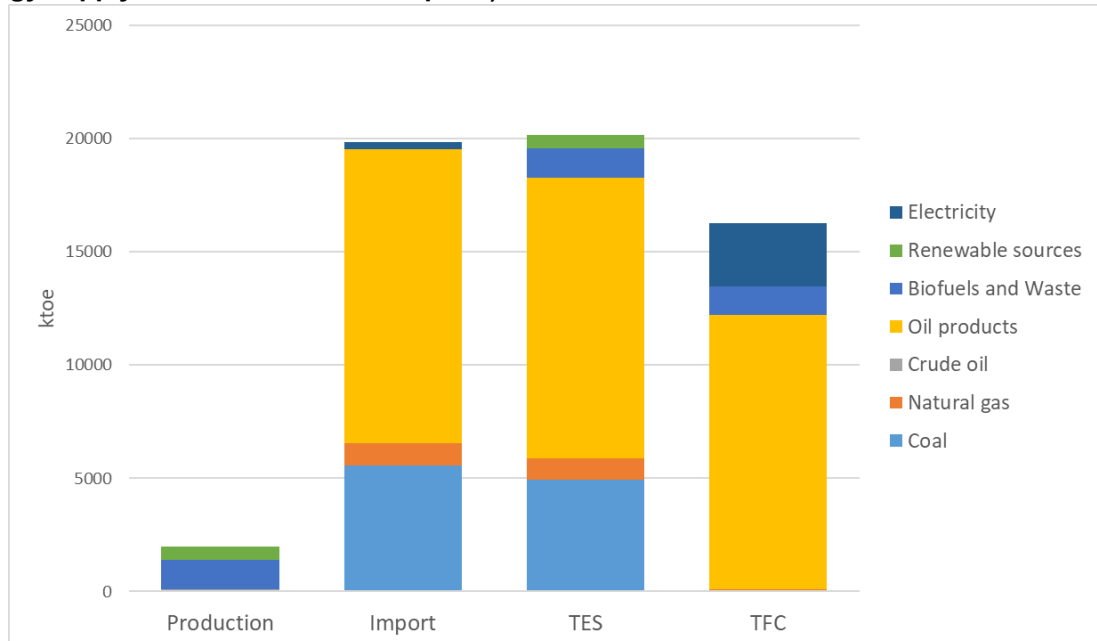
¹⁸ Hydrogen Europe. (2020) 'Green Hydrogen for a European Green Deal A 2x40 GW Initiative'.

¹⁹ Kudria, S. *et al.* (2021). 'Resource potential for wind-hydrogen power in Ukraine', *International Journal of Hydrogen Energy*. Elsevier Ltd, 46(1), 157–168. <https://www.sciencedirect.com/journal/international-journal-of-hydrogen-energy/vol/46/issue/1>
UABIO (2021). 'Bioenergy transition in Ukraine'. <https://uabio.org/en/bioenergy-transition-in-ukraine/>



The government of Morocco has embarked on energy reforms to promote the country's industry in the renewable energy and energy efficiency sectors, to penetrate regional and international markets and to encourage the development of local resources. The government of Morocco is aiming to drastically increase its share of domestic renewable energy to cover electricity demand and become an exporter of green energy and reduce its reliance on international fossil fuel imports (Figure 8).²⁰

Figure 8: Overview of energy sector in Morocco, 2018 (production, imports, total primary energy supply and total final consumption)



Source: IEA

Moroccan electricity sector and perspectives for green hydrogen export

Morocco is a hydrocarbon net importer, where most of the energy resources are consumed in the electricity and transportation sectors. As shown in Figure 9, only 20 per cent of power generation is from renewables (hydro, wind, solar and others), with most produced from coal. In 2019, electricity generation from coal reached a peak of 26900GWh.²¹ An ever increasing consumption of coal does not enable a reduction in CO₂ emissions, as burning coal is one of the heaviest GHG contributors (for 1 kWh from coal, 0.4 kg is CO₂ when 1kWh from natural gas is 0.2 kg of CO₂).²²

Nevertheless, Morocco's notable progress in reforming its energy subsidy system and increasing renewable energy production contributes to the effective implementation of Morocco's National Energy Strategy 2009-2030 and its national contribution (NDC). According to the strategy, by 2030 Morocco's renewable installed capacity (20% wind, 20% solar, 12% hydro) should reach 52 per cent.²³ Even though renewable energy generation is a small share today, the growth of wind and solar installed capacities within the last three years is impressive. In 2018, Morocco tripled its solar energy capacity to 711MW and increased its wind power capacity by 36 per cent, up to 1.22GW. In the last 15 years the

²⁰ International Energy Agency (IEA). (2019) 'Energy Policies Beyond IEA Countries', *International Energy Agency*, 221. https://www.connaissancedesenergies.org/sites/default/files/pdf-actualites/Energy_Policies_beyond_IEA_Countries_Morocco.pdf

²¹ International Energy Agency. (2021). 'Morocco - Countries & Regions'. <https://www.iea.org/countries/morocco>

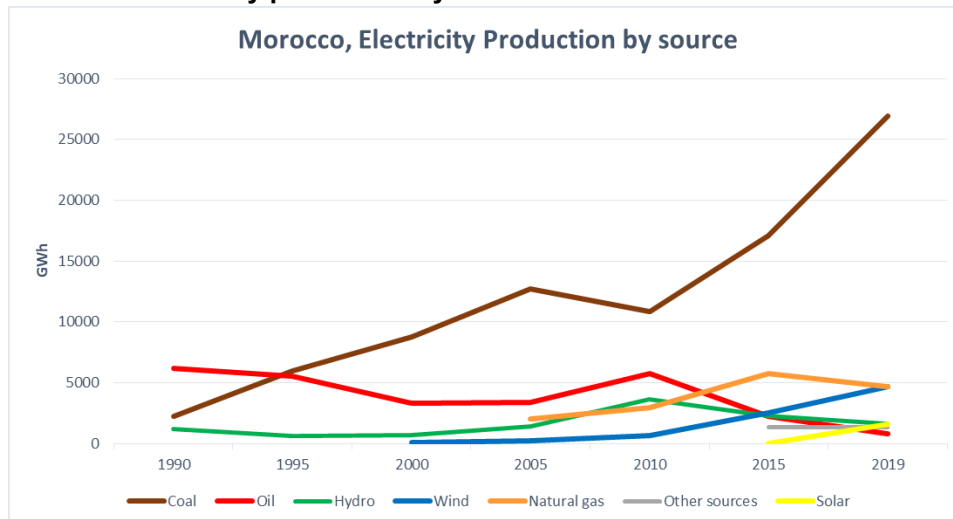
²² Volker-Quaschnig. (2019). 'Regenerative Energiesysteme Technologie - Berechnung - Klimaschutz'. 'Specific carbon dioxide emissions of various fuels'. https://www.volker-quaschnig.de/datserv/CO2-spez/index_e.php

²³ Zelt, O. *et al.* (2019). 'Long-Term Electricity Scenarios for the MENA Region: Assessing the Preferences of Local Stakeholders Using Multi-Criteria Analyses'



renewable energy capacity has grown by 25 per cent. By 2020, Morocco's renewable energy installed capacity was 3.7GW, including 700MW of solar energy, 1215MW of wind power, and 1770MW of hydro power. According to the Moroccan Agency for Renewable Energy (MASEN), the country's optimistic target was to reach 6GW of renewable energy installed capacity before the end of 2020.²⁴ Nevertheless, only 4GW has been reported as commissioned by the end of 2020.²⁵

Figure 9: Moroccan electricity production by source 1990-2019



Source: Adapted from International Energy Agency 2021

One of the biggest solar projects in Morocco is the Noor Solar complex in Ouarzazate with installed capacity of 580MW from the combination of concentrating solar power (CSP) and photovoltaic (PV) technology. Another large hybrid CSP/PV project of 800MW is planned to be built in Midelt. In 2018, Morocco had generated 3.8TWh from wind parks (second largest in Africa after South Africa). Five big wind projects, total 850MW, are under development by the Moroccan energy company Nareva, Italy's Enel Green Power (EGP), and Germany's Siemens Wind Power. Five projects (Midelt (150MW), Tangier (100MW), Jbel Lahdid (200MW), Tiskrad (300MW) and Boujdour (100MW)).²⁶

While good progress in renewables is being made, it appears likely that there will still be considerable coal-fired power generation in use in Morocco by 2030, so production of green hydrogen in Morocco would, effectively, be manufacturing hydrogen using coal-fired generation and therefore not environmentally sustainable.

Morocco is a part of the 220kV interconnector linking Tunisia, Algeria and operating synchronously with the European Union's Joint Transmission of Electricity (UCTE) through an under sea cable to Spain. The Spain-Morocco interconnection includes two 400kV lines commissioned in 1997 and 2006, whose total capacity is 800MW. There is a planned third 400kV link with a 700MW capacity. The combined three power grids will be able to carry 1500MW. Another existing infrastructure connection with Europe is the Sonatrach gas pipeline network from Algeria and Spain through the Mediterranean Sea with a capacity of 8 Bcm/y and Maghreb-Spain pipeline network with capacity of 12 Bcm. The Hydrogen Europe study has not indicated whether the intention would be to convert these pipelines or build new infrastructure.

Potential export of blue hydrogen

In the case of Morocco, export of natural gas-derived low-carbon hydrogen (blue or turquoise) is not under consideration due to insufficient natural gas resources (most of the gas originates from Algeria and Libya). Nevertheless, other countries from North Africa could potentially provide blue hydrogen to

²⁴ Masen. (2020). Masen - L'Agence Marocaine pour l'Energie Durable. <https://www.masen.ma/en>

²⁵ Energy & Utilities. (2021) 'MEE 2021: Morocco set to hit 2030 renewables target in 2024'. <https://energy-utilities.com/mee-2021-morocco-set-to-hit-2030-renewables-news112319.html>

²⁶ US Energy Information Administration (EIA). (2019). <https://www.eia.gov/international/analysis/country/MAR>



Europe. In 2015, annual natural gas supplies from Algeria to Italy made up 20 per cent of the pipeline capacity (6.6Bcm – Trans-Mediterranean pipeline) and to Spain in 62 per cent (12 Bcm Medgas and Magreb Europe pipelines). From Libya to Italy the supplies of natural gas were around 60 per cent (Greenstream). Potential export of natural gas for blue hydrogen production from Algeria to Italy is more feasible, as the pipelines capacities is not fully utilised. However, converting the existing natural gas pipeline system for hydrogen only transportation by 2030 and 2035 could be a risk to the security of natural gas supply, therefore is not realistic. In the meantime, another option could be blending hydrogen with natural gas (up to 10%).

Water availability issue

Morocco is a water-scarce country facing depletion of groundwater resources and heavy reliance on non-irrigated agriculture. Only 15 per cent of all agricultural land is irrigated, resulting in inefficient water use and management. Despite improvement in the access to water supply over the last decade, many issues remain. Environmental problems include a low level of wastewater treatment (only 13% of collected wastewater is being treated), lack of functioning water network connections in the poorest urban neighbourhoods, and limited sustainability of rural systems (20% of rural systems do not have access to water resources).²⁷

The production of hydrogen requires abundant resources of fresh water (distilled water). For example, for 1kg of H₂, approximately 9 litres of water is needed. Consequently, hydrogen production for only European imports of 30GW installed capacity, would require 27 million tonnes of water per year. The total renewable water resources in Morocco are estimated at 29 billion tonnes per year (Bt/y), where the utilization part is around 20Bt/y.²⁸ Thus, green hydrogen production would require 0.3Bt of water, 1.5 per cent of the water utilization potential in Morocco per year. To enable vast hydrogen production for export additional water desalination units would be required. According to Khan et al., the addition of a desalination unit increases the cost for H₂ production by only 1 per cent.²⁹

National hydrogen initiatives

According to the EU hydrogen strategy, the EU is highly interested in the abundant renewable resources of Africa, particularly northern Africa due to its geographic proximity. The EU funding opportunities could soon help development of renewable hydrogen projects. According to a joint communication report 'Towards a Comprehensive Strategy with Africa', funding could be obtained from the Connecting Europe Facility and Projects of Common Interests, Neighbourhood, Development and International Cooperation Instrument (NDICI), and the European Fund for Sustainable Development. The Moroccan government signed an agreement with Germany, which consists of two projects: Power-to-X and Power-to-X Research. The projects are aimed at the development of a research platform on Power-to-X and the first green hydrogen electrolysis plant by 2025, with a capacity of 100MW and the emission reduction potential of 100,000 tonnes per year.³⁰

Ukraine

Ukraine plays a crucial role in transporting natural gas from Russia to EU Member States. According to data from the IEA, Ukraine has abundant fossil fuel resources and in 2018, 2.3mtoe of crude oil, 16.5mtoe of natural gas and 14.4mtoe of coal were produced. Nevertheless, only 65 per cent of energy production is from domestic sources, half of which is from nuclear power. The power mix of Ukraine is well diversified, no individual source represents more than one third. Imported energy represents 83 per cent of Ukrainian crude oil consumption (10.4mtoe), over 50 per cent of consumed coal (13.8mtoe) and one third of natural gas consumption (8.5mtoe), see Figure 10.³¹

²⁷ US Agency for International Development (USAID). (2020). 'Water and Sanitation' Morocco. <https://www.usaid.gov/morocco/water-and-sanitation>

²⁸ Hssaisoune, M. et al. (2020) 'Moroccan groundwater resources and evolution with global climate changes', *Geosciences (Switzerland)*, 10(2). <https://www.mdpi.com/2076-3263/10/2/81>

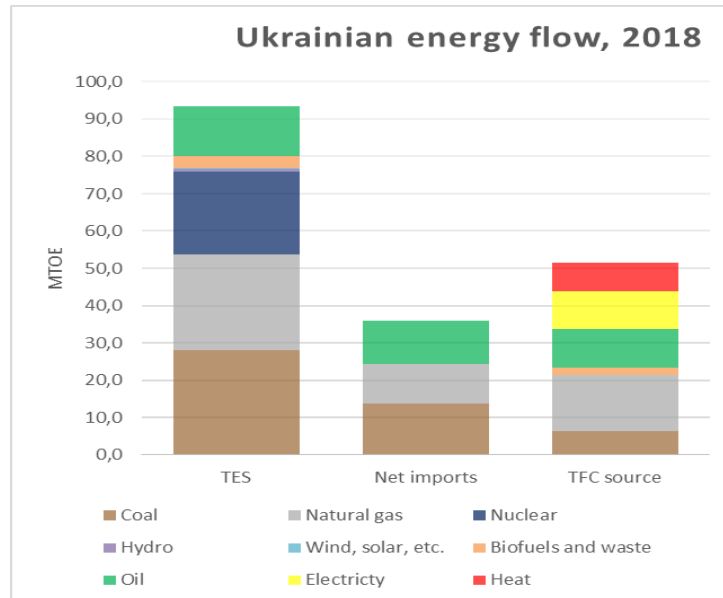
²⁹ Khan, M. A. et al. (2021). 'Seawater electrolysis for hydrogen production: a solution looking for a problem?', *The Royal Society of Chemistry, Energy & Environmental Science*. 14(9), 4831–4839. <https://pubs.rsc.org/en/content/articlelanding/2021/ee/d1ee00870f>

³⁰ Clifford Chance. (2021) 'Focus on Hydrogen: A New Energy Frontier for AFRICA'. <https://www.cliffordchance.com/briefings/2021/01/focus-on-hydrogen--a-new-energy-frontier-for-africa.html>

³¹ IEA. (2020). 'Ukraine energy profile'. <https://www.iea.org/reports/ukraine-energy-profile>



Figure 10: Overview of the energy sector in Ukraine (imports, total energy supply and total final consumption)

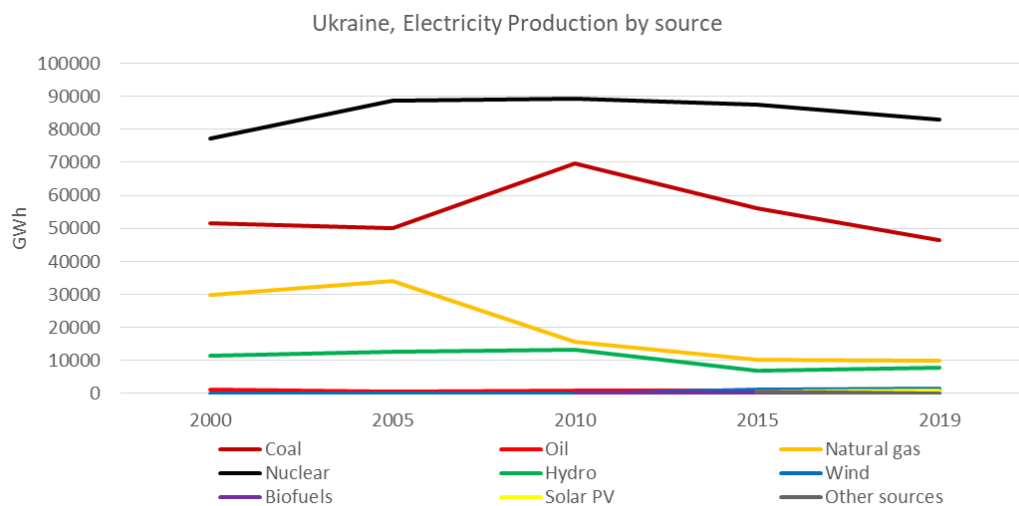


Source: IEA 2020

Nuclear and coal combined represent 85 per cent of the total electricity production (30% coal and 55% nuclear) as shown in Figure 11. In 2018 electricity exports from Ukraine totalled 500ktoe (6GWh).³²

The Ukrainian electricity system shows a decline in the use of carbon intensive fossil fuels within the last decade. Due to high shares of low-carbon energy sources for production of electricity (nuclear power plants), the carbon intensity per kWh is 0.23kgCO₂eq which is considered a moderate value. For comparison, German CO₂ intensity indicator is 0.4kgCO₂eq/kWh.³³

Figure 11: Ukrainian electricity production by source 1990-2019



Source: Adapted from IEA 2020

³² IEA. (2020). 'Ukraine energy profile'. <https://www.iea.org/reports/ukraine-energy-profile>

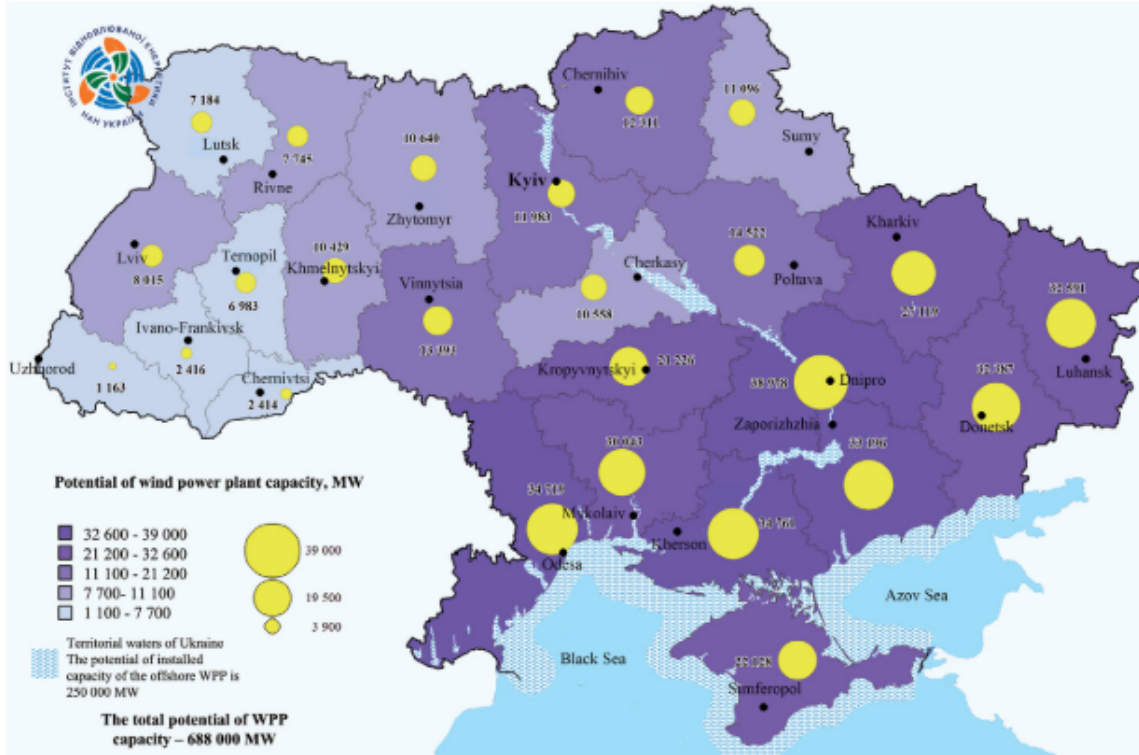
³³ electricityMap (2021) 'electricityMap - Live CO₂ emissions of electricity consumption'. <https://www.electricitymap.org/zone/DE>

Renewable energy potential for hydrogen production

Wind energy

In 2018, renewable energy comprised only 5 per cent of the energy mix and in 2019 the share of RE in electricity production was 9 per cent (13.4TWh). By 2020, Ukrainian wind-installed capacity accounted for 1.17GW. The Ukrainian government, in cooperation with the European Union, is planning to expand wind electricity generation, creating the wind-hydrogen sector. Authors suggest that the wind capacity factor varies between 0.21 and 0.53 for Ukraine and the total potential capacity for wind power plants (WPP) is estimated at the level of 688GW, mostly in the south, see Figure 12.34 To calculate the potential of green hydrogen production, studies by the International Renewable Energy Agency (IRENA), the US National Renewable Energy Laboratory (NREL) and the Institute of Renewable Energy (IRE) of the National Academy of Sciences of Ukraine (NAS) were compared. The results are summarised in Figure13 and Table 3. The wind power plant capacities presented on Figure 12 are based on regional wind speeds. The authors highlight the fact that the Ukrainian energy system is not capable of integration of variable power generation due to the lack of a flexible and agile balancing energy market. The theoretical potential of total wind capacity varies between 466 to 688GW and hydrogen production between 28 to 43MMtons. The range is due to the different assumptions of different authors of wind speeds, technology type and efficiency. Availability of country specific information is limited. Nevertheless, an overview of the wind-hydrogen potential shows a sufficiency of resources for decarbonizing the domestic energy sector and establishing green hydrogen exports (10GW in 2030 according to Hydrogen Europe). In 2020 the government of Ukraine and the Norwegian company NBT announced an 800MW wind power project with electrolysis H₂ production facilities, with capacity of 200MW in the Zaporizhzhia region of Ukraine. Given Ukraine already has a low carbon intensity of power generation and large untapped wind potential, if it can accelerate the roll out of wind power projects, it appears better placed than Morocco to be able to produce genuinely low carbon green hydrogen.

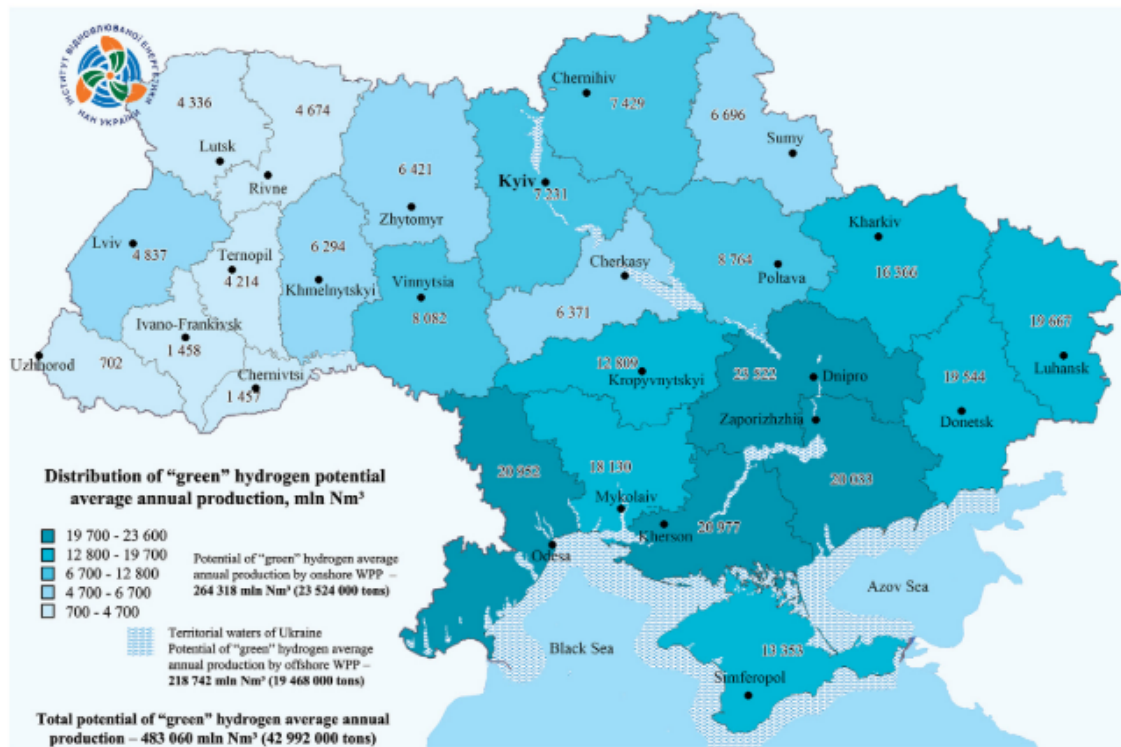
Figure 12: Potential of wind power plant capacity in Ukraine



Source: Kudria et al. (2021)

³⁴ Kudria, S. et al. (2021). 'Resource potential for wind-hydrogen power in Ukraine', *International Journal of Hydrogen Energy*. Elsevier Ltd, 46(1) 157–168

Figure 13: Potential of average annual green hydrogen production in Ukraine



Source: Kudria et al (2021)

Table 3: Assessment of the theoretical wind power potential and hydrogen production in Ukraine

Wind Power Plant	Source	Wind capacity in GW	H ₂ production in MMt/y
On-shore	IRENA	320	17
Off-shore	NREL	146	11
Total		466	28
On-shore	IRE NAS Ukraine	438	23.5
Off-shore	IRE NAS Ukraine	250	19.5
Total		688	43

Source: Kudria et al (2021)

Biomass and biofuels

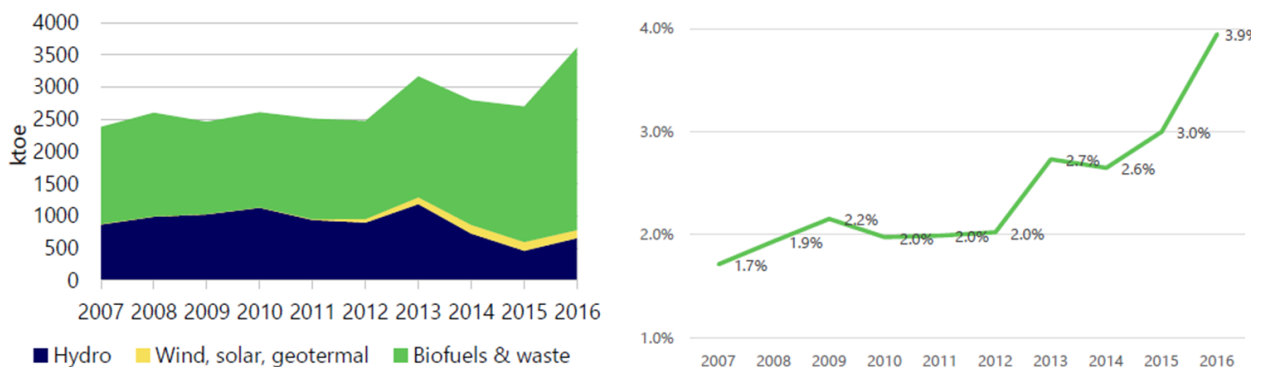
According to Hydrogen Europe, Ukraine also has a vast potential for bioenergy that could be utilized for hydrogen generation. There is a discussion as to whether the production of hydrogen from biomass should be initiated, as it would compete with the other efficient applications of biomass and biofuels. Although biomass gasification is a well-established method for hydrogen production, biomass and biofuels are already a renewable energy source that could be used directly for electricity and heat generation or injected and stored as biomethane, which would be lower cost and easier to transport than hydrogen.

Among the renewable sources in Ukraine, biomass and biofuels show high potential to contribute to the domestic decarbonization of the energy sector as well as establishing international relationships as a green fuel exporter. The agricultural sector in Ukraine is one of the largest in Europe and Ukraine is one of the main exporters of different types of grain. Moreover, Ukraine has become one of the exporters of biofuel feedstock, primarily grain and corn for bioethanol and in case of biodiesel – sunflower, soybeans



and rapeseed. Biomass residues and wood pellets are used for electricity and heat production.³⁵ In the last 15 years, the use of biomass in the energy sector has increased almost three times, showing in 2007 1.1 per cent, 3.1 per cent in 2016 and 3.4 per cent in 2018 (see Figure 14).³⁶ The increase of biomass consumption in total energy supply (TES) was mainly due to the heating sector, as the prices for gas and heat reached peak levels in 2014-2016 for households. Nevertheless, the share of biofuels and waste in the heating sector in Ukraine is on average two times less compared to OECD countries. Ukraine is focusing on the export of agricultural raw materials. These volumes (for example, rape and soya) in 2017-2018 could cover 35 per cent of the cost of imported diesel and 10 per cent of gasoline.³⁷ Thus while Ukraine does have abundant biomass resources, it is unclear the extent to which biomass use for hydrogen export to Europe would be a policy priority.

Figure 14: RE supply in 2007-2016, Ukraine; RE supply as a share of TPES in 2007-2016, Ukraine



Source: IEA (2018)

Reform of the energy sector in Ukraine started in 2015. In 2017, the government released the Energy Strategy of Ukraine until 2035 (ESU 2035), which has three main phases: Energy Sector Reforms up to 2020, Optimization and Innovative Development of The Energy Infrastructure up to 2025 and Ensuring Sustainable Energy Development up to 2035. The Energy Strategy of Ukraine is aimed at integrating into the European energy market and therefore the basis for all Ukrainian energy reforms is structured around EU legislation. Reforming the energy sector includes restructuring institutes of state, energy companies and assimilation to ENTSO-G (European Network of Transmission System Operators for Gas), ensuring energy independence by increasing domestic natural gas production and a share of renewable energy. Targets mentioned in the Energy Strategy refer to total energy supply (TPS) as a change in percentage in 2035 compared to the baseline year, 2015. That includes reduction of the coal share from 30.4 per cent to 12.5 per cent and an increase in renewable energy share from 3 per cent to 25 per cent, where biofuels represent 11.5 per cent by 2035.³⁸ Again, it is not clear whether these policy priorities would support hydrogen export to western Europe.

Besides the growing interest of the government in biomass and biofuels, the Bioenergy Association of Ukraine has released a study where the overall energy potential from biomass is around 23mtoe, which can be unlocked by 2050 (see Figure 15). Almost half the potential is from plant residues (10mtoe or 44%, mainly grain crops and rapeseed, corn stalks, sunflower husk) and energy crops (7.5mtoe or 32%, mainly willow, poplar, miscanthus and corn).³⁹ Half of all biofuel potential will be used in the heating

³⁵ MPRA. (2017). 'Biofuels Markets and Policies in Ukraine'. https://mpr.aub.uni-muenchen.de/76747/1/MPRA_paper_76747.pdf

³⁶ UABIO. (2021). 'Bioenergy transition in Ukraine'. <https://uabio.org/en/bioenergy-transition-in-ukraine/>

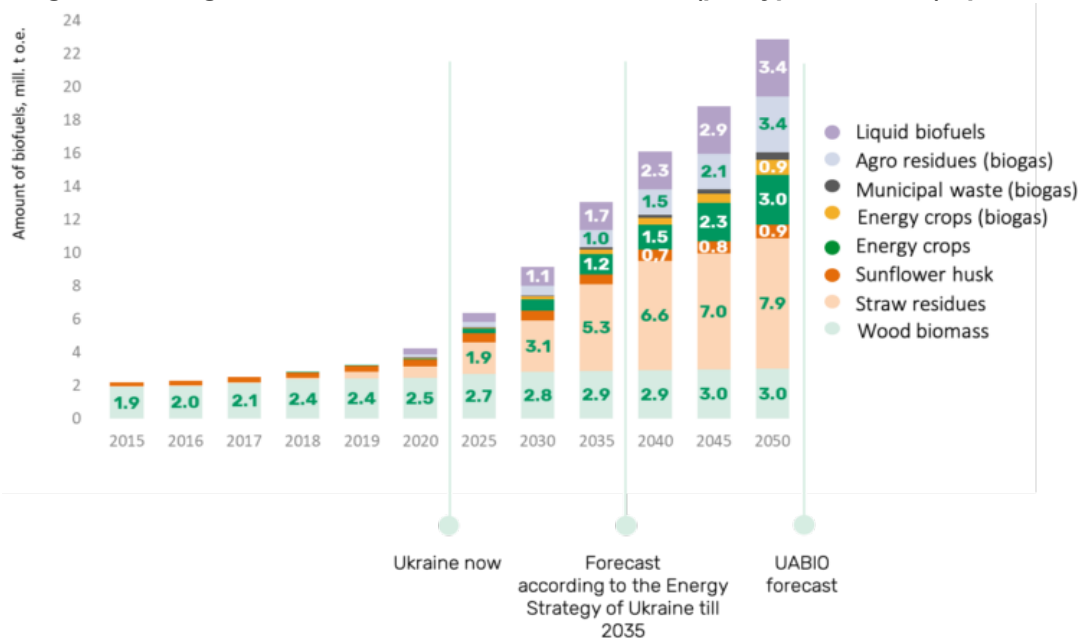
³⁷ BRDO. (2019). 'Biofuel production allow Ukraine replace 35% imported diesel and 10% gasoline'. <https://brdo.com.ua/en/main/biofuel-production-allow-ukraine-replace-35-imported-diesel-10-gasoline/>

³⁸ OECD, (2020) 'Monitoring the Energy Strategy of Ukraine 2035'. <https://www.oecd.org/eurasia/competitiveness-programme/eastern-partners/Monitoring-the-energy-strategy-Ukraine-2035-EN-.pdf>

³⁹ UABIO. (2021). 'Bioenergy transition in Ukraine'. <https://uabio.org/en/bioenergy-transition-in-ukraine/>

sector by replacing natural gas (13.7 Bcm per annum), the other half will be split between electricity production (replacing coal and nuclear PP) and the transport sector (petroleum products).

Figure 15: Prognosis of the Ukrainian biofuel market (per type of biofuel) up to 2050



Source: UABIO (2021)

Ukraine must decide whether to utilize its biomass domestically to offset fossil fuel imports, or alternatively, export the biofuel directly instead of using it internally for hydrogen production. Both are strategic opportunities to increase energy security and energy supply, and to enhance the energy dialogue with EU Member States. The export of biomethane to EU countries is also questionable, as the potential of biofuels and biomass is expected to be approximately 23mtoe by 2050, when fossil fuel imports today are exceeding 35mtoe. In this case, export of biofuels seems unlikely to become significant for Ukraine. Regarding the hydrogen production from biomass and biofuels, biomethane, compared to hydrogen, can already be produced at a large scale and can help to avoid high gas infrastructure investments (starting from pipelines up to gas turbines). Biomethane and hydrogen are not mutually exclusive, but rather both could contribute to the decarbonization of energy systems and, in the long-term, there is potential to produce hydrogen from biomethane. Overall, the above discussion casts some doubt over whether it is realistic to assume large scale hydrogen exports from Ukraine.

Natural gas system

The natural gas pipeline network of Ukraine is extensive, totalling 38,600 km of pipelines: 22,200 km of main transmission pipelines and 16,400 km of distribution pipelines. The pipeline system can transport up to 80 Bcm/y for domestic consumption and can transport up to 142.5 Bcm/y of gas from Russia and Belarus to EU Member States. Currently it carries around 82 to 93 Bcm of Russian originated natural gas to Europe.⁴⁰ The pipeline infrastructure consists of two pipelines the Bratstvo (Brotherhood) and Soyuz (Union). They are designed for carrying Russian gas to Europe, covering southern and northern parts of Ukraine, they then split in different directions for supplying southern, central and northern European countries, see Figure 16.

⁴⁰ IEA, (2020). 'Ukraine energy profile'. <https://www.iea.org/reports/ukraine-energy-profile>

Figure 16: Major natural gas transit pipelines flowing through Ukraine



Source: US Energy Information Administration (EIA) (2014)

The availability of mature natural gas infrastructure is definitely an advantage for Ukraine as a potential hydrogen exporter as, according to the report *European Hydrogen Backbone*, 70 per cent of the gas infrastructure will be utilized as a basis for the hydrogen-only pipelines.⁴¹ In this case, Ukraine is in a strong position to implement electrolysis-based projects and initiate hydrogen trade. However, the main disadvantage of the Ukrainian pipeline network is its age and quality. Most was built in Soviet times in the middle of the 1950s and, by today's standards, requires a complete overhaul. Therefore, a careful review of the natural gas system should be conducted and various safety, material and risk assessment studies are needed before considering conversion to hydrogen.

Ukraine has potential to develop as an exporter of low carbon hydrogen, which could help provide domestic decarbonization and energy independence, as well as utilizing the existing gas infrastructure. In order to establish a hydrogen market by 2030, policy and financial support from the government and businesses should be granted to boost pilot projects. To date, there are no announcements of provision for policy or financial support from the government. Moreover, there are no established incentives for hydrogen projects in Ukraine.⁴² In addition, certificates of origin should be adopted in line with European standards. Taking into consideration the rapid development of renewable energy in Ukraine, the need for a proper storage and balancing system will soon be necessary. Competitive schemes for providing governmental support to renewable energy sources through auctions should also include energy storage projects.

Norway

Norway is a candidate for hydrogen export to the EU which was not mentioned in *Hydrogen Europe's* report. However, its proximity to the Northern Hydrogen cluster, or to the first EU demand centres, such as Germany, the Netherlands and Belgium, gives Norway advantages over other potential H₂ exporters. Norway is a strong leader in the supply of energy resources such as oil and natural gas, contributing to the energy security of many countries dependent on its export products. Nevertheless, Norway is one of the strongest supporters of decarbonization solutions. Their electricity sector is one of the least CO₂ intensive in Europe and the world. As part of the Paris Agreement, Norway is committed to reducing its GHG emissions by 50-55 per cent from 1990 levels by 2030.⁴³ Despite having one of the lowest CO₂ indicators on electricity, and high-energy efficiency in buildings, the target of minimum 50 per cent is unlikely to be reached due to the limited potential of hydro energy. Therefore, the government of Norway

⁴¹ Gas for Climate. (2020). 'European Hydrogen Backbone'. 24. <https://transparency.entsog.eu/>

⁴² CMS. (2021). 'Hydrogen law and regulation in Ukraine'. CMS Expert Guides. <https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/ukraine>

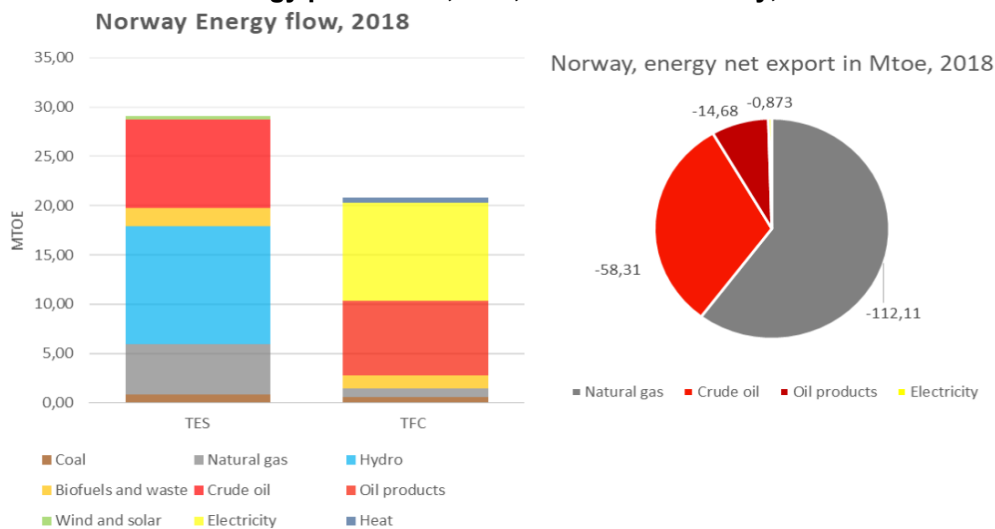
⁴³ Climate Action Tracker. (2020). Norway. <https://climateactiontracker.org/countries/norway/>



made a decision to move towards new low carbon solutions to decarbonize industry and transport sectors and, in a long-term (after 2050) perspective, to partly replace oil and natural gas production.

Norway is incorporated into the European Economic Area (EEA), so European directives and regulations are in effect for internal market operation. The electricity wholesale market could be an example of successful cross border cooperation on electricity exchange with neighbouring countries. Norway is one of the five members of the Nordic electricity market, and interconnected with Sweden, Denmark, Finland, and the Netherlands and is scheduled, in the future, for interconnection with the UK and Germany. In contrast to most European countries, the energy sector of Norway is independent from energy imports.⁴⁴ As illustrated in Figure 17, the net export of energy is mainly dominated by natural gas and oil, which is 6.4 times higher than the country's internal total energy consumption (186mtoe compared to 29mtoe in 2018). Vast resources of crude oil and gas could contribute to the financial support for low carbon initiatives, by investments of the revenues from fossil fuels export.

Figure 17: Overview of energy production, TES, and TFC in Norway, 2018



Source: Based on data from IEA (2021)

Electricity production

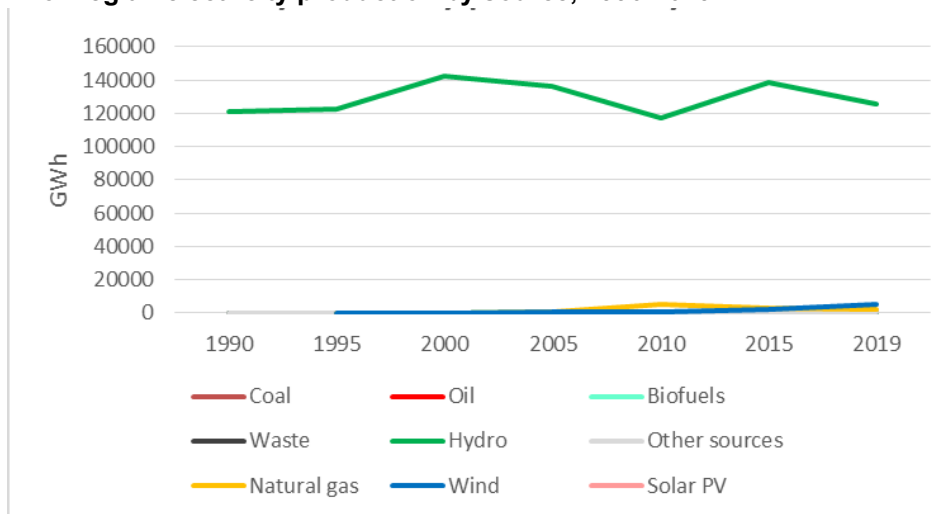
Norway is one of the countries with the lowest CO₂ footprint in electricity production, because of its vast hydropower resources which are spread around the country. The lion's share of TES comprises energy generation from hydropower, which accounted for more than 90 per cent of electricity production. Hydropower is a baseload for energy supply and provides reliable electricity – 154.2TWh in 2020 - with variations of annual inflow up to 65TWh (1990-2019) during the seasonal changes in temperature and water flows. The availability of energy storage (1000 hydro reservoirs) ensures the energy security of the country, as the total storage capacity is equivalent to 70 per cent of Norway's electricity consumption.⁴⁵ Other renewable energy sources (biomass, waste, wind, solar) only play a minor role in the electricity sector. Due to the high share of hydropower in the energy mix, the prices for electricity are low (in 2020 the household tariff was €14.27/kWh – 28% decrease compared to 2010).⁴⁶ That led to a high penetration of electricity to different sectors, for example in the residential sector (heating), households switched to heat pumps instead of using biomass or natural gas. (Figures 17 and 18).

⁴⁴ International Energy Agency. (2017). 'Energy Policies of IEA countries: Norway 2017 Review', *IEEE Aerospace and Electronic Systems Magazine*, 21(12), 27. <https://www.iea.org/reports/energy-policies-of-iea-countries-norway-2017-review>

⁴⁵ Energifakta Norge. (2021). 'Electricity production'. <https://energifaktanorge.no/en/norsk-energiforsyning/kraftproduksjon/>

⁴⁶ Strom-Report. (2021). 'Electricity Prices in Europe - Who pays the most?' <https://strom-report.de/electricity-prices-europe/>

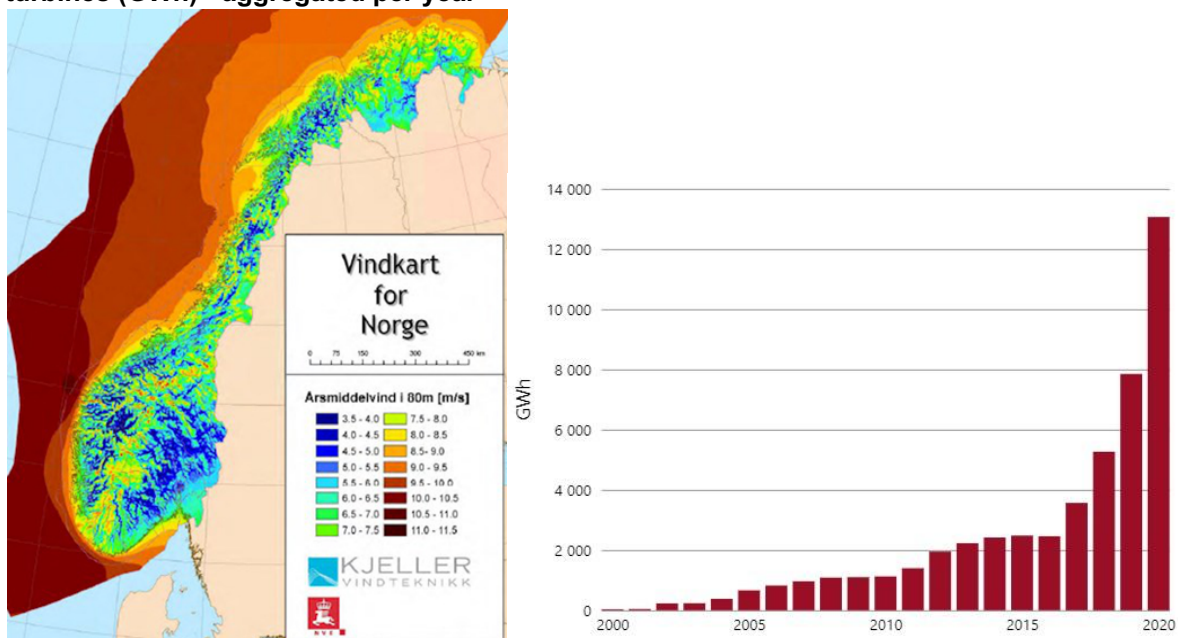
Figure 18.: Norwegian electricity production by source, 1990-2019



Source: Adapted from International Energy Agency (IEA) (2021)

In 2020, Norway's electricity production was 154.2TWh, 10TWh above the mean of the last five years. Wind generation capacity is increasing, installed capacity increased by 1405MW in 2020 to reach approximately 3977MW.⁴⁷ Norway has high potential for expansion of wind power generation. Figure 19, shows the areas with considerable wind speeds (8-11.5m/s - mainly offshore), which could be further utilized for production of green hydrogen and e-fuels, either for domestic purposes, or for export to neighbouring countries (Germany, the Netherlands and Belgium). Another advantage of integrating the hydrogen economy is the well-developed and interconnected Nordic electricity market with the European Union. In the early stages it could provide renewable electricity for H₂ production near the end consumer.

Figure 19: Allocation of the wind speed in Norway and average energy production from wind turbines (GWh) - aggregated per year



Source: NVE (2021)⁴⁸

⁴⁷ Energifakta Norge. (2021). 'Electricity production'. <https://energifaktanorge.no/en/norsk-energiforsyning/kraftproduksjon/>

⁴⁸ NVE. (2021). 'Vindkraft'. <https://www.nve.no/energiforsyning/kraftproduksjon/vindkraft>



Natural gas system of Norway – potential basis for blue hydrogen export

Norway is one of the most important players in the European natural gas market. As one of the most mature suppliers, the natural gas infrastructure in Norway is advanced. It has pipeline receiving terminals: two in the UK, one in France, one in Belgium and two in Germany, which transit gas to all continental Europe. The transport capacity of the network is 120Bcm per year while the total length of the pipeline system is about 8800km. According to the National Hydrogen strategy of Norway, blue hydrogen is essential for developing low carbon hydrogen as a new commodity.

Hydrogen Strategy in Norway

In June 2020, the Norwegian government released the National Hydrogen Strategy, highlighting the importance of low-carbon hydrogen for domestic utilization (for example in the industrial, transportation and maritime transportation sectors), as well as for international export. Norway's level of experience as a net energy exporter, combined with a developed oil and gas infrastructure representing one of the most decarbonized electricity systems in Europe, all give Norway a strong chance for a quick and easy transition to establish hydrogen trade.

The Norwegian government assesses the conditions for domestic hydrogen development as ideal, which gives a signal for businesses to cooperate towards the formation of a potential market. The Hydrogen Strategy identified the following advantages for Norway as a potential hydrogen supplier:

- long-term experience across the hydrogen supply chain (repurposing of companies for potential supply of equipment and services associated with the market);
- large potential for producing low-carbon hydrogen (large gas reserves, potential for shallow water CO₂ sequestration and storage and vast capacities for wind power generation);
- Norway provides robustness of operation and coordination of main industrial projects based on all types of petroleum sector activities;
- Norway has a leading position in expertise of technologies in the maritime sector. In recent years new solutions were demonstrated, such as liquefied natural gas (LNG) and battery applications. Some companies have shown interest in utilizing hydrogen or ammonia as an energy media storage.⁴⁹

Norwegian hydrogen strategy is divided into three parts: 1) safe use and production of hydrogen with low emissions; 2) hydrogen in Norway, and 3) Norway and hydrogen internationally. The government currently sees two methods for producing hydrogen – from natural gas via SMR with CCS and from renewable electricity with electrolysis. In order to overcome the challenges associated with hydrogen production – high costs, energy losses, safety and regulation - the government is actively encouraging pilot and demonstration projects, where these challenges are addressed and new technological and business attractive solutions are found and made available for commercial procurement. For example, the Research Council of Norway, Innovation Norway and Enova are proposing research and development (R&D) via the PILOT-E funding scheme.

Emission free transport in Norway is the main target sector for commercializing H₂ and H₂-based e-fuels. As shown on Figure 20, transport emissions, including passenger and heavy road, correspond to almost one third of the total Norwegian GHG emissions. In 2017 the government added fuel cell vehicles to the same group as electric vehicles with tax breaks and user benefits up to 2025 or until 50,000 vehicles.⁵⁰

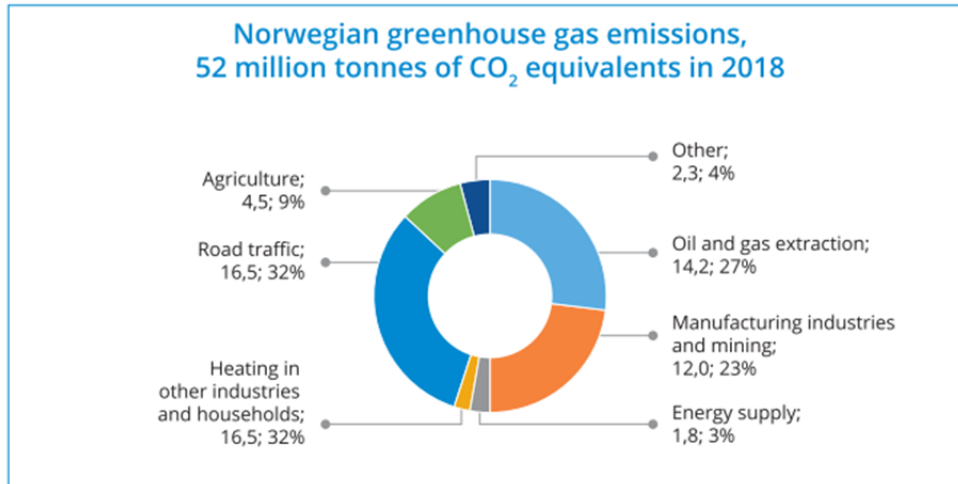
⁴⁹ Norwegian Ministry of Petroleum and Energy and Norwegian Ministry of Climate and Environment. (2020). 'The Norwegian Government's hydrogen strategy towards a low emission society'.

<https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf>

⁵⁰ <https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf>



Figure 20: Norwegian greenhouse gas emissions in 2018, million tonnes CO₂ equivalents and % of the total emissions



Source: Norwegian Ministry of Petroleum and Energy, Norwegian Ministry of Climate and Environment (2020)

On an international level, Norway has a good chance to become one of the first low-carbon hydrogen suppliers. Norway has demonstrated its interest in several low-carbon and renewable hydrogen projects. Equinor is taking part in different hydrogen projects across Europe, focused on the development of different parts of the hydrogen supply chain. Project H2morrow Steel is a blue hydrogen supply chain from Norway to Germany, where natural gas is used to produce H₂ via ATR near the industrial demand centres, for example, steel production in Germany. The CO₂ byproduct will be subsequently captured and sent back to Norway via maritime shipment for offshore sequestration in the North Sea. The project is planned to be operational by 2027, which will save 11 million tonnes of CO₂ while producing up to 7 million tonnes per year of climate-neutral steel. In order to develop blue hydrogen, Equinor, together with Shell and Total, are investing in CCUS infrastructure under the Northern Lights project. The project is scheduled for operation in 2024 with CO₂ storage capacity for the first phase of up to 1.5 million tonnes per year.

The possible supply chains in Norway could be designed both for blue and green hydrogen. Realization of blue hydrogen delivery is less complex and costly than green hydrogen. At the beginning, natural gas can be transported via an existing pipeline network to potential customers and SMR plants, which would be located near the demand centre or specific industrial facility. For the supply chain, CO₂ pipelines or shipment routes should be constructed in order to send CO₂ back to Norway for sequestration. In the medium term, the production of blue hydrogen could be organized in Norway and pure hydrogen could be sent to the northern demand sectors via pipeline, which could be a next step for supporting renewable base hydrogen production. However, technology and knowledge exchanges should be founded with other hydrogen forerunners, as most H₂ solutions come from outside Norway. In recent years, Norway has joined important international research partnerships, such as the SET Plan (European Strategic Energy Technology Plan) under the EU arena, the Fuel Cells and Hydrogen Joint Undertaking (programme no 2) (EUs FCH 2 JU), ACT (accelerating CCUS technologies), ZEP (Zero Emission Platform), Horizon Europe (2021-2027) and a number of the International Energy Agency (IEA) partnership programmes (IEA Hydrogen TCP, IEA Greenhouse Gas R&D (GHG TCP), International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and Carbon Sequestration Leadership Forum (CSLF)).⁵¹

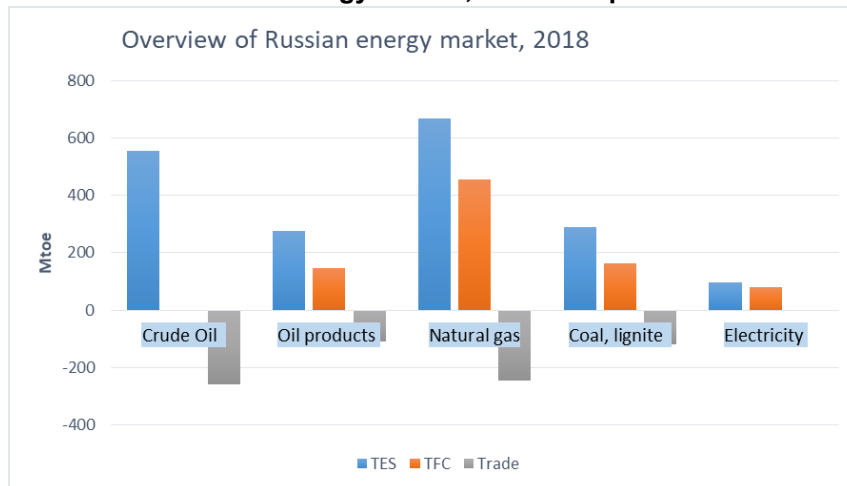
⁵¹ Norwegian Ministry of Petroleum and Energy and Norwegian Ministry of Climate and Environment. (2020). 'The Norwegian Government's hydrogen strategy towards a low emission society'. <https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf>



Russia

When analyzing Russia as a potential hydrogen supplier to Europe, only the north-western region of Russia is considered in this paper. The energy sector of Russia contributes not only to its domestic security of supply, but to security of energy supply of neighbouring countries, as 45 per cent of the produced energy in Russia is exported, according to the database of Enerdata.⁵² The energy produced in Russia contributes a quarter of national GDP, which is three per cent of the world's total GDP.⁵³ Figure 21 gathers the energy data for Russian energy production, consumption and trade (fossil fuel resources and electricity) in 2018.

Figure 21: Overview of the Russian energy market, level of exports in 2018



Source: Adapted from Enerdata (2019)

Electricity sector

The Russian electricity sector is the fourth largest in the world after China, the USA and India, with an annual generation in 2018 of 1128TWh. In 2019, thermal power plants (PP) operated on natural gas covered 46.4 per cent of the produced electricity, followed by nuclear (18.7%), hydro (17.5%) and coal (15.8%). Electricity generation from variable energy sources is insignificant at 0.11 per cent (wind – 0.08% and solar – 0.03%), see Figure 22. A third of the electricity produced in Russia is from combined heat and power plants (CHP), providing base and medium load. However, CHPs were built in the Soviet times, resulting in high inefficiency. This leads to various electricity supply problems, as in the winter these are incapable of covering the peak demand, and therefore the flexible operation of hydro, gas and biomass power plants is required.⁵⁴

Within the last 10 years, the electricity sector has not had any significant changes and proportions of energy sources for electricity production remain constant. Therefore, plans for significant expansion of variable renewable energy (VRE) are not on the agenda of the Russian government, at least not up to 2035, as described in the Energy Strategy 2035, released in 2020.⁵⁵ Therefore, the lack of decarbonization in Russia could be a concern for European countries in terms of hydrogen export.

⁵² Enerdata. (2019). 'Electrical Trades by Region | Electricity Statistics & Map'. <https://yearbook.enerdata.net/total-energy/world-energy-production.html>

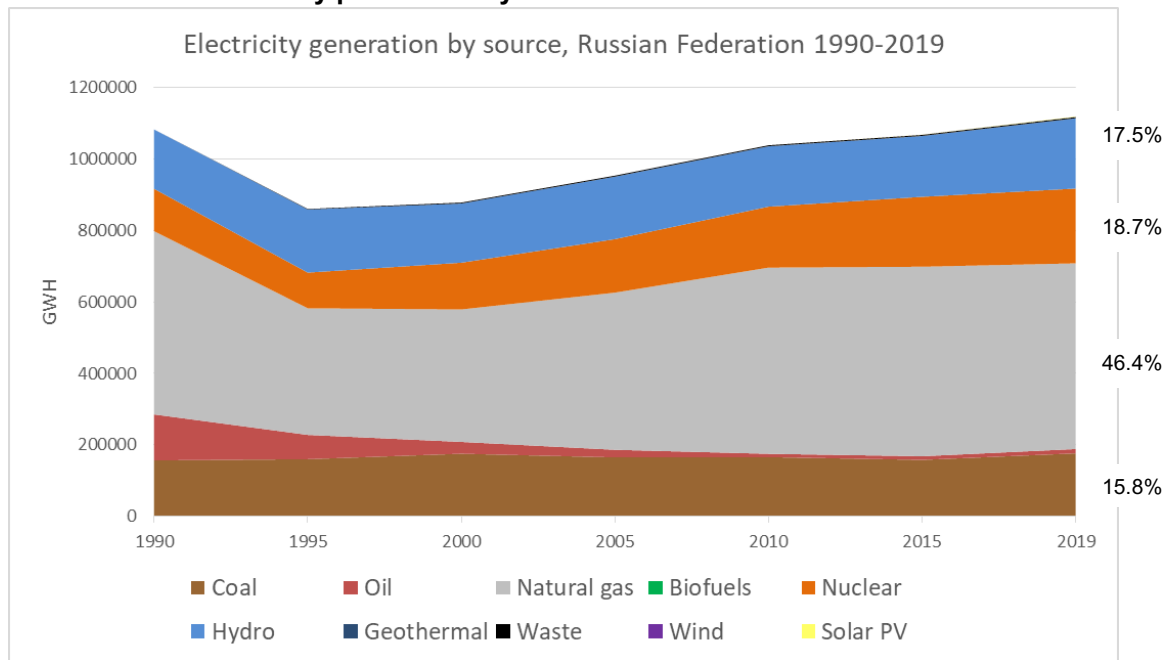
⁵³ IRENA. (2017). 'REmap 2030 Renewable Energy Prospects for Russian Federation, Working paper'. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Apr/IRENA_REmap_Russia_paper_2017.pdf

Mitrova, T. and Yermakov, V. (2019). 'Russia ' s Energy Strategy-2035'.

⁵⁴ Chukanov, D. *et al.* (2017). 'Renewable Energy and Decentralized Power Generation in Russia'. 1–8

⁵⁵ Министерство Энергетики Российской Федерации. (2020). 'Энергетическая Стратегия Российской Федерации На Период До 2035 Года', 93. <https://minenergo.gov.ru/node/1026>

Figure 22: Russian electricity production by source 1990-2019

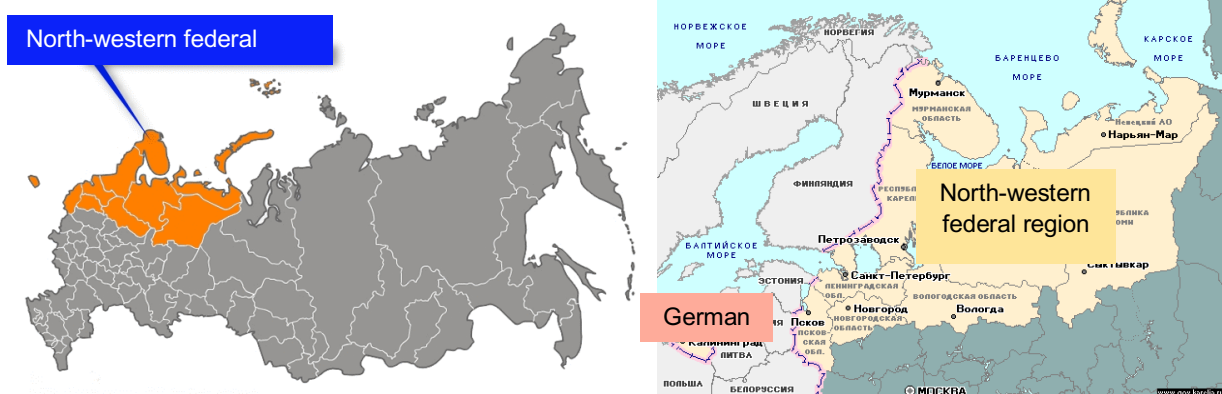


Source: IEA (2020)

Electricity production and supply in the Federal North-Western region of Russia

The Federal North-western region of the Russian Federation could be suitable for hydrogen exports to the German and European hydrogen markets. In Figure 23, the region is marked in orange. Proximity to the first H₂ demand centres, accessibility to transportation of gas molecules via pipeline (Nord Stream I and II) or via maritime shipment are all beneficial. Moreover, the North-western region of Russia shares a border with Finland, Estonia, Latvia, Lithuania, Belarus and Poland. One of Russia's largest harbours, receiving the majority of all international maritime cargo, is based in St Petersburg, where 70 per cent of the population in the region is concentrated.

Figure 23: Map of Russian Federation, North-western federal region



Source: Северо-Западный федеральный округ. Available at: <https://www.bankgorodov.ru/fed-district/szfo>

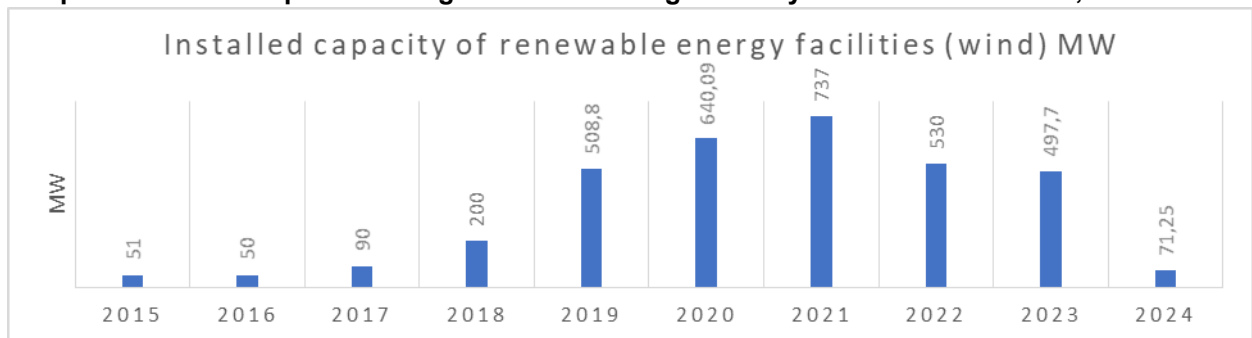
According to data from the Ministry of Energy of the Russian Federation, the North-western region has in total 24.5GW of installed capacity (on 1 January 2020). The majority of energy capacity is thermal power plants (63.6%) operated mainly on natural gas, followed by nuclear power plants (24.3%), hydro



(12%) and wind energy (0.02%).⁵⁶ The fuels for thermal and nuclear PP are transported from the eastern regions of Russia, whereas the local hydro potential is high. Considerable water resources are concentrated in the north west: 7000 lakes (Ladoga, Onega, Chudskoe, Ilmen), and a dense river network (Neva, Volkhov, Lovat).⁵⁷

Russia has vast potential for wind energy – valued at 17.1 thousand TWh, located mainly in the north along the Arctic Ocean coast.⁵⁸ In the last decade especially since 2015, renewable capacity is growing in Russia. Figure 24 shows total wind capacity additions up to 2024, according to Russian Association of Wind Industry & Skolkovo Energy Center, an overall total of 3375.84 MW. The RE development in Russia is based on the mechanism of capacity supply agreements (CSA). The RE capacity market has an established realization plan financed by the state up to 2024.⁵⁹ However, considering the current wind projects, the target for 2024 is unlikely to be met. Investment in green energy (apart from hydro power plants) does not have enough support from the government and lacks an attractive business case, as the decarbonization targets are only briefly reflected in the national energy legislation, lowering the motivation and interest in further investment.

Figure 24: New installed capacity of renewable energy facilities (wind) based on the results of competitive selection power wind generators starting in each year from 2015 to 2024, in MW



Source: Adapted from Russian Association of Wind Industry and Skolkovo Energy Center (2021)⁶⁰

Production of low-carbon hydrogen in Russia Two documents are relevant to Russia’s plans for low-carbon hydrogen, the Energy Strategy to 2035 and the Roadmap for Hydrogen development to 2024’

Energy strategy of Russia 2035 (ES-2035)

According to ES-2035, which was adopted in June 2020, by 2035-2040 the Russian energy sector should reflect the changes in other international energy systems due to the growth in decarbonization and innovation. Nevertheless, the role of hydrocarbon exports remains crucial and natural gas, as well as LNG, exports are expected to grow. The importance of a more flexible, efficient and sustainable domestic energy system is highlighted in the strategy, which could, in future, reflect in the rationale of adopting a low-carbon economy and raise awareness of the H₂ supply to the first potential markets, such as the EU, Japan and South Korea.⁶¹

Renewable sources such as wind turbines or photovoltaics are usually accompanied by energy storage technologies, of which the most common are batteries and power-to-gas systems. In the Russian Federation’s energy strategy to 2035, hydrogen could be beneficial as a seasonal/long-term storage

⁵⁶ Ministry of Energy of the Russian Federation. (2019). ‘Энергетическая стратегия Российской Федерации на период до 2035 года’

⁵⁷ Geography of Russia. (2017). *Комплексная характеристика Северо-Западного района*. <https://geographyofrussia.com/kompleksnaya-kharakteristika-severo-zapadnogo-rajona/>

⁵⁸ Mitrova, T., Melnikov, Y. and Chugunov, D. (2019). ‘The Hydrogen Economy - a path towards development’

⁵⁹ Lanshina, T. (2021). ‘Climate change, energy and environment - Russia’s wind energy market: Potential for New Economy Development’

⁶⁰ Russian Association of Wind Industry and Skolkovo Energy Center. (2021). ‘Review of the Russian wind energy market. Ranking of Russian regions for 2020’. https://rawi.ru/wp-content/uploads/2021/06/rawi_eng.pdf

⁶¹ Министерство Энергетики Российской Федерации. (2020). ‘Энергетическая Стратегия Российской Федерации На Период До 2035 Года’. 93. <https://minenergo.gov.ru/node/1026>



option for small decentralized systems, and as an innovative tool for the decarbonization of different sectors (transport and industry), however the main function of hydrogen is as a potential export commodity. According to expert estimates, Russia could export a significant share of the global hydrogen fuel market by 2035, through hydrogen production from existing Russian generation facilities alone. In terms of figures, the target for annual hydrogen exports is 2 million tonnes in 2035.⁶²

The Roadmap for Hydrogen Development until 2024

The Roadmap, released in 2020, includes an overview of the main hydrogen actors for realization of H₂ production and supply chains, such as giant energy companies like Gazprom, Rosatom and Novatek and a group of six research institutes - the so-called 'Technological Hydrogen Valley'. Russia has not yet released its National Hydrogen strategy, however the detailed Concept for Hydrogen Development with an outlook for 2050 is currently being processed by the Ministry of Energy of the Russian Federation, where cooperation with Germany, France, Japan and South Korea are set as strategic goals. The draft provides information on low-carbon H₂ exports varying between 7.9-33.4 million tons of H₂ per annum resulting in \$100 billion in revenue.⁶³

The North-Western federal region is planned as a strategic hydrogen cluster, with a focus on hydrogen exports to European countries. Different H₂ production pathways could be established: from natural gas with CCUS or pyrolysis (blue/turquoise H₂), from nuclear based electricity (yellow H₂), and from hydro PP and wind farms (green H₂).

- Gazprom is considering different options for producing hydrogen from natural gas mainly within the territory of the consumer, for example Germany, via SMR with CCS or pyrolysis. However, extraction of the CO₂ content from the gas mix is problematic, as Russia does not share any experience in CCUS and for methane pyrolysis the technology readiness level cannot be upscaled to export volumes. Therefore, in order to initiate trade with Germany and additional member states, the gap in the supply chain must be filled.
- Electrolysis-based hydrogen requires clean or carbon-free sources of electricity, where nuclear energy can play a big role. Rosatom, the holder of all nuclear power plants in Russia, has plans to initiate investments among the entire H₂ supply chain and the company has set a goal of becoming an electrolysis equipment manufacturer and supplier. In light of the increasing awareness of a hydrogen economy in Europe, in April 2021, Rosatom signed an agreement with EDF (Électricité de France) group on participation in a low-hydrogen project for decarbonization of transport and industrial sectors domestically in Russia and internationally in Europe.⁶⁴ The Infrastructure Center, EnergyNet, conducted a study on the potential production of nuclear-based hydrogen in Russia, where, in the North-Western region, the volumes of generated hydrogen could reach 160 thousand tons of H₂ per year, by 2025-2030, simply by increasing the capacity factor from 70 per cent to 93 per cent of two nuclear power plants. The overall estimated production capacity could reach 430 thousand tons of H₂ when utilizing the electricity generation facilities in the region.⁶⁵
- Novatek, the Russian independent LNG company, has announced several upcoming projects on production of low-carbon and renewable hydrogen in 2021. For example, Novatek and Uniper signed a memorandum of understanding (MoU) on H₂ supplies to Russian and European H₂ pilot projects.⁶⁶ Novatek is unlocking the hydrogen-ammonia industry in Russia to produce around 2.2 million tons of low-carbon ammonia at its Yamal LNG port in Sabetta and to develop hydrogen transportation via maritime routes in the form of ammonia.⁶⁷

⁶² Ministry of Energy of the Russian Federation. (2019). 'Энергетическая стратегия Российской Федерации на период до 2035 года'

⁶³ Zabanova, Y. and Westphal, K. (2021) 'Russia in the Global Hydrogen Race', 34

⁶⁴ EDF Russie. (2021) 'Rosatom and EDF Group join forces to develop green hydrogen'. <https://russia.edf.com/en/edf-in-russia/news/rosatom-and-edf-group-join-forces-to-develop-green-hydrogen>

⁶⁵ Infrastructure Center EnergyNet. (2018). 'Перспективы России на глобальном рынке водородного топлива'

⁶⁶ Zabanova, Y. and Westphal, K. (2021). 'Russia in the Global Hydrogen Race'. 34

⁶⁷ Upstream. (2021). 'Novatek to consider ammonia and hydrogen options for Obsky LNG'.

<https://www.upstreamonline.com/energy-transition/novatek-to-consider-ammonia-and-hydrogen-options-for-obsky-lng/2-1-1005160>



Russia is showing great interest and has the opportunity to enter the developing hydrogen market. Nevertheless, the competition with the other potential H₂ suppliers will require integration of decarbonization concepts into the energy system. Current energy policy does not include the control of GHG emissions, such as CO₂ emission trading schemes, or the standardization that goes in line with European norms. Therefore, this question needs to be addressed before low-carbon and renewable hydrogen for export is established.

Summary and comparison of the case studies for hydrogen import to EU demand centres.

Table 4 provides comparison of the potential hydrogen suppliers to Europe by 2030 through a traffic light assessment. The analysis of each supply chain for hydrogen export is based on five criteria mentioned in the beginning of Part III:

- extent of decarbonization of domestic energy system;
- water availability;
- proximity to H₂ demand centres;
- state of development of the infrastructure and readiness for H₂ injection;
- history of bilateral relationships and security of supply.

Morocco, despite the positive assessments by Hydrogen Europe, has many barriers to development of hydrogen. The main limitations are water scarcity and the high carbon footprint of the domestic electricity system, where coal power plants are covering more than two thirds of the electricity production. Direct usage of renewable electricity should be a higher priority. Successful decarbonization of their domestic energy system would bring more benefit than focusing on supplying green gas to Europe. Existing natural gas infrastructure connecting Morocco with Spain, with a capacity of 12 Bcm, only allows for injection of hydrogen up to 10 per cent and further pipeline retrofit for hydrogen only does not seem to be realistic up to 2030.

Ukraine shows a less carbon intensive footprint for their electricity production and benefits from an advanced and well interconnected natural gas infrastructure. The current unutilized capacity for transporting natural gas could potentially be converted to hydrogen. The drawback of the Ukrainian energy system is an inefficient energy market, which hinders the integration of renewables, such as wind farms. Although the renewable potential is high, the high price for renewable electricity and stalling investments in renewable energy and hydrogen infrastructure will not allow Ukraine to start H₂ exports until 2030.

Norway is the most positive example of the short-term readiness for initiation of hydrogen export to Europe. All criteria have a green light for successful roll out, firstly blue hydrogen and afterwards green hydrogen. Norway is already participating in the first stages of H₂ projects, targeting hydrogen export to Europe, and therefore is one of the first candidates to become a hydrogen supplier before 2030.

In the case of Russia, blue/turquoise hydrogen supplies could possibly reach Europe by 2030 but only when hydrogen separation from methane takes place near to the demand centres. Transport of pure hydrogen via pipeline appears to be a long-term strategy for Russia. Production of green hydrogen has some potential in Russia, nevertheless, the energy market, like Ukraine, does not provide an attractive business case for deployment of PVs and wind parks.



Table 4: Comparison of case studies for hydrogen import to EU demand centres

	Morocco	Ukraine	Norway	Russia
Decarbonisation of energy system	●	●	●	●
Water availability	●	●	●	●
Proximity to H ₂ demand centres	●	●	●	●
Gas infrastructure	●	●	●	●
Geopolitics and security of supply	●	●	●	●
Planned hydrogen projects	●	●	●	●

Source: Author's assumptions

IV. Economic assessment of European hydrogen supply chains

Introduction of supply chains based on the map: blue/turquoise vs. green hydrogen

The fourth part of the paper considers the economics of various potential supply chains linking the supply sources identified in Part 3 with the markets identified in Part 2. It evaluates some indicative supply chains, covering blue and green hydrogen being delivered by several alternative routes. While, the energy source of hydrogen would ideally be renewable, as an interim step there is an opportunity for blue and turquoise H₂, so long as the resulting CO₂ emissions are not released into the atmosphere. The basic stages of hydrogen supply chain can be generalised into the following steps:

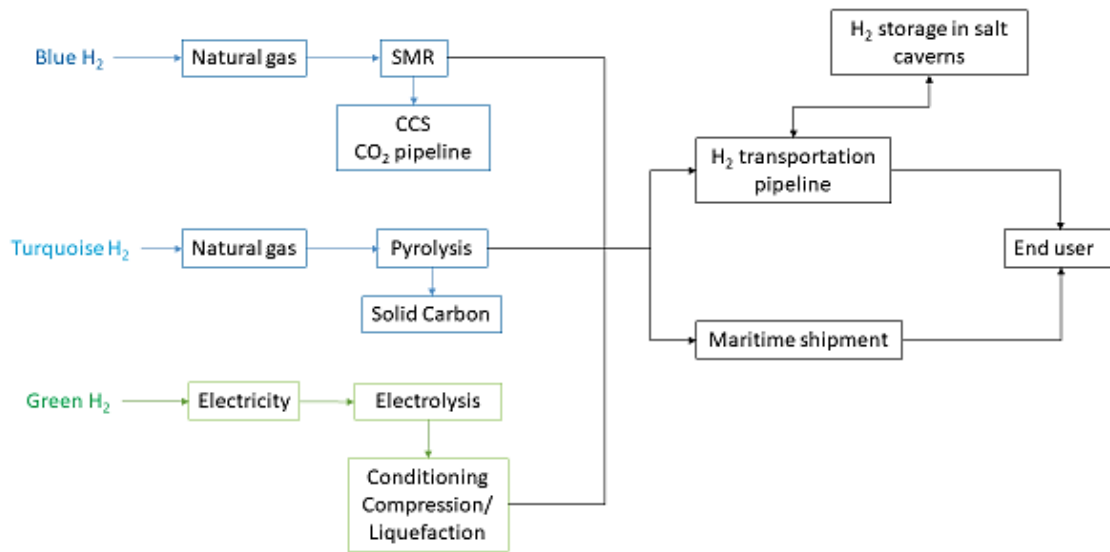
- energy source/feedstock;
- delivery of energy/feedstock;
- H₂ production;
- H₂ transportation;
- H₂ storage;
- H₂ retail and end use.⁶⁸

By 2030, renewable electricity-based hydrogen facilities will most likely be located near to demand centres, as the hydrogen infrastructure will not be integrated across Europe to carry H₂ gas over long distances. In the beginning phase, when H₂ demand is not high, hydrogen transportation via maritime shipment could also take place and deliver limited volumes of H₂ to European consumers. In the middle- and long-term scenarios up to 2040 and 2050 respectively in line with expansion of H₂ producing capacity, H₂ transport infrastructure will become a necessity and, according to several studies by Gas for Climate (European Hydrogen Backbone), should be developed (see Figure 26).

Three examples of supply chains were chosen, each one representing blue, green and turquoise hydrogen, as shown in Figure 25.

⁶⁸ Robles, J. O., Almaraz, S. D. L. and Azzaro-Pantel, C. (2018). 'Hydrogen supply chain design: Key technological components and sustainable assessment', <https://www.sciencedirect.com/science/article/pii/B9780128111970000026?via%3Dihub>

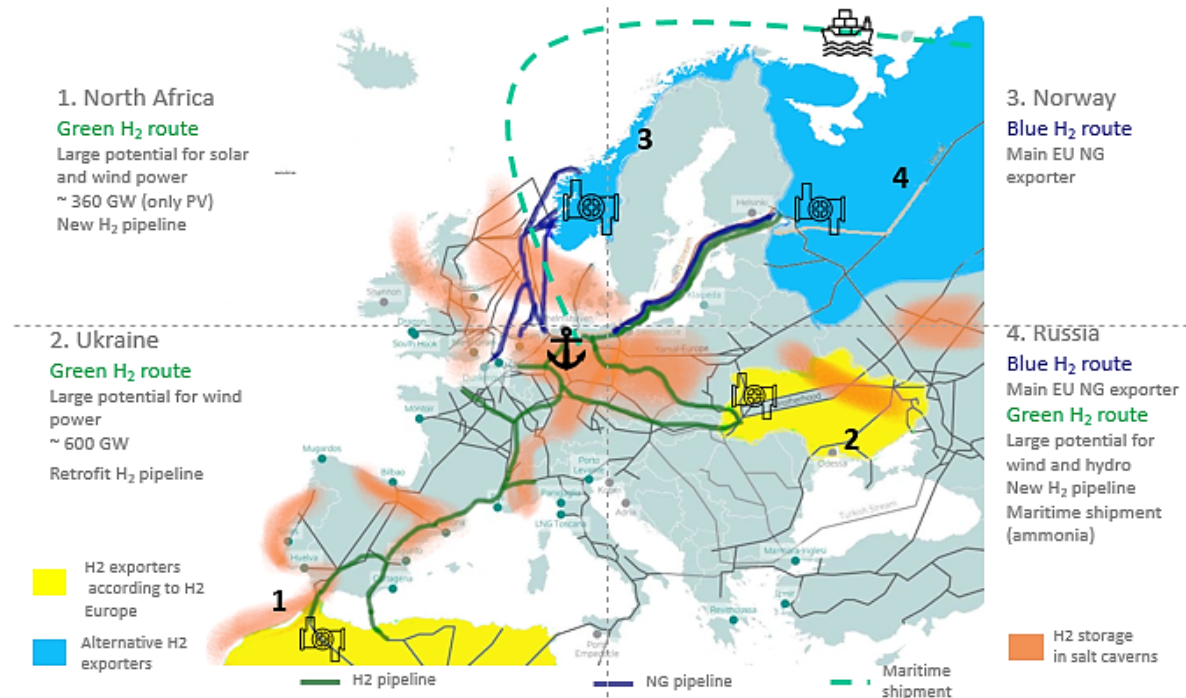
Figure 25: Process supply chains for different types of hydrogen: blue, turquoise and green



Source: Author's assumptions

Figure 26 shows the potential supply chains considered. The coloured areas, numbered 1-4, show potential low-carbon hydrogen exporters. Yellow represents the main candidates for H₂ export: North Africa (1) and Ukraine (2), according to Hydrogen Europe. Blue represents alternative hydrogen suppliers: Norway (3) and Russia (4). Another important part of the hydrogen supply chain is underground storage such as solution-mined salt domes, aquifers, excavated rock caverns, or mines, marked with red on the map. Several H₂ transportation routes are illustrated on the map: pipeline systems from the four H₂ exporters and one maritime route connecting Russia and the Netherlands. Two types of pipeline are shown on the map: the blue line refers to the natural gas pipeline network, while green refers to the potential pure hydrogen pipeline network. The map also shows key elements of the existing natural gas infrastructure.

Figure 26: Overview of the possible hydrogen supply routes 2030-2040



Source: Author's assumptions



From Part II, the hydrogen demand in 2030 will be mostly concentrated in north-western Europe (Germany, the Netherlands, Belgium and the UK). Therefore, the closer H₂ suppliers would be Norway, Ukraine and Russia. Up to 2030, considering the renewable energy (solar) potential in Spain, H₂ trade inside Europe is more likely than imports from North Africa. Such imports may happen around 2040 or later.

Currently, the longest H₂ pipeline network in Europe (Belgium) is 600 km long (operators Linde and Air Liquide).⁶⁹ Development of hydrogen infrastructure by 2030 is uncertain and could force H₂ production (electrolysis, SMR or pyrolysis) to be located near demand centres (industrial facility or cluster). As an example, Norway could transport natural gas to an industrial facility in the Netherlands, where H₂ could be produced, and CO₂ sent back to Norway to be sequestered offshore. This could be a temporary solution, while the H₂ infrastructure is under development.

Hydrogen infrastructure costs

This subsection considers the costs of required elements from production to transportation, distribution and storage.

H₂ production

Natural gas-based hydrogen, combined with CCS

Blue hydrogen costs depend primarily on the price of natural gas, the cost of the steam methane reformer, the cost of the implementation of the CO₂ capture, transport and storage/utilisation facilities, and the operating costs for the combined system of natural gas reformation and CCS.⁷⁰ SMR and ATR are globally well-established mature processes, however, CCS processes meet a lot of criticism and projects are still at the pilot stage (although the process has existed since 1977). Several uncertainties, risks and specific geological limitations exist that affect the cost for CCS. According to the authors Newborough and Cooley, the uncertainties are:

- legal responsibilities and liabilities (public or private);
- insurance arrangements for the high-pressure CO₂ infrastructure;
- the extensiveness of the infrastructure required for transporting CO₂ from inland sites;
- monitoring arrangements for CO₂ leakage and upstream methane leaks;
- the government subsidy scheme required to establish a suitable business model;
- public attitudes towards CCS and blue hydrogen.

For countries whose energy systems are built on the export and import of fossil fuels, specifically natural gas, blue hydrogen could become a low-carbon solution for hard to abate sectors. The main consumers of grey hydrogen today could be potentially transitioned to blue hydrogen clients, without fundamental changes in their entire supply chain system, and thus saving on the costs of expansive infrastructure adjustments. Moreover, production of hydrogen via SMR and CCS would allow gas companies to provide large, constant and continuous volumes of H₂ gas for the customer, which is crucial for industrial companies, as they cannot withstand variabilities in H₂ supply. To enable blue hydrogen production near demand centres, CO₂ transport systems and storage sites will need to be developed.

The production cost of blue hydrogen would allow for competitive market development of hydrogen fuel by 2025, with the production cost of around €2.6/kg (Figure 27). According to Tlili et al., electrolysis based H₂ will be competitive from 2035.⁷¹ For total blue H₂ cost, the CCS/CCUS cost part is decisive. Some captured CO₂ can be utilized in other industrial processes (a feedstock to synthesise chemicals,

⁶⁹ ACER. (2020). 'NRA Survey on Hydrogen , Biomethane , and Related Network Adaptations - Evaluation of Responses Report'.

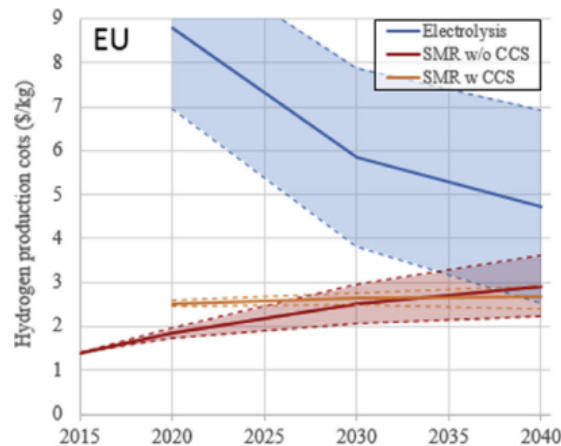
⁷⁰ Newborough, B. M. and Cooley, G. (2020) 'Developments in the global hydrogen market : The spectrum of hydrogen colours', *Fuel Cells Bulletin*. Elsevier Ltd, 2020(11), 16–22

⁷¹ Tlili, O. et al. (2019). 'Hydrogen market penetration feasibility assessment: Mobility and natural gas markets in the US, Europe, China and Japan', *International Journal of Hydrogen Energy*. Pergamon, 44(31), 16048–16068. doi: 10.1016/j.ijhydene.2019.04.226



for enhanced oil recovery, food industry and others) but most will require sequestration in a suitable geological structure. Thus, according to Agora Energiewende, blue hydrogen supply (including SMR + CCS) could be considered realistic only for Norway, the UK, Belgium, Denmark, Ireland, the Netherlands and Poland.⁷² The levelized cost of blue hydrogen (LCOH) is dependent on natural gas prices, capital expenditure (CAPEX) and operating expenditure (OPEX). Natural gas prices usually account for the largest part of production costs. For producers and exporters of natural gas such as Russia, Middle East and the USA, the natural gas price represents on average 40 per cent of LCOH. For importers of natural gas, such as in Europe, the price is higher and results in 60 per cent of LCOH, with 25 per cent Capex and 15 per cent OPEX.⁷³

Figure 27: Hydrogen production cost evolution in the European Union up to 2040



Source: Tlili et al (2019)⁷⁴

Renewable electricity-based hydrogen

The electrolytic method of H₂ generation is a well-known technology and has existed for over 100 years. Nevertheless, the technology is currently more expensive compared to SMR. The production cost of green hydrogen is mainly dependent on the electricity price and load factor of the electrolyser.⁷⁵ Therefore, the renewable energy source used is highly important. By integrating energy storage into the electricity system at a large scale, the value of renewable generators can be increased, leading to lower energy market prices and to the increased deployment of power-to-gas systems and decreased cost for generation of green hydrogen. Furthermore, the potential for green hydrogen production to align with periods of low demand, provides both a new market for renewable energy suppliers, which does not affect the conventional electricity demand profile, and adds higher flexibility to the energy system by supporting the grid operator in balancing the electricity grid.

The important cost drivers are renewable electricity, operating factors and investment costs of the electrolyser (CAPEX). In Figure 28, the authors plotted different hydrogen cost curves, depending on different electricity prices, electrolyser investment costs and the availability factor over the year. The

⁷² Trinomics. (2020). 'Opportunities for Hydrogen Energy Technologies considering the National Energy & Climate Plans' Agora Energiewende et al. (2021). 'No-regret hydrogen'. https://static.agora-energiewende.de/fileadmin/2/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf

⁷³ IEA. (2019). 'The Future of Hydrogen: Seizing today's opportunities'. Proposed Documents for the Japanese Presidency of the G20, (June), 203

Gaffney Cline. (2020). 'Focus on Blue Hydrogen'. www.gaffneycline.com

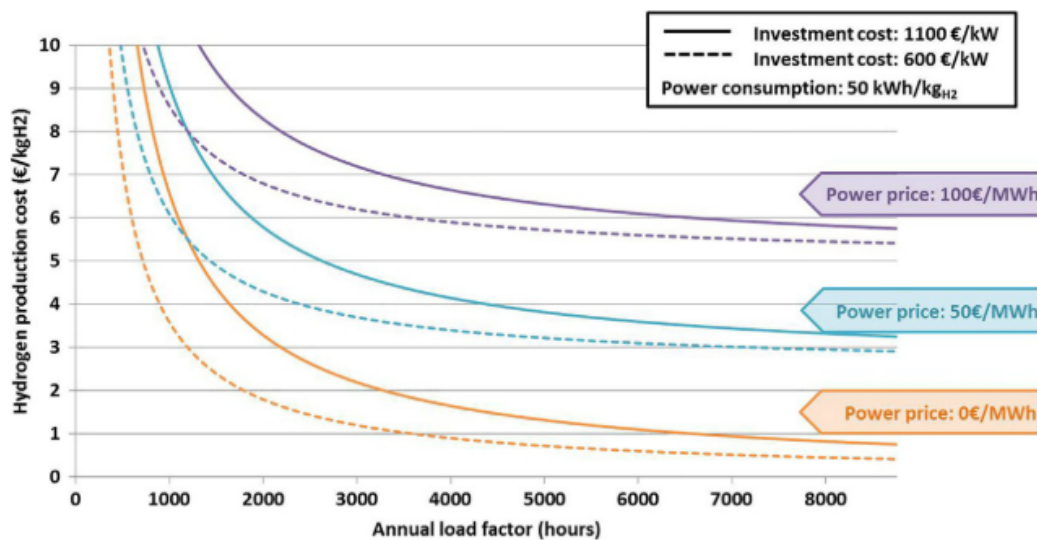
⁷⁴ Tlili, O. et al. (2019). 'Hydrogen market penetration feasibility assessment: Mobility and natural gas markets in the US, Europe, China and Japan', *International Journal of Hydrogen Energy*. Pergamon, 44(31) 16048–16068. doi: 10.1016/j.ijhydene.2019.04.226.

⁷⁵ Newborough, B. M. and Cooley, G. (2020). 'Developments in the global hydrogen market : The spectrum of hydrogen colours', *Fuel Cells Bulletin*. Elsevier Ltd, 2020(11) 16–22. doi: 10.1016/S1464-2859(20)30546-0



results show that the most significant effect on H₂ cost is the electricity price. In order to reach a target cost for hydrogen of €3/kg, the electricity price should not exceed more than €50/MWh. Investment costs have a tremendous impact on H₂ costs only with a low availability factor (<2500h/a). The higher the operation hours for electrolysis within the year, the less the role of investment costs for electrolysis plays, as the curves are narrowed and flattened.⁷⁶

Figure 28: Hydrogen production costs via electrolysis, impact of the investment cost for electrolyser equipment and power price (example of French power market)



Source: Mansilla et al. (2018)

Water consumption in H₂ production via electrolysis raises a critical question regarding freshwater scarcity issues in several regions. In order to conduct not only a renewable but also a sustainable H₂ production process, the water footprint per kg of H₂ should be taken into account when planning large scale hydrogen industries. In the electrolysis process 1kg of H₂ requires 8.92 litres of demineralised water. When considering the targets of the European Hydrogen strategy, approximately 90MMtonnes of water will be needed to produce 10MMtonnes of H₂ by 2030. In comparison to European freshwater consumption, 90MMtons of water corresponds to 0.0048 per cent of annual freshwater resources. Furthermore, renewable hydrogen production consumes 40 per cent less water in comparison to crude oil recovery and diesel refining. At the end of the hydrogen cycle, when talking about fuel cell electric vehicles (FCEV), water vapour molecules are released in the purest form.⁷⁷

Scaling up electrolyser manufacturing is another obstacle to a green hydrogen economy. To date, in the EU, only around 1GW per year of electrolyser manufacturing capacity exists. According to the study of H₂ Europe (Green Hydrogen for a European Green Deal A 2x40 GW Initiative), to reach the target in 8.5 years, each year the installed electrolyser capacity will need to be on average twice as high as the previous year, starting from +35MW in 2020 and ending +22790MW. Such scaling up of electrolyser manufacturing capacities is unrealistic and would require significant investment by electrolyser manufacturers. Currently, the biggest operational electrolyser is Air Liquide's 20MW PEM electrolyser in Canada.⁷⁸ Scaling up would require large investment (in total 80GW electrolyser capacity costs €25-30 billion) and radical changes in legislation leading to an integrated policy approach, which does not happen overnight.⁷⁹

⁷⁶ Mansilla, C. et al. (2018). 'Hydrogen applications: Overview of the key economic issues and perspectives'. *Hydrogen Supply Chain: Design, Deployment and Operation*. Elsevier Ltd. doi: 10.1016/B978-0-12-811197-0.00007-5

⁷⁷ Hydrogen Europe. (2020) 'Hydrogen production and water consumption', (December)<https://hydrogeneurope.eu/reports/>

⁷⁸ IRENA. (2020). 'Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5 C Climate Goal'. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

⁷⁹ Hydrogen Europe. (2020). 'Green Hydrogen for a European Green Deal A 2x40 GW Initiative'



Hydrogen transportation

Hydrogen transportation infrastructure is one of the crucial elements of total hydrogen systems and costs. Until 2030, very limited pipeline infrastructure will be developed. Some low volumes of H₂ transportation via maritime shipment, rail or road is achievable, however such transportation methods will result in high hydrogen costs. In order to unlock and boost the hydrogen market in Europe, in a long-term perspective, a hydrogen pipeline network will be required, as discussed below.

Hydrogen pipeline

In April and June 2021, the European Hydrogen Backbone (EHB) initiative (a group of European gas Transmission System Operators (TSOs)) released detailed studies on the progressive development of hydrogen transportation infrastructure on a European level. In Figure 29 the potential developments of the EHB in 2030 and 2035 are represented. According to a consortium of 23 gas infrastructure companies from 21 countries (EU and neighbours), the proposed hydrogen network could reach 11600km by 2030, be located near demand centres and connect the emerging hydrogen valleys on a national level. By 2030, H₂ pipeline systems could develop in Germany, Belgium, Italy, Hungary, Spain and the UK, according to a report from EHB. At that point, hydrogen pipelines will be mainly based on reconverted natural gas pipelines and only a few Greenfield hydrogen pipelines will have evolved. By 2035, the potential hydrogen infrastructure is envisaged to expand significantly in order to reach the authors target of 39700 km by 2040. From 2030 onwards, the hydrogen infrastructure becomes interconnected between the member states and represents the preliminary version of EU H₂ backbone.⁸⁰

If the hydrogen backbone is developed as proposed, starting from 2035, hydrogen imports could be initiated from the EU's neighbours (North African countries and Ukraine). Pipeline connections, such as Morocco-Spain, Egypt-Italy, Hungary-Ukraine, Russia-Germany and Norway-the Netherlands (from 2040), are illustrated in Figure 29. As the north-western European cluster will prevail over the south in terms of H₂ demand, several important H₂ transition import routes could form according to the authors. Import routes from Ukraine to the EU through Slovakia and the Czech Republic into Germany and from Northern Africa through Spain and France. However, questions arise from the side of economic feasibility of such long distance H₂ transportation, as due to specific physical properties, hydrogen requires three times more powerful pumps and compressors compared to natural gas. Therefore, distance and type of transportation play the main role when designing the supply chain route. The planned 39,700 km of H₂ network requires investment of around €43-81 billion where, according to EHB, 69 per cent of the pipeline will be repurposed natural gas and the remaining 31 per cent will be new H₂ specific pipelines. The initiation of EHB calls for collaboration between EU Member States in order to develop an elaborate, flexible and adaptive regulatory framework.

It is not certain whether natural gas pipelines will be available for repurposing, because of the rising role of natural gas as insurance of energy security in many national energy systems. Flexible natural gas power plants (combined cycle gas turbines, open cycle gas-turbine and other turbines) are one of the main and only tools for balancing out variable renewable energy generation, at least for the next decade. Furthermore, the European Union is highly dependent on natural gas imports (83% of natural gas consumption in 2020) and by 2030-2035 demand for natural gas may grow, replacing fossil fuels with higher carbon content, such as coal and oil, in various sectors (electricity generation, heating, industry and transport). Thus, import of low-carbon hydrogen is likely to require new pipeline construction for transporting large volumes. In a study by the Institute of Energy Economics at the University of Cologne (EWI), the authors provided input data for modelling of levelized costs of hydrogen. The range of the cost for new hydrogen pipelines is between \$0.24-0.64/kg, whereas retrofitted pipelines have the lowest cost of \$0.16/kg, see Table 5.⁸¹

⁸⁰ European Hydrogen Backbone (2021) 'Analysing future demand, supply, and transport of hydrogen', (June).

https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/. European Hydrogen Backbone (2021) 'Extending the European Hydrogen Backbone', (April), 1–32

⁸¹ Brändle, G., Schönfisch, M. and Schulte, S. (2020). 'Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen'. 20/04

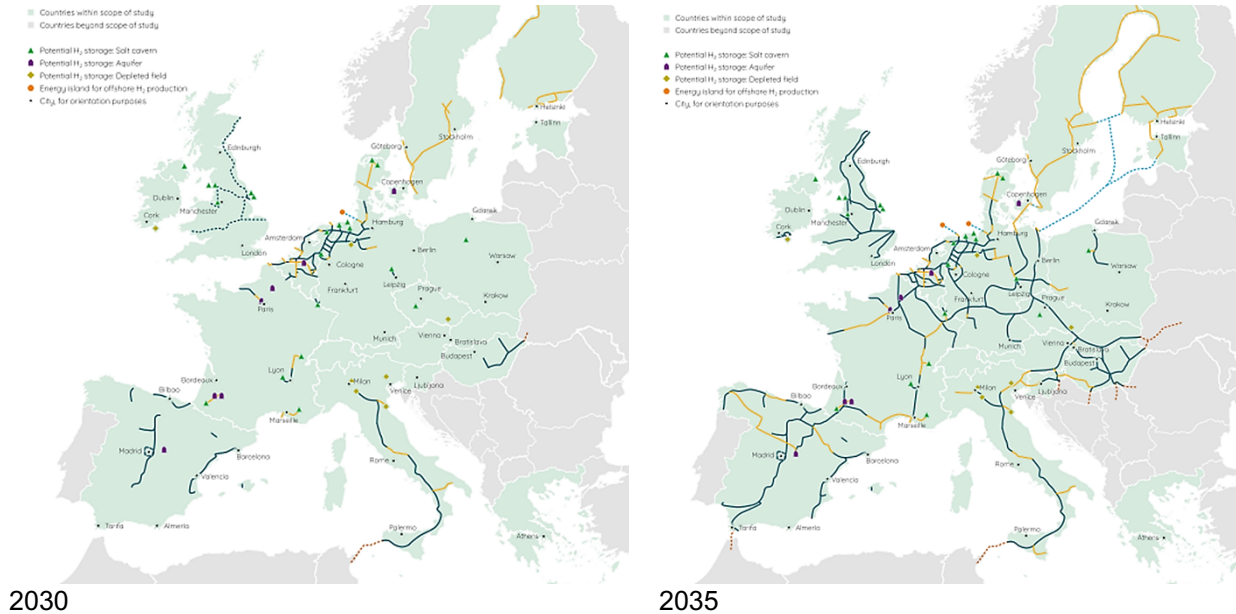


Table 5: Cost comparison of different types of pipeline transportation for hydrogen

	High cost new H ₂ pipeline	Low cost new H ₂ pipeline	Retrofit
Cost of pipeline transportation (\$/1000km/kg H ₂)	0.64	0.24	0.13

Source: Brändle, Schöfnisch and Schulte (2020)

Figure 29: Emerging European Hydrogen Backbone by 2030 and growing network coverage across more countries in 2035



Source: European Hydrogen Backbone (2021)

Maritime Transportation

Transporting H₂ as cargo would be available only in liquid form or as a part of chemical compounds such as ammonia (NH₃) or liquid organic hydrogen compounds (LOHC), due to the low volumetric energy density in H₂ gaseous form. Nevertheless, shipping liquid H₂ is highly energy intensive, as it requires extremely low temperature conditions, -253°C, which results in losses of a third of the total energy content transported. Chemical compounds LOHC and NH₃ feature better operational conditions, however, the transportation process involves more steps of converting and extracting hydrogen, which reflects on the total efficiency, purity of hydrogen and, thus, on the total cost. Authors Wijayanta et al., provided a full techno-economic comparative overview of the different hydrogen maritime transportation technologies.⁸² Maritime transportation of hydrogen cannot compete with a pipeline network, due to volumes of hydrogen to be shipped on the medium distance (up to 3700km for new H₂ pipeline and <6000km for retrofitted natural gas pipelines, see Figure 30). Over long distances, for example between Australia and Japan, construction of a pipeline is infeasible and maritime transportation is the unrivalled solution.

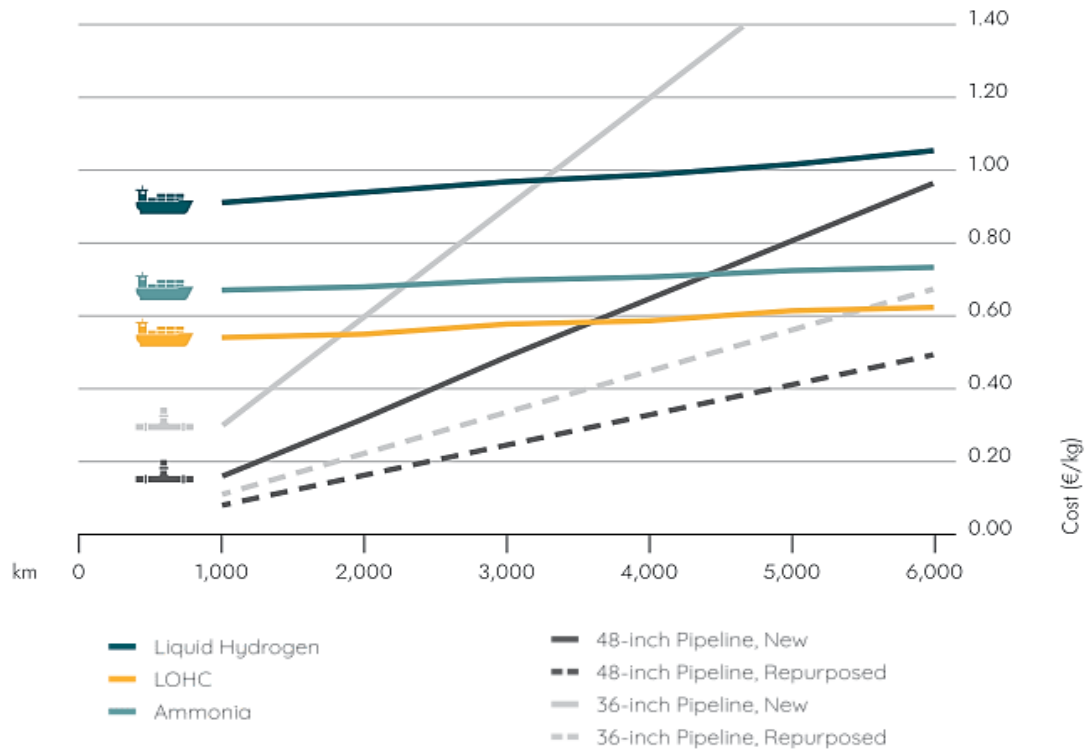
In general, hydrogen pipelines, compared to maritime shipment, are considered a mature technology and practised worldwide, thus the cost for transportation can be considered stable over time. By contrast, liquid H₂ tankers are a new technology. In 2019 the first and now only liquid hydrogen tanker Suiso Frontier with a capacity of 1250m³ (or 3GWh, 1kg liquid H₂= 71kg/m³) was launched in Kobe,

⁸² Wijayanta, A. T. et al. (2019). 'Liquid hydrogen, methylcyclohexane, and ammonia as potential hydrogen storage: Comparison review', *International Journal of Hydrogen Energy*. Elsevier Ltd, 44(29), 15026–15044. doi: 10.1016/j.ijhydene.2019.04.112



Japan, in order to deliver Australian coal-based hydrogen.⁸³ For comparison, capacity of a 48-inch H₂ pipeline can provide up to 16.9 GW.⁸⁴ Transporting liquid hydrogen via maritime shipment requires large investment in the development of transportation technologies, routes and infrastructure, that is hardly imaginable in the next 10 years. H₂ incorporated in different chemical compounds has a higher potential, for example in the case of ammonia, the tanker can be fueled with its own cargo and simultaneously provide CO₂ emission reduction.⁸⁵

Figure 30: Economical comparison of hydrogen transport options over different distances



Source: European Hydrogen Backbone (2021)

Hydrogen Storage

Hydrogen storage is an essential link in any hydrogen supply chain. Similar to the natural gas supply chain, gas storage can be geological underground storage, suitably depleted gas fields, salt caverns and domes and aquifers or smaller scale pressurised steel tanks. Hydrogen storage can be extremely energy intensive and therefore expensive. Hydrogen storage in salt caverns is one of the technologies with the highest potential because of its high capacity, operational safety, sealing capacity and low cushion gas requirements.⁸⁶ In order to lower the total hydrogen cost, only large-scale geological storage can be considered in the supply chain. Thus, the design of the supply chain must reflect the geological features of each country.

Caglayan et al's study provides a suitability assessment of geological salt structures in the EU, highlighting that the overall technical storage potential is approximately 84.8 PWh_{H₂}, 27 per cent of which refers to onshore locations. Germany is leading with the highest share of 41 per cent of technical onshore storage potential, followed by the Netherlands and the United Kingdom, with 10.4 and 9.0

⁸³ Kawasaki Heavy Industries. (2019). 'World's First Liquefied Hydrogen Carrier SUISSO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society'. https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487

⁸⁴ European Hydrogen Backbone. (2021) 'Analysing future demand , supply , and transport of hydrogen', June

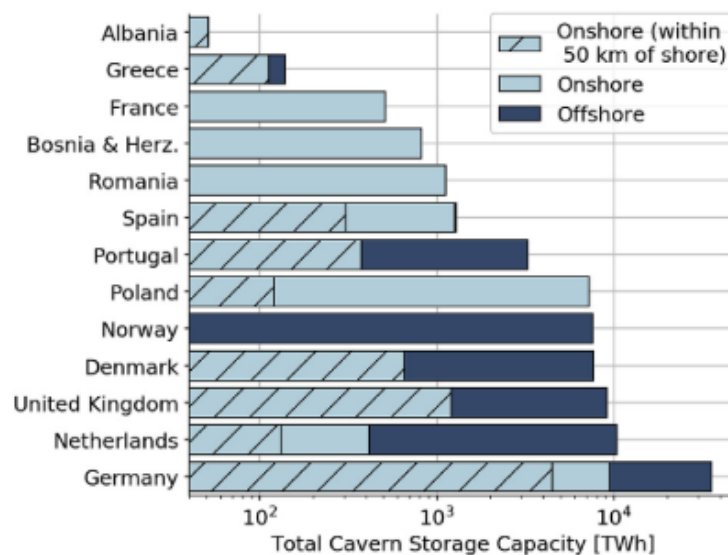
⁸⁵ Ammonia Energy Association. (2018). 'Pilot project: an ammonia tanker fueled by its own cargo - Ammonia Energy Association'. <https://www.ammoniaenergy.org/articles/pilot-project-an-ammonia-tanker-fueled-by-its-own-cargo/>

⁸⁶ Caglayan, D. G. et al. (2020). 'Technical potential of salt caverns for hydrogen storage in Europe', *International Journal of Hydrogen Energy*. Elsevier Ltd, 45(11) 6793–6805. doi: 10.1016/j.ijhydene.2019.12.161

PWh₂ respectively (See Figure 31).⁸⁷ Further economic and environmental analyses are required to provide more accurate representation of the realistic utilization rate of the potential technical capacity of the salt caverns.

The 2021 study by Agora Energiewende, provides an analysis of different H₂ storage demand profiles for four European regions (North, Central/West, South and Central/East). In the modelling scenarios, North Europe has the highest requirement for storage reaching 12 per cent of annual demand. Table 6 shows the levelized cost of hydrogen storage in salt caverns and in pressurised tanks in €/kg. Underground storage is the only economically viable option, being on average 33 times less expensive than H₂ storage in pressurised tanks. The authors show the regional differences in H₂ storage costs (North Europe – €0.67/kg, South €0.16/kg), which are explained by the number of full-duty cycles per annum for each regional demand. In the case of North Europe, despite the highest requirement for storage capacity, the number of full cycles is 2.06, whereas South Europe has approximately 8.45 full cycles per year.⁸⁸

Figure 31: Total salt cavern potential in European countries (onshore, offshore and onshore within 50km of shore)



Source: Caglayan et al (2020)

Table 6: European regional levelized costs of storage (salt caverns and pressurised tanks)

€/kg	North Europe	Central/West Europe	South Europe	Central/East Europe
LCOS pressurised tanks*	22.24	10.84	5.42	7.17
LCOS salt caverns*	0.67	0.33	0.16	0.22

*Max cycles

Source: Agora Energiewende et al. (2021)

⁸⁷ Caglayan, D. G. et al. (2020). 'Technical potential of salt caverns for hydrogen storage in Europe', *International Journal of Hydrogen Energy*. Elsevier Ltd, 45(11) 6793–6805. doi: 10.1016/j.ijhydene.2019.12.161

⁸⁸ Agora Energiewende et al. (2021). 'No-regret hydrogen'. https://static.agora-energiewende.de/fileadmin2/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf



Categorisation of the cost scenarios based on supply chains

The following hydrogen supply chain cases are analysed based on their cost structures and on the timing of the realisation of particular supply chains. Time constraints are one of the main barriers to the development of a hydrogen economy.

Hydrogen routes up to 2030

Figure 32 compares the indicative costs of hydrogen import routes which could potentially be in operation prior to 2030 based on an analysis of published data, together with a comparison with hydrogen production from local sources:

- The first and perhaps most advanced option for the northern cluster is the H2morrow project where natural gas is used to produce H₂ via ATR near the industrial demand centres in Germany and later CO₂ is captured and sent back to Norway via maritime shipment for offshore sequestration in the North Sea. The cost for the hydrogen produced in the H2morrow project consists of several parts, particularly natural gas price, the CO₂ liquefaction, transport and offshore storage and capital investment costs for ATR. According to the project details, H₂ price is predicted to be between €2-3/kg or €50-80/MWh, where H₂ cost is €2.6/kg or €65/MWh. Variations in natural gas prices have the highest sensitivity on the H₂ cost. In the example of Norway, the fuel part represents one third of the total cost, €22/MWh. Higher natural gas prices, as in late 2021, would clearly result in correspondingly higher H₂ prices. The cost for CO₂ is assumed to be €50-70/ton. Commissioning of the pilot project is scheduled to start by 2030.⁸⁹
- The next blue H₂ route could also be developed between Norway and Germany and requires a hydrogen pipeline system (approximately 650-700km). Hydrogen can be produced on a large scale via SMR in Norway and CO₂ can be captured and sequestered at offshore storage locations in the North Sea. Then pure H₂ gas can be sent via pipeline directly to Germany or the Netherlands and distributed on to other countries. By 2030, the price for blue hydrogen could be in the range of €2.5-3/kg, depending on the natural gas price. For Norway-Germany SMR+CCS, the natural gas price estimate is IEA forecast \$25/MWh.⁹⁰
- In another initiative, Gazprom has showed its interest in the supply of low-carbon turquoise hydrogen to Germany. Turquoise hydrogen is achieved via thermal decomposition of methane into hydrogen and solid carbon. Such a method avoids the additional costs for CO₂ capture and utilization that is met with criticism in many countries. According to the Pöyry study, the production cost for turquoise H₂ is in the range of €2-3/kg.⁹¹ However, the technology is in the laboratory stage and requires pilot project scale up, therefore up to 2030, large-scale production of turquoise hydrogen is unlikely and the actual costs remain uncertain.
- By 2030 renewable hydrogen imports are only expected from Norway, supplementing domestic green hydrogen production in different parts of Europe (Germany and Italy, Figure 32). The Norway to Germany/the Netherlands example represents hydrogen produced from offshore wind and results in production costs of approximately \$2.5/kg. The example of a green H₂ supply route from Norway to Germany/the Netherlands involves maritime shipments of hydrogen in ammonia form. The total cost for green hydrogen in this case is €3.5/kg, which is relatively high compared to methane based H₂.⁹²

⁸⁹ Equinor and Open Grid Europe (no date) 'The Potential of Hydrogen for Decarbonization of German Industry. A joint study by Equinor and OGE

DNV GL. (2019). 'Hydrogen in the electricity value chain'

⁹⁰ Pöyry and Zukunft ERDGAS. (2019). 'Hydrogen from natural gas - The key to deep decarbonisation 31'.

https://afry.com/sites/default/files/2020-06/zukunft_erdgas_key_to_deep_decarbonisation.pdf

Brändle, G., Schönfisch, M. and Schulte, S. (2020). 'Estimating Long-Term Global Supply Costs for Low-Carbon Hydrogen'. 20/04

Agora Energiewende et al. (2021). 'No-regret hydrogen'. https://static.agora-energiewende.de/fileadmin/2/Projekte/2021/2021_02_EU_H2Grid/A-EW_203_No-regret-hydrogen_WEB.pdf

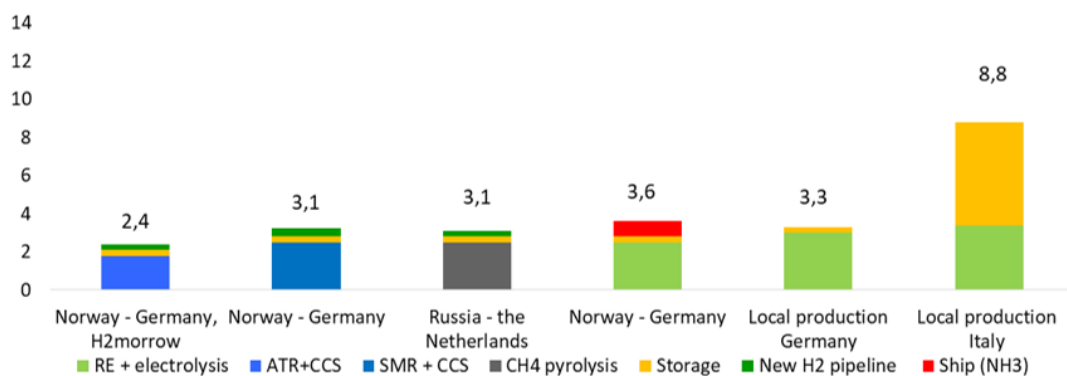
⁹¹ Pöyry and Zukunft ERDGAS. (2019). 'Hydrogen from natural gas - The key to deep decarbonisation 31'.

⁹² Brändle, G., Schönfisch, M. and Schulte, S. (2020) and Agora Energiewende et al. (2021)

- For local production in Germany, the cost of green hydrogen is estimated at €3/kg, and there is assumed to be adequate available storage in salt caverns at a cost of €0.3/kg.⁹³ For Italy on the other hand, there does not appear to be suitable salt cavern storage, so it is assumed that any storage would need to be in steel tanks, which results in the cost increasing by almost three times to €8.8/kgH₂, where €5.4/kgH₂ is storage cost. In such a case, H₂ import by pipeline is likely to be more competitive, provided that demand fluctuations can be met by pipeline deliveries.

Figure 32: Possible hydrogen supply routes to Europe up to 2030

Hydrogen supply routes up to 2030



Source: Adapted from IRENA, 2019; Brändle, Schönfisch and Schulte, 2020; Ishimoto et al., 2020; Agora Energiewende et al., 2021; European Hydrogen Backbone, 2021; Ukrainian Hydrogen Council and UNECE, 2021 and author's assumptions

Hydrogen routes 2030-2035

Beyond 2030, assuming expansion of the European Hydrogen Backbone as envisaged, new hydrogen import routes could evolve, such as H₂ from Spain, North Africa and Ukraine. According to Hydrogen Europe, North Africa and Ukraine could provide 40GW of installed capacity for electrolysis by 2030. Nevertheless, such an approach could be optimistic for a number of reasons: (a) the lack of hydrogen infrastructure connecting north-western Europe and North Africa or Ukraine; (b) the ability to expand electrolyser manufacturing globally to provide total 80GW electrolyser capacity; (c) competition in the utilization of renewable energy (direct electrification vs e-fuels) and (d) absence of adequate policy support and adoption of international safety regulations and emission standards.

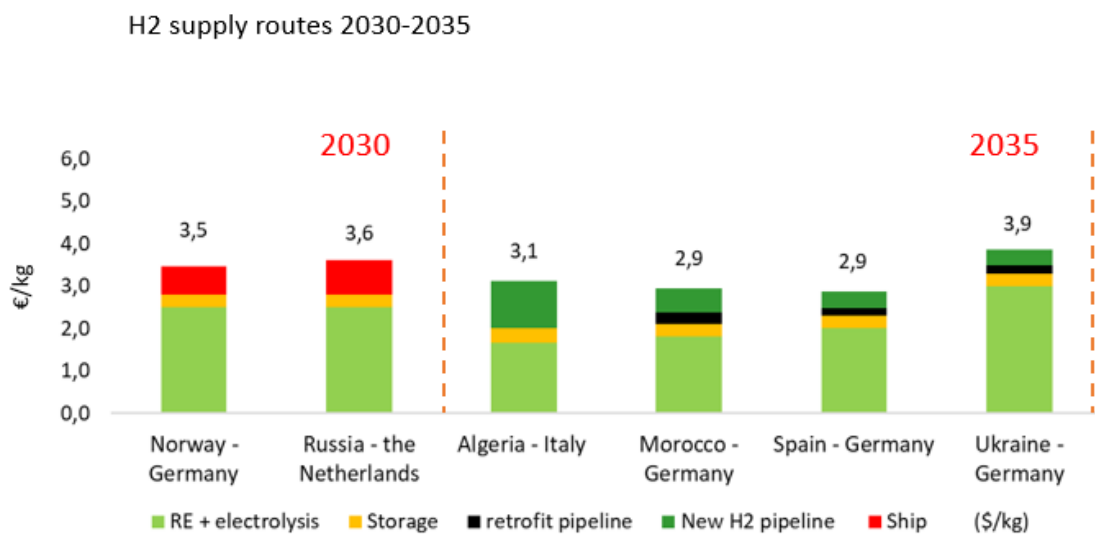
Figure 33 compares the indicative costs of hydrogen import routes which could potentially be in operation prior to 2030 based on an analysis of published data, including the latest information from the European Hydrogen Backbone, companies' reports, and techno-economic feasibility studies. Figure 33 contains only new green hydrogen supply chains, bearing in mind that blue and turquoise H₂ routes shown in Figure 32 exist in parallel:

- Green hydrogen production costs in supply cases such as Algeria, Morocco and Spain, do not exceed €2/kg and are lower than other green H₂ alternatives, mainly due to the vast potential for solar power and high PV capacity factors.
- According to Brändle, Schönfisch and Schulte, hydrogen produced in Spain and North Africa shows similar results when transported to Germany.

⁹³ Brändle, G., Schönfisch, M. and Schulte, S. (2020) and Agora Energiewende et al. (2021)

- Hydrogen produced in Norway and in Russia shows similar cost structures and results, due to similar technologies and capacity factors for offshore wind parks, resulting in €2.5/kg. The transportation in these two cases is assumed to be maritime shipment of H₂ in the form of ammonia. Despite the significant difference in distance (800km from Norway to Germany and 4000km from Russia to the Netherlands, see Figure 26), the transport costs only differ by €0.65/kg and €0.8/kg respectively, due to characteristics of the cost for maritime shipment over distance, see Figure 30.
- Ukraine has high potential for wind energy, however, there is a lack of information on the development of wind capacity and cost for H₂ production between 2030 and 2035. Therefore, wind-based H₂ costs are derived according to the recommendations from Ukrainian Hydrogen Council and UNECE and are significantly higher than PV-based green hydrogen from Spain/North Africa.⁹⁴

Figure 33: Development of hydrogen import routes between 2030 and 2035



Source: Adapted from IRENA, 2019; Brändle, Schönfish and Schulte, 2020; Ishimoto et al., 2020; Agora Energiewende et al., 2021; European Hydrogen Backbone, 2021; Ukrainian Hydrogen Council and UNECE, 2021 and author's assumptions

Conclusion

The interest in low-carbon/renewable hydrogen economy is rising dramatically in the EU and globally. In the last few years, several countries (including the Netherlands, Germany, Portugal, France, Norway, UK, Spain and Italy) have shown serious commitment to hydrogen technologies and released national hydrogen strategies, roadmaps and finance plans. By 2030, according to the European Hydrogen Strategy and Hydrogen Europe, the installed capacity for electrolyzers should be 40GW within Europe plus 40GW of imported hydrogen, supplying in total approximately 15-20 million tons of H₂.

In 2030, H₂ demand could be high enough to initiate some limited international hydrogen trade, most likely between European countries initially. Low-carbon/renewable hydrogen demand will initially come from the sectors that are currently utilizing conventional hydrogen for industrial purposes, such as oil refineries, petrochemicals, and the ammonia and methanol industries, plus some potential additional demand for steelmaking. In the period 2020-2030, industrial hydrogen demand is estimated to be between 257 and 278TWh. Additional demand could appear from the transportation and heating sectors, however, this demand is quite uncertain. Geographically, the northern hydrogen cluster will be

⁹⁴ Ukrainian Hydrogen Council and UNECE (2021) 'Draft Roadmap for production and use of hydrogen in Ukraine', 1-101



more significant for hydrogen demand than the southern hydrogen cluster. At the same time, north-western countries, led by Germany, are likely to be the first to start hydrogen imports, as local hydrogen production from renewable energy is predicted to be insufficient to meet demand even before 2030.

Different hydrogen production methods should be considered, provided they contribute to an overall reduction in GHG emissions. Thus, blue H₂ could support expansion and growth of the green hydrogen market up to 2030 and beyond. Especially, in the absence of a multinational hydrogen pipeline network (European hydrogen backbone) by 2030, imports of green hydrogen will be restricted by available transportation methods of H₂.

This paper investigated some of the potential H₂ exporters to Europe, including Ukraine and North African countries (as a recommendation from Hydrogen Europe), and Norway and Russia. Ukraine and North Africa have advantages in terms of RE potential and cost, as well as mature NG infrastructure. However, the following criteria should be also considered as these might hinder the export of decarbonized gas to the EU by 2030:

- limited decarbonization of domestic energy system;
- water availability;
- proximity to H₂ demand centres;
- state of development of the infrastructure and readiness for H₂ injection;
- history of bilateral relationships and security of supply.

In the case of Norway and Russia, the two main natural gas providers to the EU, the initiation of low-carbon and renewable hydrogen could be faster and at a lower cost, starting H₂ supplies with blue and, perhaps, turquoise hydrogen. Furthermore, these countries show a higher likelihood (according to above mentioned criteria) for roll-out of hydrogen exports. Nevertheless, diversity of H₂ exporters will increase security of supply and promote competition. (As mentioned earlier, this research pre-dates recent political and military tensions between Russia and Ukraine which are likely to have a long-term impact on European priorities regarding energy security.)

Supply cost of hydrogen in 2030 is predicted to be around €3/kg from various sources and supply chains. Natural gas-based hydrogen shows the lowest total cost, however in the long run, the cost may increase as natural gas and CO₂ prices are expected to increase. For green hydrogen, further cost reduction is required to be competitive. The key factors in green H₂ production costs are the electricity price, operating hours and capital expenditure for electrolyser equipment. In terms of infrastructure, retrofit or construction of new H₂ pipelines are a promising solution for transporting energy over long distances. H₂ transport by ship and electricity transmission is significantly more expensive. For hydrogen storage, the only economical viable solution would be storage in underground geological formations, such as salt caverns and depleted gas fields. Lack of H₂ storage in underground formations, for example in Northern Italy, leads to significant increases in total H₂ costs (approximately by three times).

Another important, and currently missing, part of the hydrogen economy is the establishment of a hydrogen target price that would be acceptable among different end-use sectors. What measures should be taken by governments to achieve the development and establishment of hydrogen in the energy market by 2030 and how high should carbon pricing be? In addition to the above, Guarantees of Origin (GoO) is a crucial topic for assessment of the carbon footprint of hydrogen supply chains. Developing green certificate schemes for electricity and gases that meet international standards can significantly simplify trade, increase credibility and lead to long-term cooperation with international consumers. While these questions are beyond the scope of this paper, they will be considered further in future OIES research.

Overall, while imports of hydrogen to Europe are certainly possible in the longer term, there are many challenges to be addressed and it appears unlikely that they will occur by 2030 in the manner and at the scale envisaged by the Hydrogen Europe study.