European Commission

ENTEC

Energy Transition Expertise Centre

Report

The role of renewable H_2 import & storage to scale up the EU deployment of renewable H_2

The role of renewable H_2 import & storage to scale up the EU deployment of renewable H_2

Consortium Leader

Fraunhofer Institute for Systems and Innovation Research ISI, Breslauer Straße 48, 76139 Karlsruhe, Germany
Barbara Breitschopf, barbara.breitschopf@isi.fraunhofer.de; Andrea Herbst, andrea.herbst@isi.fraunhofer.de

Consortium Partners

Guidehouse, Stadsplateau 15, 3521 AZ, The Netherlands
McKinsey & Company, Inc., Taunustor 1, 60310 Frankfurt, Germany
TNO, Motion Building, Radarweg 60, 1043 NT Amsterdam, The Netherlands
Trinomics, Westersingel 34, 3014 GS Rotterdam, The Netherlands
Utrecht University, Heidelberglaan 8, 3584 CS Utrecht, The Netherlands

Contributed by

Trinomics, Westersingel 34, 3014 GS Rotterdam, The Netherlands, Frank Gérard, frank.gerard@trinomics.eu
Fraunhofer Institute for Energy Economics and Energy System Technology IEE, Königstor 59, 34119 Kassel, Germany
TNO, Motion Building, Radarweg 60, 1043 NT Amsterdam, The Netherlands
Fraunhofer Institute for Systems and Innovation Research ISI, Breslauer Straße 48, 76139 Karlsruhe, Germany

Authors

Barbara Breitschopf, barbara.breitschopf@isi.fraunhofer.de; Lin Zheng, Lin Zheng, lin.zheng@isi.fraunhofer.de; Marie Plaisir, marie.plaisir@iee.fraunhofer.de; Jochen Bard, jochen.bard@iee.fraunhofer.de; Ramona Schröer, ramona.schro-eer@iee.fraunhofer.de; Durgesh Kawale, durgesh.kawale@tno.nl; Joris Koornneef, joris.koornneef@tno.nl; Yeshambel Melese, yesh.melese@tno.nl; Marianne Schaaphok, marianne.schaaphok@tno.nl; João Gorenstein Dedecca, joao.dedecca@trinomics.eu ; Csinszka Bene, Csinszka.Bene@trinomics.eu ; Ondrej Cerny, Ondrej.Cerny@trinomics.eu ; Frank Gérard, frank.gerard@trinomics.eu

Prepared for

European Commission, DG ENER under contract N° ENER/C2/2019-456/ SI2.840317

Published: February 2022

PDF	ISBN 978-92-76-48847-7	doi 10.2833/727785	MJ-01-22-112-EN-N

List of abbreviations

Acronym	Full description
ACER	Agency for the Cooperation of Energy Regulators
CBA	Cost Benefit Analysis
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CEHC	Central European Hydrogen Corridor
CGH_2	Compressed Gaseous Hydrogen
CH_4	Methane
CO_2	Carbon dioxide
DAC	Direct Air Capture
EBRD	European Bank for Reconstruction and Development
ENTSO (E/G)	European Network of Transmission System Operators (electricity / gas)
EU	European Union
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FLH	Full Load Hours
FT	Fischer-Tropsch
FTA	Free trade Agreements
H_2	Hydrogen
HHI	Hirschman-Herfindahl Index
HHV	Higher Heating Value
IP	Interconnection Point
JRC	Joint Research Centre
kt	Kilotonne
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LH_2	Liquefied Hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
MENA	Middle East-North Africa
MeOH	Methanol
Mt	Megatonne
MS	Member State
NDP	National Development Plan
NECP	National Energy and Climate Plan
NG	Natural Gas
NH_3	Ammonia
NRA	National Regulatory Authority

Acronym	Full description
PEM	Proton Exchange Membrane
PAC	Paris Agreement Compatible
RES	Renewable Energy Sources
SOEC	Solid Oxide Electrolyser Cell
Sm^3	Standard cubic meter
SNG	Synthetic Natural Gas
TEN-E	Trans-European Energy Network
TFEC	Total Final Energy Consumption
TPA (rTPA / nTPA)	Third Party Access (regulated TPA / negotiated TPA)
TRL	Technology Readiness Level
TRP	Technology Risk Profile
TYNDP	Ten-Year Network Development Plan
UHS	Underground Hydrogen Storage
WACC	Weighted Average Cost of Capital

Glossary of terms

Term	Full description
Renewable hydrogen	Hydrogen produced via electrolysis, using renewable (mainly wind and PV) based electricity
Renewable hydrogen derivatives	Comprises all products and fuels produced with renewable hydrogen. In the frame of this study they include e-ammonia, e-methanol, e-liquids (also called liquid derivatives), e-gases
PtX	Power-to-X is used when it refers to specific literature (mainly in chapter 2). They comprise renewable hydrogen and derivatives
e-fuel	E-fuel is used when it refers to specific literature (mainly in chapter 2). E-fuels comprise all electricity based hydrogen derivatives which are used as fuels
e-liquids	E-liquid is used when it refers to specific literature (mainly in chapter 2). E-liquids are similar to PtL or liquid derivatives
PtL or Liquid derivatives	Power-to-Liquids or liquid derivatives are all hydrogen based derivatives produced via Fischer Tropsch synthesis. They comprise e-kerosene, e-diesel and e-gasoline.
e-ammonia	Ammonia produced with renewable hydrogen
IEE Global PtX Atlas	Fraunhofer IEE Global mapping of potential Power-to-X production worldwide, available at https://maps.iee.fraunhofer.de/ptx-atlas/
Green hydrogen	Refers to the EU hydrogen strategy concept of green hydrogen.

Table of Contents

Executive summary

The **European Commission's hydrogen strategy**[1] presented in July 2020 outlines, amongst other elements, how to upscale the demand and supply of renewable hydrogen. It has set the strategic objective to install at least **40 GW of renewable hydrogen electrolyser capacity within the EU (producing about 5 Mt of renewable hydrogen) based upon an estimated demand of up to 10 Mt per year of renewable hydrogen** in the EU by 2030.

To produce 10 Mt of renewable hydrogen, a substantial amount of additional **renewable electricity**[2] will be needed to produce renewable hydrogen, on top of the large amounts of renewable electricity that will be needed to electrify end-uses that are currently served by other energy carriers. The characteristics of renewable electricity generation, such as its variability and the time needed to realize additional solar and wind parks, the need to minimise the costs of the energy transition, and security of supply considerations require taking an in-depth look into the **role of renewable hydrogen import (infrastructure)** as well as into the **role of hydrogen storage (infrastructure)** to decarbonize the EU economy.

At the moment, it is not clear whether domestic production of hydrogen will achieve the strategic EU 2030 goal to cover 10 Mt of renewable hydrogen demand, leading to the potential need for imports. Therefore, this research paper intends to assess the supply gaps and possible **options for cost-effective renewable hydrogen carriers imports** and **transport modes**, given the broad diversity of potential supply scenarios. *Hydrogen carrier* refer to the chemical compound by which hydrogen is transported. *Hydrogen-derivative* refers to the (end) product that is derived from hydrogen. '*Hydrogen*' refers to compressed gaseous hydrogen (CGH_2), liquefied hydrogen (LH_2) forms, and hydrogen bound to other molecules such as liquid organic hydrogen carriers (LOHC's), while derivatives comprise:

- Liquid derivatives or PtL (e-kerosene, e-gasoline, and e-diesel);
- Methanol (MeOH), Ammonia (NH_3);
- E-gases, such as Synthetic Natural Gas (SNG);

Supply and demand of renewable hydrogen and its derivatives in 2030

The study provides an overview of renewable hydrogen and derivatives supply and demand in 2030, projected in various studies addressing climate neutrality of the entire energy system within EU27 by 2050 (with the contribution of different energy carriers, not only hydrogen and its derivatives). It aims at identifying gaps, to be filled with international supply through import. Scenarios with a minimum installed electrolyser capacity of 40 GW in 2030 were considered. Four scenarios from four different studies fulfilling these criteria are chosen for the further analysis:

- EC MIX-H2: achieving the target of 55% GHG in 2030 - European Commission (2021) Impact Assessment Report;
- Paris Agreement Compatible (PAC[3]): Building a PAC energy scenario, for pathway towards the 1.5°C target of the Paris Agreement - Climate Action Network Europe (2020);

---

1 https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

2 Electrolyser efficiency can be considered at 48.89MWhel/tH_2, meaning that producing 10Mt H_2 would require 488.9 TWh electricity (in average), which can be rounded to 500 TWh

3 https://caneurope.org/building-a-paris-agreement-compatible-pac-energy-scenario/

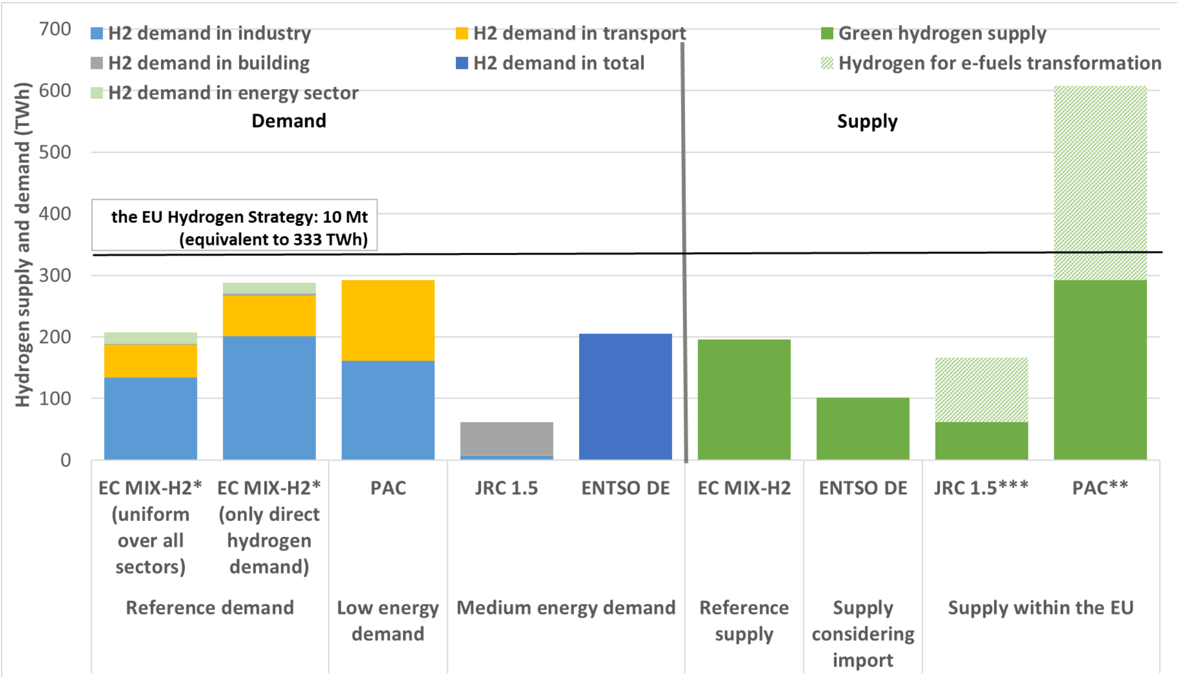
- ENTSO DE: TYNDP 2020 Scenario Report[4], through a bottom-up approach (based on historical energy balance data), considering NECPs - ENTSO-E and ENTSOG (2020);
- JRC 1.5: Global Energy and Climate Outlook (GECO) 2020, A New Normal Beyond Covid-19[5], the 1.5°C scenario - Joint Research Centre (2021).

The European Commission's scenario EC MIX-H2 is used as an anchor scenario in the analysis, due to its objective to align with the target of the Hydrogen Strategy[6] (40 GW installed capacity of electrolysers, leading to 5 Mt H_2 produced on the EU territory, based on 4,162 hours equivalent and the energy content of hydrogen ~33,3 kWh/kg H_2). As the other target of reaching 10 Mt (equivalent to 333 TWh) H_2 demand in 2030 (including for the production of derivatives) is not met by this original scenario (and is only reached between 2030 and 2035), upscaling the EC MIX-H2 to fulfill the target is foreseen through the following two variations:

1) Uniform over all sectors: the scale-up of demand will occur evenly to both hydrogen and its derivatives in all sectors.
2) Only direct hydrogen demand: the scale-up of demand occurs firstly to the direct use of hydrogen.

The modelling results from these selected scenarios will be used to provide an overview of demand and supply of hydrogen and its derivatives. The following figure illustrates the imbalance between the domestic demand and supply projected in the different scenarios, showing the possible need for renewable hydrogen import.

Figure 1 Overview on supply and demand of hydrogen in 2030 in selected scenarios



* Adjusted demand with total H_2 demand of 10 Mt (equivalent to 333 TWh)
** Based on an electrolyser efficiency of 60%
*** Based on assumption of 1 GW electrolyser produces 4.16 TWh hydrogen per year

4 https://www.entsog.eu/sites/default/files/2020-07/TYNDP_2020_Joint_Scenario%20Report%20ENTSOG_ENTSOE_June_Final.pdf

5 This report is the sixth edition of the Global Energy and Climate Outlook (GECO), available at https://publications.jrc.ec.europa.eu/repository/handle/JRC123203

6 https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Overall, **it can be concluded** that the development of hydrogen and its derivatives is uncertain, further causing different levels of possible import demand. Nevertheless, if the European Commission's hydrogen strategy concretizes, meaning 10 Mt demand of hydrogen in 2030 including to produce derivatives, supply gaps will more than likely exist in 2030 and importing these energy carriers will be required under most circumstances. These supply gaps in 2030 need to be covered by importing from countries and regions outside of the EU.

The role of renewable H_2 import to the EU

Market trend and gap analysis

The study analyzes the various factors influencing to which extent the EU could start, or even massively import renewable hydrogen and its derivatives, at the 2030 horizon. These influencing factors are driven by:

- EU and international market developments, with potential gaps between the production and demand of hydrogen and derivatives in the EU;
- The total cost of hydrogen and derivatives, along the entire supply chain (import cost, consisting of production and transportation costs);

The study assesses the current market trend, and, assuming that there are supply gaps at EU scale, identifies how international market (potential exporting markets) could fill in such gaps. Thereafter, it describes the main elements, technical characteristics and costs of production, transformation (or conversion) and transport of renewable hydrogen and its derivatives. The study also analyses the costs for hydrogen, Power-to-Liquids (PtL), Methanol, and liquid synthetic natural gas (SNG) production and transport up to the EU borders. Finally, it discusses the barriers and regulatory needs for developing hydrogen imports to the EU, with a focus on renewable hydrogen and its derivatives.

Potential future exporting countries, as well as their potential export volumes of renewable hydrogen on the short term, are analyzed on the basis of the IEE Global PtX Atlas published in June 2021[7]. In order to rank the potential exporting regions at the 2050 horizon, the PtX Atlas methodology is based on the extensive analysis of the production potential of each region. The largest land potentials for the production of renewable hydrogen and derivatives arise in large countries such as the United States, Australia, Argentina, or Russia, with coastal or inland waterways accesses (more than 70% of the PtX potential is located near freshwater resources, due to the fact that electrolysis requires significant amounts of water). Inland waterways would also provide efficient transport means.

This first PtX Atlas concludes that in the long term (2050), outside Europe, a total of around 109,000 TWh of liquid hydrogen and respectively 85,000 TWh of derivatives could be produced. Of course, the suitability for the development of a renewable hydrogen and derivatives infrastructure also depends on the socio-economic conditions in the renewable hydrogen and derivatives producing country.

Regarding the current global development of a hydrogen economy, it appears that more and more renewable hydrogen projects are being announced around the world. An analysis of the largest projects, the expected derivative and the potential amount produced was carried out based on an IEA project pipeline and on *Recharge Global* news and Intelligence for the Energy Transition[8]. These

7 Source IEE Global PtX Atlas https://maps.iee.fraunhofer.de/ptx-atlas/

8 https://www.rechargenews.com/energy-transition/growing-ambition-the-worlds-22-largest-green-hydrogen-projects/2-1-933755

major projects announced worldwide will reach a total capacity of 58 GW of electrolysis in 2030, allowing to import between 5 - 7.25 Mt/a to the EU.

In the long term (2050), there is a huge potential worldwide for the production of renewable hydrogen and derivatives. However, in the very short term, given the fact that there is no international hydrogen market yet, and at the same time expectations across the world are also ramping up, export capacities to Europe remain uncertain and based only on the current announced projects. Now, it is also assumed that new important projects will emerge in a near future, bringing additional capacities worldwide and opportunities to export to Europe.

To complete the assessment the cost of these imported products to the EU should also be considered, in order to compare their competitiveness with production within the EU.

Production, transformation and transport technology

The supply chain of imported products from different regions in the world comprises the production of hydrogen by electrolysis fueled by renewable electricity, its conversion to transportable hydrogen (liquefied LH_2 or compressed gaseous CGH_2), its conversion to derivatives (PtL like Diesel/Kerosene, methanol - MeOH, ammonia - NH_3, Synthetic Natural Gas – SNG), or its binding with Liquid Organic Hydrogen Carriers (LOHCs) and finally the transport of the fuel by ship for all liquids, and by pipelines for gaseous forms.

The technical characteristics and costs for the production and transport of renewable hydrogen and its derivatives are described in the study. Some results are illustrated by the three next figures concerning the import cost of liquid hydrogen, of Fischer Tropsch[9] fuels (Diesel/Kerosene), and methanol in 2030 (the details, and the other above mentioned fuels can be found in the main report, under chapter 3.2).

[9] The Fischer Tropsch process produces liquid and gaseous hydrocarbon fuels (as gasoline, diesel, kerosene or gas oil) by passing a mixture of carbon monoxide and hydrogen over metal or other catalysts at elevated temperatures and at normal or higher pressures

Figure 2 **Cost of Liquid Hydrogen supply chain: import cost 2030**

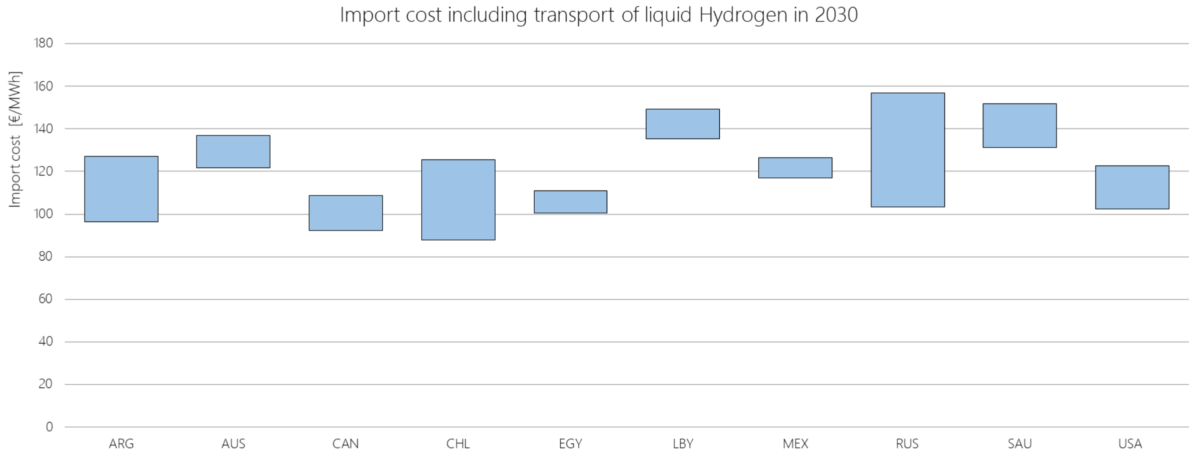


Figure 3 **Cost of Fischer Tropsch (Diesel/Kerosene) supply chain: import cost 2030**

*

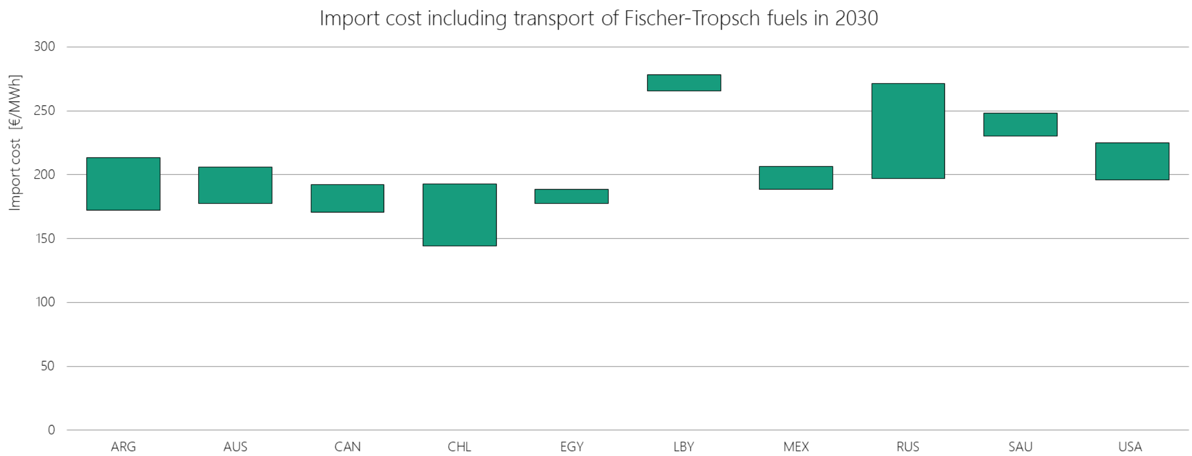
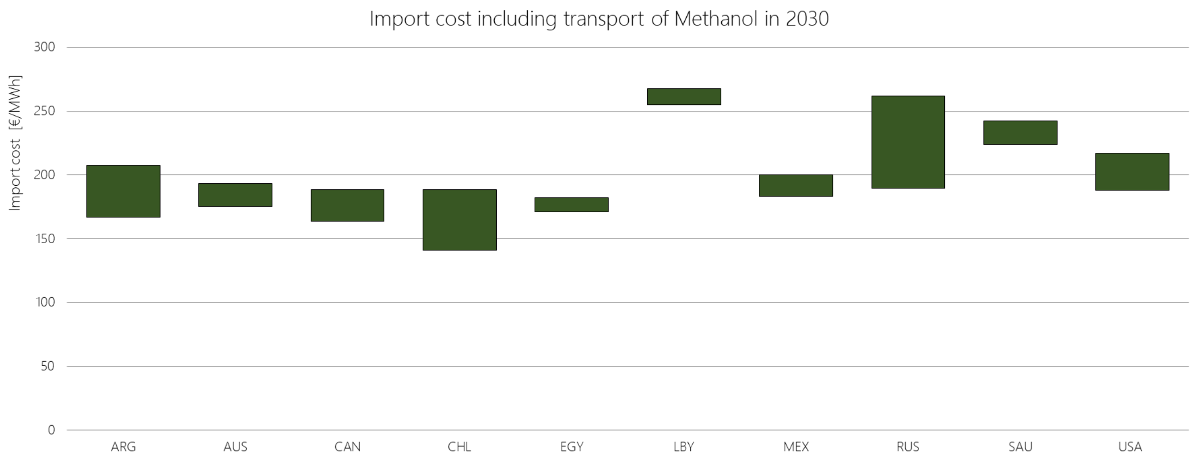


Figure 4 **Cost of Methanol supply chain: Import cost 2030**



In **conclusion**, generally the more conversion steps the process chain contains, the lower its efficiency, leading to higher costs, although the ease of transport/storage/market opportunities also influences the cost and economic attractiveness of a product. However, due to i.e. excellent renewable energy resources with accordingly low LCOE and high full load hours, the combined production and transport cost can be a very attractive option for the EU – in particular when considering renewable hydrogen derivatives which are cheap and efficient to transport.

The import of ammonia, methanol, e-diesel and e-kerosene seems to be the most straightforward to realize at the present time. The infrastructure for transporting these fuels already exists and is already being used for the fossil hydrocarbons as well as fossil-based ammonia to be substituted. Additional transport capacities and some new export terminals might however be necessary. The cost of transporting these liquids to the EU has proven to be the most economical in the analysis, especially compared to the transport of liquefied hydrogen which remains expensive due to the need for new infrastructure (terminals, tanks), the energy intense liquefaction and boil-off losses during transport.

It can be suitable to import hydrogen via a pipeline from neighboring countries e.g. from the MENA region. Important renewable energy resources near the EU with accordingly low LCOE and high full load hours would lead to very attractive production and transport costs of gaseous hydrogen. New storage and a grid infrastructure (new built pipelines or rededicated natural gas infrastructure) would still be required. This option, for the direct use of hydrogen (in the industry or in transport), only requires hydrogen compression for the transport and will remain more attractive than the reconversion of the liquid derivatives back to hydrogen.

The main cost drivers for import costs of renewable hydrogen and derivatives remain the availability and costs of renewables. The transport costs, in turn, depend mainly on the transport distance (including the losses). Despite the comparatively long distance between some of these regions and EU and the correspondingly higher transport costs, the cost advantages of these regions due to extremely advantageous renewable resources may outweigh the economic disadvantages of transport costs, especially for derivatives.

Regulatory needs for hydrogen imports and import infrastructure

The EU Hydrogen strategy addresses cooperation in the field of "clean hydrogen" with the EU's neighbouring countries/regions and other international partners to establish secure hydrogen supply chains and diversify imports. The EU's Eastern and Southern[10] neighbours, especially Ukraine, are set to be priority partners due to renewable potential, existing infrastructure and physical interconnections with EU Member States. To address production and market uncertainties, the strategy aims for coordination with neighbours on research, innovation and policy as well as direct investments and fair trade of hydrogen and derivatives. Hydrogen imports from Energy Community[11] countries or North Africa (e.g. Egypt, Libya) could potentially be competitive. Moreover, supplies through pipelines could be more secure than shipments from other regions, as competition with e.g. Asian markets would be more limited.

Concerning regulatory and market barriers for hydrogen imports to the EU, some studies exist, but the topic is rather new and few principles exist yet on how to foster international hydrogen trade and hydrogen imports to the EU. In this study we provide recommendations on policy and regulatory frameworks to promote the import of hydrogen and its derivatives to the EU.

[10] The Southern neighborhood includes Algeria, Egypt, Israel, Jordan, Lebanon, Libya, Morocco, Palestine, Syria and Tunisia

[11] Albania, Bosnia and Herzegovina, Kosovo*, North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine

Context and analysis of barriers

The study addresses contextual topics and barriers to consider when establishing policies and regulations around international hydrogen trade, specifically regarding EU imports. Some of the barriers are generally referring to the lack of international trade at the moment, others are related to hydrogen infrastructure and market design. It must be noted that several of these barriers should be addressed once the legislative proposals of the Hydrogen and Decarbonised Gas Market Package are agreed on and implemented.

- Besides every player in the value chain needing clarity about the future hydrogen agenda, preferred production technologies, as well certification criteria have to be defined in order for investments to start;
- The lack of harmonized certification schemes for hydrogen poses an issue, as it blocks the accounting of emission reductions achieved towards sectoral renewable energy targets and allows possible false claims by hydrogen producers, as well as results in a lack of trust by the public in low-carbon character of hydrogen;
- Intergovernmental agreements and strategic partnerships can foster international hydrogen trade, and bilateral agreements are most fit to do this (as opposed to multilateral);
- Development of import infrastructure will require certainty regarding hydrogen volume forecasts. Sales agreements, multilateral agreements to address country specific risks, and permit and licenses.
- The future regulatory framework should address the repurposing of existing regulated Liquified Natural Gas (LNG) terminals, otherwise the lack of a framework in this regard could slow down investments into critical hydrogen infrastructure. Significant components of an LNG terminal need to be repurposed/replaced in order to convert it to an LH_2 terminal, meaning that the cost advantage of a repurposed LH_2 terminal is not significant compared to a new built. It is unlikely that existing LNG terminals can be adapted to handle multiple carriers simultaneously.
- Existing long-term gas capacity contracts may hamper conversion of existing assets due to supply commitments, more likely in case of pipelines than in LNG terminals.

Possible policy and regulatory measures

Five policy recommendations to address the aforementioned barriers that hamper international hydrogen trade are summarised:

- Bilateral and multilateral strategic partnerships and dialogue have to be established with exporting countries as a framework for future trade, providing certainty to investments, developing technical expertise, addressing financing, and considering the wholistic context;
- Market-making mechanisms could be developed at EU level. Given the lack of an international hydrogen value chain, the capital intensity of the investments and future uncertainties, a coordinated approach to developing supply and demand is necessary;
- Compliance of imported hydrogen and carriers with EU certification standards, with national and international bodies facilitating the adoption of the certification schemes;
- Clear regulatory frameworks for import infrastructure in order to reduce regulatory risk to potential investors and ensure that new infrastructure investment is aligned to energy & climate objectives, including quality standards, allowing the repurposing of infrastructure;
- Incentivise measures by infrastructure operators and market parties to address constraints of existing long-term natural gas contracts and new contracting terms to allow the repurposing of existing gas infrastructure for hydrogen import.

Importance of hydrogen storage facilities in the EU

The significant deployment of hydrogen and derivatives foreseen in the European Commission's Hydrogen Strategy will require the deployment of various forms of hydrogen storage for a number of reasons. The main reason concerns the match between hydrogen supply and demand profiles, driven by the intermittency of renewable energy sources, the use of hydrogen in industry, transport and eventually power generation. Hydrogen storage should increase economic value to market participants (hydrogen producers and consumers), increase the security of supply of the EU energy system, and provide flexibility to the electricity and (methane) gas sectors avoiding the need for additional investments in e.g. hydrogen production capacity.

There are significant differences between the various hydrogen storage technologies regarding maturity, technical and economic characteristics, and potential applications. Technical improvements, cost reductions, and demonstration and large-scale deployment all need to be achieved in order for hydrogen storage to fulfil its potential.

In addition to technical and economic challenges, regulatory barriers exist for the deployment of hydrogen storage. The main objective of this section is therefore to conduct an analysis of the potential and measures to develop hydrogen and derivative storages in the EU.

Hydrogen and derivatives storage technologies

With its low density[12], hydrogen poses unique challenges for storage and transport. To increase stored hydrogen quantity, hydrogen gas can be compressed (CGH_2) or liquefied (LH_2) and stored in above-ground tanks. Compressed hydrogen gas can also be stored underground in salt caverns (UHS – Salt caverns) or porous reservoirs (UHS – porous reservoirs). Alternatively, it could also be stored by entrapping it within other products such as *Liquid Organic Hydrogen Carrier* (LOHC) or by chemically converting it to ammonia (NH_3), methanol (MeOH), liquids such as e-kerosene, or synthetic natural gas. All these options for storing hydrogen present a broad technology platter to integrate hydrogen into the future energy mix. Each storage technology has different energy density (volumetric/gravimetric) and storage capacity, time-scales and charge-discharge rates. For instance, hydrogen storage capacity can vary from hundreds of kg to several kilotonnes (kt) for a pressurized tank to salt cavern storage technology respectively. The specific investment cost of storage also varies strongly from approximately 535 €/kg for compressed tank storage to 7 €/kg for salt caverns; and possibly[13] even lower for depleted gas reservoirs. The operational strategy (e.g. amount of annual cycles) and costs then also have a very important impact on the storage costs. Matching the right storage technology with the right purpose in the hydrogen value chain is thus not only a technical choice but highly influenced by value chain economics.

The following storage technology concepts are explained with their current technical status and challenges:

- Pressurized hydrogen gas storage options: compressed hydrogen gas storage in tanks (CGH_2), with a typical unit consisting of a rack of tanks able to store 500 kg or, equivalently, 16.7 MWh[14] of hydrogen at 200 bar; underground storage in salt caverns with pressures ranges from 35 bar to 210 bar and capacity range from 100,000 m^3 -1,000,000 m^3 (several kt of H_2; underground storage in depleted gas field, which is not a proven technology to store hydrogen (TRL 2-3), but has a very large potential (between 1 and 3 billion Sm^3, or tens or hundreds of kt of H_2); line packing in transport and transmission pipelines.

[12] Hydrogen molecule with molecular mass of 2g/mol has a density of 0.09 kg/Sm^3 (standard cubic meter)

[13] Storage in porous reservoirs has currently a TRL of 2-3

[14] The volumetric density of hydrogen compressed at 200 bar and 273°C is 15.6 kg/m3 or 520 kWh/m3 (Lower Heating Value)

- Liquefied hydrogen / liquid derivatives in tanks (which has a considerably higher energy density than in gaseous form, making it an attractive storage and transport medium:
    - **Liquefied hydrogen in tanks**. LH_2 is currently typically stored at -254 °C in a cryogenic insulated spherical tank. LH_2 tanks are preferred for small and medium scale storage applications;
    - **Ammonia** is conventionally stored in liquid form under atmospheric pressure and a temperature of -33 °C, from large scale (4,500 to 55,000 tons of NH_3) to small scale (less than 270 ton of NH_3);
    - **LOHCs** can exist in liquid form at atmospheric conditions, with similar properties as conventional liquid fuels which makes them suitable to store in tanks;
    - **Methanol** has high hydrogen storage density (99 kg H_2/m^3 MeOH) and exists in liquid form under atmospheric conditions (20 °C and 1 bar), with capacity up to 50,000 m^3 (~ 40 kt of methanol or 5 kt of hydrogen);

Typically, the storage capacity in surface tanks varies from 500 kg for CGH_2 to ~ 10kt of hydrogen for the largest NH_3 tanks. These capacities are typically smaller in comparison to underground hydrogen storage with typical capacity of 180kt H_2 in a porous reservoir or ~8kt H_2 in a salt cavern. From an economic perspective, the specific investment cost of underground hydrogen storage normalised with energy capacity is lowest for porous reservoir at 0.05 €/kWh H_2, LHV (2 €/kg)[15]. For compressed H_2 in tanks, these costs can be as high as 16 €/kWh H_2, LHV[16]. In spite of the large variation in costs, a portfolio of surface and subsurface storage technologies will be needed across the entire hydrogen value chain.

To conclude, hydrogen storage options benefit from economies of scale: specific investment cost decrease with storage capacity; subsurface storage offers lower specific investment cost than surface storage; large scale hydrogen and derivatives surface facilities offer low-cost storage but often require high (pre-and post) processing energy need and costs.

Storage potential in the EU

There are limited technical constraints to exploit the potential of surface hydrogen storage options. However, the technical potential[17] for surface storage of hydrogen is typically limited by spatial constraints.

Tanks located at import terminals are used to store fuels (e.g. LNG, NG, other petroleum products) and chemicals (e.g. methanol, bio-ethanol). In 2019, the total LNG storage capacity within EU27 + UK amounted at approximately 10 million m^3 LNG or 55 TWh.[18] Most of LNG storage tanks are located at import/export terminals and availability of space in harbours is a major constraint. Capacities of LNG tanks vary from 50,000 m^3 to 250,000 m^3.

The availability of salt caverns and depleted gas fields is unevenly distributed across the EU. For instance, the technical potential for salt caverns in Europe is limited to some member states, and a lot of the potential is located offshore, mainly in the North Sea. Overall, the total technical potential

[15] This excludes surface facilities for compression and gas treatment and focusses on cushion gas investments. A recent study by H. Yousefi 'Design considerations for developing an underground hydrogen storage facility in porous reservoirs' (2021) indicates that specific investment costs, including more detailed cost assessment, for a 0.8 bcm working volume porous reservoir gives results between 5 and 7 €/kg H_2,

[16] 1 kg H_2 = 33.33 kWh (LHV) and 1 k H_2 = 39.4kWh (HHV). LHV was chosen because not all combustion heat released as water vapour is recovered, therefore LHV is more pragmatic for the cost (for HHV, it should be 13.5 €/kWh H_2).

[17] Technical potential refers to the theoretical or resource potential constrained by real-world geography and system performance, but not by economics.

[18] Derived from GIE LNG Import Terminals Map Database May 2019

of salt caverns in Europe is estimated at approximately 85 PWh of hydrogen[19]. The technical storage capacity in depleted gas fields across the EU is most likely to be larger than in salt caverns, but is currently not quantified.

In a nutshell, a broad portfolio of hydrogen storage options is very likely necessary to meet market needs and surpass geographical challenges. Market potential for hydrogen storage is dominated by subsurface storage and alternative hydrogen storage options become key when subsurface storage is absent or has capacity limits. The technical subsurface storage potential is very large but there is unequal distribution of salt caverns storage potential across member states. The repurpose potentials of natural gas caverns and porous media storages can reach 265 TWh. There is theoretically substantial potential for hydrogen storage at import locations, but repurposing LNG capacities is not straightforward from a techno-economic point of view, mainly due to the heavy investments required to rededicate LNG assets.

Contribution of storage to the system in terms of flexibility, supply security and economic value

Hydrogen storage benefits at system level and at individual level (bringing economic value to individual actors in the hydrogen supply chain).

In terms of systemic impact of deploying hydrogen storage, the contributions are categorised as:

- Security of supply for the hydrogen sector; primarily in the ability to stock hydrogen reserves, available to be released in case of supply disruptions;
- Energy system flexibility, categorised by the time horizon in which the flexibility is deployed: close-to-real-time horizon, short-term time horizon, period of months to years;
- Optimal (cost-effective) development of network infrastructures, and electrolysers localisation, if the role of storage is appropriately considered in the integrated network planning process.

Considering the impacts of hydrogen storage on individual actors in the hydrogen supply chain, the main benefit for electrolyser operators is the possibility to decouple the time of hydrogen production and consumption. This enables price arbitrage on hydrogen markets, as well between the electricity markets and hydrogen market. Where Underground Hydrogen Storage (UHS) is available, electrolyser operators or suppliers are more likely to invest in or contract (fast-cycling) UHS services rather than operate their own hydrogen tanks for managing supply variability. In the case of hydrogen end-users, hydrogen storage offers a greater stability of hydrogen supply, avoiding higher price fluctuations on the market, and seasonal storage].

Case studies conducted in the frame of the study (archetypes) confirm that hydrogen storage deployment results in lowering investment and operational cost of the whole energy system. They also show that access to large scale hydrogen storage options lowers overall system costs, suggesting that interconnection across the EU for regions with limited access to storage is of high strategic value.

Asset and risk classifications per storage technology

The study conducts an analysis of hydrogen storage assets and classify them according to risks per storage technology. This should facilitate the development of policy measures targeted at reducing financial barriers to the investment in hydrogen storage assets due to high actual or perceived risks (country risks, market risks, policy and regulatory risks, technology risks and project-specific risks).

---

[19] Suitability assessment was conducted by applying land eligibility constraint. It is done to bedded salt deposits only . The study assumed that domal salt deposits are suitable for unground hydrogen storage. Moreover, the estimate includes also the UK, Norway, Bosnia & Herzegovina, and Albania.

Future hydrogen storage projects should face non-negligible technology risk premiums. While storage of hydrogen in salt caverns is a proven technology (TRL 9), fast cycling of those storages is less mature (TRL 7). Also, storage in porous reservoirs is at a much lower maturity (around TRL 2-3).

Salt cavern hydrogen storage projects could achieve technology risk premiums close to 3% by 2030. Future projects for storage in porous reservoirs could face Technology Risk Profiles (TRP) of around 6%.

The absence of a clear and predictable regulatory framework will lead to policy and regulatory risks which would further increase total risk premiums. Hydrogen storage projects are CAPEX-intensive and economic support will be required, at least initially, for investments to take place.

There is a lack of familiarity of the financial sector with hydrogen storage technologies and projects. EU and Member States can support not only technological innovation but also financial learning around hydrogen storage, in order to reduce risk premiums.

Context and analysis of barriers for the development of hydrogen and derivatives storage

The study details five contextual topics and barriers which shape the necessary policies and regulations to develop a hydrogen system, with a specific focus on hydrogen storage.

1/ Hydrogen markets will develop slowly. Hydrogen purchase agreements complemented with long-term network capacity bookings should provide the certainty for initial investments in hydrogen infrastructure. However, a development based on long-term bilateral agreements may initially restrict the liquidity of organised markets. In addition, low market liquidity may hinder the ability of hydrogen storage to profit from price differentials. Moreover, underground hydrogen storage capacity may in the beginning largely exceed storage needs due to minimum project sizes.

2/ The need for regulation of storage will vary across Member States and storage types. Hydrogen storage capacity for all salt cavern is unevenly distributed across Member States. Repurposed H_2 storage capacity may be limited for 2050. The development of new UHS storage assets is likely to be necessary to meet the 2030 storage needs if the storage levels foreseen in the Hydrogen and Decarbonised Gas Market Package[20] impact assessment modelling are to materialise. Each storage type and size may be more suitable to a specific storage need, and in specific cases and countries other storage forms than salt caverns could be more competitive or be the only available solution. Integrating future hydrogen storage markets provides countries without salt cavern potential access to underground storage capacity and can decrease market concentration. It is likely that large-scale storage in some/several Member States will require EU regulation.

3/ Energy sector planning may not consider fully storage needs & benefits, potentials and interaction with other sectors, although there has been some progress in the recent years in integrating the hydrogen sector into network planning (e.g. joint ENTSOs' TYNDP scenario[21]). However, electricity and (natural) gas system projects are still assessed separately in the TYNDP process, with hydrogen supply and demand being considered only on the `boundaries` of the system.

4/ Market design and network tariffs may not reward the benefits of hydrogen storage. While the market value may be adequately rewarded, that may not occur for the system (flexibility) and security of supply values. Inadequate consideration of the system value may occur due to a lack of integrated systems planning, entry barriers in wholesale or ancillary services markets, lack of incentives for network users to minimise imbalances, and other barriers.

[20] https://ec.europa.eu/energy/topics/markets-and-consumers/market-legislation/hydrogen-and-decarbonised-gas-market-package_en

[21] ENTSO-E and ENTSOG (2020). TYNDP Scenario Report. Available at: https://2020.entsos-tyndp-scenarios.eu/wp-content/uploads/2020/06/TYNDP_2020_Joint_ScenarioReport_final.pdf

5/ There is regulatory uncertainty concerning the conversion of currently regulated gas storages, since the current EU and most national regulatory frameworks for natural gas do not cover hydrogen yet. Projects need to be started soon if storage capacity is to be available by 2030, as from a technical point of view, repurposing hydrogen storages can take anywhere from 1 to 7 years, and developing new storage assets can take from 3 to 10 years.

Policy and regulatory measures to address barriers to hydrogen storage

Three main recommendations are provided regarding policy and regulatory measures for the development of hydrogen storage . Again, the adoption and implementation of the legislative proposals of the Hydrogen and Decarbonised Gas Market Package should address several of the barriers identified.

1/ A **clear, predictable regulatory framework for large-scale hydrogen storage** should be set in place, comprising provisions for Third Party Access rules, horizontal & vertical unbundling, Cost Benefit Assessment for regulated hydrogen storage investments, rules regarding repurposing, a potential role for the Commission disseminating best practices and providing guidance on permitting procedures

2/ **Integrated planning** (of hydrogen, methane and electricity systems) should be promoted, including the following provisions: having minimal requirements for cross-sectoral planning in NDP ; ; requiring that NDPs are based on hydrogen demand and supply forecasts defined or approved by policy makers or National Regulatory Authorities (NRAs), in order to ensure planning alignment ; ; requiring hydrogen adequacy assessments to be conducted by system operators

3/ Develop **hydrogen markets design and network tariff structures** to adequately value the contributions of storage and other flexibility resources.

Prospective analysis 'domestic' vs. 'external' H_2 production

The aim of this chapter is to combine the findings and data from the previous chapters in order to build complete pathways from production to end-use and assess and compare these pathways. It connects EU H_2/derivatives demand and H_2/derivatives supply, being domestic or import.

Demand scenario

The demand scenario will ensure it reaches at least 10 Mt renewable H_2 per year[22] as demand across EU27, equivalent to 28,600 ktoe[23].

According to the FCH JU Observatory, total hydrogen production capacity in EU27 countries at the end of 2019 has been estimated at 10.8 Mt per year.[24] The corresponding consumption of hydrogen has been estimated at 8.4 Mt (~280 TWh_{HHV}), which means an average capacity utilization of 80%, with the biggest share coming from refineries (~49%), followed by ammonia production (~31%).

The demand scenario (as illustrated in the following table) is based on the literature review, and especially on the different studies analysed under chapter 1, including the MIX-H2 scenario.

[22] H_2 strategy "In a second phase, from 2025 to 2030, hydrogen needs to become an intrinsic part of an integrated energy system with a strategic objective to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10 million tonnes of renewable hydrogen in the EU"

[23] 1 metric ton of hydrogen contains 2.86 toe

[24] https://www.fchobservatory.eu/sites/default/files/reports/Chapter%202%20Hydrogen%20Supply%20and%20Demand%202021.pdf

Table 1 Hydrogen demand scenario

kt H_2	2030-35							
	Hydrogen direct use	Ammonia	PtL diesel	PtL fuel oil	PtL gasoline	PtL kerosene	SNG	Total
H_2 production for the se/conversion of…	4.700	1.500	1.700	500	400	900	300	10.000
H_2 production (in ktoe)	13.400	4.400	4.800	1.500	1.100	2.500	800	28.500

Source: own elaboration, based on several scenarios (cf. chapter 2)

Supply chain description

The 4 steps covered in the supply chain are

- Production of hydrogen, based on local resources and electricity cost; including conversion in the case derivatives are considered;
- Exporting infrastructure, including storage of products before loading ships;
- Transport, by ships & pipelines;
- Import infrastructure, such as terminals and import storage facilities. These entry points to EU when imported from non-EU are located.

In Chapter 3, the cost of producing hydrogen and its derivatives was calculated for the top 10 countries with the greatest renewable hydrogen and derivatives potential, with calculations based on the PtX Atlas of Fraunhofer IEE, which provides a cost-optimized system design and cost-optimized fuel production cost.

These data from PtX Atlas should enable comparability between imported hydrogen and hydrogen produced within the EU, as the latter one is calculated with completely different tools (based on METIS). The results from such different calculation tools cannot be compared directly. This is why, for the purpose of chapter 5, a very simplified tool was developed that calculates LCOE and LCOH, using specific EU and non-EU data within the same simplified tool (only for hydrogen, not for derivatives).

The calculations are carried out using the same assumptions, the only varying factors are the full load hours of renewable energies (wind) and the resulting full load hours of electrolysis.

The **production cost for hydrogen**, based on the simple tool shows costs around 88 €/MWh for EU countries and in a range of 32-46 €/MWh for non-EU countries (based on a simplified tool, cf chapter 3).

Transport cost comprises investment in assets (ships and pipelines, possibly trucks)[25]; operation of the assets (OPEX and fuel costs), depending on the average distance; conditioning of derivatives product for transport (liquefaction, compression). Transport cost of gaseous hydrogen between EU countries is comprised in the range of 7-29 €/MWh (METIS, B optimised scenario), while pipeline transport from non-EU countries is estimated in the range 6.3-13.5 €/MWh (PtX Atlas, from Africa / Eastern countries with 3 000 km distance). Shipping cost of LH_2 from the top 10 countries to EU is comprised in the range 11.2-39.2 €/MWh (PtX Atlas).

The transport cost for different end products increase depending on the transport distance, but also depending on the derivative under investigation. While the cost of hydrogen transport by pipeline increases with the distance, mainly because of intermediate compression, for LH_2 transport liquefaction is the cost-intensive part of the chain.

[25] The cost for quality adaption after transport is not taken into account

Importing infrastructure would comprise especially handling infrastructure (offloading) and terminal storage infrastructure (usual medium scale storage, whose costs are presented in the following section).

Regarding **storage costs** for hydrogen and derivatives, the table below presents a comparison of the costs and sizes of new storages, based on the overview of chapter 4 as well as additional sources for PtL and SNG.

Table 2 EU storage infrastructure costs[26]

Storage infra costs	H_2 (salt caverns)	Liquid H_2 (tanks)	Methanol (tank)	Ammonia (refrigerated tank)	PtL (diesel, kerosene - tanks)	SNG (underground)
Average storage size	0.263 TWh	0.009 TWh	0.165 TWh	0.328 TWh	0.45 TWh[27]	> 5 TWh[28]
Costs of new storage (CAPEX)	200 €/MWh	2,700 €/MWh	113 €/MWh	194 €/MWh	Stored in existing infrastructure	Stored in existing underground facilities

Source: this study and DNV GL, 2020

The comparison of hydrogen production cost leads to lower production cost of hydrogen in non-EU-countries because of cheaper resources. The transport costs for imported hydrogen are in turn higher than the costs for intra-European transport. However, the hydrogen landed at the terminal has also to be distributed within the EU, which leads to additional distribution costs compared to domestic production and straight distribution.

To conclude, it can be stated that the costs for imported hydrogen is lower than for hydrogen produced within the EU. There are countries in the world where the derivative products can be produced at lower cost because of outstanding wind and PV resources, as highlighted within the EC Long Term Strategy[29]. However, as the cost of the products increases with increasing transport distance, products from the EU can remain competitive. To ensure that all options are available in the long term, the relevant import infrastructures as well as the European ramp up of derivatives production facilities should be considered at an early stage. Furthermore, the factor of additionality of renewable energies is decisive for the advantageousness in terms of climate effectiveness. Thus, derivative production can only succeed sustainably on a large scale if it is accompanied by a massive expansion of renewable.

Plausible supply pathways

To supply the forecasted EU demand for hydrogen and derivatives, several options are possible, through domestic production (with intra-EU trade) and/or by importing from non-EU countries and regions. Transport over very long distances (around 2,000 km and above) through ships can often be economically more advantageous (and sometimes the only alternative) to transporting gaseous

[26] DNV GL study, 2020-09-09 - DNV GL - GIE database Liquid Renewable Energy (draft final).xlsx

[27] Assuming an average tank size of 50 000 m^3, based on https://www.vopak.com/terminals/vopak-terminal-europoort-rotterdam?language_content_entity=en

[28] Based

[29] See the LTS page 64, footnotes 187, 188, available at https://ec.europa.eu/clima/system/files/2018-11/com_2018_733_analysis_in_support_en.pdf

hydrogen through pipelines, leading to imports of liquefied hydrogen and/or derivatives being favoured over imports of gaseous hydrogen. Pipeline transport over 2,000-3,000 km could be considered. Therefore, a gaseous hydrogen import pathway is considered only from Northern Africa (e.g. Algeria, Morocco) or Eastern Europe.

The re-conversion (from any derivative back to (gaseous) hydrogen) significantly decreases the total efficiency and is therefore currently not considered as a plausible pathway (this does not mean such configuration will not happen or does not make sense, but rather that it would probably not be deployed at large scale in the coming decade).

The following Figure 58 details the supply volumes of hydrogen and derivatives for the different plausible pathways according to the origin (domestic or imported).

Table 3 Hydrogen and derivatives supply pathways to 2030/2035

(kT H_2-equivalent)	Hydrogen	Ammonia	PtL diesel	PtL fuel oil	PtL gasoline	PtL kerosene	SNG	Total
				Pathway 1 – Imported liquids				
Domestic	4 690						282	**4 971**
Import		1 543	1 652	562	390	883		**5 029**
				Pathway 2 - NH_3 domestic				
Domestic	3 176	1 543					282	**5 000**
Import	1 514		1 652	562	390	883		**5 000**
				Pathway 3 - PtL domestic				
Domestic	1 233		1 652	562	390	883	282	**5 000**
Import	3 457	1 543						**5 000**
				Pathway 4 – NH_3 & PtL domestic				
Domestic		1 543	1 652	562	390	883		**5 029**
Import	4 690						282	**4 971**

The next table summarises the main characteristics of each pathway, and their impacts on each step of the supply chain.

Table 4 Summary of the supply pathways characteristics

		Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
High-level description		Renewable hydrogen produced in the EU to supply the direct use of hydrogen, produced close to end-use, transported through the hydrogen backbone or through ships (intra-EU) to main ports. A small share of the domestic renewable H_2 is converted to methane (SNG), close to gas network infrastructure, for injection. Alternatively, the hydrogen could be blended directly in gas networks. Derivatives (PtL and NH_3) are produced close to H_2 production in partner countries and exported to the EU.	Renewable hydrogen is mainly produced in the EU, but with some imports (1.5 Mt) of hydrogen. Renewable ammonia is fully produced in the EU, close to chemical plants mainly in Central-Western and Eastern Europe. A small share of the domestic renewable H_2 is converted to SNG, close to gas network infrastructure. PtLs are produced close to H_2 production in partner countries and exported to the EU.	Domestic renewable hydrogen is used mainly for power-to-liquids production. A small share is used for production of synthetic natural gas, which is injected in gas networks. Up to 1.2 Mt of domestic hydrogen is used in pure form, especially close to end-uses in coastal areas or distributed through local/regional networks, trucks or barges. Most of the hydrogen used in pure form is imported from partner countries.	Domestic renewable hydrogen is used fully for ammonia and power-to-liquids production. All hydrogen used in pure form is imported. Part is consumed near entry points while the rest is distributed through the hydrogen backbone. A small quantity of SNG is imported through existing LNG terminals.
Cost competitiveness of imported hydrogen/ derivatives		As stated above, the costs for imported H_2 is lower than for H_2 produced within the EU, and the same cost difference would apply to derivatives. However, import cost does not include the cost of import infrastructure (terminal & storage), and transport cost increases with increasing transport distance, both leading to situations where EU production would remain competitive. For liquid derivatives, the existing import infrastructure would be used with very limited or no investments. Therefore, for those products, the import (production & transport) cost difference will certainly remain an important factor,			
Import routes	**Hydrogen**	N/A	H_2 transport via pipelines (from Eastern Europe or North Africa) and/or ships from other countries (liquefied H_2). Lower pipeline transport costs from neighboring regions potentially counterbalanced by lower production costs in other regions.		
	Derivatives	NH_3 imports via ships to use existing infrastructure. PtL import via ships due to limited volumes for pipeline transport & to use existing infrastructure.	PtL import via ships due to limited volumes for pipeline transport to use existing infrastructure.	NH_3 imports via ships to use existing infrastructure.	Limited SNG imports through existing gas infrastructure (pipelines and/or LNG terminals).
Entry points		Imports of ammonia through ships to any of the coastal MSs using existing facilities.	Import of CGH_2 through pipelines from Eastern Europe / North Africa – 1 to 2 pipelines to be repurposed.	Import of CGH_2 through pipelines from Eastern Europe / North Af-	Import of CGH_2 through pipelines from Eastern Europe / North Africa -

	Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
	Imports of PtLs distributed in current fuel terminals.	Alternatively (but less likely), import of liquefied H_2 in CWE. Imports of PtLs distributed in current fuel terminals.	rica – 3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Imports of ammonia through ships to any of the coastal MSs using existing facilities.	3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Minimal imports of SNG injected into existing gas infrastructure or liquefied in terminals.
Impact on import infrastructure	Hydrogen trade mainly between EU Member States, no need for LH_2 terminals or import pipelines. Ammonia imported via ships using existing port facilities, likely only limited new infrastructure needed. Imports of PtLs distributed in current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Import through pipelines would use 1-2 pipelines. Otherwise, 1-2 LH_2 terminals (less likely). Imports of PtLs distributed over current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Import through pipelines would use 4-5 pipelines. Otherwise, 5-6 LH_2 terminals (less likely). Ammonia imported via ships using existing port facilities, likely only limited infrastructure needed. No PtL imports, thus no terminals required.	Import through pipelines would use 3-6 pipelines. Otherwise, 7-8 LH_2 terminals (less likely). SNG injected in existing NG infrastructure
Impact on storage	No need for additional NH_3 or PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. At least 1.25 TWh of liquefied H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 3 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional NH_3 storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 4 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No additional need for SNG storage in existing LNG terminals.

1 Introduction and general context

The **European Commission's hydrogen strategy**[30] presented in July 2020 year outlines, amongst other elements, how to upscale the demand and supply of renewable hydrogen. It has set the strategic objective to install at least **40 GW of renewable hydrogen electrolysers within the EU (producing about 5Mt renewable hydrogen) based upon an estimated** demand of up to **10 million tonnes of renewable hydrogen** in the EU.

According to the European Commission Hydrogen Strategy, 'renewable hydrogen' is hydrogen produced through the electrolysis of water (in an electrolyser, powered by electricity), and with the electricity stemming from renewable sources. The full life-cycle greenhouse gas emissions of the production of renewable hydrogen are close to zero. Renewable hydrogen may also be produced through the reforming of biogas (instead of natural gas) or biochemical conversion of biomass, if in compliance with sustainability requirements. According to this strategy, the long-term priority is to produce renewable hydrogen, made from using mainly wind or solar energy.

Currently, the European Commission is working on the finalisation of detailed methodologies for renewable hydrogen, which will ensure that green hydrogen is truly sourced from renewable energy sources and achieve significant emission savings. While these rules are obviously tailored to the specific regulatory needs of the EU and will only apply for counting hydrogen to the renewable energy targets in the EU, they could serve as a benchmark to develop the trade of green hydrogen at an international market.

Where reference is made to renewable hydrogen throughout this study, it should be read in conjunction with the definition as outlined in the Commission's hydrogen strategy, without pre-empting ongoing discussions on the final methodology to define renewable hydrogen (standards).

To reach the aforementioned targets, a substantial amount of additional **renewable electricity** (~500 TWh[31]) will be needed to produce renewable hydrogen (on top of the large amounts of renewable electricity that will be needed to electrify applications that are currently served by other energy carriers) and to achieve 55% CO_2-emission reduction by 2030.

The characteristics of renewable electricity generation, such as its seasonal variability, the time needed to realize (additional) solar and wind parks to produce electricity to produce renewable hydrogen, as well as potentially low public acceptance for the development of (additional) renewable production sites, except for off shore production sites, requires us to have an in-depth look into the **role of renewable hydrogen import (infrastructure)** as well as into the **role of hydrogen storage (infrastructure)** to decarbonize the European economy.

1.1 Research questions

At the moment it is not clear whether domestic production of H_2 will achieve the strategic EU 2030 goal to cover 10Mt of renewable H_2 demand, leading to possible imports. Therefore, **domestic production and import** volumes are not clear.

This research papers intends to address the following questions:

[30] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

[31] Electrolyser efficiency can be considered at 48.89MWhel/tH_2, meaning that producing 10Mt H_2 would require 488.9 TWh electricity (in average), which is rounded to 500 TWh

- What is the expected domestic production in 2030 based on current plans and project developments out of EU?
- Is there a gap between expected domestic demand for H_2 and its carriers in 2030 and beyond (2050) in the EU and how does this match with the production capacities in the EU?
- What is more cost-efficient – imports of H_2 or increase of domestic production capacity (in case of a gap between expected domestic production and demand) in 2030 and beyond? This entails an outline of competitive advantages (production outside vs inside EU)
- What are the likely imports of H_2 and its carriers in 2030 and beyond? And which are countries that will most likely export to the EU?

There exist many scenarios about the future energy mix and demand in the EU including imports of renewable H_2 and its carriers, but less information and assessments are available on infrastructure needs, especially regarding H_2-carrier-specific **transport modes**. H_2-carriers refer to the way hydrogen is transported. This could be in gaseous form (compressed gaseous hydrogen-CGH_2, synthetic natural gas-SNG), liquid form (Power-to-Liquid, or liquefied hydrogen-LH_2), or bound/converted into other molecules such as liquid organic hydrogen carrier (LOHC) or Ammonia (NH_3). H_2-derivative refers to the (end)product that is derived from H_2. H_2 is being 'processed' further into a fuel/feedstock.

- Which transport modes are needed and suited for the different types of H_2 carriers and the expected imports?
- What role could non-network-based transport modes e.g. LNG terminals play for H_2 imports?
- What role could network-based transport modes (outside the EU) such as existing pipelines for natural gas play in light of natural gas supply security?
- What are cost-efficient transport modes for H_2/H_2 carriers imports?

In view of variable RE electricity generation and seasonal variations, the questions of **storage** and its economic value and impact on the energy system arise.

- What storage options do exist (potentials, costs, etc.) for different types of H_2 and its carriers across the EU?
- Which revenues can storage generate in this system? Are there non-captured revenue streams?
- Does the use of storage options reduce the required electrolyser capacities for a secure base-load supply of industries?
- What is the impact of storage options on the electricity system? Does an increase in storage affect flexibility, and hence electricity prices? Or does it substitute other sources of supply security?
- What kind of asset is storage? What are the risks (classes) and what are the resulting cost of capital?
- What are potential regulatory needs to incentivize the development of hydrogen storage locations?

2 Supply and demand of hydrogen and its derivatives in 2030

Although strategic targets regarding supply and demand of hydrogen have been set in the European Commission's Hydrogen Strategy, it is unclear how the supply and demand will develop. Nevertheless, the importance of both domestic supply and import (supply outside of the EU) has been emphasised in the strategy.

To compare with the targets set, this chapter provides an overview on supply and demand of hydrogen and its derivatives in 2030 projected in various studies addressing decarbonisation of the entire energy system. This chapter aims to identify the supply gaps, which represent the volume of demand that exceeds domestic (within the EU) supply capacity. These supply gaps need to be filled from international supply through import, which will be investigated in the next chapters.

2.1 Scenario selection

There are a series of studies and scenarios investigating the energy system development required for the EU to realize climate neutrality in 2050 of which the contribution of different energy carriers, including hydrogen and its derivatives, is analysed.

In order to allow for comparison and deep analysis, the studies (or scenarios) were selected based on the following criteria:

- scenarios achieving carbon neutrality by 2050 (100% GHG reduction);
- scenarios with a minimum electrolyser installed capacity of 40 GW in 2030 (one of the most important targets in the EU Hydrogen Strategy);
- scenarios investigating the geographic area or including a detailed resolution of the EU-27 (or EU-27 and the UK)[32] are analysed.

Four scenarios fulfilling these criteria are chosen for the further analysis and a brief description regarding each selected study and scenario is provided in Table 5 below and more information can be found in Annex 1.

Table 5 Description of four selected scenarios

Study and scenario	Short description
European Commission (2021): Impact Assessment Report **EC MIX-H2**	The study focuses on three core scenarios (REG, MIX and MIX-CP), achieving the target of 55% GHG in 2030 and results with the cost-effective range for RES shares of 38-40% in 2030 (already established in the CTP[33] impact assessment). EC MIX-H_2 scenario is one variant building on the MIX scenario, helping to assess policy options regarding the promotion of RFNBOs in industry and transport. The core models used are PRIMES and PRIMES-TREMOVE for energy, transportation, and CO_2 emission projections. Scope: EU + UK H_2: exclusively renewable H_2 and derivatives; model results with electrolyser capacity of 47 GW in 2030, which is above the EU Hydrogen Strategy (40GW); CCS is considered to a very limited extent and not for H_2 production.

[32] Depending on the time when the study was conducted, the geographical coverage differentiates between the current EU-27 and former EU-28, which is EU-27 plus the United Kingdom (UK).

[33] Climate Target Plan

Study and scenario	Short description
Climate Action Network Europe (2020): Building a Paris Agreement Compatible (PAC[34]) energy scenario **PAC**	The PAC Scenario, published by Climate Action Network (CAN) Europe was drafted by a broad range of civil society organisations, reflecting NGOs´ priorities for pathway towards the 1.5°C target of the Paris Agreement. It shows that the level of ambition can be raised substantially (up to 65% in 2030 compared to 1990, with an Energy Efficiency target of 45%, and a renewable of at least 50%, with limited bioenergy). This study is based on research figures from a variety of studies and models, via a collective bottom-up research process, with involvement of up to 150 representatives from organizations, industry and science collaborated. The electricity supply with different flexibility options is simulated through PowerFlex electricity market model run by Öko-Institut. Scope: EU + UK H_2: exclusively renewable hydrogen and derivatives; no information on electrolyser capacity; supply of 566 TWh of RES H_2 and derivatives in 2030 (> 40 GW in 2030); no CCUS.
ENTSO-E and ENTSOG (2020): TYNDP 2020 Scenario Report[35] **ENTSO DE**	The TYNDP 2020 scenario analysis is built based on three scenarios, with two main drivers being decarbonisation and centralised or decentralised innovation. The scenario development uses supply and demand data, collected from both gas and electricity TSOs, through a bottom-up approach (based on historical energy balance data), considering NECPs (National Trends scenario), and 2 scenarios complying to the 1.5°C target (Global Ambition (GA) and Distributed Energy (DE)). Scope: EU + UK H_2: renewable and blue H_2 (produced from natural gas with CCS technology). Import of H_2 and derivatives is considered (most likely in form of LNG from Russia and Norway). The installed electrolyser capacity in 2030 in the DE scenario amounts to 41 GW.
Joint Research Centre (2021): Global Energy and Climate Outlook (GECO) 2020: A New Normal Beyond Covid-19[36] **JRC 1.5**	The GECO analysis develops 4 scenarios (a baseline without considering covid-19 pandemic, a "New Normal" with covid-19, and 2°C and 1.5°C scenarios from the new). The 1.5°C scenario was selected for this study, in line with the climate neutrality and the EU Hydrogen Strategy. The GECO analysis is built on the JRC-POLES (global) and JRC-GEM-E3 models. The models estimate the energy sources, sectors, and GHG emissions, trends in international energy prices and trade used in the EC energy modelling. Scope: globe, EU-27 + UK (breakdown available). H_2: not limited to renewable (e.g. CCS for power). Since it is a global model, there is no information regarding import/export. It considers the EU Hydrogen Strategy, assuming the 40 GW in 2030 is achieved.

Among the selected scenarios, the European Commission's scenario EC MIX-H2 is used as an anchor scenario in the analysis, due to its objective to align with target of the Hydrogen Strategy (40 GW installed capacity of electrolyser, leading to 5Mt produced on the EU territory). The modelling results from these selected scenarios will be used to provide an overview of demand and supply of hydrogen and its derivatives.

Annex 1 provides general information of the selected studies and the corresponding scenarios, including the background, principle and logic of the respective models, brief description of the

[34] https://caneurope.org/building-a-paris-agreement-compatible-pac-energy-scenario/

[35] https://www.entsog.eu/sites/default/files/2020-07/TYNDP_2020_Joint_Scenario%20Report%20ENTSOG_ENTSOE_June_Final.pdf

[36] This report is the sixth edition of the Global Energy and Climate Outlook (GECO), available at https://publications.jrc.ec.europa.eu/repository/handle/JRC123203

scenarios in the studies, elaborated information of the selected scenarios as well as the essential assumptions regarding hydrogen made in these respective scenarios.

2.2 Assumption matrix and classification of the selected scenarios

As indicated in the Hydrogen Strategy, both domestic supply and import will be important to satisfy the hydrogen and e-fuels demand. However, due to the limitation of the applied models or up-front assumption, import is not considered in most scenarios. In addition, the supply and demand development in the future is uncertain depending on the framework conditions (e.g. bioenergy potential) and the development of multiple aspects (e.g. carbon price), which further lead to different outcomes regarding supply and demand of hydrogen and its derivatives. Therefore, for the identification of supply gaps the scenarios are clustered according to the comparison from supply perspective as well as from the demand perspective (Table 6) and each supply cluster of a set of scenario(s) will be paired with demand cluster of the same or a different set of scenario(s) respectively. The supply gaps identified under each pair will represent combinations of different supply development with different demand development (e.g. fast ramp-up of renewable energy supply and electrolyser installation, while high energy demand in general remains).

For the classification of scenarios, the anchor scenario EC MIX-H2 is used as reference to cluster the other scenarios. The key assumptions and framework conditions related to the scenarios in general, and supply and demand aspects are summarised in Table 6 below (further assumptions and framework conditions can be found in Annex 1). The studies published in 2020 differentiated from the ones in 2021 In terms of geographic coverage due to Brexit (see in Annex 1).

As for supply of H_2 and e-fuels, both EC MIX-H2 and PAC scenarios consider only renewable hydrogen and assume that all H_2 and e-fuels will be supplied within the EU, while ENTSO DE and JRC 1.5 scenarios consider both renewable and blue hydrogen with the help of CCS. Furthermore, ENTSO DE indicates the import of liquid natural gas (LNG) from Russia and Norway is partly used for blue hydrogen production and JRC 1.5 discloses no information regarding the regions of supply.

Regarding the demand related aspects, the total final energy consumption (TFEC) in 2030 of the reference scenario EC MIX-H2 ranks the second lowest among all scenarios. The PAC scenario appears to be the most ambitious scenario with the lowest TFEC. The other two scenarios both have higher TFEC than the reference scenario, of which ENTSO DE has the highest TFEC among all scenarios.

Moreover, EC MIX-H2 results with a H_2 demand of 13 Mtoe and e-fuels demand of 3.2 Mtoe. The ambitious PAC scenario has the highest H_2 and e-fuels demand of all scenarios, followed by ENTSO DE, and JRC 1.5 has the lowest demand.

Table 6 Matrix of assumptions and framework conditions in the selected scenarios

Scenario	EC MIX-H2	PAC	ENTSO DE	JRC 1.5
General and supply-related aspects				
Geographic coverage	EU-27	EU-27 plus UK	EU-27 plus UK	EU-27 (integrated in global model)
Supply of H_2 and e-fuels	No import, all within the EU (incl. the UK)	No import, all within the EU (incl. the UK)	Inside but also outside of the EU	n/a
Shade of H_2 and e-fuels considered	Renewable only	Renewable only	Renewable and blue	Renewable and maybe blue
Installed capacity of electrolyser in 2030 [GW]	47	> 40	41	n/a
Demand related aspects				
TFEC in 2030 [TWh]	9,304	**8,955**	10,537	9,432
Demand of H_2 and e-fuels in 2030 [TWh]	H_2: 151[1] e-gas: 2 e-liquid: 35	H_2: 209 e-ammonia: 47 e-methane: 35 e-liquid: 198	H_2: 209[1] e-methane: 70	H_2: 58 e-fuels: 0

[1]: Values include demand in energy sector (used for e.g. dispatchable power, electricity and heat transformation)

Based on the assumptions and framework conditions in the selected scenarios, a classification is suggested to group the scenarios by demand and supply separately. As mentioned above, the EC MIX- H2 scenario is a core scenario of this analysis and is used as reference for the classification of both demand and supply. The other scenarios are grouped by comparing to the TFEC of the EC MIX- H2 scenario:

- "Low energy demand" - scenario with lower TFEC: PAC
- "Medium energy demand" – scenarios with higher TFEC: ENTSO DE and JRC 1.5

As for supply scenarios, the classification is done in accordance with the supply region defined in the selected scenarios (except for the reference scenario EC MIX- H2):

- "Supply within the EU": PAC and JRC 1.5[37]
- "Supply considering import": ENTSO DE

The classification is used to identify H_2 and e-fuels' supply gaps by combining and comparing the different groups of demand scenarios and/to different groups of supply scenarios, which will be elaborated in the next section 2.3.

2.3 Overview on supply and demand and supply gap analysis (production vs consumption)

2.3.1 Balance of hydrogen demand & supply

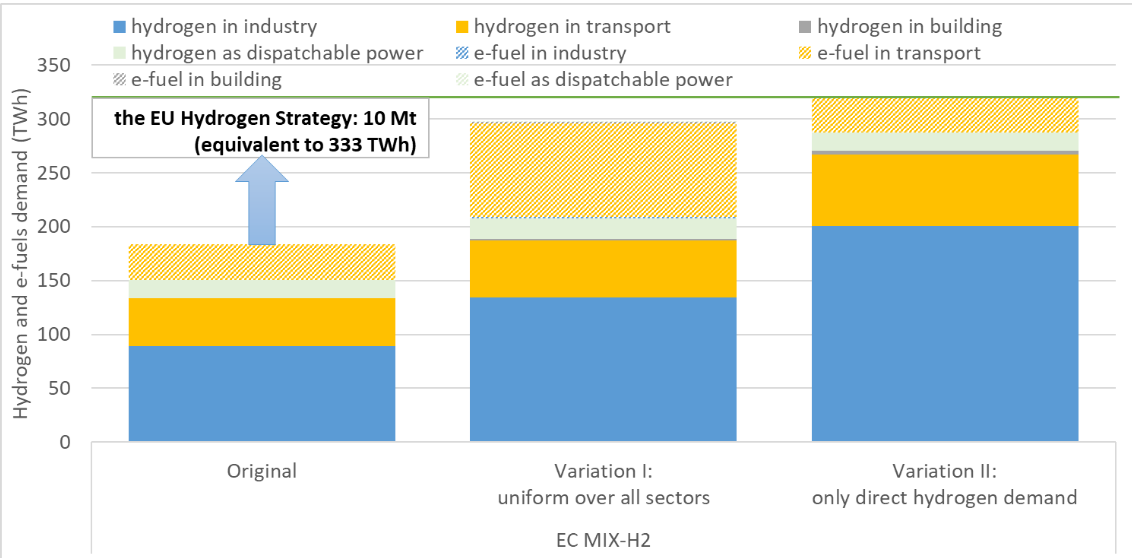
Although the reference scenario EC MIX-H2 aims to align with the EU Hydrogen Strategy and fulfills the target of 40 GW installed capacity of electrolysers in EU in 2030, the target of reaching 10 Mt (equivalent to 333 TWh) H_2 and e-fuels demand in 2030 is not met by the scenario (it is reached

[37] Since no information regarding supply region is available for the JRC 1.5 scenario, it is assumed that the supply of this scenario is be within the EU given its low H_2 and e-fuels demand in 2030.

between 2030 and 2035 in the scenario). For the sake of this study, upscaling the EC MIX-H2 to fulfill the target is foreseen. As shown in Figure 5 below, a gap of 137 TWh hydrogen equivalent (incl. transformation loss from hydrogen to e-fuels) need to be filled for the scale-up, which is distributed through two variations:

1) Uniform over all sectors: under this variation, it is assumed that the scale-up of demand will occur to both hydrogen and its derivatives in all sectors. The additional demand is therefore allocated evenly (the same share) to each sector, including the transformation sector. As a result, 57 TWh of hydrogen are scaled up to the "direct" demand and 80 TWh to demand for the production of hydrogen derivatives.
2) Only direct hydrogen demand: this variation focuses on a potential development that the scale-up of demand occurs firstly to the direct use of hydrogen. Thus, the additional demand of H_2 is only allocated to sectors directly consuming H_2 in 2030, including both energy and non-energy applications (as feedstock);

Figure 5 Upscaling EC MIX-H2 to 10 Mt (equivalent to 333 TWh) hydrogen demand in 2030 to align with the EU Hydrogen Strategy



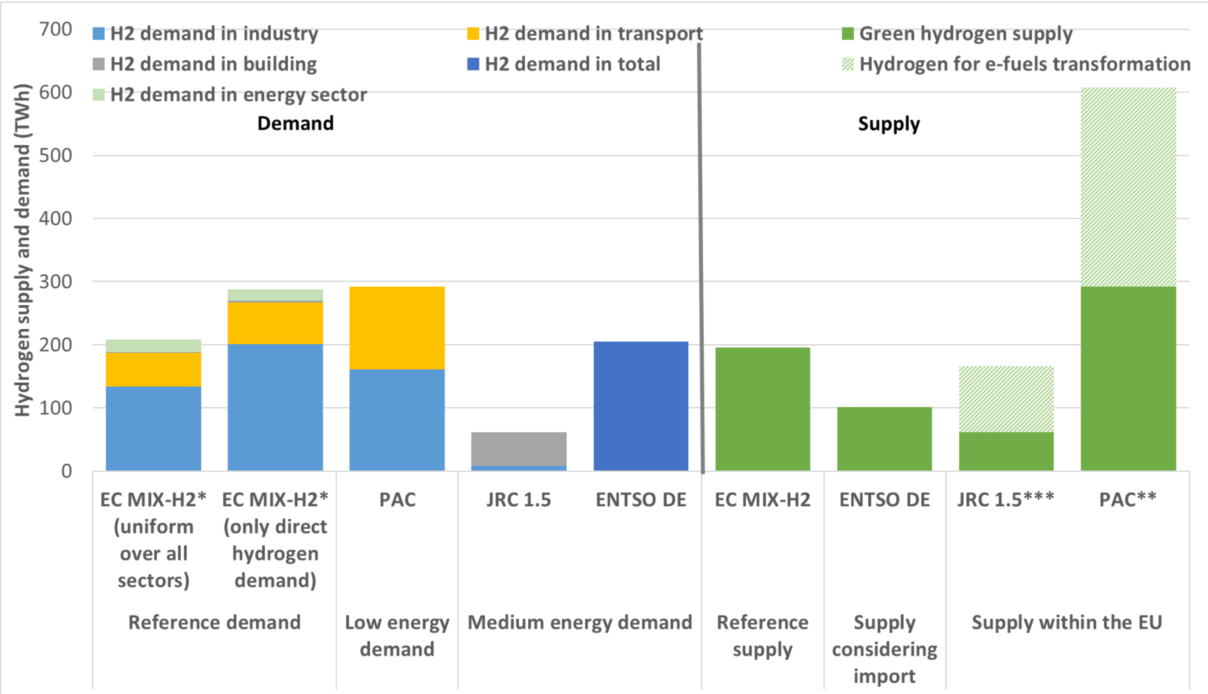
An overview of hydrogen supply and demand in 2030 across the 4 scenarios is shown in Figure 6 below. The direct hydrogen demand (only under the form of gaseous hydrogen) in 2030 varies from 61 TWh (JRC 1.5, with an important place for bioenergy[38]) to 292 TWh (PAC), mainly in the industry and transport sectors with an exception of the JRC 1.5 scenario having most of the demand from the building sector through blending hydrogen in the current natural gas infrastructure.

On the supply side, the hydrogen produced domestically through electrolysis ranges from 101 TWh (ENTSO DE) to 607 TWh (PAC), of which 105 TWh (JRC) to 315 TWh (PAC) of the supplied hydrogen in the "Supply within the EU" scenarios is used for e-fuels transformation.

The nature of the models as well as the up-front assumptions have limited the import possibility in most scenarios.

[38] while the other scenarios expect steady or decreasing bioenergy consumption due to the limited bioenergy potential

Figure 6 Overview on supply and demand of hydrogen in 2030 in selected scenarios



* Adjusted demand with total H_2 demand of 10Mt (equivalent to 333 TWh)
** Based on an electrolyser efficiency of 60%
*** Based on assumption of 1 GW electrolyser produces 4.16 TWh hydrogen per year

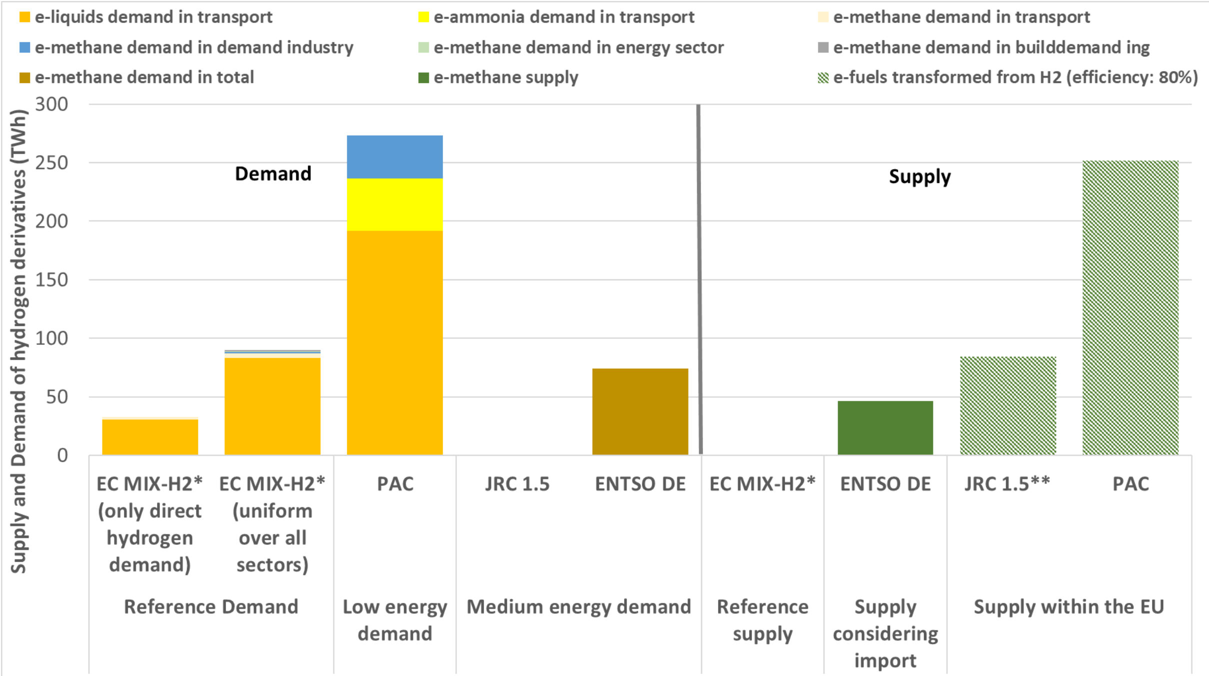
Here are the first observations:

- The EC MIX-H2 scenario variations have clearly a deficit of supply, which could be supplemented through either import, domestic production (by increasing the EU capacity), or non-renewable hydrogen;
- Both the PAC and JRC 1.5 C scenarios are balanced with domestic production being sufficient to supply all direct H_2 demand, and additional capacity to produce e-fuels;
- The ENTSO DE scenario has clearly a deficit of supply, which is fulfilled by import and blue hydrogen.

2.3.2 Balance of e-fuels demand & supply

For e-fuels, the demand situation differentiates among scenarios in terms of energy carriers as well as end-use sectors (Figure 7). Among these scenarios, only the JRC 1.5 scenario foresees no e-fuels demand at all in 2030, although it foresees surplus hydrogen capacity for the production of e-fuels. The ENTSO DE scenario estimates only e-methane demand due to its unique modelling approach building on gas and electricity transmission systems. The EC MIX-H2 and PAC scenarios expect that e-liquids (e-diesel, e-gasoline, and e-kerosene) used in transport sector contribute the most to total e-fuels demand, followed by other energy carriers – e-methane and e-ammonia - used for transport. Besides the e-fuels demand in transport sector, e-methane is also used in industry, building and energy sectors to a limited extend. Except for scenario expecting no demand, the demand of e-liquids in 2030 ranges from 30 TWh (EC MIX-H_2) to 192 TWh (PAC), e-methane from 2 TWh (EC MIX-H2) to 74 TWh (PAC), and e-ammonia 45 TWh (only shown in the PAC scenario for long-distance shipping).

Figure 7 **Overview on supply and demand of hydrogen derivatives (e-fuels) in 2030 in selected scenarios**



* Adjusted demand with total H_2 demand of 10Mt (equivalent to 333 TWh). The average transformation efficiency from hydrogen to its derivatives in 2030 from the scenario is used.
** Based on assumption of 1 GW electrolyser produces 4.16 TWh hydrogen per year

Here are the first observations:

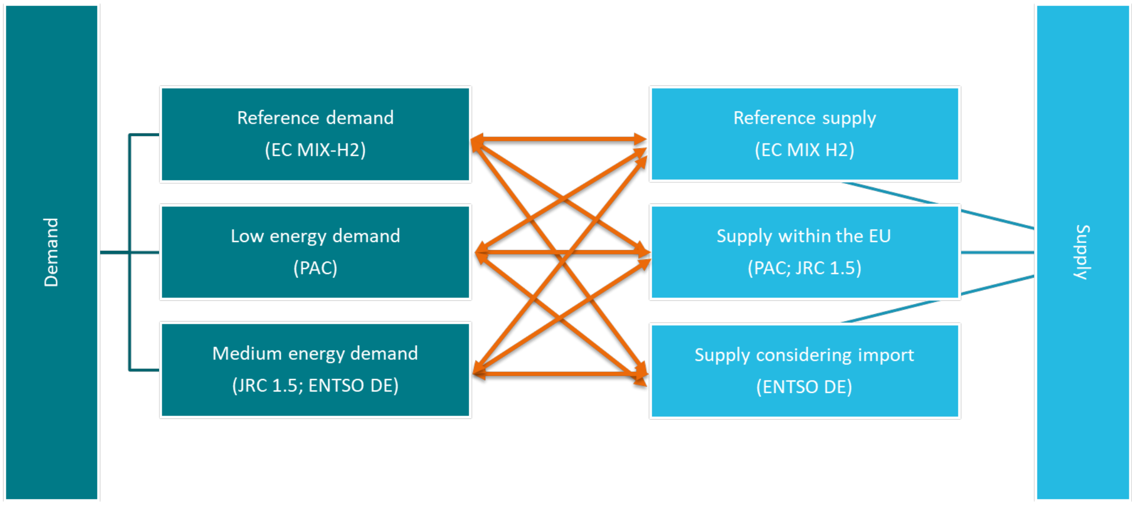
- As a result of the upscaling, the EC MIX-H_2 scenario does not end up with excess hydrogen capacity (beyond direct hydrogen demand) for e-fuel production. Hence, there is a gap in e-fuel supply, which should probably be imported. The gap increases with the "uniform over all sectors" scenario variation;
- The PAC scenario (using 315 TWh excess hydrogen capacity to produce 252 TWh e-fuels) is almost covering the demand (273 TWh) with the domestic e-fuels supply;
- The JRC 1.5 scenario results with excess hydrogen capacity for the supply of e-fuels due to the low direct hydrogen demand, while no demand of e-fuels is foreseen. This indicates low utility rate of installed electrolyser in the scenario;
- The ENTSO DE scenario has a clear deficit of supply, given its demand for e-methane. This is covered through import in the scenario;
- Globally, it is assumed that the supply prioritises direct hydrogen demand, and the surplus of hydrogen supply will then be transformed into e-fuels (like in JRC and PAC), unless the scenario indicates specific e-fuels supply (as in ENTSO DE, 46 TWh of domestic e-methane supply).

The uncertain development of framework conditions (e.g. RE deployment, bioenergy potential, energy savings) causes different projections of hydrogen and e-fuels supply and demand in 2030 in the selected scenarios.

2.3.3 Pairing scenarios

To assess the hydrogen and its derivatives' supply gaps under different combinations of supply and demand development, the 3 groups of supply scenarios are paired with the 3 demand scenario groups respectively, as illustrated in Figure 8 below. Under each of the 9 pairs, the demand of specific energy carrier will be compared to the supply of the corresponding carrier to conclude if the domestic supply sufficiently covers the demand or if a supply gap exists. The minimum supply gap is obtained by deducting the lowest demand by the highest supply within each pair of demand and supply groups, while the maximum supply gap is obtained by deducting the highest demand by the lowest supply.

Figure 8 The paring approach for the identification of hydrogen and its derivatives' supply gaps



Following this pairing approach, the supply gaps of hydrogen as well as e-fuels are identified and listed in Table 7 below. This remains a conceptual exercise, as we are mixing different scenarios with different models and assumptions. It remains clear that in view of the early stage of development of both the EU and global hydrogen markets, concrete figures are difficult to estimate. Overall, the hydrogen supply situation of all pairs differentiates from completely sufficient domestically to a supply gap up to 191 TWh, which highlights the huge variation, and difficulty to estimate the gap. We could already conclude it is not yet possible to define the gap with concrete figures.

For hydrogen derivatives, the supply gaps of different energy carriers are analysed correspondingly, with the largest supply gap identified for e-liquids (up to 192 TWh).

Table 7 Supply gaps of hydrogen and e-fuels in 2030

Hydrogen supply gap [TWh]		Reference supply	Supply considering import	Supply within EU
Reference Demand		12 - 92	106 - 186	0 – 121
Low energy demand		97	191	0 – 126
Medium energy demand		0 – 10	0 – 104	0 – 39
E-fuels supply gap [TWh]		**Reference supply**	**Supply considering import**	**Supply within EU**
Reference Demand	**e-liquids**	30 - 83	30 - 83	Sufficient domestically
	e-methane	2 - 7	Sufficient domestically	Sufficient domestically
Low energy demand	**e-liquids**	192	192	0/22[1] - 189
	e-ammonia	45	45	0/22[1] - 45
	e-methane	37	Sufficient domestically	0/22[1] - 37
Medium energy demand	**e-methane**	74	28	Sufficient domestically

[1]: Two lower ranges are provided. JRC 1.5 scenario predicted no e-fuels demand in 2030, therefore no supply gap is identified for this case. The other lower range of 22 TWh results from the PAC scenario itself.

Overall, it can be concluded that the development of hydrogen and its derivatives is uncertain, further causing different levels of import demand. Nevertheless, if the Hydrogen Strategy is to be complied, meaning 10 Mt demand of renewable hydrogen and its derivatives in 2030, supply gaps will more than likely exist and importing these energy carriers will be required under most circumstances. These supply gaps in 2030 need to be covered by importing from countries and regions outside of the EU, which will be further analysed in the following chapter.

3 The role of H_2 import in the EU

Today, Europe imports large quantities of energy in the form of oil, gas and coal, and in the long term, Europe could have to import hydrogen and its derivatives as well. The future EU energy system is expected to be climate-neutral, mostly relying on renewable and low-carbon energy sources. Due to the different pace in deploying these sources per MS, imports will certainly be necessary on the short and long term. In addition, imported fuels may be more competitive than domestically produced.

The aim of this chapter is to analyze the various factors influencing to which extent the EU could start, or even massively import hydrogen and derivatives, at the 2030 horizon. These influencing factors are driven by:

- EU and international market developments, with potential gaps between the production and demand of hydrogen and derivatives in the EU;
- The total cost of ownership of hydrogen and derivatives, along the entire supply chain (import cost).

Section 3.1 identifies the relevant countries within an international market (**potential exporting markets**) in terms of hydrogen production.

Section 3.2 **describes the main elements**, technical characteristics and costs (CAPEX and OPEX) of production, transformation (or conversion) and transport of renewable hydrogen and its derivatives.

Section 3.3 analyses the costs for Liquid Hydrogen, Methanol, PtL and Liquid SNG production and transport **from around the world up to the EU borders**. Import costs consist of production costs and transportation costs. It also summarizes the main findings and highlights the fuel competitiveness.

Section 3.4 discusses the barriers and regulatory needs for developing hydrogen imports to the EU, with a focus on renewable hydrogen and its derivatives.

'Hydrogen' refers to compressed gaseous hydrogen (CGH_2) and liquid hydrogen (LH_2) forms, while derivatives comprise:

- Ammonia (NH_3)
- Methanol (MeOH)
- PtL or liquid derivatives (e-kerosene, e-gasoline, and e-diesel)
- E-gases, such as Synthetic Natural Gas (SNG)

3.1 Potential exporting markets at 2050

Potential future exporting countries, as well as their potential export volumes of renewable hydrogen on the short term, are analyzed in this section in order to figure out where the renewable hydrogen and derivatives for Europe could come from.

The analysis of potential future exporting countries was carried out on the basis of the IEE Global PtX Atlas published in June 2021 (Source IEE Global PtX Atlas[39] https://maps.iee.fraunhofer.de/ptx-atlas/). The fuel variants or renewable hydrogen and derivatives studied and addressed in this study are the following:

[39] The first global Power-to-X Atlas, elaborated by the Fraunhofer IEE, shows where the energy carrier could come from in 2050. It is a free WebGIS application and presents temporally and spatially high-resolution simulations for a first non-European power-to-X volume scenario as well as country-specific location analyses of the production characteristics and long-term production costs of electricity-based fuels. The atlas was developed to provide stakeholders from politics and industry with a comprehensive insight into the research results

- FT fuel (diesel, paraffin)
- Methanol
- Methane (SNG, compressed)
- Methane (SNG, liquid)
- Hydrogen (compressed)
- Hydrogen (liquid)

Ammonia and e-kerosene are not directly studied.

In order to rank the potential exporting regions at the 2050 horizon, the PtX Atlas methodology is based on the extensive analysis of an assessment of the export potential of each region.

The **largest land potentials** for the production of renewable hydrogen and derivatives arise in large countries such as the United States, Australia, Argentina, or Russia, with coastal or inland waterways accesses (more than 70% of the renewable hydrogen and derivatives potential is located near freshwater resources, due to the fact that electrolysis requires significant amounts of water). Inland waterways would also provide efficient transport means.

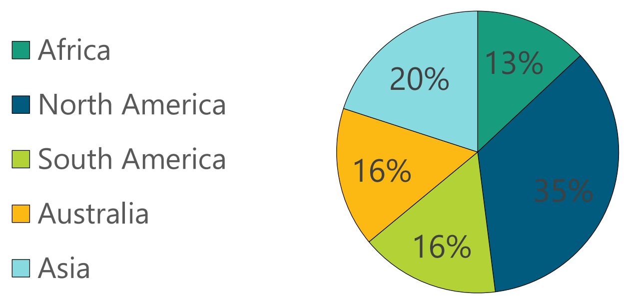
The source of renewable energy is country specific. Wind, solar and hybrid systems consisting of a combination of wind and solar are considered as energy resources. In Australia, renewable hydrogen and derivatives are mainly solar powered (PV only sites), in Russia there are many wind-only sites and in Africa often hybrid configurations of renewable generation lead to the lowest renewable hydrogen and derivatives costs.

In addition, some exclusion criteria for land use have also been considered, such as nature conservation, water stress, land for food cultivation, built-up areas, densely populated areas, agricultural land and forest.

Based on these premises, the atlas concludes that in the long term (2050), outside Europe, a total of around 109,000 TWhs of liquid hydrogen and respectively 85,000 TWhs of derivatives could be produced.

Figure 5 shows the main continents or regions that have a potential to produce large amount of renewable hydrogen and derivatives.

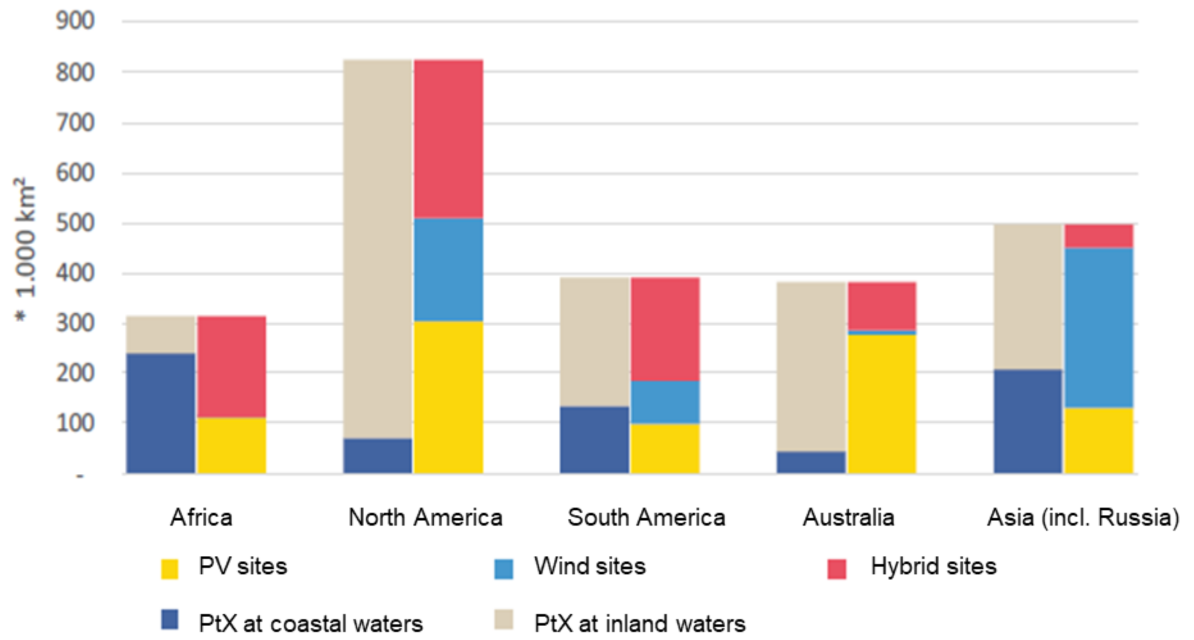
Figure 9 Export potential of regions[40]



[40] PtX-Atlas https://maps.iee.fraunhofer.de/ptx-atlas/

Figure 10 shows the available land area for renewable energy sources used to produce the hydrogen through electrolysis for each region, and whether the production potential is localized inland (along waterways) or in coastal areas:

Figure 10 Available land area of regions specifying source of RE and water supply[41]



Based on the potential assessment, the Atlas identifies areas that are suitable for the generation of renewable hydrogen and derivatives. The countries with the largest areas are taken into account for the following analysis, as depicted in Table 8.

It shows the area in km² and potential production volumes of renewable hydrogen OR derivatives (in TWh) of the top 10 countries with the largest potentials depending on the efficiency of the chosen supply chain:

Table 8 Top 10 countries with the largest renewable hydrogen and derivatives potential areas[42]

		Area [km²]	Energy GH_2 [TWh]	Energy PtL (FT) [TWh]
1	**USA**	684,873	32,188	23,623
2	**Australia**	427,501	16,702	12,296
3	**Argentina**	279,901	14,079	10,389
4	**Russia**	320,497	11,881	8,208
5	**Egypt**	84,020	4,720	3,693
6	**Canada**	111,029	3,815	2,657
7	**Mexico**	67,428	3,208	2,255

[41] PtX-Atlas https://maps.iee.fraunhofer.de/ptx-atlas/

[42] PtX-Atlas https://maps.iee.fraunhofer.de/ptx-atlas/

		Area [km²]	Energy GH_2 [TWh]	Energy PtL (FT) [TWh]
8	**Libya**	78,885	3,359	2,740
9	**Chile**	61,127	2,884	2,051
10	**Saudi Arabia**	51,424	2,675	1,778

The four countries with the highest renewable hydrogen and derivatives potential are the USA, Australia, Argentina and Russia.

If socio-economic criteria are used on top of the technical potential criteria, then Canada and Chile would also become interesting countries for exporting.

The suitability for the development of a renewable hydrogen and derivatives infrastructure also depends on the socio-economic conditions in the renewable hydrogen and derivatives producing country. Using the method of a global high-level country analysis, the socio-economic potential was investigated in the PtX Atlas. Various thematic fields were taken into account in the process, such as global economy, politics, society, technology, natural conditions and proximity to Europe.

In order to determine plausible pathways for importing these fuels to Europe, production and transport costs for renewable hydrogen and derivatives need to be assessed for each country. This is the aim of section 3.3. Beforehand, the supply chains are described technically in section 3.2.

3.2 Production, transformation and transport technology of renewable hydrogen & derivatives

The supply chain of imported products comprises the production of hydrogen, its conversion to transportable hydrogen (liquefied or compressed) or to derivatives, and finally the transport of the fuel:

1) **Hydrogen production** by electrolysis fueled by renewable electricity, possibly including storage of hydrogen
3) On site **conversion**, comprising of:
   a) Compression of hydrogen (compressed gaseous hydrogen, or CGH_2)
   b) Liquefaction of hydrogen (liquid hydrogen, or LH_2)
   c) Conversion to PtL (Diesel/Kerosene), methanol, ammonia
   d) Conversion to synthetic methane (SNG), which is then compressed or liquefied
4) **Transport** options, possibly including storage of final product (hydrogen or derivatives)
   a) By ship for all liquid fuels (PtL, LH_2, NH_3, MeOH, liquid SNG)
   b) By pipeline for gaseous forms (CGH_2, SNG)

The aim of this section is to describe the main elements, technical characteristics and costs of these steps for the following fuels (hydrogen and derivatives)

Section 3.2.1 describes the main elements, technical characteristics and costs of production and transport of renewable hydrogen. It comprises the following steps

- 3.2.1.1 – H_2 production by electrolysis
- 3.2.2.2 – Transport of liquefied hydrogen by ship
- 3.2.2.3 – Transport of gaseous hydrogen by hydrogen pipeline
- 3.2.2.4 – Liquid Organic Hydrogen Carrier (LOHC)

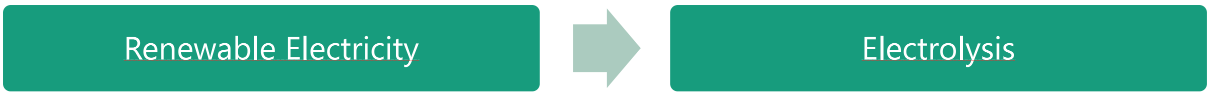
Section 3.2.2 describes the main elements, technical characteristics and costs of production, transformation (or conversion) and transport of renewable hydrogen derivatives. It comprises the following steps

- 3.2.2.1 – Ammonia production and transport
- 3.2.2.2 – CO_2 production by Direct Air Capture
- 3.2.2.3 – Methanol production and transport
- 3.2.2.4 – PtL (diesel / kerosene) production and transport
- 3.2.2.5 – SNG production and transport

3.2.1 H_2 production and transport

3.2.1.1 H_2 Production by electrolysis (2030)

Renewable hydrogen is produced by water electrolysis, which is powered by renewable sources.



The hydrogen produced is gaseous, its storage is optional and can be used as a buffer before liquefaction, or other further conversion synthesis. Electrolysis is a mature and commercialized technology, although the cost of hydrogen remains high compared to other gases (fossil-based).

The cost of hydrogen mainly depends on the fuel costs (electricity), CAPEX and the electrolyser's efficiency. The upfront investments and operational cost for electrolysis (for the year 2030) based on the Fraunhofer IEE cost model[43] are shown in following table.

Table 9 Upfront investments and operational cost for electrolysis for 2030

	CAPEX [€/kW]	OPEX [€/(kW*a)]	Efficiency [MWh/t H_2]	Stack lifetime [h]
Electrolysis (2030)	590.20	9.74	48.89	90,000

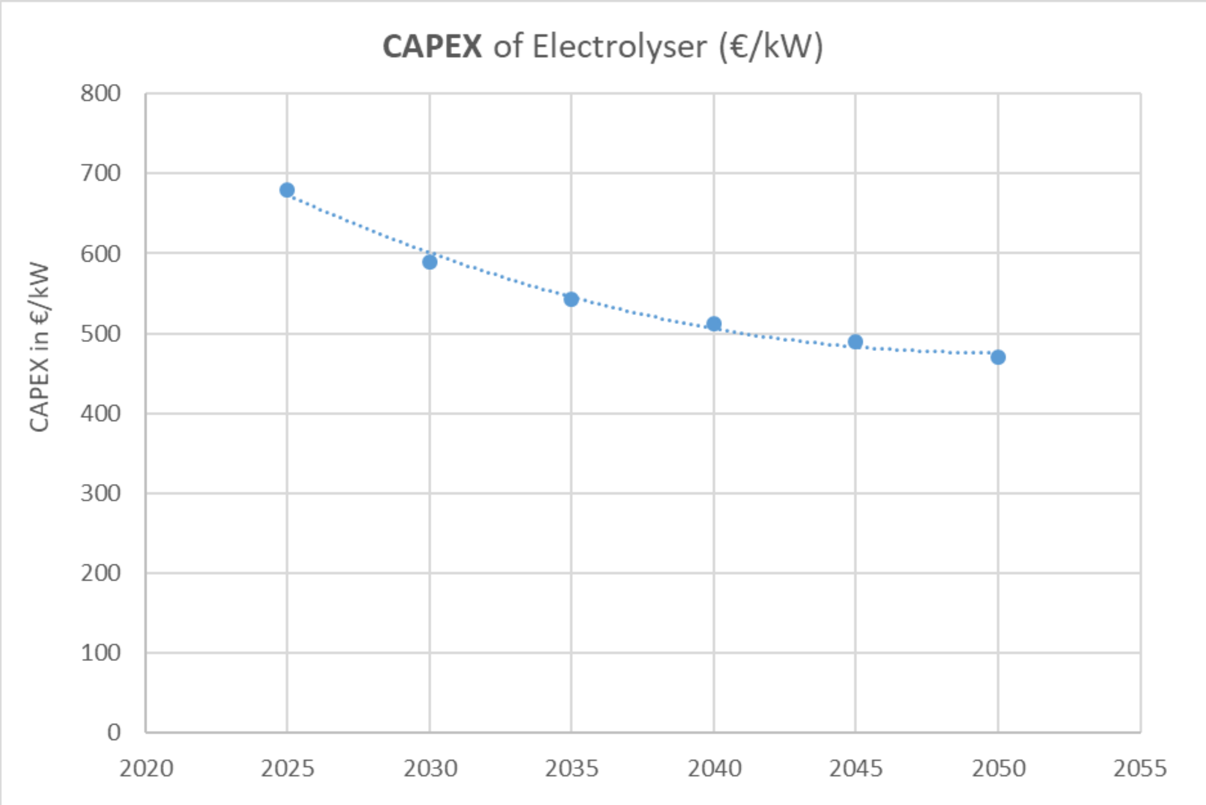
Source: [Fraunhofer IEE cost model[44]]

The following figure illustrates the evolution curves for the estimated CAPEX of electrolysers.

[43] For the calculation of the PEM electrolyser cost Fraunhofer IEE used a cost curve model taking into account data from : International Energy Agency (IEA) 2019 ; Smolinka et al. 2018; Bertuccioli et al. 2014; van 't Noordende und Ripson 2020; Bazzanella und Ausfelder 2017

[44] For the calculation of the PEM electrolyser cost Fraunhofer IEE used a cost curve model taking into account data from : International Energy Agency (IEA) 2019 ; Smolinka et al. 2018; Bertuccioli et al. 2014; van 't Noordende und Ripson 2020; Bazzanella und Ausfelder 2017

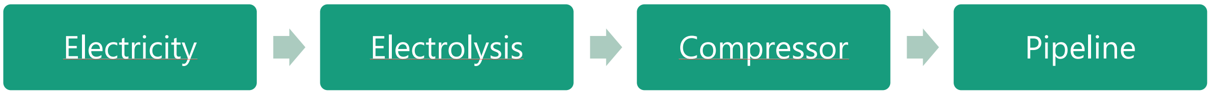
Figure 11 Capex of electrolyser



3.2.1.2 Transport of gaseous hydrogen by pipeline

The straightest way to transport hydrogen is by pipelines, in gaseous compressed form (CGH_2).

The following figure illustrates the steps of the chain of gaseous compressed hydrogen included in the cost assessment: hydrogen production, compression, and transport by pipeline.



The pipes are the most expensive and most important component of the pipeline system. The selection of the material for the pipelines is important because hydrogen can lead to embrittlement and thus to cracks and fractures in the material, which influences the long-term stability of the infrastructure[45]. At a pressure level of 65 bar and a flow velocity of 15 m/s the pressure losses amount to about 7 bar per 100 km and must be compensated by intermediate compression in the case of longer distances[46], making the compressors relevant components of a pipeline system.

In 2016, more than 4,500 km of hydrogen pipelines exist worldwide, most of which are operated in the USA[47]. In Europe, a large private hydrogen network was built by Air Liquide with a length of 1,000 km which connects Rotterdam, Zeeland, Belgium and the north of France. Another large private hydrogen network in the Ruhr area in Germany is owned by Air Liquide[48].

[45] Krieg 2012, NREL 2013

[46] Krieg 2012

[47] Shell 2017

[48] TKI Nieuw Gas 2018

Repurposing of existing natural gas pipelines is in the demonstration stage. The construction of new pipelines is associated with significant additional costs compared to the repurposing of existing natural gas pipelines. Repurposing, on the other hand, is only a viable option if a certain amount of hydrogen is to be transported on a regular basis.

Annex 2 presents the hydrogen backbone, and the plans of the major long-distance gas-network operators regarding the timeline and geographic scope of a future hydrogen network.

The efficiency of hydrogen transport by pipeline depends on the pipeline length[49]. The following assumptions are taken into account:

- Conditioning of the gas (Compressor): 2.5% losses of Hydrogen energy content
- Compensation of pressure losses (Pipeline): 1.5-2.3% of the transported hydrogen's energy content is consumed for compression purposes for every 1,000 km of distance covered, assuming electricity-driven compressors[50]
- These assumptions lead to 0.07-0.15 €/kg/1,000km using mainly rededicated pipelines

Compressing hydrogen to be transported by pipeline (@ 100bar) requires 0.025 $kWh_{el}/kWhH_2$. For transporting the compressed hydrogen through the pipeline additional 0.0509 $MWh_{el}/kWhH_2/km$ are necessary[51].

The upfront investments and operational cost for hydrogen transport by pipeline for the year 2030 are summarized in Table 10 below.

Table 10 Upfront investments and operational cost for Pipeline infrastructure in 2030

	CAPEX	OPEX (% of CAPEX /y)
Pipeline new	1.4 – 3.4 Mio€/km	0.8 – 1.7 (excluding electricity for compression)
Pipeline retrofitted	0.2 – 0.6 Mio€/km	
Compressor	2.2 – 6.7 Mio€/MW 0.09 – 0.62 Mio€/km	

Source: [European Hydrogen Backbone]

3.2.1.2.1 European gas grid connection to North Africa

North Africa is mentioned as a potential producing region supplying hydrogen imports to Europe. The (gaseous) hydrogen production potentials of some MENA countries are shown in Table 11.

Table 11 Hydrogen potential of some MENA countries

Country	Potential hydrogen production [TWh]
Morocco	586
Algeria	649
Tunesia	385
Egypt	4,720
Saudi Arabia	2,675

Source: [Fraunhofer IEE PtX-Atlas]

49 European Hydrogen Backbone

50 Wang et al. 2020

51 Dambeck et al. 2020

Figure 12 presents the existing gas infrastructure between the MENA region and Europe which could be rededicated for transporting hydrogen instead of natural gas. Alternatively, blending would also be an option, but this requires further technical adjustments to the infrastructure and the decarbonized energy content by renewable hydrogen is low due to its low volumetric density (a H_2 content of 20% by volume corresponds to a calorific value related energy content of only approx. 7%). Many natural gas pipelines are equipped with two parallel pipes. In a first step, the partial rededication of natural gas pipelines would be a solution to transport pure hydrogen and natural gas to Europe.

Figure 12 Pipelines in North Africa connecting Europe with the MENA region

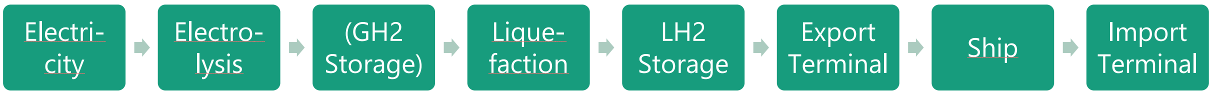
The following pipelines are already connecting the European gas grid infrastructure and North Africa:

- Morocco-Spain:
  - Maghreb Europe Gas Pipeline (2 x 24 in.)
- Algeria – Spain
  - MEDGAZ; (24 in.) in operation since 2011
  - 210 km offshore
- Algeria – Sardinia:
  - Galsi Project (24 in.) planned
- Tunisia-Italy:
  - Transmediterranian Gas Pipeline (2 x 48 in.)
- Libya-Italy
  - Green Stream; 32 inch

3.2.1.3 Transport of liquefied hydrogen by ship

Hydrogen can also be liquefied (LH_2) in order to be transported by ship (inland or over the sea). Liquid hydrogen pipelines are only profitable for large quantities and long-term use due to the high investment cost[52], and are therefore not considered in the scope of this study.

The following figure illustrates the steps of the chain of liquified hydrogen included in the cost assessment: hydrogen production, storage of gaseous hydrogen, liquefaction, storage of liquified hydrogen, export terminal, transport by ship, and import terminals.



Depending on the intermittency of hydrogen production, a buffer for gaseous hydrogen can be required to ensure continuous liquefaction.

The main steps influencing the cost of liquefied hydrogen are:

- The liquefaction process
- The terminal infrastructure
- The storage infrastructure

3.2.1.3.1 Liquefaction

The hydrogen is liquefied by cooling and compression. The boiling point of hydrogen is at -253°C under ambient pressure. The liquefaction of hydrogen for storing the gas is energy intensive. Approximately 30% of the hydrogen energy (@LHV) is currently required for liquefaction, although processes are under development to reduce this demand to below 20%. The industry is working on energy optimized large scale hydrogen liquefaction with 100 TPD of hydrogen.

Electricity consumption of most liquefaction processes is between 5 & 8 kWh/kg LH_2[53]. The assumption used in this study is 6.1 kWh/kg LH_2[54] .

3.2.1.3.2 Terminal infrastructure and port facilities

Port facilities are needed to import and export hydrogen by ship and transport the hydrogen to the hinterland. Port facilities can include, amongst others: liquid hydrogen terminals, liquid hydrogen storage tanks, liquid hydrogen truck loading, evaporation units, Liquid Organic Hydrogen Carrier (LOHC) terminals, storage tanks, dehydrogenation plants, ammonia terminals, storage tanks, ammonia cracking installations and other equipment.

Estimated investments that need to be carried out in a port, are:

- Liquid hydrogen terminal and storage, Capex about 1 billion Euros.
- Ammonia terminal, storage and ammonia cracking installation, Capex about 300 M Euros.
- LOHC terminal, storage and dehydrogenation plant, Capex – especially dehydrogenation – plant 200 M Euro
- Port pipeline infrastructure for hydrogen, ammonia, bunkering facilities and multi modal logistic centers – Capex 1 billion Euros.

---

52 Fischedick et al. 2017

53 Yin & Ju 2020

54 IEA 2019

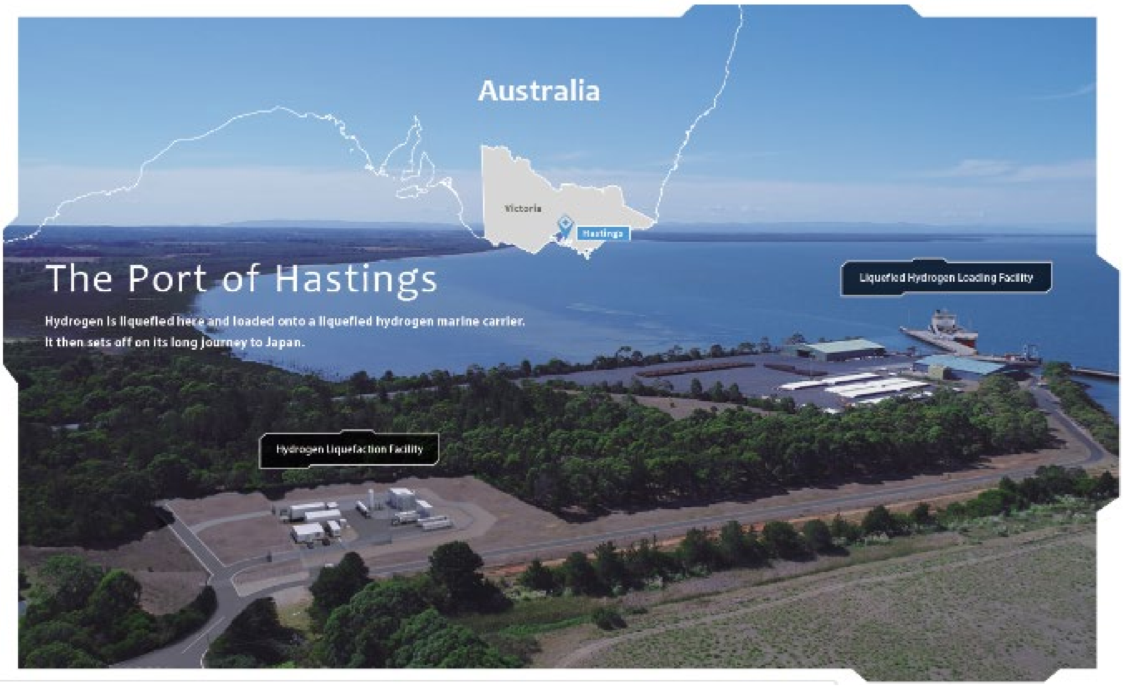
In total an investment of about 2.5 billion Euros in port facilities is needed. An estimated total of 8 ports in Europe needs to realize these port facilities, which is a total investment of 20 billion Euros[55].

Ships and terminals are the two main bottlenecks in the chain of liquefied hydrogen by 2030 as these are currently neither available, nor mature. There are currently only two projects of small scale LH_2 ships, with the first LH_2 terminals to be built in Australia (Figure 14) and Japan (Figure 13.).

Figure 13 Port for liquid hydrogen in Kobe, Japan [HYSTRA-Project]

[55] Hydrogen Europe, 2020

Figure 14 Port for liguid hydrogen in Hastings, Australia [HYSTRA-Project]



LH_2 is lost during storage and handling operations through the following stages:

- Pump operation (loading and unloading) of LH_2 leads to 0.6% average loss due to boil-off[56] ;
- boil-off for stationary LH_2 storage (located at terminal, import and export) reaches 0.1%/d [57]

Once arrived at the import terminal, liquefied hydrogen can be transported in liquid form or can be gasified and be transported and used as gaseous hydrogen. The cost for further transport depends on the chosen technology.

3.2.1.3.3 Storage infrastructure for export

The cooled and liquefied gas is stored in special insulated, cryogenic tanks, which maintain the gas condition (-253°C) and reduce evaporation losses. Stationary tanks consist of an outer and an inner tank, high quality insulation and pressure relief valves to compensate for evaporation losses. These tanks can be transported by trailer, train, or ship if the appropriate infrastructure, such as loading terminals, is available. With trailers for liquefied hydrogen, 3,600 to 4,000 kg can be transported and they have a range of approx. 4,000 km so that transports over long distances are possible[58].

Kawasaki Heavy Industries is currently designing tank ships for intercontinental transport. Each tank ship will hold 4 tanks with a volume of 40,000 cubic meters each. A demonstration ship under construction with the new tank with high-performance insulation to minimize H_2 losses has a capacity of 1,250 cubic meters.

[56] Petitpas 2018

[57] IEA 2019

[58] Fischedick et al. 2017

3.2.1.3.4 Summary

The upfront investments and operational cost for the LH_2 chain for the year 2030 are shown in Table 12.

Table 12 Upfront investments and operational cost for LH_2 chain in 2030

	CAPEX	OPEX (% of CAPEX/y)
Liquefaction for GW-scale electrolysis	4,450 €/ (t_{H2}*y)	4%/y
Export / Import terminal (including storage) Depending on capacity of ship and loading frequency	75,000 €/t_{H2}	4%/y
Ship (capacity 11,000 t_{H2})	340 Mio €	4%/y

Source: [IEA 2019]

Assuming a transport duration of 15 days, the total transport and storage efficiency, including loading and unloading, would decrease to 53.2% when importing liquid hydrogen.

The upfront investments and operational cost for the LH_2 chain for the year 2030 are shown in Table 12.

3.2.1.4 Liquid organic hydrogen carrier (LOHC)

In addition to gaseous compressed hydrogen and liquefied hydrogen, another way to transport hydrogen is via LOHC (Liquid Organic Hydrogen Carriers) technology, in which hydrogen is chemically bound to liquid organic substances. In this form, the hydrogen can be easily stored and transported.

The following figure illustrates the steps and main features of the chain of Liquid Organic Hydrogen Carriers.

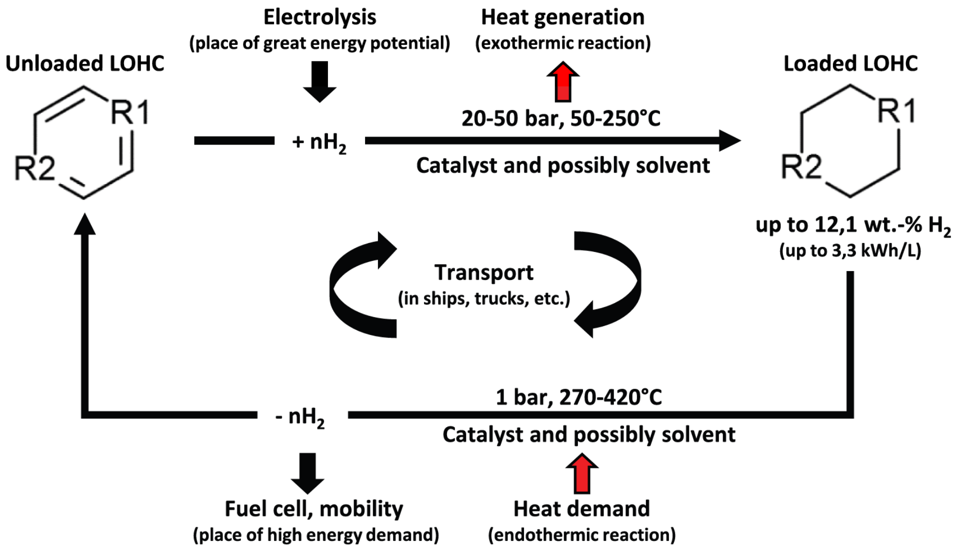
1,800 kg of hydrogen can be stored in dibenzyl toluene and benzyl toluene as LOHC in a large trailer[59]. Compared to liquid gas transport, no evaporation losses occur[60]. The following figure shows the LCOH's reaction cycle from Niermann[61].

59 Aakko-Saksa 2018

60 Wasserscheid 2019

61 Niermann et al. 2021

Figure 15 Concept of hydrogen transport via LOHC and reaction cycle from Niermann[62].



For the LOHC transport, the infrastructures from the mineral oil industry can be used as far as possible, which means that the effort is low. The main disadvantages of LOHC's are the complex H_2 loading and unloading processes (hydrogenation / dehydrogenation) and the poor efficiency. On the other hand, the dehydrogenation does not necessarily have to take place at the point of unloading and the loaded LOHC can be transported further by trucks or train.

In terms of costs and efficiency, it has to be taken into account that the unloaded LOHC has to be transported back, including storage capacities for import and export. The return transport is taken into account by doubling the transport costs (double transport route, energy requirement, double number of containers)[63].

The LOHC's are reversibly hydrogenated and dehydrogenated using catalysts at elevated temperatures. The dehydrogenation requires heat at 50-420°C, depending on the usage of LOHC and catalyst[64]. The processes and catalysts have still to be developed for example in terms of selectivity and fast kinetics of the system[65].

The hydrogenation is an exothermic process. Without recovering this heat, 7-29% of the hydrogen energy (@LHV) is lost[66], due to 26-29%[67] of the hydrogen energy is lost. In order to improve the energy balance/efficiency, the waste heat (from hydrogenation) should be used. In addition it is also possible to use nearby heat sources for dehydrogenation (high temperatures) in order to increase the efficiency.

62 Niermann et al. 2021

63 Fraunhofer ISS 2021

64 H_2 Infra-Teil von ISS

65 Aakko-Saksa 2018

66 Niermann et al. 2021

67 Aakko-Saksa 2018

Various organic substances are used as carrier media. These are also used in industrial processes and have a low price[68]. (Di-)benzyltoluene seems to be LOHC compounds of choice[69]. Dibenzyl toluene and benzyl toluenes can store 6.2 wt.% hydrogen[70].

A readiness of transport technology report[71] has identified 17 projects with LOHC, 11 of them in Germany, further 4 in Europe. 7 projects are in design phase, 9 in implementation, and 1 completed. Many projects are mainly concepts for successfully implementing the still young LOHC technology. Most projects do not cover the complete LOHC supply chain.

The efficiency of the LOHC transport chain is about 48.8%, assuming a distance of 12,000 km for the transport between Europe and South America. The following assumptions are taken into account[72]:

- Hydrogenation: around 5% losses
- Ship: losses negligibly[73]. Fuel for transport around 5% losses, twice.
- No Boil-off. Terminal losses 0.03% [IEA 2019], twice
- Dehydrogenation (and purification): 4.5% losses, 90% H_2 recovery rate in dehydrogenation, 98% recovery rate in PSA H_2
- The high heat demand is covered by hydrogen[74], this is not included in efficiency (due to the approach of using the waste heat)

Potential barriers for the hydrogen transport by LOHC: Terminal, storage, and ships for oil products are mature technology and available, but LOHC technology (hydrogenation and dehydrogenation) is still under development.

Potential usage of final product: The reconverted hydrogen can be used in the hydrogen value chain to substitute grey hydrogen.

The upfront investments and operational cost for the transport of hydrogen by LOHC for the year 2030 are shown in following tables. Table 13 shows the cost based on the toluene weight and Table 14 shows the cost based on the hydrogen weight using the assumption, that toluene can load 6.2 % of its own weight as hydrogen.

68 Aakko-Saksa 2018

69 Fraunhofer ISS 2021

70 Aakko-Saksa 2018

71 Fraunhofer ISS 2021

72 IEA 2019, Niermann et al. 2021

73 Niermann et al. 2021

74 Ibid.

Table 13 Upfront investments and operational cost for components in the LOHC transport chain in 2030[75]

Figure based on toluene weight

Costs based on toluene weight	CAPEX	OPEX (% of CAPEX /y)
Hydrogenation process (toluene→ methyl-cyclohexane)	55 €/ (tTol/y)	4%/y
Toluene cost (Start-up toluene: 260 kt Tol, Toluene markup: 100 kt Tol/y	330 €/ (tTol/y)	
Export / Import terminal (including storage/tank) Depending on capacity of ship and loading frequency	568 – 812 €/tTol	4%/y
Ship (capacity 110,000 tTol)	63 Mio €	4%/y
Dehydrogenation process (methyl cyclohexane → toluene	160 €/ (tTol/y)	4%/y

Source: [IEA 2019]

Table 14 Upfront investments and operational cost for components in the LOHC transport chain in 2030[76] **(Toluene-cyclohexane couple)**

Figure based on hydrogen weight

Costs based on hydrogen weight (6.2 wt% of toluene)	CAPEX	OPEX (% of CAPEX /y)
Hydrogenation process	883 €/ (tH_2/y)	4%/y
Toluene cost (Start-up toluene: 260 kt Tol, Toluene markup: 100 kt Tol/y)	330 €/ (tTol/y)	
Export / Import terminal (including storage/tank) Depending on capacity of ship and loading frequency	9,164 – 13,090 €/tH_2	4%/y
Ship (capacity 6,820 tH_2)	63 Mio €	4%/y
Dehydrogenation process	2,573 €/ (tH_2/y)	4%/y

Source: [IEA 2019]

3.2.2 Conversion to derivatives and transport

Under section 3.2.1, renewable hydrogen was transported as a molecule of hydrogen, being gaseous compressed, liquefied or bound to an organic carrier (LOHC).

In this section, renewable hydrogen is first converted to one of its derivatives to ease and reduce the cost of its transport. The derivatives assessed in this section are

- Ammonia
- Methanol
- Power-to-Liquids, or liquid derivatives (e-kerosene, e-disesel)
- Synthetic Natural gas

[75] IEA 2019

[76] IEA 2019

3.2.2.1 Ammonia production and transport

According to ISPT[77], the annual production volume of ammonia worldwide was approximately 180 million tons in 2017 with an expected yearly production growth of 1 to 1.5 %. Approximately 12% of this volume (21 million tons) was produced in Europe. Most of the NH_3 (approx. 90%) is used as a feedstock at production sites. The remaining 10% (around 20 million ton per year) is traded and transported often covering large distances. Western Europe and the US are the two major importers of NH_3.

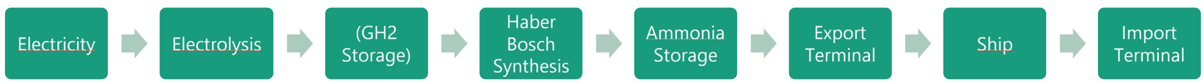
Ammonia accounts for about 40% of the current global hydrogen demand with 31.5 million tons of H_2[78], of which 80% is used for fertilizers.

Renewable ammonia can replace grey ammonia in the fertilizers and the chemical industries, as well as be used as fuel in the shipping industry and can be used as transport option for hydrogen.

Roughly, ocean transportation cost of ammonia is about 2/3 lower in comparison to the transport of liquefied hydrogen (LH_2)[79].

Assuming the transport over a distance of 12,000 km, the total efficiency for Ammonia along the entire supply chain is about ~ 51.4%, taking into account the following assumptions:

- Haber-Bosch synthesis (including electrolysis): Electricity requirement for production of renewable hydrogen based ammonia of 9.8 – 10.2 kWh_{el}/kg NH_3 (including electrolysis: 4.3 kWh/Nm^3 H_2; Nitrogen generation + compression in Haber-Bosch: 1.7 kWh/kg NH_3)[80]
- Ammonia storage, shipping, import & export terminals: Boil-off gas is reliquefied[81]
- Energy for transport per ship according to: 2,500 MJ/km for ship with 53,000 t NH_3 capacity[82]



Modern LNG ships are NH_3-ready and with ammonia as base chemical for fertilizers, the distribution network is well established. Export & Import LNG terminals can be repurposed for 11% of the initial CAPEX[83], making it an attractive solution. In Saudi Arabia, a 4 GW renewable hydrogen based ammonia plant was announced within the NEOM initiative.

Techno-economic challenges for ammonia production and transport currently[84]:

- Cheap, efficient production of ammonia using renewable hydrogen, from sustainable sources;
- Large-scale conversion to power with low emissions and high stability;
- Public perception that enables the global deployment of the molecule as an energy vector;
- Feasible economics that can compete with current electro-fuels;
- Safety aspect as ammonia is toxic – technical solutions available.

[77] ISPT 2017

[78] IEA 2019, FCHJU 2019

[79] Breiki 2020

[80] IEA 2019, Valera-Medina 2021, Bazzanella 2017

[81] Ishimoto 2019

[82] IEA 2019

[83] Black & Veatch

[84] Valera-Medina, Agustin; 2020

The upfront investments and operational cost for ammonia production and transport for the year 2030 are summarized in following table:

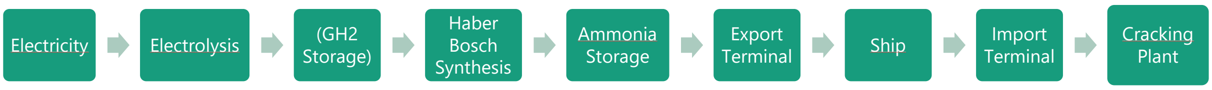
Table 15 Upfront investments and operational cost for Ammonia production and transport in 2030

	CAPEX	OPEX (% of CAPEX /y)
Ammonia Synthesis and Electrolysis	705 €/t NH_3	1.5 %/y
Export / Import terminal (including storage) Depending on capacity of ship and loading frequency	1,400 – 2,150 €/t NH_3	4 %/y
Ship (capacity 78,000 t NH_3)	102 Mio €	4 %/y

Source: [IEA 2019, Ishimoto 2019]

3.2.2.1.1 Ammonia as transport option for hydrogen

If ammonia is used as transport option for hydrogen, an ammonia cracking and purification plant is necessary to reconvert hydrogen after the transport of ammonia.



The efficiency for hydrogen import via ammonia is about 37.6 %, assuming a distance of 12,000 km. The used assumptions are: Energy consumption for additional cracking plant 1.5 kWh/kg NH_3, 98% H_2 recovery rate in cracking, 85% recovery rate in in purification).[85]

The upfront investments and operational cost for ammonia cracking for the year 2030 are shown in following table.[86]

Table 16 Upfront investments and operational cost Ammonia Cracking in 2030

	CAPEX	OPEX (% of CAPEX /y)
Cracking plant	253 €/t NH_3/a	4 %/y

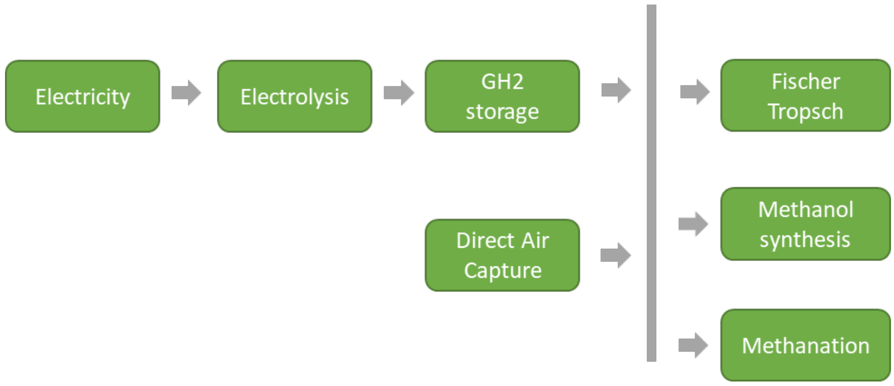
Source: [IEA 2019, Ishimoto 2019]

85 IEA 2019

86 IEA 2019, Ishimoto 2019

3.2.2.2 CO_2 Production by Direct Air Capture (2030)

CO_2 is necessary for methanol synthesis, Fischer-Tropsch synthesis and methanation (as illustrated by the figure below). Besides concentrated CO_2 sources like biogas or flue gas from e.g. the cement industry, Direct Air Capture (DAC) is usually needed to provide CO_2.



The extraction of CO_2 from the air is energy-intensive and therefore expensive. Since there are only 400 ppm of CO_2 in the air, at least about 1,370 m^3 or 1.65 tons of air must be moved through the capture system to recover one kilogram of CO_2.[87]

DAC is a technology that is operated and researched by a few research institutions and companies with different technologies.[88] The company Climeworks aims at reducing the cost of CO_2 to 80 €/t (target value). Today's DAC costs are in the range of 500 €/ t CO_2. Other companies active in the field of DAC counts Global Thermostat (USA) and Carbon Engineering (Canada).

An important challenge is the scaling and cost reduction of DAC technology (investment cost and reduction of energy demand). The upfront investments, operational cost, and fuel cost for DAC technology for the year 2030 are shown in Table 17

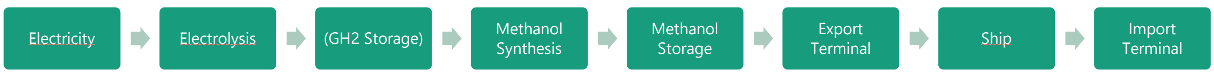
Table 17 Upfront investments and operational cost for DAC in 2030

	CAPEX [€/t CO_2]	OPEX [%/y]	Electricity demand [kWh/ t CO_2]	Heat demand [kWh/ t CO_2]
DAC (2030)	1,275	4.0%/y	700	2,200

Source: [Prognos 2020]

3.2.2.3 Methanol production and transport

Methanol production from synthesis gas is fully commercial. As a liquid it is easily transportable, like other common petroleum fuels. The following figure illustrates the steps of the chain of methanol, from the production of renewable hydrogen to import terminal: hydrogen production, gaseous hydrogen storage, methanol synthesis, methanol storage, export terminal, transport by ship, and import terminals.



[87] Prognos 2020

[88] Ibid.

In 2021, 110 million tons methanol were produced[89] with 60% of the global market demand coming from China[90]. The company Waterfront Shipping (subsidiary of market leader Methanex, wfs-cl.com) has 30 ships, size class up to 50,000 tons, and intent to drive its ships with methanol, from currently 11 ships up to 19 until 2023.

Around 40% of global methanol production today is used for energy purposes, but methanol can also be used as the building block for synthesizing a range of chemicals, e.g. for the production of plastics[91]. Currently there are 100 ports available for methanol shipping worldwide.

This section describes

- The cost of renewable methanol production, in 2018 and 2050
- The efficiency and cost along the chain (incl. transport) in 2030

Cost of renewable methanol production in 2018 and 2050

Five million liters per year renewable methanol are produced today[92]. There are currently 36 renewable methanol projects in the pipeline, of which 3 Mt would be bio-based, and 1 Mt would be e-methanol. Cost for bio- and e-Methanol are mainly dependent on cost for feedstock and electricity.

The cost of e-methanol depends largely on CO_2 and H_2 costs. Biomass, industrial processes exhaust fumes or DAC are possible CO_2 sources. The total cost of e-methanol production comprises[93]:

- The cost of CO_2 from biogas capture from biogas plants, which is about 10-50 USD/t CO_2, while the cost of CO_2 from DAC is still about 300-600 USD/t (and even above, see section 3.2.2.2.1);
- The cost of renewable hydrogen (see section 3.2.1.1);
- The electricity consumption to convert H_2 & CO_2 into MeOH;

The resulting cost for methanol in 2018 is about 800-1,600 USD/t methanol (based on CO_2 from a biogas plant), or about 1,200-2,400 USD/t methanol (via DAC).

Based on the Capex, OPEX and feedstock costs, the total cost of production range of bio-based methanol is forecasted for 2050 at 220-560 USD/t Methanol.[94]

The cost reduction potentials are related to renewable power generation, electrolysers, efficiency and durability. The following figures illustrates the estimated costs of renewable e-methanol up to 2050 depending on the renewable CO_2 source and the development of cost for e-methanol, bio-methanol and fossil methanol.

[89] methanol.org

[90] methanex

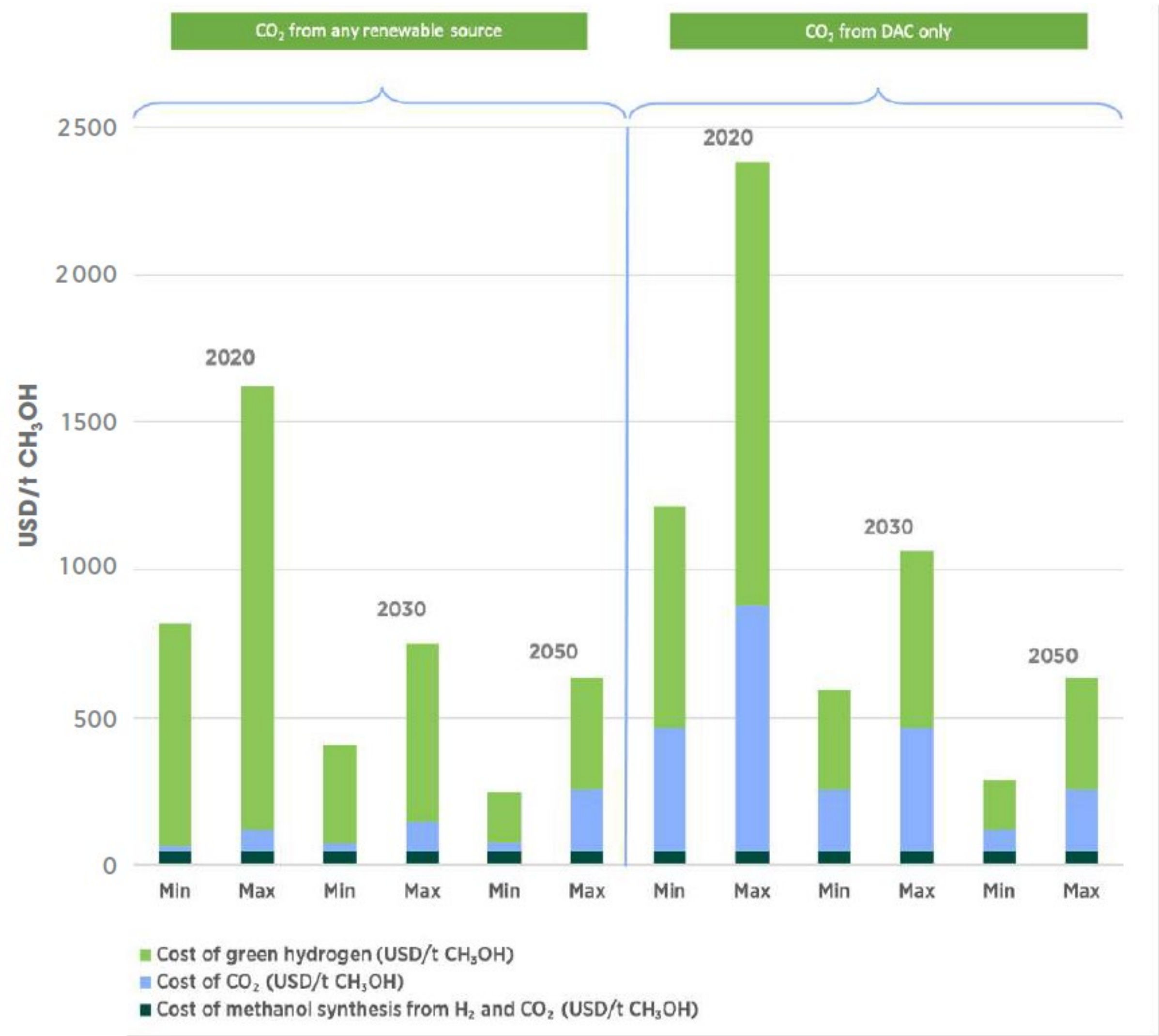
[91] IEA 2019

[92] CRI

[93] IRENA 2021

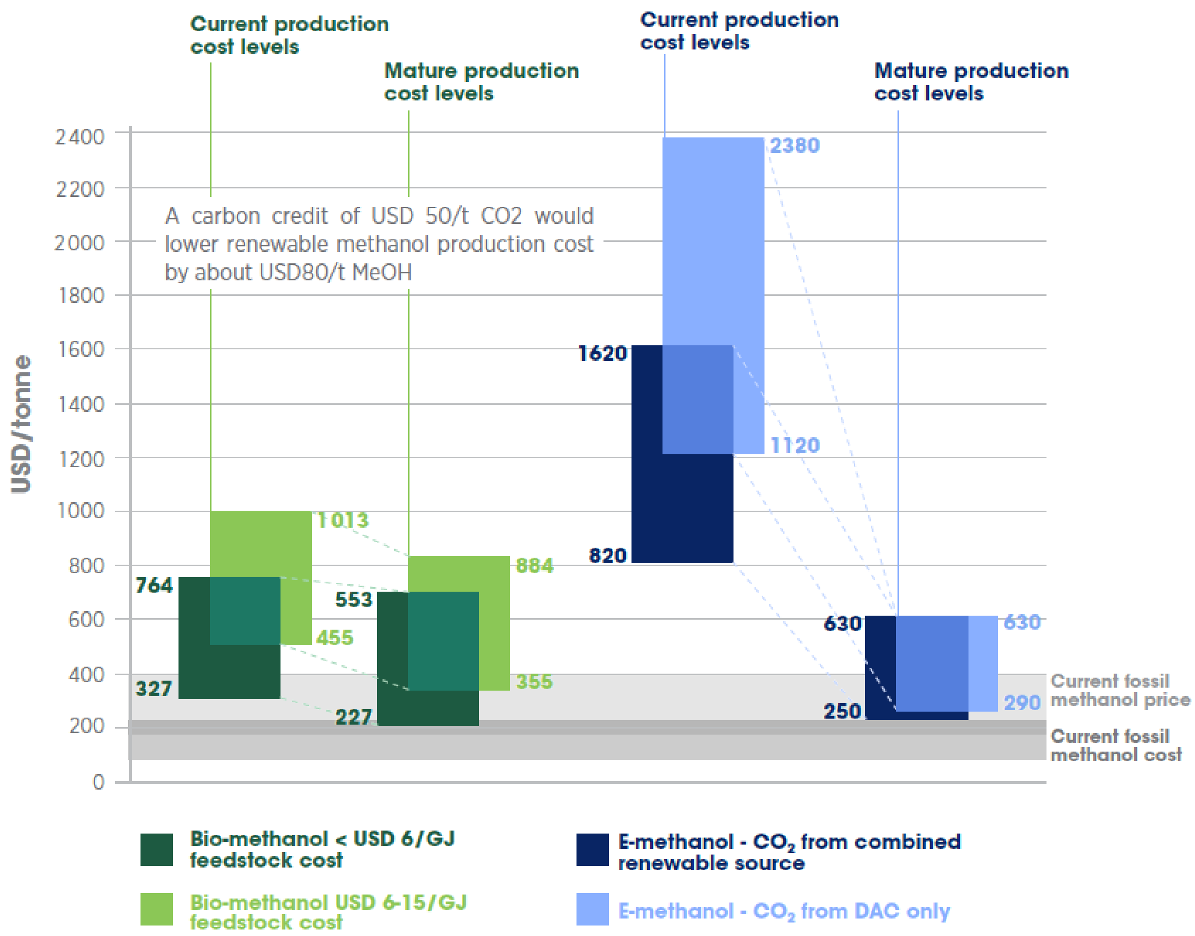
[94] IRENA, 2021

Figure 16 Estimated costs of renewable e-methanol up to 2050 depending on the renewable CO_2 source



Note: *CAPEX and OPEX for the production of hydrogen and CO_2 are already included in the respective cost of hydrogen and CO_2.*

Figure 17 Development of cost for e-methanol, bio-methanol and fossil methanol



Note: *Exchange rate used in this figure USD 1 = EUR 0.9.*

Total cost of renewable methanol production and transport in 2030

The production of methanol from biomass and from CO_2 and H_2 does not involve experimental technologies. Almost identical, proven and fully commercial technologies are used to make methanol from fossil fuel-based syngas and can be used for bio- and e-methanol production[95].

As explained in the introduction, transport cost is also commercially mature, and is estimated at 30.6 USD on average per ton.

The following summarizes the main assumptions regarding the efficiency and driving the total cost of methanol production:

- Electricity consumption to produce methanol with H_2 and CO_2: 6.58MWhe[96]/t MeOH[97] with an efficiency of 83.5%[98]
- CO_2 demand for methanol synthesis: 1.4 kg CO_2/kg Methanol
- H_2 required for methanol synthesis: 0.1875kg H_2/kg Methanol

[95] IRENA 2021

[96] Or 23.7 GJ/t MeOH

[97] IEA 2019

[98] Theoretical efficiency according to [Prognos 2020] is 85%

- Ship transportation boil-off with a value of 0.0005% is negligible[99]

The upfront investments, operational cost and fuel cost for methanol production for the year 2030 are shown in following table.

Table 18 Upfront investments and operational cost for methanol production in 2030[100]

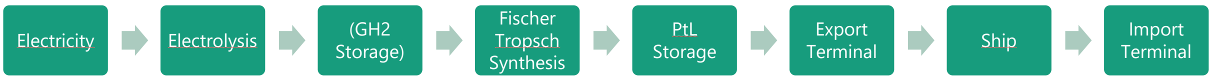
	CAPEX	OPEX (% of CAPEX /y)
Electrolysis + Methanol synthesis	491 €/($t_{Methanol}$*y)	1.5 %/y
Methanol synthesis	641 €/($kW_{Methanol}$)	4 %/y

Currently the main barrier to renewable methanol uptake is its higher cost compared to fossil fuel-based alternatives (hydrogen produced from renewable electricity versus hydrogen produced from steam methane reforming)[101].

3.2.2.4 PtL (Diesel/Kerosene) production and transport

Power-to-Liquid processes or liquid derivatives like e-diesel and e-kerosene production from hydrogen is an advanced technology. Liquids are easily transportable, like other common petroleum fuels. PtL can use the existing infrastructure (terminal, tanks, ships, ...).

The following figure illustrates the steps of the chain of liquid derivatives, from the production of renewable hydrogen to import terminal: hydrogen production, gaseous hydrogen storage, Fischer-Tropsch synthesis, liquid storage, export terminal, transport by ship, and import terminals.



There are several applications, where decarbonization will remain complicated to switch to low-carbon alternatives, like electrification or other renewable fuels (solar, geothermal, or even bio-based), especially for heavy duty and maritime transport and aviation. For some of these applications, it is expected that liquid fuels will be used in the long term.

The efficiency of Fischer Tropsch Synthesis converting H_2 to liquid fuels is about 66 – 76.3%[102], meaning that the energy content of the final product (PtL) comprises about 66-76.3% of the energy content of the hydrogen that has been used to produce it. The FT synthesis consumes 23.5-26 MWh_{el}/t product. The efficiency of the entire PtL (Diesel/Kerosene) chain, comprising production, storage and transport, is estimated to be about 45– 50% excluding transport via ship.

PtL products can be shipped by a usual product tanker fleet. The deadweight of large range vessels is between 80,000 to 120,000 tons[103], however it is assumed existing vessels and infrastructure will be used, considering PtL will replace the use of the incumbent fossil-based fuels.

The upfront investments and operational cost for Fischer Tropsch Synthesis for the year 2030 are shown in the following table.

99 Al-Breiki & Bicer 2020

100 IEA 2019, Prognos 2020

101 IRENA 2021

102 Prognos 2020, IEA 2019; PtX-Atlas 2021

103 Fasihi 2016

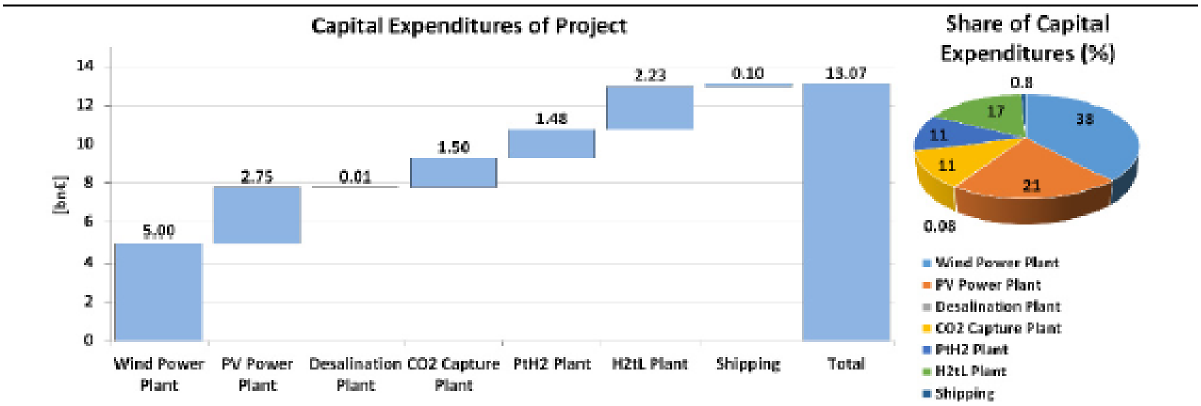
Table 19 Upfront investments and operational cost for Fischer Tropsch Synthesis in 2030

	CAPEX	OPEX (% of CAPEX /y)
Fischer Tropsch Synthesis	627-833 €/kW $_{liquid}$	4 %/y
Ship (capacity 100,000 t_{liquid})	48 Mio€	3 %/y

Source: [IEA 2019, Prognos 2019, Fasihi 2016]

The capital expenditure breakdown of the hybrid PV-Wind-PtL shows that nearly 60% of CAPEX is still spent on electricity generation.

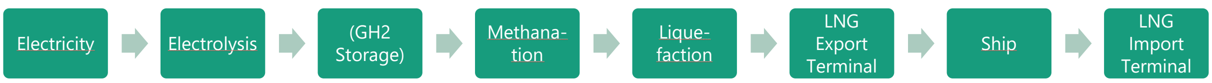
Figure 18 Capital expenditure breakdown of the hybrid PV-Wind-PtL



3.2.2.5 SNG (liquid synthetic methane)

Synthetic Natural Gas production from hydrogen is an advanced technology but still in the demonstration phase. As a gas, SNG can thereafter be further processed into liquefied methane, for transport via ships, or it can be directly fed in the natural gas grid to substitute grey methane. It also can be used as fuel or in production industry as feedstock.

The following figure illustrates the steps of the chain of SNG, from the production of renewable hydrogen to LNG import terminal: hydrogen production, gaseous hydrogen storage, methanation process, liquefaction (for ship transport), LNG export terminal, transport by ship, and LNG import terminal.



For the transport of SNG, only its liquid state (liquid synthetic methane) can be transported over long distance. Therefore, the following components are necessary to develop: liquefaction, LNG export terminal, ships and LNG import terminal. Feeding synthetic methane into the existing natural gas network is not considered here, although it could come from North Africa interconnection through the Mediterranean Sea, or from Ukraine, Russia or other bordering countries.

The methanation technology (transforming H_2 into CH_4) is available but not proven for large scale application. It is still in demonstration phase (highest readiness has fixed-bed reactor with TRL 8/9)[104].

[104] TF-Energiewende

For transport of liquid synthetic methane, exactly the same technology and infrastructure as for natural gas can be used: Liquefaction, LNG-Terminals and ships are already in use and available. In Europe (2017) a total of 28 large-scale import terminal are in operation or being built, incl. UK & Turkey[105].

The efficiency of the entire SNG supply comprising hydrogen production, methanation and the transport of methane is about 49%, assuming 15 days shipping transport (about 12,000 km distance). The following assumptions are taken into account:

- Methanation efficiency: 77%[106] - 80%[107]
- CO_2 demand for methanation: 2.8 kg CO_2/kg methane
- SNG liquefaction: 96.5% efficiency[108]
- Modern LNG carriers (ships) feature boil-off rates between 0.10 – 0.15% per day[109]. This is used for propulsion of the ship[110]

A potential barrier for methanation and transport of methane is the scaling of methanation technology.

The upfront investments and operational cost for methanation and transport of methane for the year 2030 are shown in Table 20. Additional CAPEX and OPEX for a DAC unit to provide CO_2 are not included in these costs. Cost for DAC technology are shown in chapter 3.2.2.2.

Table 20 Upfront investments and operational cost for methanation and LNG transport 2030

	CAPEX	OPEX (% of CAPEX /y)
Methanation	562 – 607 €/$kW_{methane}$	3.5 – 4%/y
Liquefaction	660 -1,500 €/t_{LNG}*y	2.5%/y
LNG Export / Import terminal (including storage) Depending on capacity of ship and loading frequency	3,000 – 10,000 €/t_{LNG}	2 – 5%/y
LNG Ship (tanker of 140,000 m^3 (approx. 59,000 t))	140 Mio €	

Source: [IEA 2019, Prognos 2020, ERIA 2018, ERIA 2017, Oxford 2018, Merkel 2017]

3.3 Production and import cost for several derivatives from different countries

This section analyses the costs for liquid derivatives, methanol, liquid SNG and liquefied hydrogen production and transport up to the EU borders. Figures are based on the Fraunhofer IEE PtX Atlas. Import costs consist of production costs and transportation costs.

The countries are selected based on the assessment carried out under section 3.1 on potential exporting market at 2050.

105 King & Spalding 2018

106 IEA 2019

107 TF-Energiewende

108 Hank et al. 2020

109 Ibid.

110 Ibid., Prognos 2020

Methodology

The cost-optimized system design and fuel production cost are established based on:

- Electricity production by wind, solar or hybrid (wind and solar)
- Hydrogen production by electrolysis
- Derivatives production
- Transport cost

The calculation of the **fuel production cost** is carried out using the net present value method for all individual technologies in the respective renewable hydrogen and derivatives supply pathway. For this purpose, the investment[111], operating and capital cost, the fuel cost, the technical properties of the aggregates used and the economic useful life of the project are determined. The capital cost is country specific, and depends on the socio-economic context, with as reference the "Renewable Energy" category from the RISE Score[112] (with a total range of 3% - 12%).

The weighted average cost of capital is a common way to determine required rate of return of projects. The project lifetime is assumed to be 20 years.

CAPEX assumptions for the cost calculations for 2030 are in Table 21. Assumptions for 2050 can be found online[113].

Table 21 Summary of investments and operational cost for derivatives (2030)

	PEM electrolysis [€/kW][114]	Synthesis [€/kW][115]	DAC CAPEX [€/t][116]	Liquefaction [€/t*a][117]	H_2 buffer [€/kWh][118]	CH_4 buffer [€/kWh][119]
FT-fuels by low temperature PEM	590	833	1,275	-	25	5
Methanol by low temperature PEM	590	641	1,275	-	25	5
CH_4 (LNG) by low temperature PEM	590	562	1,275	500	25	5
H_2 (liquid) by low temperature PEM	590	-	-	3,500	25	5

Assumptions for the DAC operation are 700 kWh electricity per ton of CO_2 and 2,200 kWh of heat per ton of CO_2.

[111] Investment and operating cost vary depending on the technology and the year of installation. The assumptions for 2050 are listed in the table available at : https://devkopsys.de/ptx-atlas/#ermittlung-der-kraftstoffgestehungskosten

[112] https://rise.esmap.org/scores

[113] https://devkopsys.de/ptx-atlas/#ermittlung-der-kraftstoffgestehungskosten

[114] Fraunhofer IEE cost model 2022

[115] Prognos 2020: Kosten und Transformationspfade für strombasierte Energieträger

[116] Prognos 2020: Kosten und Transformationspfade für strombasierte Energieträger

[117] Fraunhofer IEE cost model 2022

[118] J. Gorre, F. Ortloff und C. van Leeuwen 2019: Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage

[119] J. Gorre, F. Ortloff und C. van Leeuwen 2019: Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage

Hydrogen production costs by electrolysis

The hourly resolved generation time series are used to model different minimum-cost renewable hydrogen and derivatives generation systems. In total, a minimum cost system is designed for 12 technology options and simulated for representative sites from the previous area analysis. The 12 technology options differ firstly based on the electrolysis system used (low temperature PEM or high temperature SOEC) and the renewable hydrogen and derivatives variant.

In determining the cost-optimal system design, different system components are considered. For electricity generation, ground-mounted solar power systems and onshore wind power systems are taken into account, as large farm and not connected to the grid. The design can be optimized with intermediate storage of electricity, such as integrating battery storage into the system. In a first step, the generated electricity is required by the electrolysis for hydrogen production. In the case of high-temperature SOEC plants, there is also a heat requirement for hydrogen production. This can be covered by large heat pumps or electric boilers. It is assumed that the electricity for the electrical heat supply also comes from the system's wind or solar plants or, if applicable, from the battery storage.

Derivatives production cost

The hydrogen produced can optionally be temporarily stored in a hydrogen storage tank before it is liquefied (depending on the end product), compressed for storing reasons or even further synthesized into other derivatives. For the synthesis of carbon-based derivatives (most of the derivatives), CO_2 capture from the air is included, whose electricity demand also comes from the system and whose heat demand is covered by the heat generators, possibly in combination with a heat storage system. Part of the waste heat from the synthesis can be used for high-temperature electrolysis. Optionally, a methane storage can be included in the system to make liquefaction more flexible in terms of time. The power supply for the compression or liquefaction of the fuels also comes from the system.

The cost-optimal composition of a system is determined from the above-mentioned components for a determined location for any fuel type. The cost optimized design is determined based on investment cost, fixed and variable operating costs, and fuel costs (electricity). The system operation is mapped in hourly resolution for an entire year, taking into account seasonal fluctuations and short-term of wind and PV power supply.[120]

Transport cost

Transport cost of hydrogen and derivatives (PtL, Methanol, Liquid SNG and Liquid Hydrogen) is another cost component that needs to be determined in order to map the renewable hydrogen and derivatives import costs. For this purpose, a cost model for tanker ships was developed, which calculates the transport costs in €/MWh for each fuel variant, depending on the distance between the importing (EU) and exporting country. To calculate the distance, the largest port of the exporting country is taken into account in each case, with the nearest importing port in EU. If the country does not have its own port, the nearest foreign port is selected. The tankers are propelled by the same fuel that they transport. For example, it is assumed that the hydrogen tanker has a propulsion system consisting of a polymer membrane fuel cell and an electric motor, including the associated power electronics. The technology-specific costs for the corresponding propulsion systems are accounted for in the investment costs, which are included in the annual fixed costs of the tanker

[120] The assumptions and parameters for the operation of the plants are listed in the table available at https://devkopsys.de/ptx-atlas/#kostenoptimale-systemauslegung-von-ptx-technologien

service using the net present value method. For this purpose, a depreciation period of 25 years is applied.

The total annual costs of the ship, consisting of the fixed and the variable costs, are divided by the annual transport performance, which depends among other things on the ship size and the ship speed, in order to represent the costs in the target unit €/MWh of the transported fuel.

To understand the dependencies of the transport, the section starts with the costs for shipping the different final products (liquids) to Europe. The detailed assumptions about transport can be found in the following paragraphs and in section 3.2.

The following parameters have influence on the cost of transportation:

- Transport distance

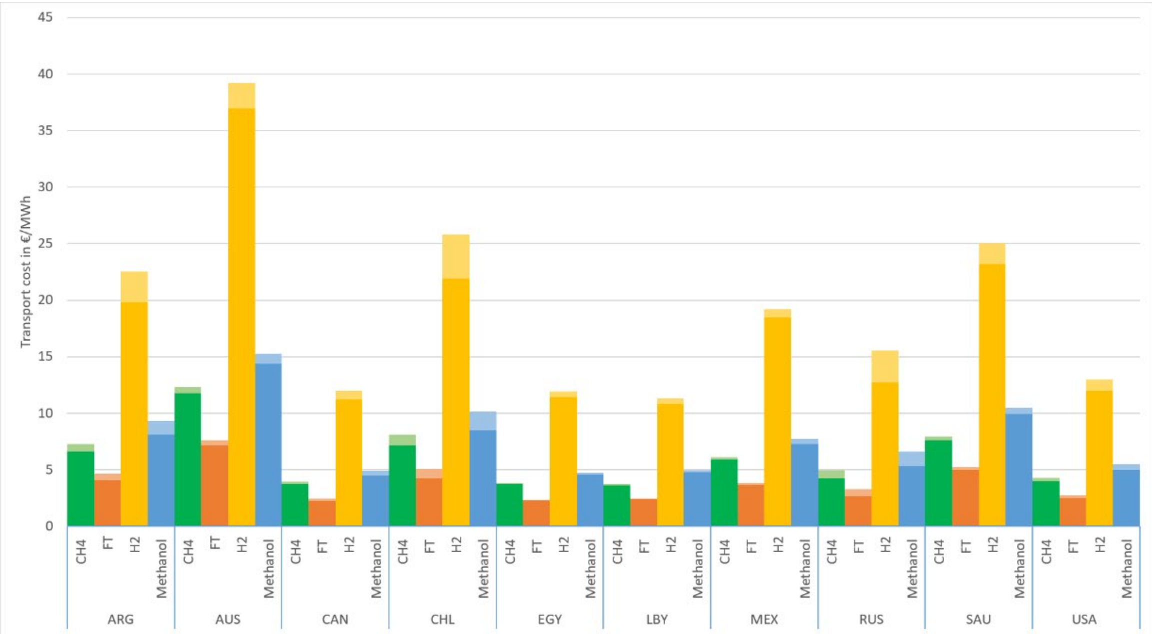
Table 22 Average transport distance from different countries up to EU borders

	ARG	AUS	CAN	CHL	EGY	LBY	MEX	RUS	SAU	USA
Transport distance	12,302	22,015	6,544	14,413	6,451	5,166	10,318	7,187	12,497	6,733

- Losses of final product during transport (e.g. boil-off), which differs significantly from one product to another one
    - 0.2 %/d for LH_2 and CH_4
- Energy losses due to conditioning of final product (e.g. liquefaction)
    - Included in final product amount

Transport cost of derivatives by country vary depending on the location of the renewable hydrogen and derivatives plant within a country. The ranges of transport cost are shown in Figure 19 for the 10 countries which have been identified as potential exporting parties to EU (section 3.1).

Figure 19 Transport cost for RES-H_2 and derivatives products from Top 10 countries to Europe



The detailed average costs for transport for each carrier from each country (well defined distance) are shown in Table 23.

Table 23 Average transport cost (2030)

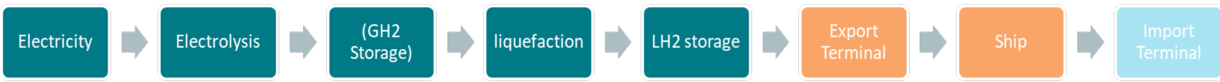
[€/MWh]	ARG	AUS	CAN	CHL	EGY	LBY	MEX	RUS	SAU	USA
LH_2	21.17	38.07	11.59	23.86	11.69	11.07	18.84	14.13	24.13	12.47
Methanol	8.73	14.82	4.70	9.32	4.64	4.88	7.51	5.99	10.23	5.26
FT	4.36	7.41	2.35	4.66	2.32	2.44	3.76	2.99	5.11	2.63
SNG	6.93	12.02	3.82	7.65	3.78	3.67	5.99	4.61	7.79	4.13

3.3.1 Cost of Liquid Hydrogen (LH_2) supply chain

This section presents the costs for each of the Top 10 countries of

- Liquid hydrogen production, which is detailed in section 3.2.1;
- Import cost, meaning liquid hydrogen production and transport.

The "production cost" comprises the supply chain steps illustrated in green boxes in the figure below, while the "import cost" comprises the green and orange boxes (while the blue box is not comprised in the cost).



The following figures show the LH_2 production cost (Figure 20) and LH_2 import cost (Figure 21) in 2030.

Figure 20 Liquid Hydrogen Production cost 2030

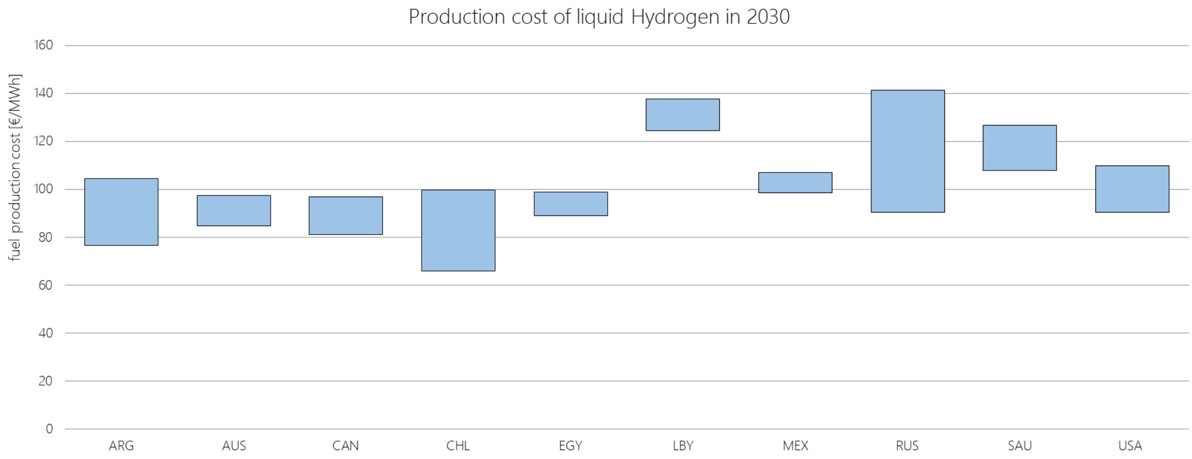
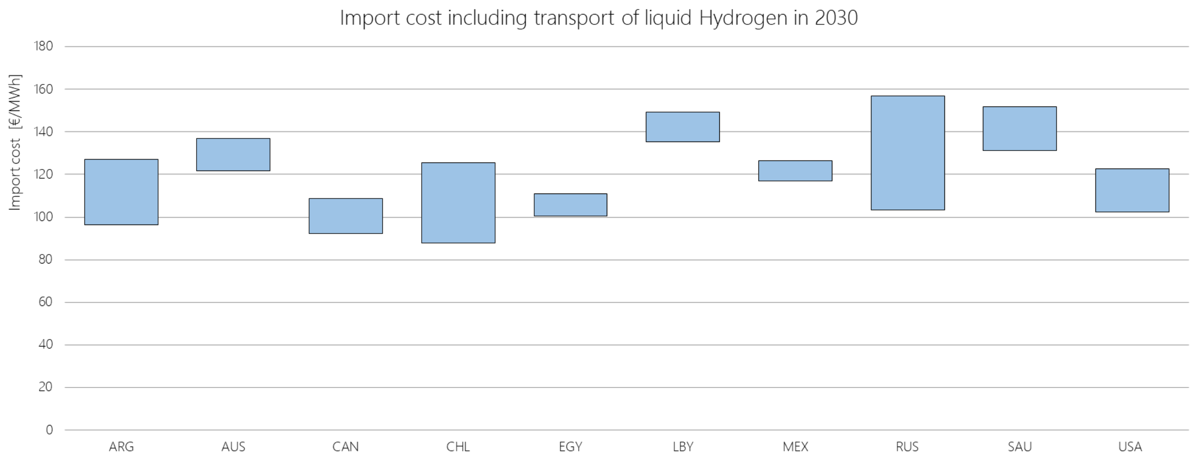


Figure 21 Liquid Hydrogen Import cost 2030

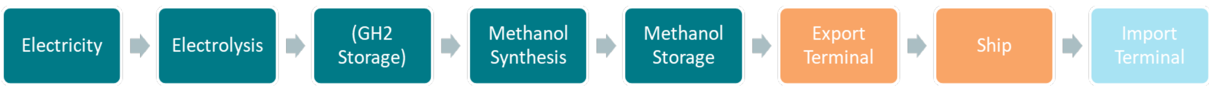


3.3.2 Cost of Methanol supply chain

This section presents the costs in each of the Top 10 countries with respect to:

- E-methanol production, which is detailed in section 3.2.2.2;
- Import cost, meaning MeOH production and transport.

The "production cost" comprises the supply chain steps illustrated in green boxes in the figure below, while the "import cost" comprises the green and orange boxes (while the blue box is not comprised in the cost).



The following figures show the MeOH production cost (Figure 22) and import cost (Figure 23) in 2030.

Figure 22 Methanol Production cost 2030

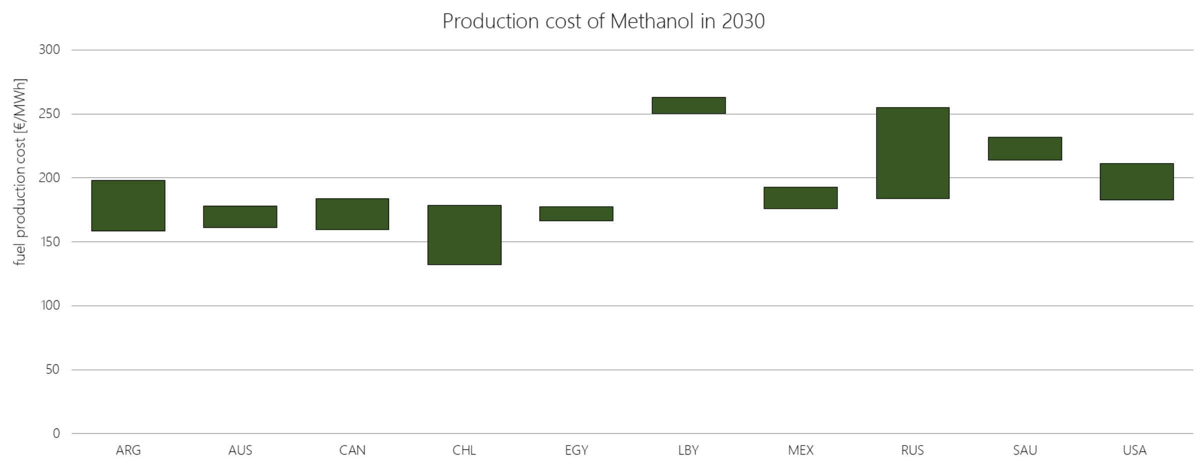
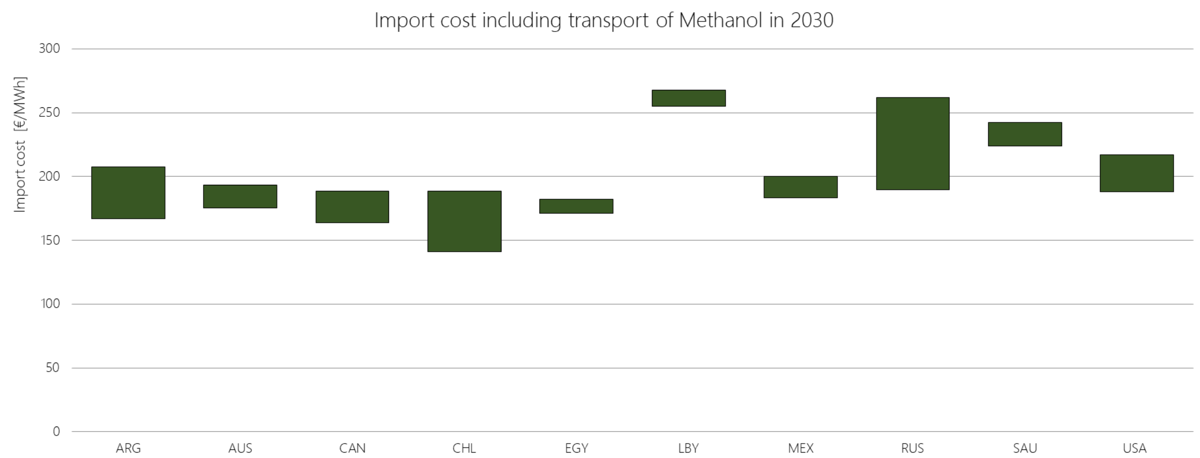


Figure 23 Methanol Import cost 2030

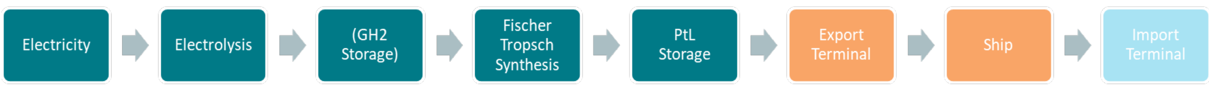


3.3.3 Cost of Fischer Tropsch PtL (Diesel/Kerosene) supply chain

This section presents the costs in each of the Top 10 countries with respect to:

- Power-to-liquid (e-diesel / e-kerosene) production (via Fischer Tropsch process), which is detailed in section 3.2.2.3;
- Import cost, meaning Power-to-liquid production and transport.

The "production cost" comprises the supply chain steps illustrated in green boxes in the figure below, while the "import cost" comprises the green and orange boxes (while the blue box is not comprised in the cost).



The following figures show the Fischer-Tropsch-fuels like diesel and kerosene production cost (Figure 24) and import cost (Figure 25) in 2030.

Figure 24 Fischer Tropsch (Diesel/Kerosene) <u>Production</u> cost 2030

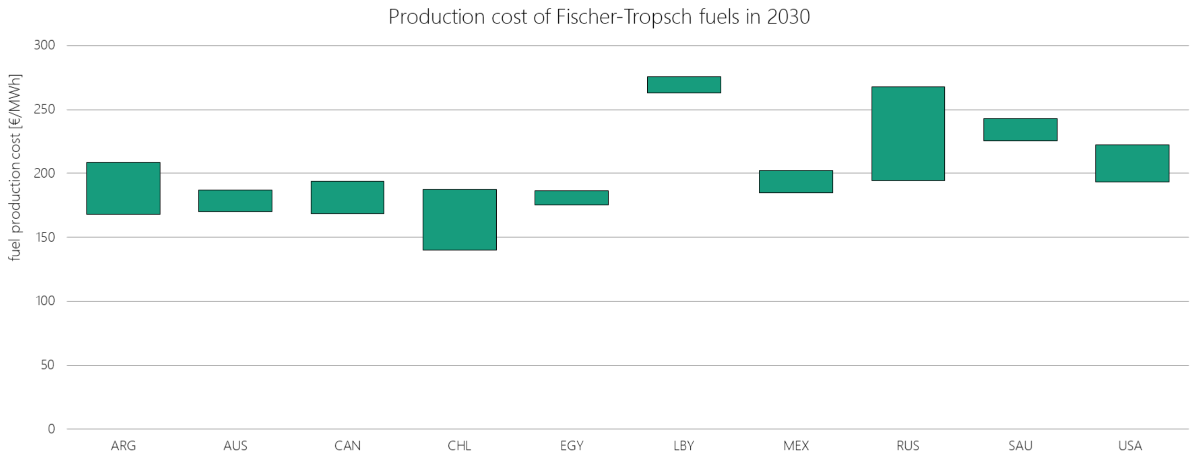
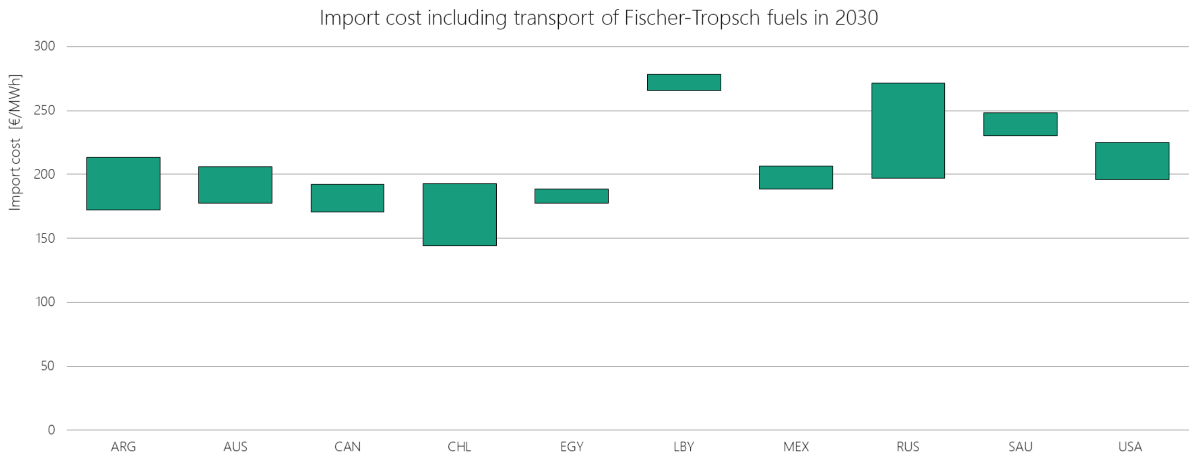


Figure 25 Fischer Tropsch (Diesel/Kerosene) <u>Import</u> cost 2030

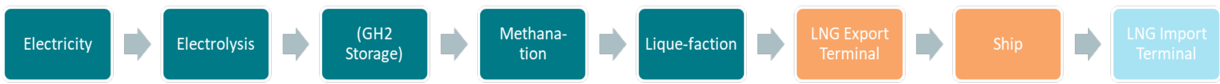


3.3.4 Cost of Liquid Synthetic Natural Gas (SNG) supply chain

This section presents the costs in each of the Top 10 countries with respect to:

- Synthetic Natural Gas (SNG) production, which is detailed in section 3.2.2.4, and liquefaction (or synthetic LNG);
- Import cost, meaning SNG production, liquefaction and transport.

The "production cost" comprises the supply chain steps illustrated in green boxes in the figure below, while the "import cost" comprises the green and orange boxes (while the blue box is not comprised in the cost).



The following figures show the SNG production and liquefaction cost (Figure 26) and import cost (Figure 27) in 2030.

Figure 26 Liquid Synthetic Natural Gas Production cost 2030

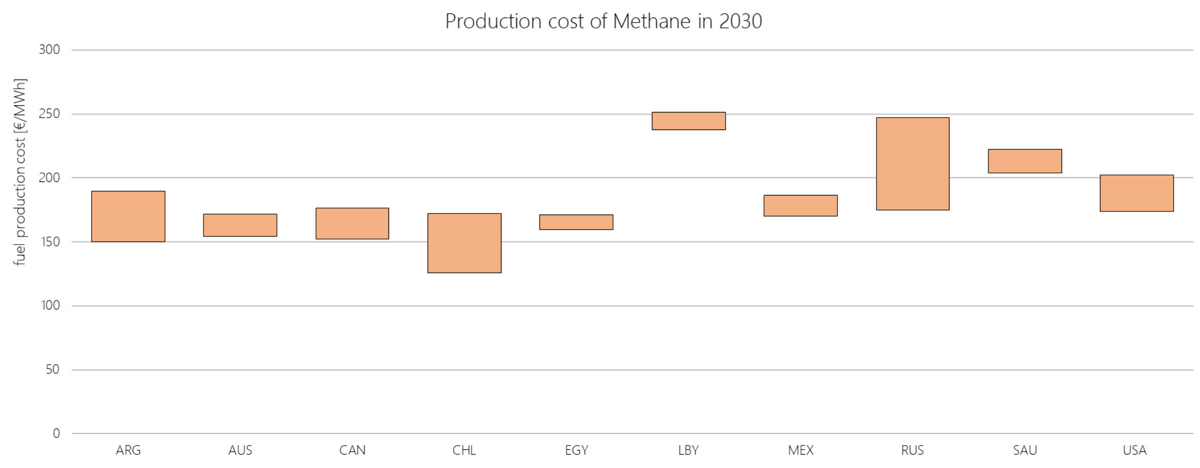
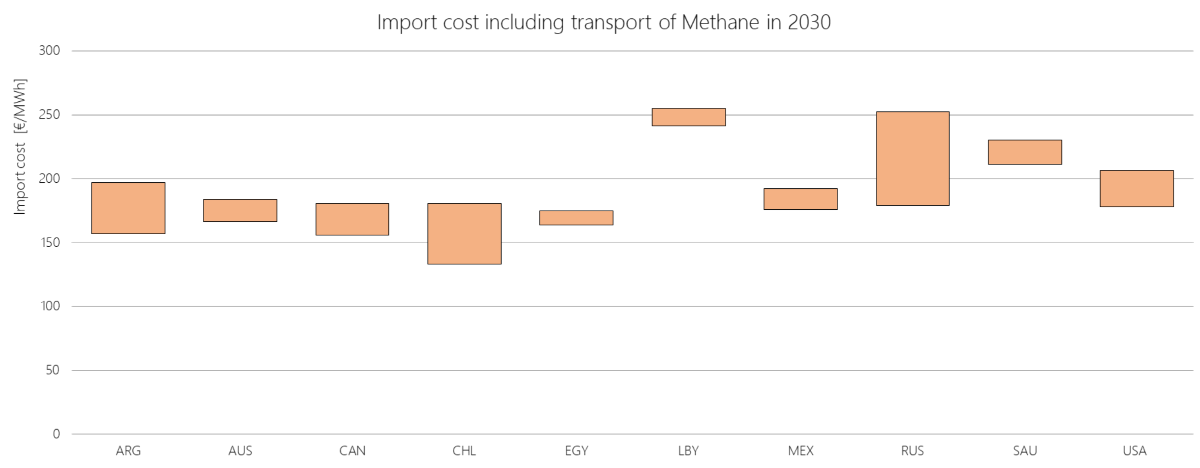


Figure 27 Liquid Synthetic Natural Gas Import cost 2030



3.3.5 Main conclusions and takeaways regarding carriers' competitiveness

As identified in this section, supplying the future European economy, its energetic and industrial demand as well as the transport sector (including aviation and the maritime industry) can be covered also by imports of renewable hydrogen and derivatives.

In section 3.2, various production and transport technologies for the import of renewable hydrogen and its derivatives were described. As indicated, the more conversion steps the process chain contains, the lower its efficiency, which **directly leads to the higher costs of those derivatives**. However, due to i.e. **excellent renewable energy resources with accordingly low LCOE and high full load hours, the combined production and transport cost can be a very attractive option for the EU – in particular when considering renewable hydrogen derivatives which are cheap and efficient to transport**.

The import of ammonia, methanol, e-diesel and e-kerosene seems to be the most straightforward to realize at the present time. The **infrastructure for transporting these fuels already exists** and is already being used for the fossil hydrocarbons as well as fossil-based ammonia to be substituted. Additional transport capacities and some new export terminals might however be necessary. The cost of transporting these liquids to the EU has proven to be the most economical in the analysis, especially compared to the transport of **liquefied hydrogen** which remains expensive due to the need for new infrastructure (terminals, tanks), the energy intense liquefaction and boil-off losses during transport.

If the demand for pure hydrogen exceeds the domestic European production capacities, it is suitable to import hydrogen via a pipeline from neighboring countries. Chapter 3.2.1.2 described what a future European hydrogen network could look like and the routes via which it seems plausible today to import hydrogen in the future. **Excellent renewable energy resources near the EU with accordingly low LCOE and high full load hours would lead to very attractive production costs of gaseous hydrogen. New storage and a grid infrastructure (new built pipelines or rededicated natural gas infrastructure) would still be required. This option, for the direct use of hydrogen (in the industry or in transport), requires only hydrogen compression for the transport and will remain more attractive than the reconversion of the liquid derivatives back to hydrogen.**

The main cost driver for import costs of renewable hydrogen and derivatives remains the availability and cost of renewables. This is demonstrated in section 3.1 by the extremely favorable production costs of derivatives in the Top 10 countries, such as in Chile. The transport costs, in turn, depend mainly on the transport distance (including the losses). Despite the comparatively long distance between Chile and Europe and the correspondingly higher transport costs, the cost advantages due to extremely advantageous renewable resources outweigh the disadvantages.

Nevertheless, the large-scale renewable hydrogen production projects announced to date are not yet sufficient to meet the EU's needs. However, new projects with increasing scale and thus production capacity are being announced continuously and so this situation can change in the coming years.

Renewable hydrogen derivatives like ammonia, or methanol, can also replace existing industrial use of hydrogen, which is currently fossil-based. The EU industry could directly import these final feedstocks (e.g. fertilizer industry importing renewable NH_3 from outside EU), or could purchase renewable hydrogen produced within the EU, and convert it on-site (as is currently the case) to NH_3. Nevertheless, importing liquid hydrogen in order to produce the derivatives within Europe leads to very low efficiencies and high costs compared to directly importing the derivative needed. Producing the derivatives within the EU from gaseous hydrogen which is imported via pipelines leads to lower losses and costs. Comparing these options is not done in the frame of this study, as it would require to assess the NH_3 production cost of the EU fertilizer industry.

3.4 Regulatory needs for hydrogen imports and infrastructure

Renewable hydrogen and derivatives will become increasingly important for the energy transition in Europe, and imports may play a big role in the European hydrogen economy as discussed in section 3.4. Besides the techno-economic aspects (technologies, geographies and transport methods), there are multiple uncertainties to tackle when establishing international H_2 markets and import infrastructure which require a policy response from the EU and Member States alike, if hydrogen and derivative imports from non-EU countries is to take place. This section discusses the barriers and regulatory needs for developing hydrogen imports to the EU, with a focus on renewable and low-carbon hydrogen.

The EU Hydrogen strategy (*'A hydrogen strategy for a climate-neutral Europe'*) released in July 2020 sets out the vision of installing at least 6 GW of hydrogen electrolysers in the EU by 2024, increasing to 40 GW by 2030. It further addresses the EU strategy for H_2 imports and the international dimension, placing hydrogen high on its external policy agenda. Its goal is cooperation in the field of clean hydrogen with the EU's neighbouring countries/regions and other international partners to establish secure hydrogen supply chains and diversify imports. Africa - North Africa in particular - is considered as a potential future partner due its geographical proximity and RES potential, while the EU's Eastern and Southern[121] neighbours, especially Ukraine, are also set to be priority partners due to existing infrastructure and physical interconnections. To address production and market uncertainties, the strategy aims for coordination with neighbours on research, innovation and policy as well as direct investments and fair trade of hydrogen and derivatives, recognising the importance of a full value chain approach and that to establish demand for the fuel parallelly with an adequate market.

The strategic importance of partnerships with Eastern and Southern neighbours of the EU are not to overlook, even if some market and regulatory barriers need to be overcome. Hydrogen imports from Energy Community[122] countries or North Africa could potentially be competitive. Some Southern neighbourhood countries like Egypt and Libya are already on list of main potential hydrogen exporting countries of this chapter, while some Energy Community countries are prime candidates for imports given their planned EU accession (e.g. Ukraine). Hydrogen would need to be transported shorter distances to the EU borders. Moreover, supplies through pipelines could be more secure than shipments from other regions, as competition with e.g. Asian markets would be more limited (however, this could also lead to a greater dependency on specific suppliers).

Besides cooperating under existing trade agreements, the EU already announced plans to provide targeted assistance to North African countries on renewable electricity and hydrogen production, as well as to facilitate imports to Southern Europe, with multiple electricity transmission interconnectors already under construction or in the study phase. Financing instruments will come from the Neighbourhood Investment Platform set up by the European Commission[123].

Textbox 1 Commission priorities set in the Hydrogen Strategy regarding the international dimension of hydrogen markets

- Strengthen EU leadership in international fora for technical standards, regulations and definitions on hydrogen
- Develop the hydrogen mission within the next mandate of Mission Innovation (MI2)
- Promote cooperation with Southern and Eastern Neighbourhood partners and Energy Community countries, notably Ukraine on renewable electricity and hydrogen
- Set out a cooperation process on renewable hydrogen with the African Union in the framework of the Africa-Europe Green Energy Initiative
- Develop a benchmark for euro denominated transactions by 2021

Concerning regulatory and market barriers for hydrogen imports to the EU, some studies exist, but the topic is rather new and few principles exist yet on how to foster international H_2 trade and hydrogen imports to the EU. **In this section we provide recommendations on policy and regulatory frameworks to promote the import of hydrogen and its derivatives to the EU.**

[121] The Southern neighbourhood includes Algeria, Egypt, Israel, Jordan, Lebanon, Libya, Morocco, Palestine, Syria and Tunisia

[122] Albania, Bosnia and Herzegovina, Kosovo*, North Macedonia, Georgia, Moldova, Montenegro, Serbia and Ukraine

[123] A Mediterranean Green Deal For An Effective Energy Transition As Part Of The Sustainable Post-Covid Recovery: https://www.cmimarseille.org/sites/default/files/newsite/energy_report_final_final_online_0.pdf

3.4.1 Context and analysis of barriers

Main Take-aways of the section

This section addresses five contextual topics and barriers to consider when establishing policies and regulations around international hydrogen trade, specifically regarding EU imports.

Some of the barriers are generally referring to the lack of international trade at the moment, others are related to hydrogen infrastructure and market design.

- Besides every player in the value chain **needing clarity about the future H_2 agenda, preferred** production technologies, as well certification criteria have to be defined in order for investments to start.
- **There are no established international renewable hydrogen markets presently**, thus creating international renewable and low-carbon hydrogen markets will require developing supply and demand as well as the entire value chain
  - The development of an initial demand for renewable and low carbon hydrogen can start from substituting existing fossil hydrogen demand.
  - Further developing hydrogen demand will require the deployment of new uses
  - Therefore, initially investments will be especially needed in supply and transportation of hydrogen if end-use initially focuses on substituting existing grey hydrogen consumption, but in the long run this will apply to the entire value chain
- Intergovernmental agreements and strategic partnerships can foster international hydrogen trade, and bilateral agreements are most fit to do this (as opposed to multilateral)
- Development of import infrastructure will require certainty regarding hydrogen volumes. Investors will only provide sufficient capital for repurposing and new infrastructure if:
  - A long-term and reasonably secure **supply and demand for hydrogen** can be foreseen;
  - **H_2 purchase/sale agreements and reasonable forecasts of associated capacity purchases** are in place for new and repurposed infrastructure
  - Bilateral and multilateral agreements address **country-specific risks** and provide the adequate **legislative and regulatory framework** for trade
  - **Permits and licenses** (new or automatically transferred from gas or liquid fuel assets) are in place for new fuels, as proof of safety and operation.
- There is no harmonised system for the certification of renewable and low-carbon fuels, which blocks the accounting of emission reductions achieved towards sectoral renewable energy targets and allows possible false claims by hydrogen producers, as well as results in a lack of trust by the public in low-carbon character of hydrogen.
  - EU policy makers must ensure that standards for accounting of the environmental impact of imported synthetic fuels (including gases) are agreed upon and are aligned with EU regulations, to avoid penalising EU producers and carbon leakage.
- The future regulatory framework should address the repurposing of existing regulated LNG terminals, otherwise the lack of a framework in this regard could slow down investments into critical H_2 infrastructure
- Existing long-term gas capacity contracts may hamper conversion of existing assets due to supply commitments, more likely in case of pipelines than in LNG terminals.

Textbox 2 Challenges and measures for the development of an international hydrogen market according to the literature

Some of the main requirements for the development of an international hydrogen market according to the literature

- As hydrogen consumers, the European industrial sector needs **clarity about the future H_2 agenda** and implications to their operations, while investors in the future hydrogen value chain need **more certainty in the transition pathway**;
- There needs to be clear understanding of H_2 production technologies as well as on **what can be counted as renewable and low-carbon hydrogen** under EU and national legislation;
- **EU-wide instruments are needed that clarify the above terminology** of renewable and low-carbon hydrogen and derivatives, and establish quality standards;
- Important **infrastructural investments** will be required to establish the conditions for trade (in terminals, storage, transport and delivery), mostly by partner countries, with eventual support from the EU by e.g. subsidies for energy prices. In the long-run investments have to cover the entire value chain.

Hydrogen Europe's 'Green Hydrogen for a European Green Deal'[124] presents the 2x40 GW initiative, which is aimed at scaling up electrolyser production capacity in the EU up to 40 GW and in addition deploying capacity in and sourcing imports from North Africa and Ukraine - both sources totaling ca. another 40 GW in electrolyser capacity by 2030. For hydrogen imports as well as domestic markets to materialize, the following would be needed, among others:

- A H_2 market design with flexible market regulations allowing for hybrid connections (i.e. enabling connection to both the electricity and hydrogen grids);
- Hydrogen market stimulation programs
- EU tenders for renewable electricity-based hydrogen;
- Developing a long-lasting and mutual cooperation between the EU and North Africa (as one of the main potential import partners) on political, economic and societal levels.

3.4.1.1 There are no established international hydrogen markets presently

This barrier concerns the fact that starting (international) renewable (or low-carbon) hydrogen markets will require **developing supply and demand as well as the entire value chain.** Companies and investors will require long-term certainty to take the decision to make capital-intensive investments in the entire value chain.

There is limited hydrogen trade in the EU, while international (renewable and low-carbon) hydrogen markets are practically inexistent. Significant captive hydrogen demand exists in industry. As fossil and renewable hydrogen are interchangeable, this means the development of an initial demand for renewable and low carbon hydrogen is less challenging, as it could substitute existing fossil hydrogen demand. However, further developing hydrogen demand will require the deployment of new uses, and this could take place in parallel with the substitution of fossil hydrogen use. Therefore, initially investments will be especially needed in supply and transportation of hydrogen, but in the long run this will apply to the entire value chain.

[124] https://dii-desertenergy.org/wp-content/uploads/2020/04/2020-04-01_Dii_Hydrogen_Studie2020_v13_SP.pdf

In order to support the development of an international hydrogen market, **bilateral and multilateral intergovernmental agreements will play a key role.** Investors can address commercial, currency and other risks, but intergovernmental agreements target **country and regulatory risks.**[125]

Most likely concrete intergovernmental agreements fostering hydrogen markets will be bilateral (as opposed to multilateral). Existing multilateral partnerships do help to foster an international value chain, and include the Clean Energy Ministerial Hydrogen Initiative, the IRENA Collaborative Framework on Green Hydrogen, Mission Innovation and the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). However, international hydrogen initiatives are still focused on mapping and disseminating best practices and pilot projects, rather than establishing international hydrogen trade. There is a lack of suitable energy treaties under which hydrogen cooperation can really develop, as many multilateral initiatives are non-binding, while Energy Charter Treaty does not include major potential hydrogen exporters such as AU, CL, CN, MA, NO, SA[126]

In contrast, bilateral agreements can be less complex to negotiate and can be based on a more concrete business case, and therefore could more readily kick-start an international value chain[127]. Certain Member States or national group of actors have already started identifying the potential for hydrogen imports, such as Denmark, Belgium and the Netherlands. Furthermore, a few bilateral agreements have been signed for fostering international hydrogen trade - Germany has signed agreements with Australia, Canada and Saudi Arabia.[128] Section 3.4.2.1 provides further details on some of these initiatives. Countries such as the Energy Community Contracting Parties may have to implement the EU energy acquis, but as this process can be long, even for these countries bilateral agreements could provide the incentives for accelerating hydrogen-related initiatives and the acquis implementation process.

Textbox 3 Australia-Japan cooperation agreement[129]

Australia and Japan released on 10 January 2020 a *Joint Statement on cooperation on Hydrogen and Fuel Cells* whereby they commit to cooperate on the deployment of hydrogen as a key contributor to reducing emissions in the energy sector, especially when produced from RES or fossil fuels combined with CCUS.

The cooperation will involve exchanging views on their respective national hydrogen strategies; shaping the global hydrogen market regulations, codes and standards and their harmonisation to expand domestic and international demand and supply; including through international fora and exchanging safety information on hydrogen to ensure safe and sustainable production, delivery, storage and infrastructure operation. They will also exchange views on policies and measures towards an effective hydrogen market, including demand-side support measures, H_2 certificates and RDI both domestically and internationally. The Hydrogen Energy Supply Chain project - HESC[130] was created in order to safely produce and transport clean liquid hydrogen from Australia to Japan and thus as a first attempt to create an end-to-end supply chain.

[125] Frontier Economics for World Energy Council Germany (2018) International Aspects of a Power-to-X Roadmap

[126] Frontier Economics for World Energy Council Germany (2018) International Aspects of a Power-to-X Roadmap

[127] In order to avoid distortions though, some elements of the EU regulatory framework should be implemented in partner countries too.

[128] German Federal Ministry for Economic Affairs and Energy (2021) Minister Altmaier signs Memorandum of Understanding on German-Saudi hydrogen cooperation ; Declaration of Intent signed to establish German-Australian hydrogen alliance ; Altmaier: „Mit Kanada wichtigen Partner für transatlantische Energiewende gewonnen"

[129] Microsoft Word - 【set】Japan Australia JS on Hydrogen (Japan) .docx (meti.go.jp)

[130] https://hydrogenenergysupplychain.com

In 2021 the first liquefied hydrogen cargo ship has been completed, and the first shipment from Australia to Japan of liquefied hydrogen produced by HESC was expected between October 2021 and March 2022.[131]

The Council Conclusions "Towards a hydrogen market for Europe"[132] of 2020 highlight the importance of international partnerships with public and private stakeholders to develop the hydrogen value chain. It stresses the importance of assessing infrastructure options, considering where needed hydrogen and derivative imports. It also mentions the need to use domestic hydrogen potential, while developing international cooperation, in particular from partners with high renewable energy potential, while developing international hydrogen markets.

In order to have a direct impact on the development of an international hydrogen value chain, **partnerships should address 4 points in particular** :

- Develop expertise, including technical expertise but also on setting up projects and business development (through participation in tenders or other means);
    - Promote certainty of demand to incentivise supply (and to a more limited extent demand) investments;
    - Address financing and establish incentives, especially to address capital expenditures;
- Exchange regulatory practices and establish minimum principles to avoid unfair competition between domestic and foreign hydrogen producers
- Consider the holistic context, promoting local development and addressing resource neo-colonialism concerns, i.e. concerns that local resources are being exploited without benefitting the non-EU countries and their populations[133].

A minimum scale of demand is required for developing an international value chain, given the important investment needs and relevant operational costs. Investments in hydrogen/derivatives production and export capacity are capital intensive. Not all Member States may have sufficient financial means or forecasted hydrogen demand to meet the minimum scale to develop an international value chain on its own. As an example, the German H_2Global project aims to initially incentivise the investment in an electrolyser capacity of 500 MW, with a funding from the German government of 900 billion € and leveraging over 1.5 billion € in private investments[134]. Therefore, regional or EU instruments combining financing capabilities and demand volumes of multiple Member States could facilitate early inclusion of Member States with such constraints to international hydrogen value chains.

Hydrogen trade should be based on mutually respected rules to ensure a level playing field and avoid national governments unduly supporting their own hydrogen value chain against the EU's. Minimum requirements can comprise unbundling and third-party access rules, and avoidance of (cross-)subsidies in the hydrogen value chain. Oversight on regulated natural monopoly activities could provide confidence to investors[135] and avoid (cross-)subsidisation in these activities.

[131] https://www.spglobal.com/platts/en/market-insights/latest-news/shipping/072321-australias-first-liquid-hydrogen-shipment-to-japan-delayed-to-oct-mar

[132] European Council (2020) Council Conclusions "Towards a hydrogen market for Europe" 13976/20

[133] Fraunhofer ISI (2020) Opportunities and challenges when importing green hydrogen and synthesis products

[134] German Federal Ministry for Economic Affairs and Energy (2021) New funding instrument H2Global launched – H2Global Foundation established

[135] Huurdeman et al. (2021) Issues in development and interaction of gas and hydrogen transport networks

Therefore, market-making mechanisms and trade agreements will be necessary to develop hydrogen markets. These are detailed in section 3.4.2

3.4.1.2 Development of import infrastructure will require certainty regarding hydrogen volumes

To enable hydrogen and derivative imports to the EU that complement domestic supply, investments are needed for **developing repurposed and new infrastructure** (terminals and pipelines). The **European Hydrogen Backbone**[136] study indicates that repurposed gas infrastructure can significantly contribute to a future hydrogen network. Combined with targeted investments in new pipelines and compressor stations, this setup enables long-distance hydrogen transport at an affordable cost. Proper, interconnected transport infrastructure that reaches all of Europe could be in place by 2040 – which would also enable foreign imports. To prepare EU infrastructure for hydrogen trade, gas networks can be repurposed, along with LNG and other terminals to receive liquid hydrogen or hydrogen derivatives. Pipelines are the most economical alternative to carry hydrogen in large volumes for up to even 3,000, while shipping (potentially in the form of derivatives) is a more economical alternative for longer distances – although the exact figures vary per study and depend on multiple assumptions.[137]

Due to uncertainty about supply and demand though, these developments might not happen fast enough to accommodate future import volumes.

Investors will only provide sufficient capital for repurposing and new infrastructure if:

- A long-term and reasonably secure **supply and demand for hydrogen** can be foreseen;
- Associated with this, **H_2 purchase/sale agreements and reasonable forecasts of associated capacity purchases** are in place for new and repurposed infrastructure.
- Bilateral and multilateral agreements address **country-specific risks** and provide the adequate **legislative and regulatory framework** for trade;
- **Permits and licenses** (new or automatically transferred from gas or liquid fuel assets) are in place for new fuels, as proof of safety and operation. Industries have to adhere to operating rules such as the *Seveso directive*[138] and other safety regulations.

There is a need for a **global overview of potential supply and demand quantities** and the extent to which these match – as well as how prices will evolve – to develop the international trade value chain. Fraunhofer points[139] that this overview should:

- Consider national potentials in terms of resources (wind, solar radiation, water), technical feasibility and costs for plant facilities & infrastructure
- Integrate economic, social, energy and development policy goals into the analysis regarding both importing and exporting countries

A supply chain overview focusing on the above can help **identify candidates for bilateral/multilateral partnerships.** Moreover, such a mapping exercise could serve **transit countries too, for whom supply and demand certainty is equally important** and are reliant on gas.

136 European Hydrogen Backbone - Daniel Muthmann (europa.eu)

137 See JRC (2021) Assessment of Hydrogen Delivery Options; IEA (2019) The Future of Hydrogen

138 The Seveso Directive (2012/18/EU) aims to prevent major accidents and hazards involving dangerous substances in industrial establishments, especially chemicals.

139 Opportunities and challenges when importing green hydrogen and synthesis products (fraunhofer.de)

In the initial phases, while production of renewable hydrogen scales up, a combination of low-carbon and renewable hydrogen might be required to produce enough volume to convert a meaningful part of the EU gas infrastructure – then blue H_2 would be phased out gradually[140]. H_2 purchase agreements and associated capacity purchases are critical for defining quantities.

Therefore, policies and measures for defining supply and demand and creating new partnerships will be necessary to develop import infrastructure. These are detailed in section 3.4.2

3.4.1.3 Repurposing of LNG terminals requires significant investments and adequate regulatory frameworks

There is still a lack of studies addressing the costs of building new vs. repurposed LH_2 terminals. However, liquid hydrogen needs to be cooled to a much lower temperature (-253 °C) than natural gas (-162 °C).[141] Therefore, significant components of an LNG terminal need to be repurposed/replaced in order to repurpose the entire terminal as an LH_2 terminal. This means that **a repurposed LH_2 terminal is cheaper than a new-build[142], but the cost advantage is not as significant as for e.g. repurposing (certain) pipelines.** The specific costs of repurposing will depend on the terminal and may in certain cases make the repurposing unattractive compared to a new-build.

It is unlikely that existing LNG terminals can be adapted to handle multiple carriers simultaneously. Each carrier, be it hydrogen, ammonia or other, has different requirements regarding temperature, pressure and/or safety regarding toxicity. Even if parallel operation was possible, ports may lack space for building the parallel infrastructure. The exception would be synthetic methane, which could be readily accepted by LNG terminals. Existing ammonia/methanol terminals could be also more readily expanded.

As of end 2020, EU and national regulatory frameworks did not yet address the repurposing of LNG terminals, although the legislative proposals of the new hydrogen and decarbonised gas markets package should address this issue. Some national regulators have started or plan to start the analysis and development of a regulatory framework for hydrogen assets, although the development of H_2 terminals through repurposing of existing LNG terminals may not be explicitly addressed. For example, the Spanish Decree 335/2018 introduces provisions related to hydrogen infrastructure, but only regarding the authorisation for construction, operation, modification and decommissioning of installations for the pipeline transport of hydrogen to end-consumers. Germany has published in February 2021 a draft bill for the revision of the German Energy Industry Act (EnWG-E)[143]. However, it is focused on networks and does not address new or repurposed LH_2 terminals.

There was as of the end of 2020 in general also no regulation at the EU level or in Member States to address the impacts of the decommissioning of LNG terminals (and repurposing for hydrogen) on achieving energy & climate goals or ensuring security of supply. This could in the future lead to the decommissioning of LNG terminals when it could be more socially beneficial to repurpose the terminals to process hydrogen or derivatives. Likewise, as repurposing is generally

[140] North Africa-Europe Hydrogen Manifesto 2019-11-29_Dii_Studie2019_v03a.indd (dii-desertenergy.org)

[141] IEA (2019) The Future of Hydrogen: Seizing today's opportunities

[142] Interview with an European gas infrastructure operator

[143] https://www.bmwi.de/Redaktion/DE/Downloads/Gesetz/gesetzentwurf-enwg-novelle.pdf?__blob=publicationFile&v=4

not addressed in regulatory frameworks, **there were also no requirements on cost-benefit assessments or market tests for the repurposing of infrastructure.** Also, investments for making LNG terminals (more) future-proof may not be authorised under most regulatory frameworks.

From an economic perspective, there are advantages and disadvantages on using the regulated revenues of LNG terminal operators for financing investments in repurposed infrastructure. Some infrastructure operators[144] argue employing gas tariff revenues to finance repurposing to hydrogen would be a simple way to provide the necessary financing. A similar argument can be applied to regulated LNG terminals.

Hence, policies and measures will be necessary to repurpose LNG terminals and to ensure investments are aligned to energy & climate objectives. These are detailed in section 3.4.2.

3.4.1.4 There is no harmonised system for the certification of renewable and low-carbon fuels

The lack of harmonised certification schemes for hydrogen poses an issue, as it blocks the accounting of emission reductions achieved towards sectoral renewable energy targets and allows possible false claims by hydrogen producers, as well as results in a lack of trust by the public in low-carbon character of Hydrogen.

In order to ensure the adequacy of H_2 and derivative product imports, EU policy makers must ensure that **standards for accounting of the environmental impact of imported synthetic fuels (including gases) are agreed upon and are aligned with EU regulations,** to avoid penalising EU producers and carbon leakage. This harmonisation will be easier e.g. in case of Energy Community Contracting Parties, as the Renewable Energy Directive and other climate regulations should be transposed to the Contracting Parties' regulatory framework, leading to the development of national (sub-)targets for renewable energy as well as other measures[145]. The transposition of EU regulations into the Acquis makes it easier for respective countries to harmonise their future certification standards with the EU.

The carbon footprint of the entire value chain cannot be fully neutral, meaning that there is no fully-renewable hydrogen, but rather a substantial reduction compared to high-carbon (e.g. grey) hydrogen which needs to be thoroughly assessed and proven. Hence, thresholds must be set for a fuel to qualify as renewable or low-carbon, providing significant emission reductions compared to high-carbon counterparts.

A traceable and auditable system is needed, but **demonstrating compliance of renewable hydrogen** from third countries will not be straightforward. Despite the strong political push to request internationally-funded renewable hydrogen and derivatives -projects to be "100% green" (using only additional renewable electricity), this is difficult to implement in many countries, where experience with certification schemes is lacking and transparent monitoring of guarantees of origin is not possible. This has led to a **focus on off-grid projects**, supported by a number of stakeholders sceptical of the possibility to demonstrate additionality for grid-connected electrolysers. EU experience with sustainability criteria can thus be useful for the exporters.

[144] GIE (2021) Regulation of Hydrogen Infrastructure

[145] https://www.energy-community.org/legal/acquis.html

Certification schemes for renewable gases

There are already existing initiatives for the certification issue at hand: **CertifHy**[146] , a consortium set up by FCH 2 JU[147] aims to design the 1st EU-wide Green and low-carbon certification system during a three-year project. This means harmonizing H_2 guarantees of origin (GO) schemes across Europe and beyond to build a market for H_2 GO trade in close collaboration with market actors and the design of a certification Scheme for compliance with RED II renewable fuels. The EU's Hydrogen Strategy considers a framework based on the full life-cycle greenhouse gas emissions of hydrogen, using the CertifHy methodologies developed by industry initiatives, in consistency with the EU ETS monitoring, reporting and verification requirements and EU taxonomy for sustainable investments. According to the strategy, "the specific complementary functions that Guarantees of Origin (GOs) and sustainability certificates already play in the Renewable Energy Directive can facilitate the most cost-effective production and EU-wide trading".

Textbox 4 Book and Claim system and Mass Balance system

In RED II, two systems for tracking the consumption of renewable energy exist in parallel. Guarantees of origin under the Book & Claim (BC) system serve for the information of final energy consumers, whereas the certification system based on mass balance (MB) serves for the purpose of demonstrating the compliance with sectoral obligations for transport fuels. Hydrogen was added to both MB and BC systems which interact with each other. In the revision of RED II a union database for tracking renewable fuels should be set up – ideally expanded to all gaseous and liquid fuels - this system would be a good starting point to establish international certification of H_2 and low-carbon gases.

Source: Trinomics et al. (2021) Technical support for RES policy development and implementation - Delivering on an increased ambition through energy system integration : final report

The **TUEV Green Hydrogen certificate**[148] already takes into account the carbon footprint of hydrogen production (including the energy source) as well as transport. A certificate for green hydrogen under this scheme can be issued if the hydrogen produced has a GHG reduction potential of at least 60% compared to fossil fuels, or if produced by electrolysis, having a GHG reduction potential of 75% (based on the current reference values in the Renewable Energy Directive II and the values for conventional hydrogen produced by natural gas reforming). There is also additional criteria to the standard, such as the use of electricity from renewable sources for electrolysis and the use of biomethane. Moreover, certificate holders must prove that a robust monitoring system is in place to ensure the certified quality and that they can fulfill supply commitments. This scheme shows there will be no hydrogen with a zero carbon footprint for a long time – but a significant reduction against the MSR-hydrogen reference. Other sustainability criteria to be considered around large scale renewable hydrogen and derivatives projects could be i.e. competing land and water use and other environmental factors.

All the above shows that there are important challenges to be solved regarding certification in the international market context. It is also important, that future certification schemes are aligned with the coming EU carbon border adjustment mechanism (CBAM) and supply chain requirements (social and environmental standards) at Member State level.

[146] Certifhy

[147] www.fch.europa.eu

[148] TUEV SUED provides GreenHydrogen certification | TÜV SÜD (tuvsud.com)

Compliance of imported hydrogen with CBAM is not an issue at hand as the Commission proposal only covers industrial commodities and electricity at the moment, however it could later be extended to high-carbon hydrogen and derivatives like ammonia, which is already traded on international markets. Provided that future certification schemes adopt zero-carbon requirements, Hydrogen and derivatives certified according to EU standards should be exempt from future CBAM tariffs in case of this extension.

Therefore, policies and measures for establishing hydrogen standards in the EU and applying them to imports will be necessary. These are detailed in section 3.4.2

3.4.1.5 Existing long-term gas capacity contracts may hamper conversion of existing assets

The repurposing of existing methane pipeline faces potential availability constraints due to long-term natural gas commitments and capacity contracts[149]. Similar challenges could be faced by LNG terminals if the duration of capacity bookings is analysed, but LNG terminal operators do not see this as a barrier.

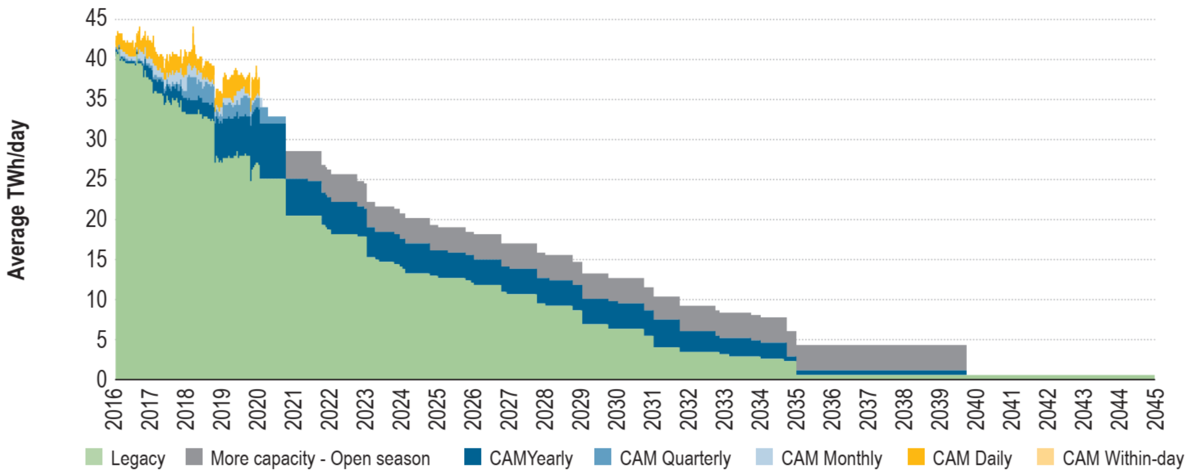
Pipelines serving non-EU transit countries (e.g. Ukraine) dependent on natural gas and with less ambitious climate targets may be particularly challenging to convert. Similar issues may occur between EU Member States, but to a lower extent and only if the Member State has limited gas supply route alternatives and is thus dependent on a specific pipeline/terminal.

Another regulatory barrier is that **often the gas pipelines are owned by network operators not (yet) allowed to own and operate hydrogen pipelines** – a review of the existing regulatory framework would be necessary if this was to be the case. This has an impact on import gas pipelines but also domestic ones.

With regards to pipelines, according to ACER (Figure 24), by 2050 legacy (agreed prior to the entry into force of the Capacity Allocation Mechanisms network code) bookings will have decreased to around 6-7 TWh/d, while other booking types amount already to another 6-7 TWh/d. This includes intra-EU interconnection points (IPs) as well as IPs with third countries. For example, Nord Stream bookings extend currently up to 2039 according to the ENTSOG transparency platform. This signals that some pipelines might be unavailable for eventual repurposing to hydrogen transport, depending on the demand quantities after 2030. **But as natural gas demand decreases in line with climate mitigation efforts, import capacities might still free up for hydrogen transport.**

[149] McKinsey (2021) Hydrogen Insights 2021

Figure 28 LNG terminal and transmission network bookings until 2045[150]



A similar situation regarding long-term bookings may exist for LNG terminals. Based on the correspondent transmission network entry points bookings, the following sample LNG terminals have long-term capacity bookings:

- Zeebrugge (BE) bookings run until 2028
- Porto Levante (IT) bookings until 2033
- Swinoujscie (PL) bookings run until 2036
- Gate terminal (NL) bookings run until 2036

However, **LNG terminal operators do not think existing bookings may constitute an important barrier.** Terminal utilisation may also be sufficiently low in order to allow reallocating capacity bookings to nearby terminals in the same or a nearby bidding zone. The duration of current long-term capacity bookings varies per terminal, and the average medium and long-term LNG supply contracts duration in 2019 was of 13.9 years[151].

Therefore, policies and measures for more to avoid long-term lock-in of supply contracts may be needed, particularly to pipelines. However, this will depend on the exact import infrastructure affected, and the attractiveness of its use for hydrogen import versus alternative solutions. Policies and measures are detailed in section 1.6.

3.4.2 Possible policy and regulatory measures

Main Take-aways of the section

This section proposes five policy recommendations as solution to the aforementioned barriers that hamper international hydrogen trade.

- **Bilateral and multilateral strategic partnerships and dialogue have to be established with exporting countries** as a framework for future trade, providing certainty to investments, developing technical expertise, addressing financing, and considering the wholistic context
- **Market-making mechanisms need to be developed at EU level.** Given the lack of an international hydrogen value chain, the capital intensity of the investments and future uncer-

[150] ACER (2020) Market Monitoring Report 2019 – Gas Wholesale Market Volume

[151] GIIGNL (2020) GIIGNL Annual Report 2020

tainties, a **coordinated approach to developing supply and demand is necessary**. Mechanisms such as **double-sided auctions** could be employed, while one-sided auctions can also help develop the H_2 value chain.
- **Require compliance of imported hydrogen and carriers with EU certification standards,** with national and international bodies facilitating the adoption of the certification schemes**.**
- **Provide clear regulatory frameworks for import infrastructure** in order to reduce regulatory risk to potential investors and ensure that new infrastructure investment is aligned to energy & climate objectives, including quality standards, allowing the repurposing of infrastructure when beneficial from a societal perspective
- **Incentivise measures by infrastructure operators and market parties to address constraints of existing long-term natural gas contracts and new contracting terms** to allow the repurposing of existing gas infrastructure for hydrogen import.

3.4.2.1 Establish bilateral and multilateral strategic partnerships and dialogue with exporting countries

To develop import and export value chains, **strategic partnerships and dialogue are needed between the EU and exporters** as a framework for future trade**.** The format can be diverse, ranging from trade forums to declarations of intent, high level steering groups, or concrete, intergovernmental partnerships. These strategic partnerships should aim to:

- Collect and develop the technical expertise
- Address financing issues and protect investments
- Promote certainty of demand and long-term purchase agreements to incentivise necessary investments
- Consider the holistic context, promoting local development and sustainability

High-level principles can be required for trade partners in **free trade and other bilateral agreements,** which agreements should **involve a mix of public and private parties.** International hydrogen trade should be based on mutually respected rules to **ensure a level playing field between EU and non-EU hydrogen value chains,** such as guaranteeing third-party access to energy networks, avoiding (cross-)subsidies, as well as ensuring non-discriminatory participation in competitive tenders. Some Free trade Agreements (FTAs) already include such rules, see e.g. EU-AU FTA proposed draft.[152]

As pointed out earlier in this report, strategic partnerships with exporting countries should **already foresee the use of EU sustainability criteria for imports to the EU**, make use of the hydrogen for RES target accounting and avoiding distortion of competition. Future bilateral or multilateral agreements could even go as far as **legally obligating certain standards or specific requirements** in order to ease the certification process. Further details are provided in section 3.4.2

[152] See Energy and raw materials chapter. https://trade.ec.europa.eu/doclib/press/index.cfm?id=1865

Textbox 5 Economic development and equity considerations in the formation of international hydrogen markets

Generally, both the available technology knowledge and the manufacturers of the technical equipment for the hydrogen value chain are currently located in future importing countries. The Fraunhofer study argues that **technology sovereignty**[153] should be promoted, with knowledge transfer from importing countries to exporting ones is needed.

There are further important equity considerations such as, that the needs of partner countries must be considered in all future strategies: exporters also need to meet their energy demand in a sustainable way and achieve their climate goals using the development opportunities arising from a hydrogen economy, besides meeting the sustainability criteria for hydrogen. There is a lack of knowledge on the opportunities for partner countries and social acceptance, and stakeholder's views need to be incorporated in planning. **We thus need assessments going beyond the techno-economic issues, as well as solid strategic partnerships based on mutual trust to ensure a fair and inclusive trade of renewable and low-carbon fuels.** Partnerships are already in the making and will be a key element of establishing international hydrogen markets, with the conditions for these detailed further in section 1.6 in of this report.

There are multiple international partnerships already being established around hydrogen markets - some of the main ones with participation of the Commission or Member State public organisations are listed below.

Central European Hydrogen Corridor Initiative (CEHC)[154]

The CEHC explores the feasibility of creating a hydrogen "highway" in Central Europe for transporting H_2 from major hydrogen supply areas in Ukraine, via Slovakia and the Czech Republic, to demand areas in Germany. Ukraine is considered as promising major supplier and large-scale producer of hydrogen, and is well connected to Europe by the existing gas pipeline system that can be repurposed for H_2 transport. The initiative is being promoted by leading Central European gas transmission infrastructure companies.

Ukraine's important role in the hydrogen supply chain has also been recognised by EBRD, in form of a Memorandum of Understanding between EBRD and Ukrainian Gas TSO GSTOU in April 2021[155]. The two entities are joining forces to promote the development and use of hydrogen in Ukraine.

H_2Global[156]

H_2Global is a German concept created to achieve the goals adopted in the German National Hydrogen Strategy in connection with the production and import of renewable hydrogen. The H_2Global foundation is committed to develop a local hydrogen economy as well as work together with partner countries to develop a hydrogen export economy. H_2Global aim to **establish international energy partnerships** that open up the potential of a 'multi-gigawatt hydrogen economy' and industry in partner countries. Although the primary aim of the H_2Global concept is to fund the

[153] "Technology sovereignty refers to the ability of a state or a federation of states to provide the technologies it deems critical for its welfare, competitiveness and ability to act, and to be able to develop these or source them from other economic areas without one-sided structural dependency" – Fraunhofer

[154] https://www.cehc.eu/en/home/

[155] https://www.ebrd.com/news/2021/ebrd-and-ukraine-boost-lowcarbon-hydrogen-development.html

[156] https://H₂-global.de/

timely market ramp-up and import of renewable hydrogen and Power-to-X products (PtX, or renewable hydrogen and derivatives) to Germany, capacity building, market entry and established value chains for these products are essential for imports to other EU countries too. H_2Global focuses on renewable hydrogen.

Belgium Hydrogen Import Coalition[157]

The Coalition is a Belgium-initiated collaboration between *DEME, ENGIE, Exmar, Fluxys, Port of Antwerp, Port of Zeebrugge* and *WaterstofNet*. The project assesses existing and future harbour facilities for terminalling and for the long-distance transportation of **renewable carrier molecules** on board large ships and has pooled market knowledge in order to map the entire value chain from production abroad to delivery via ships and pipelines to Belgium (Zeebrugge). The coalition has already identified the cost structure of the H_2 import value chain and was able to detect technological and regulatory barriers that hamper the roll-out of the import concept.

MENA Hydrogen Alliance[158]

The MENA (Middle East-North Africa) Hydrogen Alliance was launched by DII Desert energy, an industrial initiative originating from Germany with the initial aim to explore the potential of renewables in the desert areas of Northern Africa and the Middle East. The alliance is cooperating on production and export and brings together private and public sector actors as well as science and academia to kick-start renewable hydrogen economies. The alliance not only provides a meeting platform for its members, but acts as an impartial advisor to promote pilot hydrogen projects in the region, elaborates (potential) business cases and structures for large projects and proposes the necessary policy and regulatory frameworks, besides awareness-raising activities.

IPHE (International Partnership for Hydrogen and Fuel Cells in the Economy)[159]

IPHE is a high-level mechanism to coordinate multinational research, development and deployment programs that advance the transition to a global hydrogen economy. Its activities are the following: reviewing the progress of collaborative projects; identifying promising directions for R&D, demonstration, and commercial use; providing technical assessments for policy decisions; identifying gaps and developing common recommendations for international codes, standards and safety protocols. The partnership is communicating with the private sector and other stakeholders to foster collaboration and address any barriers to a cost-competitive, standardized, widely accessible, safe and environmentally benign hydrogen economy. Official Partners are the Governments of: *Australia, Brazil, Canada, China, France, Germany, Iceland, India, Italy, Japan, New Zealand, Norway, Republic of Korea, Russia, United Kingdom, the United States of America, and the European Commission*. Other Participants are International Organizations such as: *Asia-Pacific Economic Cooperative, International Energy Agency, USAID, Arctic Council, and the Association of South East Asian Nations*.

The above few initiatives are a good start to establishing International strategic partnerships around hydrogen, and the European Commission is a party in a few of them. The Commission is also **co-leading the Clean hydrogen mission at Mission Innovation** along with Australia, Chile, the UK and the US, with the goal of significantly increasing the cost-competitiveness of clean hydrogen by 2030**,** and is party to the **Clean Energy Ministerial Hydrogen initiative** (**CEM H_2I).** CEM H_2I is a voluntary multi-government initiative under the CEM framework, which aims to advance policies,

[157] https://www.portofantwerp.com/sites/default/files/Hydrogen%20Import%20Coalition.pdf

[158] MENA Hydrogen Alliance - Dii Desertenergy (dii-desertenergy.org)

[159] International Partnership for the Hydrogen Economy (unfccc.int) , Home International Partnership for Hydrogen&Fuel Cells in the Economy (iphe.net)

programs and projects that accelerate the commercialization and deployment of hydrogen and fuel cell technologies across all aspects of the economy, involving non-binding arrangements among participating national government ministries.

Germany– MA/TUN/CA/SA/AU initiatives

Germany, as frontrunner in hydrogen market development and one of the biggest potential uptakers of the fuel, has already signed a few bilateral agreements/energy partnerships for fostering international hydrogen trade – for example with Morocco, Tunisia, Australia, Canada and Saudi Arabia.[160][161] These memorandums of understanding aim to foster the energy transition by exchanges on policy, best practices and clean technologies between the countries, as well as project cooperation, including collaboration on clean hydrogen, its derivatives and potential applications.

3.4.2.2 Establish market-making mechanisms at EU level

As indicated in section 1.2.1, the development of an international hydrogen value chain will require investments at the supply and demand side. While there is an opportunity for renewable and low-carbon hydrogen initially substituting fossil hydrogen consumption in industry, increased hydrogen deployment will require also developing new end-uses. Given the lack of an international hydrogen value chain, the capital intensity of the investments and future uncertainties, a **coordinated approach to developing supply and demand is necessary**.

To create and match supply and demand for hydrogen and derivatives, mechanisms such as **double-sided auctions** could be employed. Government-backed double auctions are ideally placed to provide the initial incentives to both supply and demand in a coordinated manner.[162]

Double-sided auctions work by an auctioneer tendering and contracting both hydrogen purchase agreements with suppliers and hydrogen sale agreements with consumers. Public funding is necessary to bridge the difference between the high supply and lower offtake price (arising from the current lack of competitiveness of renewable and low-carbon hydrogen vis-à-vis fossil-based hydrogen, and eventual investments needed by new hydrogen consumers to adapt their production processes, develop refuelling infrastructure, etc). However, as renewable and low-carbon hydrogen production costs decrease and demand increases (driven by innovation, energy and climate policies, including those internalising environmental and climate externalities of fossil fuels) its competitiveness should increase. This should reduce the need for public support (on a €/MWh basis – as hydrogen consumption increases public subsidies may increase depending on the cost vs consumption volumes dynamics, for example if cost reductions do not occur fast enough).

Double auctions provide the long-term certainty for supply and, if needed, also demand-side investments. While such certainty is necessary for the supply side investments, it may not be the case for off takers which will use the hydrogen to substitute their current fossil-based hydrogen consumption (e.g. refineries and the chemical industry). Therefore, while long-term hydrogen purchase contracts are warranted, hydrogen sale contracts with a shorter duration may be acceptable for (some) off takers – as they can maintain their hydrogen production capacities on standby and thus face a lower supply disruption risk.

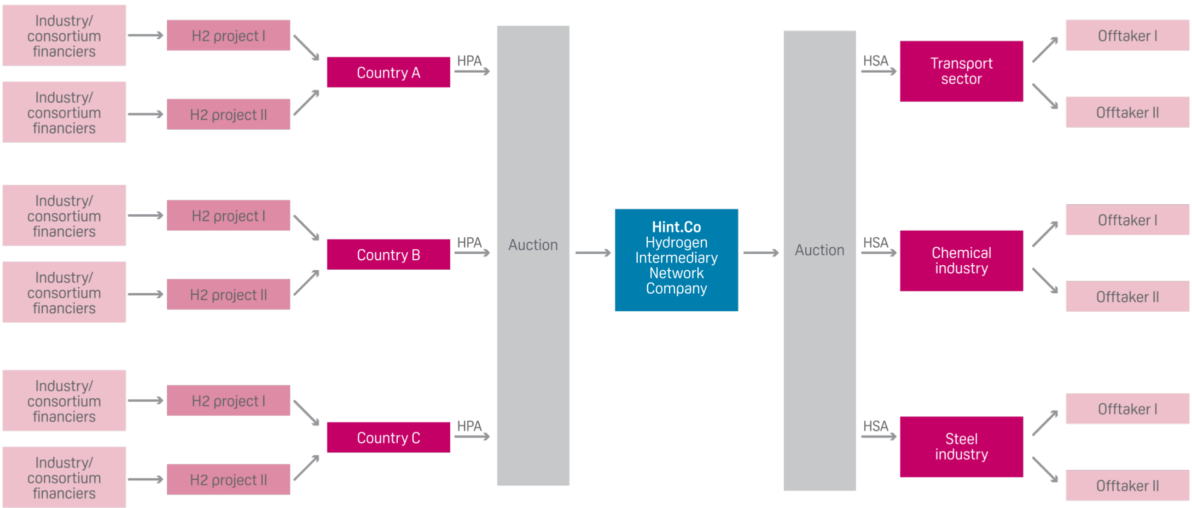
160 German Federal Ministry for Economic Affairs and Energy (2021) Minister Altmaier signs Memorandum of Understanding on German-Saudi hydrogen cooperation ; Declaration of Intent signed to establish German-Australian hydrogen alliance ; Altmaier: „Mit Kanada wichtigen Partner für transatlantische Energiewende gewonnen"

161 Morocco and Tunisia both recently signed a bilateral partnership with Germany to establish green hydrogen alliances https://www.cmimarseille.org/sites/default/files/newsite/energy_report_final_final_online_0.pdf

162 Simon Muller (2021) Developing National Policies for Hydrogen – An Overview of Principles and Processes

The first major project for establishing double-sided auctions is the H_2Global initiative. In June 2021 the H_2Global foundation was established.[163] A subsidiary company, HINT.CO, will be responsible for organising the auctions on the supply and demand side, while another will provide technical assistance to the potential participants.

Figure 29 Double-sided hydrogen purchase and sale auction with HINT.CO as intermediary[164]



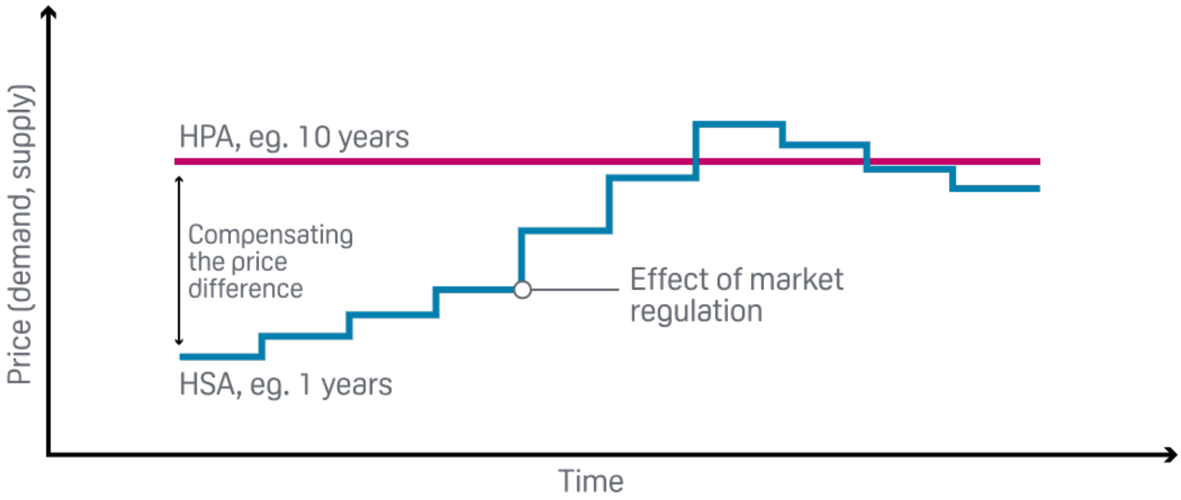
The supply-side auctions will award 10-year contracts for the purchase of hydrogen by HINT.CO, while the contract duration resulting from demand-side auctions should be one year (accounting for the readiness of hydrogen off takers to rely on more short-term suppliers). The first competitive procedure for awarding hydrogen purchase agreements is expected to take place still in 2021, with delivery in 2024, while the first demand-side auction should take place in 2023. The shorter duration of hydrogen sale agreements should also allow to adapt sale prices to external factors, as the comparative attractiveness increases due to e.g. increased carbon prices and taxation of the carbon footprint of fossil-based carriers (see Figure 30). This allows to avoid over-subsidisation and therefore comply with State Aid Guidelines.

Participation in the supply auctions should be open to all pre-qualified participants, with delivery at the German border – hence allowing for the participation of both foreign and German suppliers. This also allows bidders to internalise additional costs up to the delivery point, including additional transportation costs. It is unclear whether any import taxes and charges would be paid by the supplier or born by HINT.CO, e.g. future carbon border adjustment taxes for the transport carbon footprint of the fuel.

[163] German Federal Ministry for Economic Affairs and Energy (2021) New funding instrument H_2Global launched – H_2Global Foundation established

[164] S&P Global (2021) INTERVIEW: First hydrogen cargo into Germany to be delivered 2024: H_2Global; based on H_2Global. Available at https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/062421-interview-first-hydrogen-cargo-into-germany-to-be-delivered-2024-H2global

Figure 30 Illustration of expected convergence of hydrogen purchase and sales prices in H_2Global agreements[165]



The double-sided auctions can also be a component or be coordinated with international partnerships for developing a hydrogen value chain. As part of a declaration of intent to create the German-Australian hydrogen alliance, the German and Australian governments agreed to conduct an auction under H_2Global restricted to Australian suppliers and co-financed by both governments. Australia would provide around 50 million € to the initiative.[166]

Governments are also employing one-sided auctions to develop the hydrogen value chain. For example, Portugal announced a green hydrogen auction for consumers in April. It is focused on incentivising hydrogen demand, based on CCfDs, paying the difference between the higher bid price and the lower carbon price.

While there is still uncertainty about the future carriers and routes, national governments and the EU could help guiding the sector and providing financial resources. As indicated in section 1.2.1, not all Member States may have the demand volumes or financing means to set up such a scheme on their own. Thus, cooperation at the EU level could aggregate the contracted demand (potentially providing economies of scale) and the financing means. **A EU-level scheme for double-sided auctions aggregating demand from Member States, with their co-funding, could be an efficient channel for this cooperation.** Well-designed demand targets have proven effective in providing additional certainty to investments, as long as investors have confidence that governments will take the necessary measures to achieve them. The EU auction scheme could aggregate demand from Member States as established in national demand targets, if some Member States chose to establish those. This would help achieve a critical scale and thus kickstart supply investments. The EU could also promote the discussions and best practice exchanges between Member States in order to foster the establishment of double-sided auctions at the national and regional level.

Auctions would constitute an opportunity to develop two elements which would be necessary in liquid international hydrogen market: price benchmarks and standardised contractual products.

[165] S&P Global (2021) INTERVIEW: First hydrogen cargo into Germany to be delivered 2024: H_2Global; based on H_2Global. Available at https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/062421-interview-first-hydrogen-cargo-into-germany-to-be-delivered-2024-H_2global

[166] https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2021/06/20210613-declaration-of-intent-signed-to-establish-german-australian-hydrogen-alliance.html

Given the absence of an international hydrogen market, **there are limited international price benchmarks.** S&P Global does provide hydrogen price assessments denominated in Euro and US dollars.[167] The development of a broadly accepted international price benchmark would also facilitate the design and operation of double-sided auctions, as contracts for differences could employ the benchmark as the reference price in order to determine the price delta to be paid/received by the auctioneer. The Hydrogen Strategy supports the development of a benchmark for Euro denominated hydrogen transactions. **Standardised contractual products could help further harmonising trade** (e.g. with standardised terms and conditions and contract templates).

3.4.2.3 Require compliance of imported hydrogen and carriers with EU certification standards

As said one of the main barriers to overcome for the acceptance into the EU of hydrogen and derivative products from international markets is the lack of **sustainability standards for the production and distribution of these fuels** aligned with EU regulations. As the EU and Member States have the power to regulate what products are imported to the EU market, they can require candidate non-EU suppliers to also adopt EU standards or certification similar to EU-produced hydrogen, at least for supplies destined to the EU. A Parliament resolution[168] of 19th May 2021 stresses that the EU should **promote its own hydrogen standards and sustainability criteria** internationally and calls in this regard for the harmonisation and development of international standards, definitions and methodologies for quantifying overall emissions from each unit of hydrogen produced, as well as international sustainability criteria as a prerequisite for any hydrogen and derivatives imports. It also emphasises that all hydrogen imports should be certified in the same way as EU-produced hydrogen to avoid any carbon leakage, and should be **consistent with the future carbon border adjustment mechanism** of the European Union (depending on the exact products which will be subjected to CBAM tariffs in the future). Moreover, it encourages the Commission to promote **the role of the euro as the reference currency in the international trade of hydrogen**; [169]

Once an EU-wide certification system is set up and in order to demonstrate compliance with the criteria, **voluntary international standards** can be released by exporters that prove adequate standards of reliability, transparency and independent auditing. The Commission may adopt regulations to **specify the rules for the voluntary schemes and may accept the standards** to be used to demonstrated compliance with RES (sub-)targets.

National and intergovernmental bodies could facilitate the adoption of certification schemes, let that be regional or global. Bilateral or multilateral agreements with exporting countries (as described in Measure 1) could already foresee the use of EU criteria for Hydrogen and derivatives as a starting point, while trade partners could legally obligate certain standards or specific requirements to producers.

Criteria and standards to facilitate, based on the PtX Roadmap from World Energy Council Germany [170], could be:

[167] https://www.spglobal.com/platts/en/our-methodology/price-assessments/natural-gas/hydrogen-price-assessments

[168] https://www.europarl.europa.eu/doceo/document/TA-9-2021-0241_EN.html

[169] European Parliament resolution of 19 May 2021 on a European Strategy for Hydrogen (2020/2242(INI)). https://www.europarl.europa.eu/doceo/document/TA-9-2021-0241_EN.html

[170] frontier-int-ptx-roadmap-stc-12-10-18-final-report.pdf (frontier-economics.com)

Energy sourcing standards (carbon neutral energy sources, with given emission reduction goal)

Environmental standards (land use, water supply, CCU as source of carbon, pollution factors and leakage)

Technical standards (efficient technologies, prevention of damage/accidents, reliable emergency plans)

Moreover, social standards such as social security and responsibility, fair wages, no child labour should be respected. These should be addressed by overarching EU legislation ensuring these conditions are met as for any EU trade partnerships.

Ideally, a **global system** should be set up – if no common standards are feasible, parallel certifications schemes might evolve.

The **Fit for 55 Package** introduced in July 2021 is already touching upon the certification issue. Under the newly proposed rules, any renewable or recycled fuel and gas (including hydrogen) that wishes to demonstrate emission savings, should be included in the Union database. The database should cover life-cycle emissions, meaning also value chain steps outside the EU for imported fuels. Member States will be responsible for verifying the information about sustainability properties of the fuels, as well as for setting up certification schemes – the European Commission would later have to approve the certification scheme based on the established standards.

Another issue is whether imports of high-carbon hydrogen should be allowed. It would be likely impossible for the EU to ban imports of high-carbon hydrogen as long as production is still allowed within the EU. Therefore, other avenues for disincentivising imports of high-carbon hydrogen could be sought, such as the inclusion of hydrogen in the future carbon border adjustment mechanism.

3.4.2.4 Provide clear regulatory frameworks for import infrastructure

A clear regulatory framework should be in place for terminals for importing LH_2 and other hydrogen-based carriers in order to reduce regulatory risk to potential investors and ensure that new infrastructure investment is aligned to energy & climate objectives. This does not mean all types of terminals should be regulated, but rather that it should be clear to investors which activities are competitive and which are subject to some level of economic regulation.

For example, for some LH_2 terminals economic regulation may be warranted to ensure non-discriminatory third-party access and avoid distortion of the EU energy market, while terminals for importing power-to-liquids may not require any sort of third-party access rules.

For the terminal types where regulatory intervention is justified, harmonisation and minimum requirements at the EU level can be warranted to avoid distortion of the internal energy market, and achievement of energy & climate objectives at the EU level.

This section focuses on elements of the future regulatory framework to ensure investments in hydrogen and derivative import terminals aligned with energy & climate objectives

The EU Hydrogen Strategy recognizes the need to consider infrastructure in designing a framework for H_2 and establish market rules: for hydrogen to become widely used as a carrier, supply and demand need to be connected with the right infrastructure. The need for hydrogen infrastructure will depend and interact with the potential production and demand as well as transportation costs. Also, to ensure future interoperability of hydrogen markets once established, **common quality standards and cross-border operational rules are deemed to be necessary** by the Commission, which also impact import infrastructure.

While LH_2 terminals investments can target both new-build or repurposed LNG terminals, the development of each terminal will be case-specific. As sometimes it may be economically efficient to repurpose LNG terminals, a future regulatory framework for hydrogen should allow for repurposing. However, this framework should ensure such repurposing take place only when beneficial from a societal perspective. Conversely, LNG terminals would be decommissioned only when it would not be more efficient to repurpose them.

The EU could explicitly **allow in its regulatory framework the repurposing of LNG terminals,** with a **requirement for Member States to conduct a cost-benefit assessment** considering the impacts on security of supply and climate & targets objectives before authorizing the repurposing of regulated terminals. This could be coupled with **mandatory a market test/screening for LNG terminals to assess demand for new carrier services, and a requirement for the terminals elaborating development plans with a certain frequency (e.g. every 2 years).** This would promote the early identification of opportunities for repurposing the terminals, while ensure this was socially optimal. This should be coupled with **measures promoting integrated planning** with the participation of terminals operators (see barrier 1 of T4).

For any LH_2 terminal (new or repurposed), **Member States should be required to conduct a market assessment to define the regulatory regime** (if any) for terminals according to:

- The specific carrier (LH_2, ammonia, methanol, etc) and the potential for terminal operators to discriminate access;
- This assessment should include the involvement of neighbouring MSs, as competition could take place with neighbouring terminals;
- As the hydrogen sector will change significantly, with in certain regions increasing demand and interconnection with neighbouring systems, the assessment should be subject to review once conditions change.

Moreover, the regulatory framework should allow investment in and operation of hydrogen and derivative terminals by LNG terminal operators, as long as the regulatory regimes is the same across carriers. This would serve to avoid that the same operator handles terminals with rTPA and nTPA, without proper separation of the activities, which could allow for cross-subsidisation between consumers of natural gas and hydrogen-based carriers. **Accounts unbundling** should be required as a minimum to ensure cost-reflectivity and avoid cross-subsidisation, even in cases where the same regulatory regime is applied to multiple terminals

3.4.2.5 Incentivize measures by infrastructure operators and market parties to address constraints of existing long-term natural gas contracts and new contracting terms

Long-term natural gas contracts with a duration of several decades might represent a barrier for the repurposing of existing gas infrastructure for hydrogen import. LNG terminals/pipeline operators and buyers thus might need to reach agreement on amending these contracts. **Measures to address existing contracts** on a case-by-case basis exist, if and when long-term contracts are a constraint:

- **Renegotiation** of long-term supply contracts and capacity bookings is common practice (mostly commercially motivated) and should be possible if hydrogen hits the market
- **Switching of contracted carriers** in contracts possible if exporter interested in developing low-carbon supply (e.g. Qatar may be interested)
- **Buying back or compensating for existing capacity bookings** may be another solution, however more expensive

Renegotiation of contractual terms, including prices and duration for long-term supply contracts and capacity bookings is a common practice (mostly for commercial reasons) given the length of the contracts, as seen for example by Naturgy[171].

It must be noted that in the case of LNG terminals, interviews with infrastructure operators indicate that **while the cost of repurposing terminals to liquid hydrogen would be lower than developing new terminals, the cost savings would not be as significant as when repurposing gas pipelines.** This is due to the much lower liquefaction temperature of hydrogen compared to natural gas. Therefore, coupled with possibilities for renegotiating LNG terminals service contracts, the need for specific regulatory measures to 'releasing' LNG terminals for repurposing may not be as evident.

One regulatory measure that could be implemented is the **requirement that LNG terminal operators conduct mandatory market tests/screening and elaborate development plans.** These measures would allow to identify demand for import services of new carriers from the terminals, and elaborate development plans (e.g. on a bi-annual basis) aligned to the identified demand.

Targeting **new long-term gas supply contracts** can complement these measures: it is recommended to ensure new long-term contracts **include provisions that makes renegotiation or buy-back possible** in case of repurposing of terminals, and including measures such as "use-it-or-lose-it'. The EU could also limit new supply contracts to a certain year.

Phasing-out long-term gas supply contracts coupled with options for existing contracts might free up terminal capacities for hydrogen and derivatives, while measures targeting new contracts can prevent further constraints.

[171] https://www.argusmedia.com/en/news/2145486-naturgy-renegotiates-longterm-lng-contracts

4 Importance of hydrogen storage facilities in the EU

The significant deployment of hydrogen and derivatives foreseen in the European Commission's Hydrogen Strategy will require the deployment of various forms of hydrogen storage for a number of reasons, among which to match hydrogen supply and demand profiles, driven by the intermittency of renewable energy sources, the use of hydrogen in industry, transport and eventually power generation. Hydrogen storage should increase economic value to market participants (hydrogen producers and consumers), increase the security of supply of the EU energy system, and provide flexibility to the electricity and methane gas sectors avoiding the need for additional investments in e.g. hydrogen production capacity.

There are significant differences between the various hydrogen storage technologies regarding maturity, technical and economic characteristics, and potential applications. For example, while storage technologies such as compressed hydrogen tanks are mature (technology readiness level, TRL, of 9), storage in porous reservoirs has a TRL of 2-3 (see section 4.2). Technical improvements, cost reductions, and demonstration and large-scale deployment all need to be achieved in order for hydrogen storage to fulfil its potential.

In addition to technical and economic challenges, regulatory barriers exist for the deployment of hydrogen storage. **The main objective of this chapter is therefore to conduct an analysis of the potential and measures to develop hydrogen and derivative storages in the EU**. For this, the chapter is broken down in the sections indicated in the figure below.

Sections 4.1 address all types of hydrogen storage technologies, including storage in the form of derivatives or through liquid organic hydrogen carriers. The remaining sections focus specifically on the storage of liquid and gaseous hydrogen.

Figure 31 Structure of chapter 4

- **4.1 Characterise the various hydrogen and derivatives storage technologies**
- **4.2 Analyse the hydrogen storage potential in the EU**
- **4.3 Assess the potential contributions of hydrogen storage to the EU energy system**
- **4.4 Conduct a risk and asset classification of storage options**
- **4.5 Identify regulatory barriers for the deployment of hydrogen storage**
- **4.6 Propose regulatory measures to address these barriers**

4.1 Hydrogen and derivatives storage technologies

Main Take-aways of the section

- Hydrogen storage options can vary from hundreds of kg to several kt per facility.
- Hydrogen storage options benefit from economies of scale: specific investment cost decrease with storage capacity.
- Subsurface storage offers lower specific investment cost than surface storage.
- Large scale hydrogen and derivatives surface facilities offer low-cost storage but often require high (pre-and post) processing energy need and costs.

Hydrogen is the smallest and lightest element consisting of a proton and electron each. Hydrogen molecule with molecular mass of 2g/mol with a density of 0.09 kg/Sm^3 (standard cubic meter[172]) compared with natural gas having molecular mass of approximately 16g/mol and a density of 0.76 kg/Sm^3. With such a low density, hydrogen poses unique challenges for storage and transport. To increase stored hydrogen quantity, hydrogen gas can be compressed (CGH_2) or liquefied (LH_2) and stored in above-ground tanks. Compressed hydrogen gas can also be stored underground in salt caverns (UHS – Salt caverns) or porous reservoirs (UHS – porous reservoirs). Alternatively, it could also be stored by entrapping it within other materials such as *Liquid Organic Hydrogen Carrier* (LOHC) or by chemically converting it to ammonia (NH_3) or methanol (MeOH). All these options for storing hydrogen present a broad technology platter to integrate hydrogen into the future of energy mix comprising of diverse hydrogen supply chains. Each storage technology has different energy density (volumetric/gravimetric) and storage capacity, time-scales and charge-discharge rates. For instance, hydrogen storage capacity can vary from hundreds of kg to several kt for pressurized tank to salt cavern storage technology respectively. The specific investment cost of storage also varies wildly from approximately 535 €/kg for CGH_2 to 7 €/kg for salt caverns. Matching the right storage technology with the right purpose in the hydrogen value chain is not only technically challenging, but can also influence the overall economics.

The choice of the most appropriate storage option is contingent on the application. Key metrics to look into are: energy density (e.g. kWh per mass and per volume), energy capacity (energy that can be stored per unit of technology, e.g. MWh per tank), maximum cycling rate (in MW) and investment and operational costs (storage usually includes pre-processing such as compression and liquification). Further requirements could include safety, efficiency, space requirements and availability. In the following sections, the storage technology concepts are explained along with their current technical status and challenges. Where available, the size of storage technologies along with typical application in the hydrogen supply chain is also described. At the end of the technology briefs, an overview summary of all storage technologies considered in this work is tabulated.

4.1.1 Pressurised hydrogen gas storage options

4.1.1.1 Compressed hydrogen gas storage in tanks (CGH_2)

Compressed hydrogen gas storage in tanks requires two process components – a storage tank and a compressor to pressurise hydrogen gas. Pressure ranges from 200 bar to 1000 bar are used to

[172] Standard cubic meter (Sm3) is the volume (m3) measured at standard temperature and pressure conditions. Several standard reference conditions are currently used by various publishing entities as explained in introductory text here: https://en.wikipedia.org/wiki/Standard_temperature_and_pressure. In this report, we define standard condition at absolute pressure of 101.325 kPa and temperature of 20 °C.

achieve high volumetric storage capacities[173]. Scaling up tank size or increasing the pressure beyond 200 bar is economically challenging due to need for special materials and high operating costs[174]. Thus, compressed hydrogen tanks are appropriate for small and medium scale storage applications such as at industrial sites or at hydrogen filling stations. They are suitable for high cycle operation and provide short to medium term storage services ranging from hours to months.

Figure 32 Pressurized hydrogen storage: racks of steel tanks and hydrogen tube trailers made of steel

The current practice is that tanks are either placed on hydrogen tube trailers for transportation purposes or in racks called hydrogen batteries for stationary storage and usage, see Figure 32. A typical unit consists of a rack of tanks able to store 500 kg or, equivalently, 16.7 MWh[175] of hydrogen at 200 bar and atmospheric temperature. Investment cost of compressed hydrogen storage tanks include purchasing cost of the tank and cost for installation and both scale with the amount of hydrogen (kg or MWh) that can be stored. Reported values vary between approximately 470 €/kg -600 €/kg[176] depending on the tank type, manufacturer, etc. Compressed hydrogen gas storage in tanks is currently among the most expensive storage options but tanks can be operated at high cycling rate and this can help amortize the high investment cost. Tanks typically last 20-30 years which represents an annual OPEX between 2%-4% of the initial storage investment.

4.1.1.2 Underground storage in salt caverns

Salt caverns are artificially constructed cavities in underground salt formations. They can have depths ranging from 300 m to 1,800 m. Pressures can range from 35 bar to 210 bar depending on cavern roof depth, lithostatic gradient, and many other site specific geo-parameters, but typical operating pressures are around 80-120 bar for economic and operational reasons. Hydrogen has been successfully stored in salt caverns at four different facilities[177] for decades. As such, the technology is considered mature for hydrogen storage. However, the technological capability of fast-cycle operation of hydrogen salt cavern storage, which is the desired use-scenario for hydrogen produced from RES, has to be technically proven. In particular, the cyclic-operation of the cavern

[173] H. Barthelemy, M. Weber and F. Barbier, "Hydrogen storage: Recent improvements andindustrial perspectives," Int J Hydrogen Energy, vol. 42, no. 11, pp. 7254-7262, 2017

[174] J. Andersson and S. Grönkvist, "Large-scale storage of hydrogen," *Int.J.Hydrogen Energy,* vol. 44, no. 23, pp. 11901-11919, 2019.

[175] The volumetric density of hydrogen compressed at 200 bar and 273°C is 15.6 kg/m3 or 520 kWh/m3 (Lower Heating Value)

[176] Cost values are per kg of hydrogen. Values are adjusted from 2017 to 2021 using average eurozone inflation rate of 3.95%.

[177] Teesside, Great Britain (3 caverns, 70,000 m3 each, 370 m); Clemens Dome, Texas (1 cavern, 580,000 m3, 1,000–1,300 m); and Moss Bluff, Texas (1 cavern, 566,000 m3, 335–1400 m), USA

exerts cyclic pressure and temperature variations on to the well and wellhead. Effect of these cyclic variations on these asset integrity in the presence of hydrogen requires additional research.

Salt caverns provide large-scale and long-term hydrogen storage, that scales favourably economically with high efficiency and low operational costs. Storage geometric can range from 100,000 m^3 -1,000,000 m^3 . A salt cavern requires so-called cushion gas to operate and the pressure should be kept between a minimum safe limit, to preserve cavern integrity and a maximum allowable pressure for storage, to prevent formation damage. The two operating pressure limits[178] depend on underground storage characteristics and are therefore location specific. The operating pressure range together with the geological volume determine the storage capacity of a given salt cavern.

The investment costs for salt caverns are typically associated with large starting costs for one-off investments in the necessary geological formation site preparation costs, cushion gas costs, surface facilities and then relatively less costs for the creation of the actual or additional cavern. The cost of repurpose existing facilities (caverns, topside) or adding caverns to existing facilities is site-specific but in general much lower than developing greenfield cavern storage.

4.1.1.3 Underground storage in depleted gas fields

Existing gas reservoirs from whom the production rate and reservoir pressure has declined offer an attractive potential for large scale hydrogen storage. However, storage of pure hydrogen in depleted gas fields is not a proven technology. It is currently at TRL 2-3. In subsequent section on existing/planned projects, few R&D projects to advance the TRL level are mentioned.

The amount of hydrogen that can be stored highly depends on the size of the field, the required injection rate and the required withdrawal rate. The size of gas fields can be inferred from the volume of natural gas that was initially in place before production started. Typical storage capacity of depleted gas fields lies between 1 and 3 billion Sm^3. Given the many open fundamental questions, this storage technology is not expected to be commercially available by 2030.

4.1.1.4 Line packing in transport and transmission pipelines

Line packing as a storage option refers to the volume of gas that can be "stored" in a gas pipeline, in this case, hydrogen transport backbone anticipated to operate at ~ 50 bar. Storage is achieved by increasing the pressure within the pipeline system thereby accumulating more mass. Operationally, this means that the volume of gas injected into the pipeline can be greater than the volume of gas withdrawn from the pipeline. The actual quantity of additional gas volume that can be stored in a pipeline depends on the pressure rating of the pipes and other technical limits in the pipeline network. The method is typically used by transmission system operators to balance supply and demand on short term basis (e.g. seconds to hourly). Assuming that the operating pressure of a pipeline can be increased from 50 bar to 60 bar momentarily, then approximately 20 tons hydrogen can be stored in the pipeline per 100 km of a 24 inch pipeline. Momentarily, in this case depends on the intended storage use for line packing – for stability or balancing grid, as such can vary from seconds to hours.

4.1.2 Liquified hydrogen / liquid derivatives in tanks

Hydrogen stored as pure liquified hydrogen or as liquid derivatives has a considerably higher energy density than in its gaseous form, making it an attractive storage and transport medium. Liqui-

---

178 In practice, initial cushion gas pressure at the desired depth is taken as a reference. Following this, 80% of this initial pressure is the recommended maximum pressure and 30% of the maximum pressure is the recommended minimum pressure.

fied hydrogen allows to store pure hydrogen avoiding costly and often complex chemical conversion and reconversion processes. Liquid derivatives such as ammonia, liquid organic hydrogen carriers (LOHCs) and methanol have the advantage of using existing experience and readily available infrastructure for storage, distribution and end-user handling. Limited changes might be needed to ensure all elements in the infrastructure are compatible.[179] Hydrogen can be recovered from these liquid derivatives with a chemical reconversion step. Fischer-Tropsch synthetic fuels, albeit being liquid derivatives, are targeted to be used as fuels directly.

4.1.2.1 Liquified hydrogen in tanks

Liquified hydrogen (LH_2) has the advantage that very high hydrogen storage densities can be attained already at atmospheric pressure: volumetric energy density of LH_2 increases by factor 4 compared to 200 bar gas storage. LH_2 is currently typically stored at -254 °C in a cryogenic insulated spherical tank to minimize heat transfer leading to hydrogen loss via boil-off. Such tanks have been used in the space industry for decades: NASA operates an LH_2 storage tank with a size of 3,800 m^3 and able of storing around 270 ton of LH_2 and is building a larger LH_2 storage tank with a size of 5,300 m^3.

LH_2 tanks are preferred for small and medium scale storage applications with essentially no geographical limitation where they can be located. Investment cost of LH_2 tank is dominated by tank material, insulation and welding costs. Reported investment cost values vary widely: 750 €/MWh - 3,935 €/MWh[180,181] based on H_2 LHV of 33.3 kWh/kg.

4.1.2.2 Ammonia

Ammonia is conventionally stored in liquid form under atmospheric pressure and temperature of -33 °C. It is a convenient hydrogen storage medium because it has a high hydrogen storage density of 123 kg- H_2/m^3 of ammonia and its handling method is mature. There are three main types of liquid ammonia storage methods. The required storage capacity is the main factor determining the type of storage method. For large scale storage (4,500 to 55,000 tons of NH_3), low-temperature liquid storage (refrigerated at -33°C and atmospheric pressure) is economically feasible. Storage of liquid ammonia at such scale happens using single or double walled refrigerated tanks. The main concern for refrigerated ammonia storage is evaporation via boil-off. As a rule of thumb, the boil-off rate for refrigerated ammonia storage is in the order of 0.04 %/day.

Whereas for small (less than 270 ton of NH_3) and intermediate capacities (450-2,700 ton of NH_3), pressurized storage is suggested as the most feasible option.

Similar to other liquid storage tank, investment cost for ammonia storage tanks scale with size by a factor of 0.7. The total installed costs for 55,000 t NH_3 tanks are estimated at roughly 64 M€, which is equivalent to a specific cost of ~1,164 €/t NH_3 (or ~ 6,500 €/t H_2).

4.1.2.3 LOHCs

Liquid Organic Hydrogen Carriers (LOHCs) are chemicals that can release hydrogen and the resulting de-hydrogenated chemical can be re-hydrogenated again to obtain the LOHC back. For example, Toluene (TOL)-Methylcyclohexane(MCH) is an LOHC system. MCH can be de-hydrogenated to

[179] Trinomics 2021, Implications of the energy transition for the European storage, fuel supply and distribution infrastructure

[180] Present day values obtained using current exchange rate 1 US Dollar = 0.85 Euros

[181] Investment cost values don't include cost for liquification.

give TOL, which in turn can be hydrogenated to give MCH. LOHC system has the advantage that they can exist in liquid form at atmospheric conditions and exhibit similar properties as conventional liquid fuels which makes them suitable to store in tanks similar to conventional fuels, i.e. oil barrels or tankers with limited to no changes for storage tank. However additional chemical conversion and reconversion process will be needed to extract hydrogen. In the case of TOL-MCH LOHC system, hydrogen content in MCH is 6.2 wt. %, with MCH density of 770 kg/m^3. In addition, LOHCs tanks are preferred for large volume storage applications and have no limitation on where they can be located. They provide short to medium term storage services ranging from weeks to months. Specific investment cost for storage is € 5.2/kg-H_2, excluding cost of de-hydrogenation process.

4.1.2.4 Methanol

Methanol is an attractive hydrogen storage medium because it has high hydrogen storage density (99 kg-H_2/m^3 MeOH) and it exists in liquid form under atmospheric conditions (20 °C and 1 bar). Tanks for above ground storage of methanol are constructed from either carbon steel or stainless steel. Carbon steel has the advantage of lower capital cost, but the disadvantage of higher life cycle cost due to increased maintenance and costs associated with corrosion protection.

The size of methanol storage tanks depends on the storage amount required. Large-scale storge is considered in this study. Storage tanks up to 50,000 m^3 (~ 39,600 tons) are used for this purpose with essentially no geographical limitation where they can be located. This corresponds to storage of 39.6 kt of methanol or 4.95 kt of hydrogen at a cost estimated at 19 M€, excluding reconversion costs. The specific investment costs are 473 €/t MeOH or 3.8 €/kg H_2.

4.1.3 Overview and dashboard

Various techno-economic parameters of the storage technologies described earlier are tabulated in respective datasheets. These datasheets are contained in the excel file titled 'Storage technology overview_final.xlsx', which is provided separately. The datasheets include storage capacity and cost for each storage technology in addition to other relevant techno-economic parameters.

Table 24 shows a summary dashboard with key techno-economic parameters for all the storage technologies considered in this study. We can see from the TRL level that all but underground hydrogen storage in depleted fields (TRL 2-3) are either mature technologies or currently being piloted for hydrogen storage. Surface storage technologies such as CGH_2, LH_2, NH_3, LOHC have been technical demonstrated to a level that several commercial projects are now under construction. Typically, the storage capacity in surface tanks varies from 500 kg for CGH_2 to ~ 10kt of hydrogen for the largest NH_3 tanks. These capacities are dwarfed in comparison to underground hydrogen storage capacities, *cf*. typical storage capacity of 180kt H_2 in a porous reservoir or ~8 kt H_2 in a salt cavern. From an economic perspective, the specific investment cost of underground hydrogen storage normalised with energy capacity is lowest for porous reservoir at 0.03 €/KWh H_2, LHV. For CGH_2, these costs can be as high as 16 €/kWh H_2, LHV[182]. In spite of the large variation in costs, a portfolio of surface and subsurface storage technologies will be needed across the entire hydrogen value chain. This balance is further discussed in the next section.

[182] 1 kg H_2 (LHV) = 33.33 kWh and 1 k H_2 (HHV) = 39.4kWh. LHV was chosen because not all combustion heat released as water vapour is recovered, therefore LHV is more pragmatic for the cost (for HHV, it should be 13.5 €/kWh H_2).

Table 24 Overview of all storage technologies considered in the current study.

		Purpose of storage, relevant transport modalities	TRL	Current deployment	Typical storage capacity	Typical storage capacity	Storage capacity	Storage capacity	Investment cost, H2 energy specific	Investment cost, H2 mass specific	CAPEX, total investment cost*	Fixed Opex cost	scaling factor	EU technical storage potential	Life time	References
		(seasonal/monthly/daily/hourly)			kg H_2	t H_2	MWh_H_2, LHV	GWh_H_2, LHV	€/kWh_H_2, LHV	€/kg_H_2	M€	k€/y	-		years	source
No.	**Storage technology ***															
1	**Hydrogen storage - Compressed gas tank (CGH_2)**	Small- to medium-scale storage, short- to medium-term (hours, days). Road, rail, shipping.	9	200 bar storage tank is widely used technology in the world for medium-scale gas-phase storage	500	0,5	17	0,017	16,05	535,00	0,27	11	0,7		25	[1,3,4]
2	**Hydrogen storage - Liquefied H_2 tank (LH_2)**	Small- to medium-scale storage, short- to medium-term (hours, days). Road, rail, shipping.	8-9	Current aggregate global hydrogen liquefaction capacity is reported to be around 355 ton per day. storage proven at various locations across globe: examples NASA LH2 storage tank for its Mars mission.	270.191	270	9.005	9	2,70	90,00	24,32	486	0,7	LNG tank capacity of 8.5 - 9.1 Mm3 exists in EU. This translates to up to 173 (bcm(N) / year) regasification capacity.	30	[2,7,8,9]
3	**Hydrogen storage - LOHC (MCH)**	Medium-scale storage, short- to medium- term (hours, days). Road, rail, shipping.	9	Possibility to utilize the currently available gasoline transport infrastructure.	2.387.000	2.387	79.559	80	0,16	5,24	12,50	88	0,7	LNG tank capacity of 8.5 - 9.1 Mm3 exists in EU. These tanks could potentially be used for MCH storage as part of LOHC system.	30	[2,7,9]
4	**Hydrogen storage - Ammonia tank refrigerated (NH_3)**	Small- to medium- scale storage that can be easily scaled to larger capacities. Short to medium term (hours, days). Road, rail, shipping.	9	Global ammonia production in 2019 was 235 Mton. In Europe, there are more than 50 refrigerated ammonia storage tanks in operation.	9.840.000	9.840	327.967	328	0,19	6,48	63,79	1.276	0,7	In Europe, there are more than 50 refrigerated ammonia storage tanks in operation.	30	[2,7,9,11,13]
5	**Hydrogen storage - Methanol tank (MeOH)**	Small- to medium-scale storage, short- to medium-term (hours, days). Road, rail, shipping.	9	Global methanol production in 2019 was approximately 148 Mton	4.950.000	4.950	164.984	165	0,11	3,78	18,71	37	0,7	LNG tank capacity of 8.5 - 9.1 Mm3 exists in EU. These tanks could potentially be used for MeOH storage.	30	[7,9]

		Purpose of storage, relevant transport modalities	TRL	Current deployment	Typical storage capacity	Typical storage capacity	Storage capacity	Storage capacity	Investment cost, H2 energy specific	Investment cost, H2 mass specific	CAPEX, total investment cost*	Fixed Opex cost	scaling factor	EU technical storage potential	Life time	References
		(seasonal/monthly/daily/hourly)			kg H_2	t H_2	MWh_H_2, LHV	GWh_H_2, LHV	€/kWh_H_2, LHV	€/kg_H_2	M€	k€/y	-		years	source
6	**Hydrogen storage - Line packing**	Small- to medium-scale storage, short- to medium-term (seconds, minutes, hours). Pipeline transport	7-9	This method is widely used for natural gas, but is not proven at large scale for hydrogen.	43250***	43***	1442***	1.44***	N/A	N/A	N/A	N/A	N/A	1.2-17.76 TWh of storage capacity available (roughly estimate based on 184,634 km of EU gas transmission pipeline)	n/a	
7	**Hydrogen storage - Salt caverns UGS**	Large-scale storage, medium-term (weeks - months). Road, rail, shipping, pipeline transport.	6-9**	Proven technology, with four storage facilities currently operational in the world.	7.883.000	7.883	263.000	263	0,20	6,67	52,57	2.103	N/A	Upto 64 TWh of storage capacity (facility based: current, under construction, planned). Technical potential: Total on- and off-shore European hydrogen storage potential estimated at 84.8 PWh of H2.	30	[2,6,12]
8	**Hydrogen storage - Porous reservoirs UGS #**	Large-scale storage, long-term (seasonal). Road, rail, shipping, pipeline transport.	2-3	Pilot with natural gas and H2 mixure in Austria, no tests for pure H2 storage so far.	179.800.000,00	179.800	5.992.734	5.993	0,05	1,75	314,05	12.562	N/A	Technical potential in Netherlands in onshore depleted fields is 277 TWh	30	[2,10,12]

Notes:

* Excluding cost for compressors, liquefiers or any other pre or post storage conversion equipment

\# Cost for porous reservoir inclides only the cushion gas estimate, not the other site preparation and well adaptation cost which can be significant depending on specific site conditions.

** Fast cycle operation storage service is yet to be demonstrated , hence TRL is lower than 7. TRL = 9 for security of supply services where continuous supply is required

*** Line packing storage capacity expressed per 100 km

**** Deployment level description is qualitative. The description is meant to give a sense of the market for the hydrogen carrier or the storage technology .

No. References

1 Danish Energy Agency and Energinet (2020). Technology Data – Energy storage
2 Energy Transition Commission (2021). Making the hydrogen economy possible Accelerating clean hydrogen in an electrified economy
3 TNO (2020). ETS factsheet-compressed hydrogen storage
4 FCH JU (2017) - Study on early business cases for H2 in energy storage and more broadly power to H2 applications. Final report www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf.
5 CE Delft (2018). Feasibility study into blue hydrogen
6 TNO, 2020. Large-Scale Energy Storage in Salt Caverns and Depleted Fields (LSES) – Project Findings
7 DNV GL (2020). Study on the Import of Liquid Renewable Energy: Technology Cost Assessment
8 K. Ohlig, L. Decker (2014) The latest developments and outlook for hydrogen liquefaction technology
9 Source: www. gie.eu, Accessed 21 June 2021
10 Lord.S.A., Kobos.H.P.,Borns.J.D. (2014). Geologic storage of hydrogen: Scaling up to meet city transportation demands. International Journal of Hydrogen Energy. 41 pp. 5549-5558
11 IEA, 2020, Future of Hydrogen
12 Caglyan: D.C. Caglayan, et. Al. 2020, Technical potential of salt caverns for hydrogen storage in Europe, International Journal of Hydrogen Energy, Volume 45, Issue 11. https://doi.org/10.1016/j.ijhydene.2019.12.161.
13 Fertilizer Europe (2014). GUIDANCE FOR INSPECTION OF ATMOSPHERIC, REFRIGERATED AMMONIA STORAGE TANKS

4.2 Storage potential in the EU

Main Take-aways of the section

- Portfolio of hydrogen storage options very likely needed to meet market needs and surpass geographical challenges
- Technical subsurface storage potential very large (PWh range) but unequal distribution of subsurface storage potential across member states and potential for storage in porous media not yet quantified
- Substantial repurpose potentials for caverns and porous media storages for natural gas: 265 TWh
- Market potential for hydrogen storage is dominated by subsurface storage and alternative hydrogen storage options are very important when subsurface storage is absent or has capacity limits and in early deployment phase of H_2 infrastructure and markets
- Substantial potential for hydrogen storage at import locations in line with current LNG storage capacity, but repurpose is not straightforward.
- Meeting storage market needs in ambitious H_2 volume scenarios could be challenging in certain regions in EU27; certainly when meeting security of supply principles on par with current natural gas system.

4.2.1 Technical potential

4.2.1.1 Surface level storage

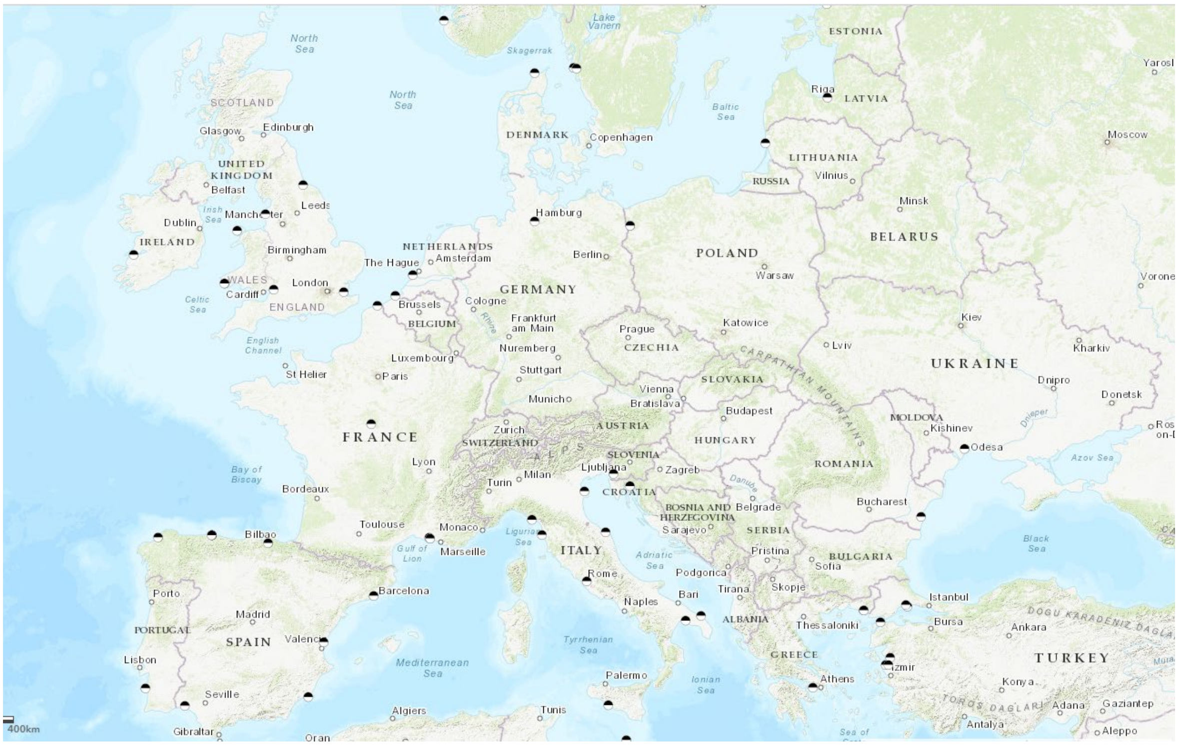
Like natural gas and Liquified natural gas (LNG), surface level storage of hydrogen can be achieved with tanks at import terminals, within pipelines (line packing) and stationary and mobile tanks. Hence, there are limited technical constraints to exploit the potential of surface hydrogen storage options. However, the technical potential[183] for surface storage of hydrogen is limited, as the available space for storage is significantly smaller than what would be required to cover the total hydrogen storage needs.

Tanks located at import terminals are used store fuels (e.g. LNG, NG, other petroleum products) and chemicals (e.g. methanol, bio-ethanol). Data on exact locations, quantity and storage volumes for these different storage tanks are not readily available. Considering only LNG tanks across EU's main import terminals can give the order of magnitude of the available potential. As such, in 2019, the total LNG storage capacity within EU27 + UK amounts at approximately 10 million m^3 or 55 TWh of LNG. This storage capacity typically represents 2-4% of the annual import capacity.[184] LNG has a volumetric energy density that is approximately 2.5 times greater than for LH_2. Assuming all LNG tanks store liquified hydrogen (LH_2), the equivalent hydrogen storage capacity is approximately 23 TWh of hydrogen. Note that it is not straightforward to repurpose existing LNG facilities to LH_2 facilities but this gives a sense of scale of surface storage potential.

[183] Technical potential refers to the theoretical or resource potential constrained by real-world geography and system performance, but not by economics.

[184] Derived from GIE LNG Import Terminals Map Database May 2019

Figure 33 Current LNG storage locations. Most of the LNG storage is limited to import/export terminals



https://www.vopak.com/terminals/gate-terminal-lng-rotterdam?language_content_entity=en

However, most of LNG storage tanks are located at import/export terminals and availability of space in harbours is a major constraint. Capacity of LNG tanks vary from 50,000 m^3 to 250,000 m^3. Furthermore, availability of space at terminals can be constrained because most hydrogen storage carriers need space for reconversion/regeneration plants to recover the hydrogen and transport to the hinterland.

4.2.1.2 Subsurface storage

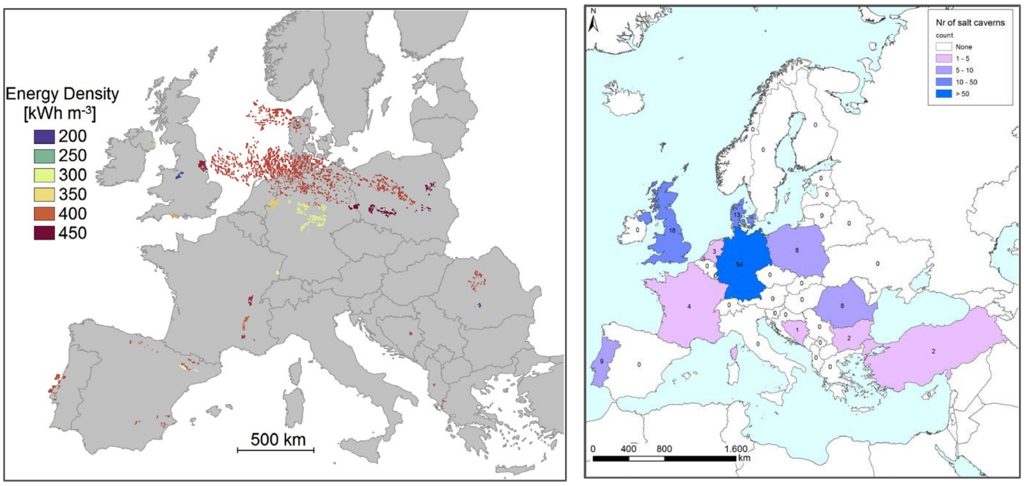
Several studies investigated the potential for subsurface storage in Europe. The Energy Storage Mapping and Planning (ESTMAP) project carried out investigation on underground hydrogen storage including depleted hydrocarbon reservoirs and salt caverns. Caglayan, et al. conducted analysis of the technical potential of salt caverns across Europe. These studies indicate that large technical potential for subsurface hydrogen storage exists in Europe.

However, the availability of salt caverns and depleted gas fields is unevenly distributed across the EU. For instance, the technical potential for salt caverns in Europe is limited to some member states, and lot of the potential is located offshore, mainly in the North Sea. Overall, the total technical potential of salt caverns in Europe is estimated at approximately 85 PWh of hydrogen[185]. Out of this, an estimated 23 PWh of hydrogen storage potential is located on onshore areas. Germany and Netherlands have the highest storage potential in both onshore and offshore locations. Figure 34 shows the location and energy density of salt deposits across Europe.

The repurposing of existing natural gas storage towards hydrogen storage would bring a technical potential of about 50 TWh of storage capacity.[186]

Figure 34 Technical potential of salt cavern in Europe:

(left) distribution of potential salt cavern sites across Europe their corresponding energy densities (cavern storage potential divided by the volume); (right) Total cavern storage potential in European countries classified as onshore, offshore and within 50 km of shore[187]**.**

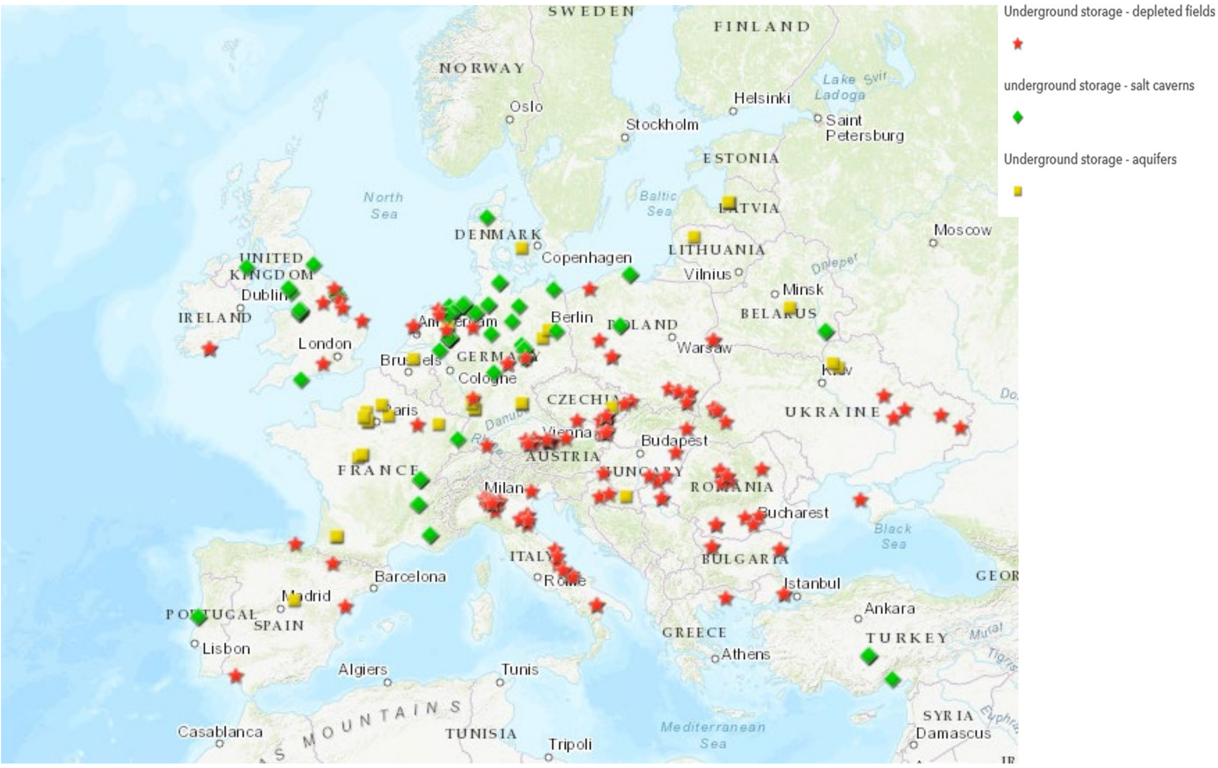


[185] Suitability assessment was conducted by applying land eligibility constraint. It is done to bedded salt deposits only. The study assumed that domal salt deposits are suitable for unground hydrogen storage. Moreover, the estimate includes also the UK, Norway, Bosnia & Herzegovina, and Albania.

[186] Picturing the value of underground gas storage to the European hydrogen system, 2021, GIE/Guidehouse

[187] 50 km of shore constraint accounts for environmental and economic limitations for disposing brine solution during cavern leaching.

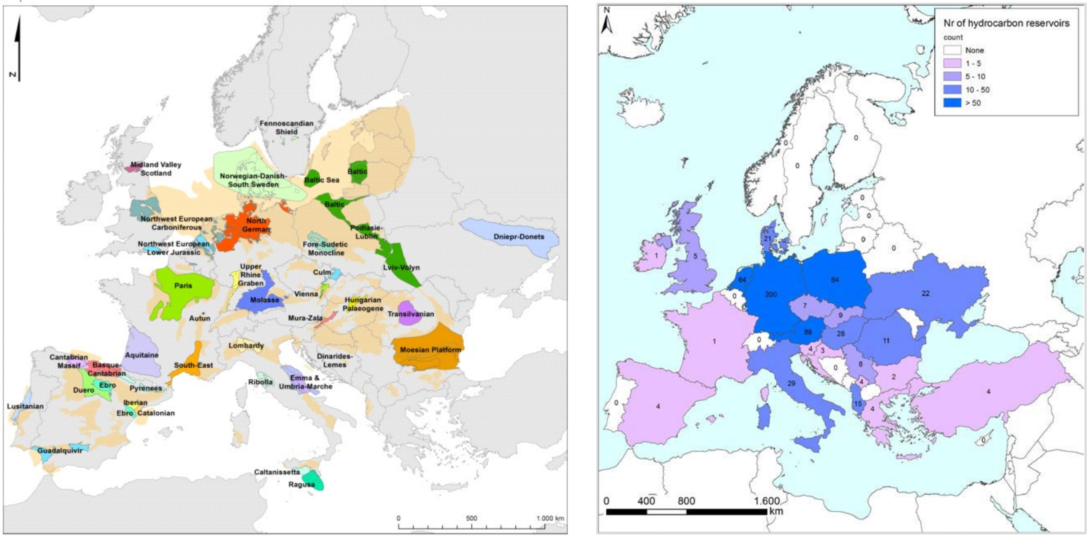
Figure 35 **Existing subsurface storage of natural gas in Europe in salt caverns, depleted fields and aquifers (source: ESTMAP.eu)**



Depleted gas fields are more widely distributed across Europe than salt caverns, see Figure 35, showing the oil and gas basins across Europe, many of which contain depleted gas fields, possibly suitable for storage. It also shows the number of depleted gas fields per country. The technical storage capacity across the EU is most likely to be very large and larger than storage capacity in salt caverns, but is currently not quantified. This is part of ongoing work in the HyUsPRe project. Considering only repurposed gas fields and aquifers, the technical potential is estimated at 215 TWh of working gas capacity[188]. As noted before, pure hydrogen storage in depleted fields and aquifers is not yet proven, and its suitability still relies on site-specific investigation such as seal capacity, geo-chemistry, wells, reservoir conditions and size.

[188] Picturing the value of underground gas storage to the European hydrogen system, 2021, GIE/Guidehouse

Figure 36 Map of oil and gas basins in Europe (left) and number of subsurface hydrogen reservoirs per country (right)



4.2.2 Economic and market potential

In this section, few key findings from recent studies regarding the economic and market potential are stated. The economic and market potential is here defined as a subset of the technical potential that can be matched in time and space with energy infrastructure with viable market prospects. This is in literature mostly estimated using (integrated) energy system models.

4.2.3 Economic and market potential

In 2019, the EU natural gas storage capacity was around 105 billion cubic meter (bcm), which equals more than 1 PWh of storage capacity. This is also equal to about 20-22% of annual natural gas demand. This is the so called Storage to Demand ratio for natural gas. Both absolute storage capacity and the Storage to Demand ratio for natural gas provide a point of reference for future hydrogen storage capacity estimates from literature.

The economic and market potential for specific hydrogen storage technologies will strongly depend on the geography, size, market structure and (existing and future) energy infrastructure. Caglayan shows, for example, demand for 562 GWh of hydrogen storage capacity using tanks or vessels. In a study by Victoria et. al a hydrogen storage need of 6.3 TWh was modelled for surface facilities, but this study excludes the option of subsurface hydrogen storage in the model. [189]

Caglayan notes that surface hydrogen storage options are expected to be installed in locations with high electricity generation and preferred in the regions where salt caverns are not available or when the discharge rate of salt caverns becomes limiting. A typical aspect is that the amount of storage cycles is much higher for surface level storage facilities (daily cycles for hydrogen filling stations) than for subsurface storage options for hydrogen (from 1 up to 14 annual full cycle equivalents reported by Groenenberg et al).

[189] Marta Victoria, Kun Zhu, Tom Brown, Gorm B. Andresen, Martin Greiner, The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system, 2019, Energy Conversion and Management, 201. The Central Thermal Energy Storage option in this study can be seen as a valid proxy to understand the potential role of (seasonal) UTES technologies in similar scenarios.

The estimated market potential for storage in caverns in that study grows towards 130 TWh of storage capacity which equals 19% of the annual hydrogen demand and 0.6% of the technical potential for salt caverns. The storage to demand ratio is in line with that of current natural gas system. However, in literature the storage to demand ratio in forecast scenarios & modelling studies shows high variability: between 1-38%. This suggests that total storage needs and the potential for specific technologies is difficult to assess ex-ante and heavily relies on modelling scope and assumptions for other flexibility options (e.g. curtailment, import/export, electricity storage, storage in electric vehicles, demand response flexibility).

According to a first order estimate by Gas Infrastructure Europe (GIE), applying a storage to demand ratio of 24%, the hydrogen storage capacity estimate for 20 EU countries (excluding UK) shows the need for around 65 TWh of hydrogen storage in 2030, growing to around 410 TWh of hydrogen storage in 2050.

According to FCH JU (Fuel Cells and hydrogen Join Undertaking), the demand for hydrogen in EU could reach between 481-665 TWh by 2030 and between 780-2,251 TWh by 2050. Assuming 10% - 20% of the demand will be met with storage, this corresponds to storage capacity of 16 bcm - 44 bcm by 2030 and 26 bcm - 150 bcm by 2050.

A recent study in Northern Europe concluded hydrogen storage would be beneficial and economically viable in a high-renewables scenario for 2050. IRENA sees a growing market for seasonal hydrogen storage in the coming two decades although not at significant scale.

Despite the large technical and foreseen market potential, the deployment of UHS in salt caverns and depleted gas fields will depend strongly on whether individual projects can develop and secure sustainable business case. High investments and long lead times (10 + years) in the required research, planning and development of underground storage options will likely slow the pace of deployment and subsequent cost reduction opportunities.

A study on large scale energy storage options in the Netherlands highlights the need for value stacking to create profitable business cases for large scale energy storage and indicates a discrepancy between long term value for the energy system and current absence of viable business models for energy storage as an important challenge towards implementation.[190] This is especially the case in early deployment period when the hydrogen infrastructure needs to be developed for relative low annual demand volumes.

4.2.4 Existing/planned projects

4.2.4.1 Surface storage

In this section, some of the recent projects focussing on hydrogen (and derivatives) production, storage & transport are listed. Note that this is an indicative list to give an impression of state-of-art projects demonstrating hydrogen storage technologies and does not aim to include all existing projects.

[190] Groenenberg et al., 2020, Large-Scale Energy Storage in Salt Caverns and Depleted Fields (LSES) – Project Findings

Table 25 **Non-exhaustive list of recent surface projects focussing on hydrogen (and derivatives) production, surface storage & transport**

Name	Country	Status, timeline
SPERA, Chiyoda corporation LOHC supply chain[191].	Japan	Ready for commercial use since 2020.
LOHC storage at CHEMPARK Dormagen, LOHC Industrial Solutions NRW GmbH jointly with Vopak.	Germany	Under construction, Commissioning planned in 2023
Hy touch Kobe, Kawasaki LH_2 terminal[192]	Japan	2500 m^3 LH_2 tank construction completed in 2020
Suiso Frontier, Kawasaki LH_2 marine carrier[193]	Japan	1250 m^3 LH_2 transport shipping carrier construction completed in 2019
Brunei – Japan LOHC Hydrogen Supply Chain[194]	Brunei-Japan	Piloted 24-kiloliter tank container transport in 2020.
ADNOC Blue ammonia 1,000 kt production capacity[195]	UAE	Start-up targeted for 2025.
HYPORT DUQM Green hydrogen – green ammonia project[196]	Oman	Cooperation agreement signed for potential green ammonia purchase between HYPORT & Uniper (Germany).
1.2 Mtons green ammonia production using 4GW RES at Neom	Saudi Arabia	1.2 Mton p.a. green ammonia production targeted for 2025

4.2.4.2 Subsurface storage

In this section, some of the recent projects focussing on hydrogen (and derivatives) production, storage & transport are listed. Note that this is an indicative list to give an impression of state-of-art projects demonstrating hydrogen surface storage technologies, and does not aim to include all existing projects.

Table 26 **Non-exhaustive list of recent surface projects focussing on hydrogen (and derivatives) production, subsurface storage & transport**

Name	Country	Status, timeline
Teesside, 3 salt caverns, 70,000 m3 each, 370 m). Compressed Gas H_2	UK	Existing
Clemens Dome, Texas (1 cavern, 580,000 m3, 1,000–1,300 m); and Moss Bluff, Texas (1 cavern, 566,000 m3, 335–1400 m). Compressed Gas H_2	USA	Existing

[191] https://www.chiyodacorp.com/en/service/spera-hydrogen/ URL Accessed 27 September 2021

[192] https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20201203_2378. URL Accessed 27 September 2021

[193] https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487 URL Accessed 27 September 2021

[194] https://www.mitsui.com/jp/en/topics/2021/1241738_12171.html URL Accessed 27 September 2021

[195] https://www.adnoc.ae/en/news-and-media/press-releases/2021/adnoc-to-build-world-scale-blue-ammonia-project URL Accessed 27 September 2021

[196] https://www.uniper.energy/news/hyport-duqm-signs-cooperation-agreement-with-uniper-to-explore-green-ammonia-offtake URL Accessed 27 September 2021

Name	Country	Status, timeline
Hyuspre – Hydrogen underground storage in porous reservoirs.	EU	$H_2$020 research programme focusing on feasibility and potential of implementing large-scale storage of renewable hydrogen in porous reservoirs in Europe. 2020 - 2023
HyStorPor, Hydrogen Storage in Porous Media.	UK	Studying whether hydrogen storage in reservoir rocks is fundamentally feasible. 2019 – 2023.
Underground sun storage 2030 - Build and test renewable hydrogen storage at natural gas porous storage.	Austria	R&D pilot construction completed 2017
H_2Cast Etzel – prepare for cavern rededication for hydrogen storage at Etzel.	Germany	Preparation phase, timeline 2022-2026
HyStock, Energystock. Hydrogen storage pilot field test in salt caverns.	Netherlands	on-going.
Hypster – large scale green hydrogen underground demonstration in salt cavern	France	Project started; Experimentation of hydrogen storage in a salt cavern

4.3 Contribution of storage to the system in terms of flexibility, supply security and economic value

Main Take-aways of the section

- The benefits of hydrogen storage are categorised here as general, system level impacts, and as benefits bringing economic value to individual actors in the hydrogen supply chain.
- In terms of **systemic impact** of deploying hydrogen storage, the contributions are categorised as
  - Security of supply for hydrogen sector;
  - System flexibility in hydrogen sector;
  - Optimal (cost-effective) development of network infrastructures
- Technically, Hydrogen storage options contribute to system **stability**, **flexibility** and **adequacy**.
- Hydrogen storage options deployment result in lowering investment and operational cost of the whole energy system.
- Access to large scale hydrogen storage options lowers overall system costs; suggesting that interconnection across the EU for regions with limited access to storage is of high strategic value.
- The contribution to ensuring **Security of supply** for hydrogen sector lies primarily in the ability to stock hydrogen reserves, available to be released in case of (unexpected) supply disruptions;

  The contribution to hydrogen **system flexibility** is categorised by the time horizon in which the flexibility is deployed.
  - In a close-to-real-time horizon, the storage contributes to maintaining the stability of the network by helping to maintain stable network pressure;

- In a short-term time horizon, storage can contribute to balance the variations in supply and demand, including seasonal variations;
- System adequacy refers to an increase in capacity to meet peak demand under extreme events over a period of months to years

- The hydrogen storage facilities can contribute to **optimal development of network** assets (in electricity, natural gas and hydrogen sectors), if their role is appropriately considered in the integrated network planning process.
- Considering the impacts of hydrogen storage on individual actors in the hydrogen supply chain, the main benefit for **electrolyser operators** is the possibility to decouple the time of hydrogen production and consumption. This enables price arbitrage on hydrogen markets, as well between the electricity markets and hydrogen market (in case of grid-connected electrolysers). Furthermore, hydrogen storage opens additional revenue streams for the grid operators, for example from offering balancing services.
- In case of **hydrogen end-users**, hydrogen storage offers a greater stability of hydrogen supply, avoiding higher price fluctuations on the market. Hydrogen storage can also enable development of hydrogen end-use sectors with significant seasonal fluctuations of demand, that would otherwise not be possible to be covered by the existing hydrogen generation assets.
- The case studies included in this section show that:
  - Hydrogen storage options deployment result in lowering investment and operational cost of the whole energy system.
  - Access to large scale hydrogen storage options lowers overall system costs, suggesting that interconnection across the EU for regions with limited access to storage is of high strategic value

This section aims at cataloguing the potential benefits of hydrogen storage operation to the energy system operation as a whole, as well as for two significant groups of market participants – electrolyser operators and hydrogen consumers – who are potentially to benefit the most from hydrogen storage development. This section concludes with representative case studies that illustrate the listed impacts of hydrogen storage.

The system-wide contributions are categorised as benefits to:

- Security of supply;
- System flexibility;
- System stability

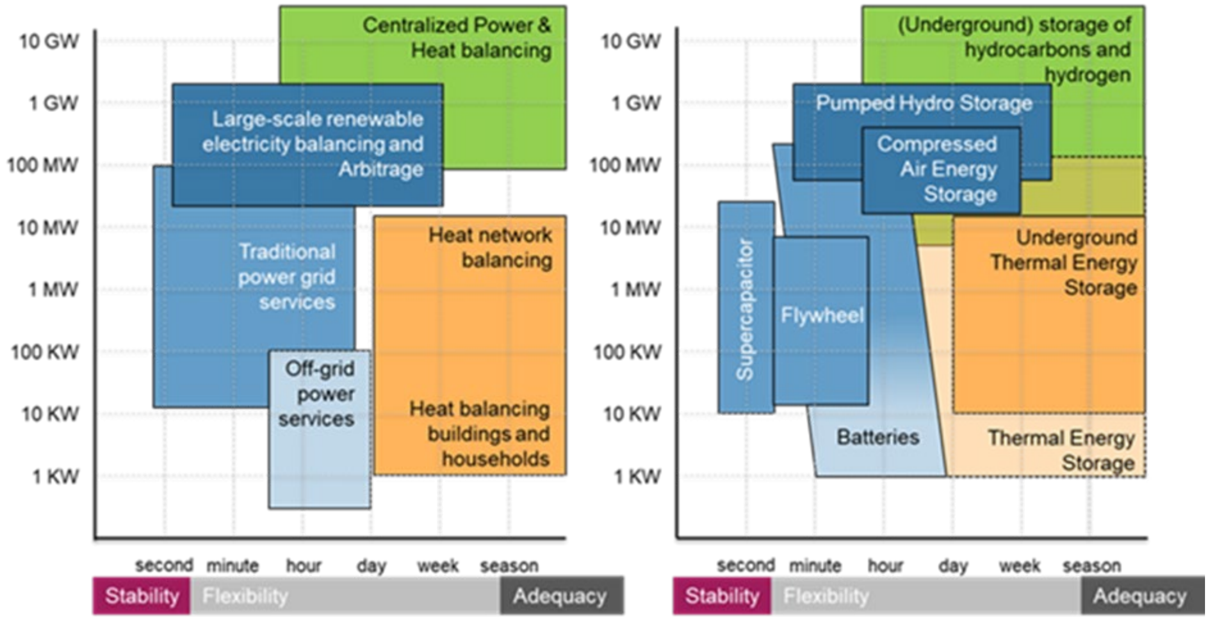
Stability is here the response to very short and fast fluctuations (especially in the power system). Flexibility is the response to load and supply variations up to the seasonal timescale, while the ability to adapt to long-term trends and emergencies is defined as 'adequacy'.

Next to these contributions, the development of hydrogen sector, enabled by deployment of hydrogen storage, will have a positive impact on sustainability. This is however out of scope of this study and has been addressed elsewhere.[197]

[197] Trinomics and Artelys (2020). Measuring the contribution of gas infrastructure projects to sustainability as defined in the TEN-E regulation. Available at: https://op.europa.eu/en/publication-detail/-/publication/364d69a4-1744-11eb-b57e-01aa75ed71a1/language-en

Figure 37 Energy system services and storage options (non-exhaustive) mapped according to their power (Watt) and relevant timescales for charging and discharging.

Colours coding indicate in which infrastructure system the storage technology is implemented: blue = electricity grids, green = (renewable) gas infrastructure; orange is heat networks.



Source TNO, inspired by IEA

4.3.1 Review of system-wide contributions of hydrogen storage

4.3.1.1 Security of supply and flexibility contributions

Storage plays an integral role in an energy system with several technical and economic benefits. Technical benefits include ensuring secure energy supply through a robust energy system that can handle supply and demand variations. Economic benefits include arbitrage services reducing costs for end users but also for other actors in the energy system and integration of complementary RES sources such as wind and solar.

Different flexibility needs have varying discharge time (seconds, minutes, hours, days), reaction time (seconds, minutes, hours), rated at typical frequency of use (daily, weekly, seasonal, annual) and scale (regional, national, continental).

Operating an energy system is challenging as it needs precise balancing of supply and demand at all times. This need to match ensures that the supply meets the demand requirements. Failure to match can have far reaching consequences for instance – the 2021 power grid failure in Texas, USA is estimated to cost $20.4 billion and 172 deaths[198].

1) In the case of hydrogen supply chain, hydrogen storage can address needs for flexibility in three ways across the electricity, gas and heat systems, depending on timescale:
5) Stability: Electrolysers are able to provide short term and high power services to the electricity grid. Electrolysers are able to deliver power grid services from seconds, minutes, hours and

[198] National Centers for Environmental Information, "Billion-Dollar Weather and Climate Disasters: Events," 2021. [Online]. Available: https://www.ncdc.noaa.gov/billions/events

weeks with fast availability and load ramp-up. On the supply side hydrogen storage in combination with (adapted) gas power plants or fuel cells could deliver fast-response and high power supply to the power grid. For both value propositions pilot and demonstration projects are conducted or in the pipeline. For the hydrogen system stability refers to pressure control to fulfil specific technical limits of the hydrogen grid. Typically, these variations occur over seconds and is most relevant for hydrogen transport through pipelines or for mobility end-use. Line packing and tank storage, are both able to react in few seconds to provide stability to the system.

6) Balancing and flexibility: this refers to load variations occurring over minutes to days to months. Such load variations are anticipated to be caused by periodic human activities, peaking during day-time of a working week and dropping during night-time and weekdays. Seasonal variations (e.g. winter-summer) on energy demand and supply can also lead to need for flexibility to balance the system. Many studies[199,200] agree that hydrogen storage has a rather unique feature to meet long-duration and high capacity storage at low cost compared to alternative storage and flexibility options. A mix of storage options is needed in the future energy system; typically VRES (solar and wind) and their installed capacities have a high impact on total volume and type of storage needs. Typically the daily cycle for solar PV is absorbed by battery storage and comparable short-duration storage options. Longer term to seasonal fluctuations are absorbed by pumped hydro, (underground) compressed air and hydrogen storage options. These needs are typically governed by installed wind capacity and the ratio between solar/wind installed capacity. If also seasonal demand profiles (e.g. built environment heating applications for hydrogen) appear then this translates also in seasonal storage needs. For long-term seasonal storage there are not many competitive storage options.
7) Adequacy: this refers to an increase in capacity to meet peak demand under extreme events over a period of months to years. Extreme events are not periodic, but still need to be accounted for as when they do occur, there will be excessive loads on the system. Few examples of extreme events include an exceptionally cold winter, or abnormal disruption to global energy supply chains amongst others. Typically long term and large scale storage technologies are suited for maintaining adequacy in both the gas and electricity system. Hydrogen storage offers unique storage potential, especially subsurface storage options, to meet security of supply challenges for long-duration and high power rating.

4.3.1.2 System-wide savings of investment and operational costs

Currently, system operation and security needs are addressed separately for each sector (natural gas, electricity). However, from a system-wide perspective, there is a potential to reach cost savings by considering these investments and systems operation together. If the existing interlinkages between sectors are not considered, there is a risk of overinvestment in network capacities, for example to cover demand in sectors where electricity and gas act as direct substitutes (such as heating). With regards to operational costs, this might relate for example to procuring more balancing services than it is actually necessary.

Deployment of hydrogen storage according to the system-wide needs assessment can contribute to addressing both the periods of peak energy production and demand. Therefore, the rest of infrastructure capacity can be rationalized to a more cost-efficient size that does not need to be able to handle peak energy volumes.

---

[199] Marta Victoria, Kun Zhu, Tom Brown, Gorm B. Andresen, Martin Greiner, The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system, 2019, Energy Conversion and Management, 2019

[200] Dilara Gülçin Çağlayan, A Robust Design of a Renewable European Energy System Encompassing a Hydrogen Infrastructure, Schriften des Forschungszentrums Jülich Reihe Energie & Umwelt / Energy & Environment, ISBN 978-3-95806-516-1

The cross-sectoral benefits of hydrogen storage for electricity system can be categorized as:

- Avoided operational costs in the electricity sector, reducing
  - Renewable power curtailment
  - Congestion management measures
  - Need for ancillary services
- Avoided investment costs in the electricity and gas sectors, reducing
  - Required transport capacity
  - Investment to guarantee SoS standards in each parallel system
- Lower variability of electricity prices

Hydrogen storage is also necessary for cost-efficient development of hydrogen sector itself. Based on the expected development of hydrogen sector, it will be initially the supply side that will drive the flexibility needs. Since demand in industry is stable and predictable, it will be the electrolytic hydrogen production from variable renewable sources that will mainly require hydrogen storage, at least initially[201]. Moreover, the seasonal storage needs might arise from the beginning as well, since vRES production is larger in summer than in winter (in contrast to a similar level of demand throughout the year). In the more long-term perspective, if hydrogen will be used in buildings and power generation sectors, demand side will also require additional flexibility capacities.

The potential of hydrogen storage to deliver system-wide benefits will also depend significantly on location, given the varying availability of suitable (underground) hydrogen storage sites per EU region (especially the salt caverns) as well as of availability and potential of renewable energy sources.

4.3.1.3 Review of benefits to electrolysers operators and end-users

Generally, hydrogen storage allows electrolyser operators to decouple hydrogen production from demand. Since the operators will not have to sell the produced hydrogen immediately to the consumers, it will be possible to produce hydrogen irrespective of the current demand on the consumer side (if the storage capacities are correctly designed to accommodate the surplus hydrogen generation).

As a result, electrolyser operators can benefit from price variations on the energy markets, both in time and also between (electricity and hydrogen) markets. Electrolyser operators, that will be directly connected to the electricity grid, can e.g. produce hydrogen during night when the electricity demand (and price) decreases, or during periods of peak renewable electricity generation, when the supply on the market is higher than demand (which also reduces the prices). It is hard to estimate to what extent the prices on electricity and hydrogen markets will be coupled, but, at least initially when most trading on hydrogen markets will be done by long-term contracts[202], there could be potential for short-term market price arbitrage. Operators of off-grid electrolysers connected directly to the renewable electricity generation capacities can produce hydrogen at marginal cost, and use storage to sell the hydrogen on the market when it is most favourable.

Hydrogen storage is a key technology for enabling seasonal flexibility to the (renewable) electricity sector. The level of production of renewable energy sources varies throughout the year (for example solar power production is higher in the summer period). On the demand side, the potential for

[201] Transport applications will require storage by definition, e.g. in the refuelling stations.

[202] This is because initially the majority of market players will be large industrial consumers and producers with significant electrolyser capacity – this is analysed in detali in Chapter 3.5.1 – Hydrogen markets will mature slowly

seasonal fluctuations will depend on the end-use sectors that will adopt hydrogen. Especially the use of hydrogen for household heating would add a significant seasonal fluctuation.

For electrolyser operators, using hydrogen storage to flatten the seasonal fluctuations would allow optimising the utilisation rate of electrolysers. For grid-connected electrolysers, the optimal utilisation (from economic perspective) rate is around 2,500-6,000 full load hours annually. With lower load, the CAPEX and OPEX costs impact the price more, whereas with higher load, the impact of electricity prices (electrolysers would be deployed in periods with too high electricity price, making the hydrogen production unprofitable) becomes more important.[203] Optimal utilization of electrolysers allows improving the profitability and shortening the return time for the investment. This can also facilitate the investment decisions for building new electrolyser capacity.

The storage buffer could also allow electrolyser operators to participate on the electricity flexibility and balancing markets, bringing additional revenue stream on top of the price of produced hydrogen.[204] This is because, as explained in previous paragraph, operating the electrolyser under full load all the time is not the most economically viable strategy (due to price fluctuations). Providing balancing services in both direction is therefore possible. Using hydrogen storage, electrolyser operators will be able to balance their position in hydrogen networks even in case the electrolyser output will have to change based on the signals form electricity market. However, even though electrolysers are able to provide almost all types of balancing services for the electricity networks (except for provision of inertia), they have to be specially designed for that task. This is especially the case for real-time balancing services, such as the Frequency Containment Reserve, where batteries might be a more cost-effective solution. For other services - automatic and manual Frequency Restoration, Replacement Reserve – the electrolysers are readily available on the current technology development level.[205]

Section 4.1 and the analysis of the archetypes in section 4.3 shows that underground hydrogen storage in salt caverns is the most economical form of storage available in 2030, while storage in tanks is more expensive and the line pack storage potential is limited. Hence, where UHS is available, electrolyser operators or suppliers are more likely to invest in or contract UHS services rather than operate their own hydrogen tanks for managing supply variability (unless this burden is left to large consumers). Therefore, (fast-cycling) UHS would bring benefits to electrolyser operators which could be quantified as the cost differential to store hydrogen in UHS vs tanks (assuming the dimensioning and operation of electrolysers remains unchanged).

For end-users, hydrogen storage offers stability of supply and better availability of hydrogen during time. Storage also reduces price volatility, for example in cases when hydrogen demand and supply volumes do not meet or when the high price of electricity input would translate in higher hydrogen price.

Moreover, storage enables development of hydrogen in sectors with high seasonal fluctuation, such as in the building sector (otherwise, capacity investments to match peak demand only during certain period of year would be too costly)

Storage is also essential for both electrolyser operators and end-users not connected to hydrogen grids, and for operation of import terminals, who cannot benefit from the pooling of production and demand capacities enabled by the grid infrastructure.

[203] IEA (2019). The Future of Hydrogen. Available at: https://www.iea.org/reports/the-future-of-hydrogen

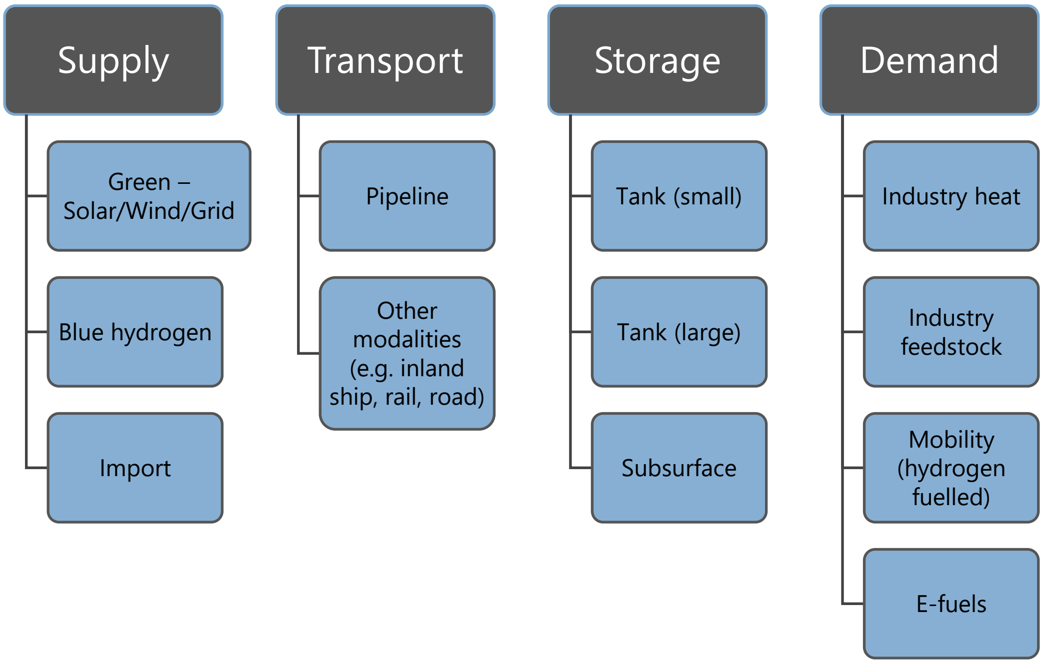
[204] Samani et al. (202). Grid balancing with a large-scale electrolyser providing primary reserve. Available at: https://doi.org/10.1049/iet-rpg.2020.0453.

[205] IRENA (2020). Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5⁰C Climate Goal. Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

4.3.1.4 Representative case studies for hydrogen storage

To study the contribution of storage in a hydrogen supply chain, a supply chain model was built. In this model, different 'archetypes' can be defined to represent the types of hydrogen supply chains relevant for the EU. An archetype is a lumped representation of supply, demand and transport that could represent a supply chain over a large international region (within the EU). In the next sections, the three archetype cases are described further.

Figure 38 Schematic of the archetype hydrogen supply chain model and the elements under each chain component. Selecting certain inputs and their magnitudes for these elements allows to define diverse archetypes



Hydrogen supply chains comprises of four major components hydrogen production – transport – storage – consumption. In this study, following elements within these major com-ponents were considered.

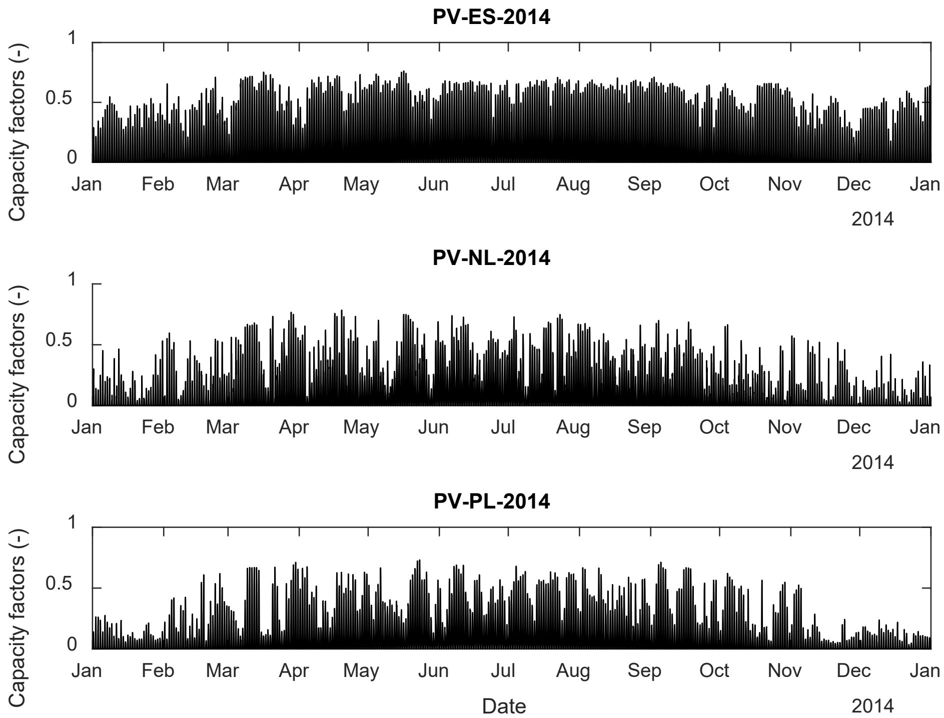
Supply

Supply of hydrogen can be parameterised as either renewable hydrogen, blue hydrogen and import (colour-independent) by selecting percent share of each. Renewable hydrogen production is modelled by water electrolysis from solar, wind or grid electricity. Note that for grid electricity, emissions are not considered in the model. For both, solar and wind electricity share, one out of three profiles can be chosen. The three profiles represent high, medium or low average capacity factors corresponding to the EMHIRES dataset for Spain, the Nether-lands and Poland respectively for 2014[206]. These capacity factors are shown in Figure 39 and Figure 40. It can be seen that the average capacity factor for a solar-following electrolyser varies from 11-17% whereas for a wind-following electrolyser varies from 22-28%. The effective load factor can be increased by adding a grid electricity contribution to the renewable hydrogen production parameters.

[206] G. A. Iratxe, Z. Andreas, C. Francesco, M. Fabio, H. Thomas and B. Jake, "EMHIRES dataset. Part I: Wind power generation European Meteorological derived HIgh resolution RES generation time series for present and future scenarios," European Commission EUR 28171 EN; 10.2790/831549., 2016. Gonzalez Aparicio I; Huld T; Careri F; Monforti-Ferrario F; Zucker A. EMHIRES dataset: Part II: Solar Power Generation: European Meteorological derived HIgh resolution RES generation time series for present and futures scenarios: Part II: PV generation uding the PVGIS model. EUR 28629 EN. Luxembourg (Luxembourg): Publications Office of the European Union; 2017. JRC106897

Lastly, blue hydrogen and import percent share can be parameterised, which assumes a flat hydrogen profile supply. The resulting hydrogen supply profile is a combination of green, blue and import profiles, of which the supply variability is captured in the renewable hydrogen profiles.

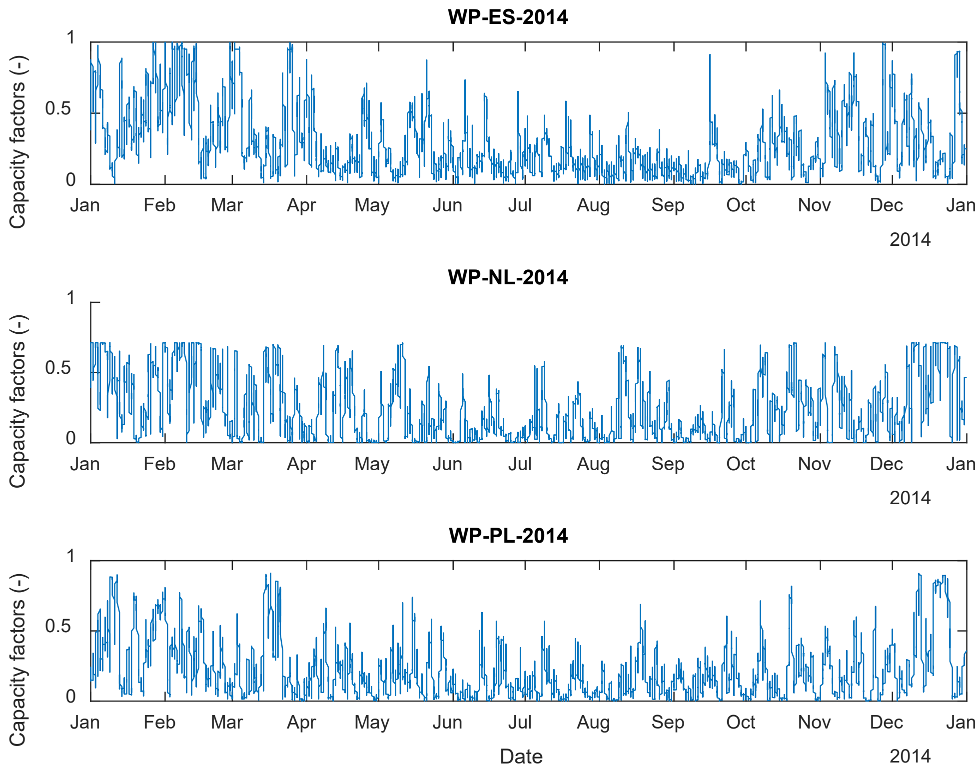
Figure 39. Capacity factors for solar power generation for 2014 in (top) Spain/high, (middle) the Netherlands/medium and (bottom) Poland/low. Average capacity factors are 17%, 11% and 10% respectively



Source: EMHIRES dataset[207]

[207] Gonzalez Aparicio I; Huld T; Careri F; Monforti-Ferrario F; Zucker A. EMHIRES dataset: Part II: Solar Power Generation: European Meteorological derived HIgh resolution RES generation time series for present and futures scenarios: Part II: PV generation uding the PVGIS model. EUR 28629 EN. Luxembourg (Luxembourg): Publications Office of the European Union; 2017. JRC106897

Figure 40 **Capacity factors for wind power generation for 2014 in (top) Spain/high, (middle) the Netherlands/medium and (bottom) Poland/low. Average capacity factors are 28%, 24% and 22% respectively**



Source: EMHIRES dataset[208]

Transport

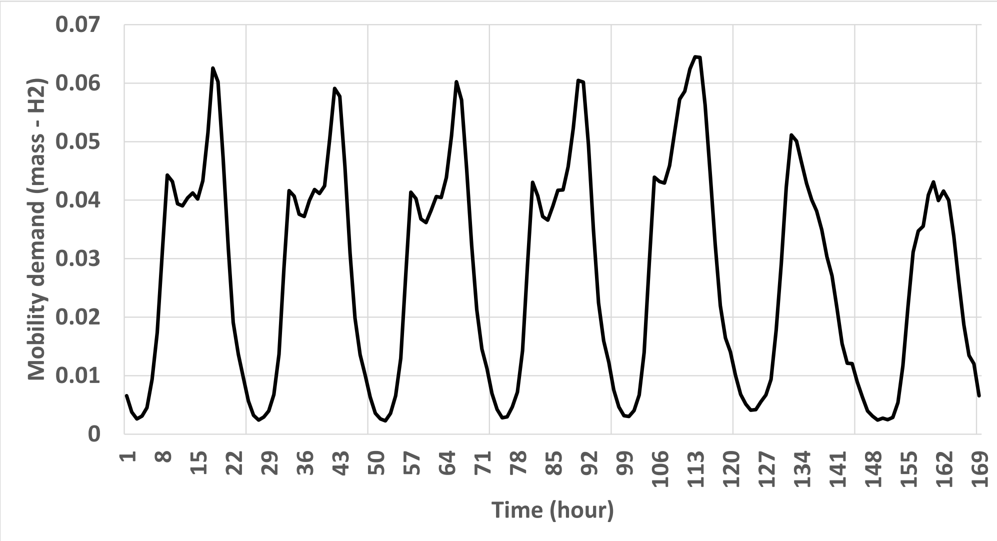
Transport of hydrogen can be parameterised to indicate the percentage transported through pipeline, shipping, road and rail modalities. For each modality, the transport distance (km) can be specified

Demand

Demand of hydrogen can be parametrised to indicate the share of industry heat, industry feedstock, mobility and renewable hydrogen and derivative fuels. Only the mobility demand profile have a choice between a flat and daily variations, with other demand types having a flat profile. The daily demand variation profile, adopted from literature, is shown in Figure 41; and are repeated every week for the whole year.

[208] Gonzalez Aparicio I; Huld T; Careri F; Monforti-Ferrario F; Zucker A. EMHIRES dataset: Part II: Solar Power Generation: European Meteorological derived HIgh resolution RES generation time series for present and futures scenarios: Part II: PV generation uding the PVGIS model. EUR 28629 EN. Luxembourg (Luxembourg): Publications Office of the European Union; 2017. JRC106897

Figure 41 Mobility demand profile showing weekly variation. Note that the y-scale unit is in H_2-mass which can be scaled according to archetype needs.



Own model adopted from[209]

Storage

Storage of hydrogen is considered in surface tanks (for shipping, road, rail, terminals), line packing (for transport pipelines) and in subsurface salt caverns. The total storage need is estimated based on the mismatch between supply and demand profiles for a whole year. The total storage need is met via the considered storage technologies. To estimate the capacity required of each storage type, the following storage-need-order is implemented –

1) Tank storage: tank storage offers not only short time scale flexibility, but also is required for transport modalities such as shipping (ships and terminals), road and rail. Within tank storage, additional tank capacity is calculated to meet one full day of demand. It is assumed that CGH_2 tanks will be used and scaled in number to meet the capacity needed.
2) Line packing: line packing offers flexibility to hydrogen transport by pipelines. The maximum line pack storage potential is considered for the total length of pipelines in the transport section. We assumed line packing capacity for a 24-inch pipeline operating pressure increasing to 60 bar from 50 bar.
3) Salt caverns: salt caverns offer large scale hydrogen storage potential and all the remaining storage capacity need in the model is met via salt caverns.

Archetypes:

In this study, three archetypes were defined to broadly cover the various geographic characteristics in the EU. These archetypes are summarised in Table 27, Table 28 and Table 29. The Aeolus is a wind-dominated archetype with 40 TWh supply/demand partially met with 10 GW electrolyser capacity. Helios is solar dominated with 20 TWh supply/demand partially met with 6 GW electrolyser capacity and the Gaia is import dominated with 10 TWh supply/demand partially met with 3 GW electrolyser capacity) fed by a mix of wind and solar energy. Aeolus archetype is comparable to the North-western EU with abundant access to offshore wind energy in the North Sea. Helios

[209] Welder, L., Ryberg, D., Kotzur, L., Grube, T., Robinius, M., & Stolten, D. (2018). Spatio-temporal optimization of a future energy system for power-to-hydrogen applications in Germany. Energy, 158, 1130–1149. https://doi.org/10.1016/j.energy.2018.05.059

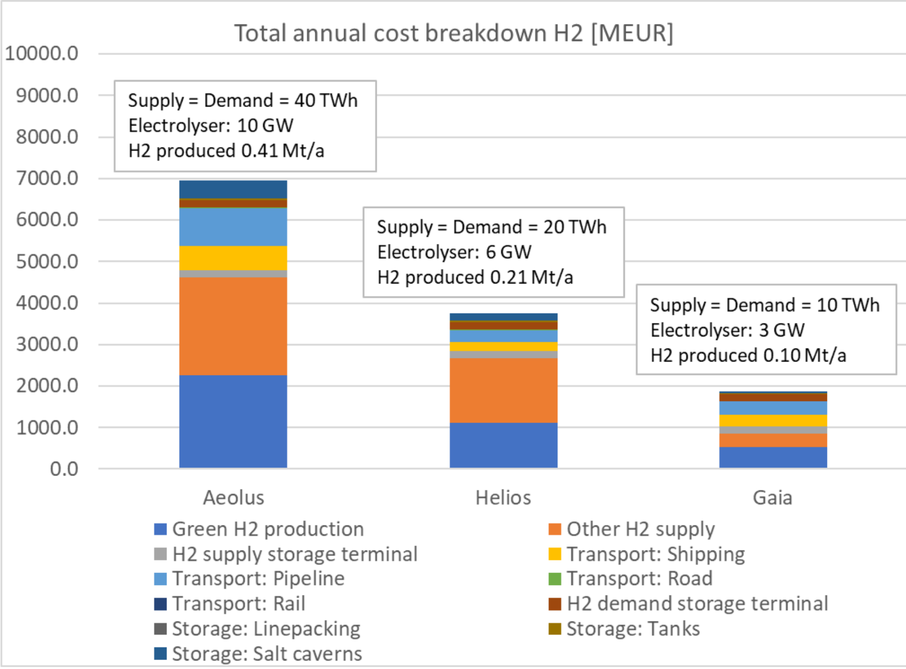
archetype is comparable to southern EU with abundant access to solar energy and the Gaia archetype could be comparable to eastern EU where H_2 import is likely to play a larger role.

For all archetypes, the transport inputs are assumed by inspiration from regional relevance. For example, 25% of natural gas pipeline network length is assumed to be available by 2030. Shipping and road transport lengths are shorter as we consider bulk of hydrogen will be shipped through pipelines, with shipping and road transport used for last-mile transport when end-users are not in the vicinity of pipeline grid station.

All archetypes have annualised cost ranging from 1.8 to 7 billion euros. The cost breakdown highlights, firstly, that Aeolus having largest magnitude results in the highest overall costs. Significant part of the costs (~ $1/4^{th}$) are from electrolyser investment and from other H_2 sources. Storage cost of tanks and salt caverns are same order of magnitude and cover roughly 10-25% of the total annualised costs. However, comparing the storage capacity of these two technologies (Figure 37), salt cavern capacity dominates tank storage capacity. This highlights the effect of large-scale storage option such as salt cavern on the total system cost in comparison with smaller scale storage solutions such as tanks. Some amount of tank storage will be needed for smooth operation of a hydrogen value chain, especially supporting batch transport options alike ship, train and truck transport of hydrogen. However, there is a cost advantage to use salt caverns where available and possible for large scale storage. Other archetypes have similar findings on the total storage capacity per type as Aeolus, those plots are not shown here.

Figure 42 Annual cost breakdown of the three archetypes

Aeolus, Helios and Gaia. Top figure shows the total annual cost breakdown whereas the bottom figure shows the specific cost breakdown normalised with the archetype supply/demand capacity. Other H_2 supply refers to Blue H_2 (2 €/kg) and Import H_2 sources (4 €/kg).



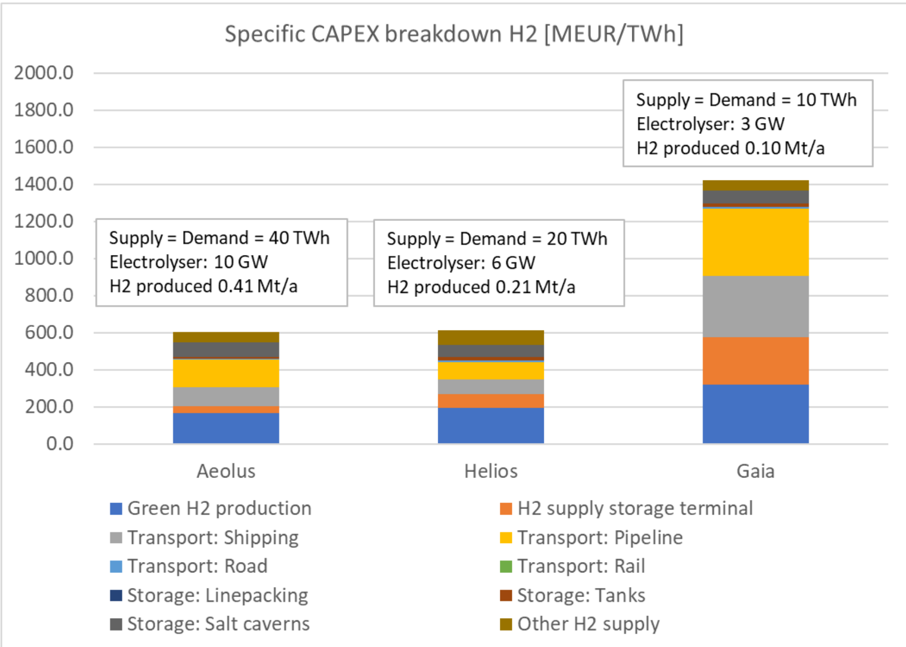


Figure 43 Total storage capacity for tank, line pack and salt cavern for the Aeolus archetype. For converting to energy units – hydrogen lower heating value is 33.33 kWh/kg

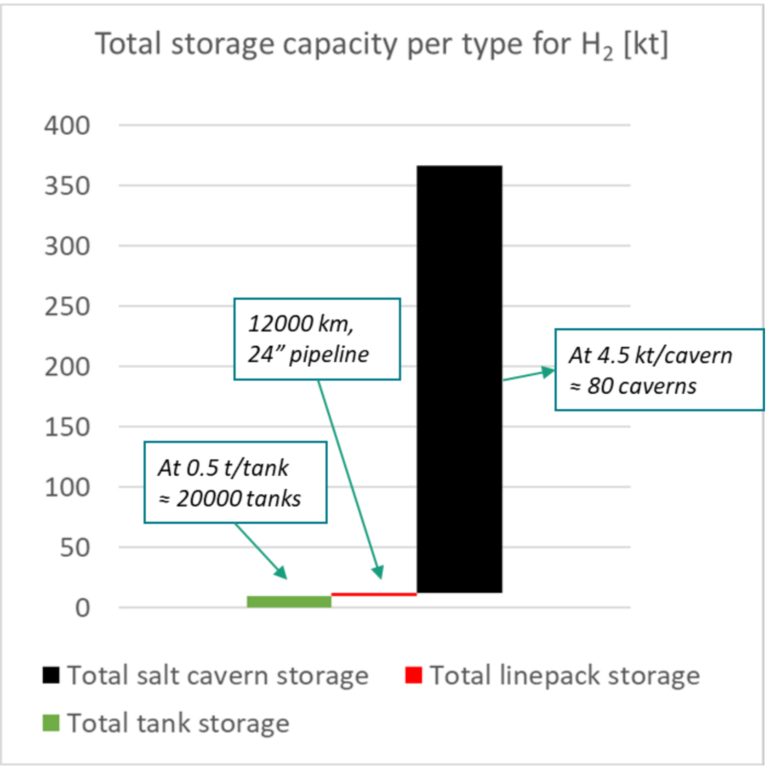


Table 27 Summary of the Aeolus archetype definition

Archetype	Supply	Transport	Storage	Demand
Aeolus	(Offshore) wind dominated	Pipeline network	Good access to subsurface storage	High industry and mobility demand
Specifications 25% Security of supply (of supply/demand)	Supply: 40 TWh 10 GW electrolyser (Renewable H_2)* Wind 70%, profile = high Solar 30%, profile = low Grid 0%. Deficit (total supply – RES H_2) 50% blue hydrogen 50% Import	Developed hydrogen backbone, equivalent pipeline lengths# of NL+BE+DE+DK Assumed 25% is available by 2030 80% transport by pipeline Pipeline ≈ 12000 km 10% by ship (≈ 200 km) 10% by road (≈ 200 km)	No subsurface storage potential limits	Demand: 40 TWh 80% industry heat + feedstock 20% Mobility, profile = daily.

* In this archetype 10 GW electrolyser with chosen profiles produce ≈ 0.41 Mt/a renewable H2
# MS chosen as representative of the archetype. Choice is not aligned with NECP.

Table 28 Summary of the Helios archetype definition.

Archetype	Supply	Transport	Storage	Demand
Helios	**Solar and import dominated**	**Pipeline network**	**Medium to Low access to subsurface storage**	**High industry demand, mobility demand**
Specifications 25% Security of supply (of supply/demand)	Supply: 20 TWh 6 GW electrolyser (RES H_2) Wind 50%, profile = low Solar 50%, profile = high Grid 0%. Deficit (total – RES H_2) 100% Import	Developed hydrogen backbone*, equivalent pipeline lengths of PT + ES Assumed 25% is available by 2030 70% transport by pipeline Pipeline ≈ 3,700 km 5% by ship (≈ 55 km) 25% by road (≈ 200 km)		Demand: 20 TWh 70% industry heat + feedstock 30% Mobility, profile = daily.

* In this archetype 6 GW electrolyser with chosen profiles produce ≈ 0.21 Mt/a renewable H_2
* MS chosen as representative of the archetype. Choice is not aligned with NECP.

Table 29 Summary of the Gaia archetype definition

Archetype	Supply	Transport	Storage	Demand
Gaia	**Import dominated**	**Emerging pipeline network**	**Medium to Low access to subsurface storage**	**Medium industry demand**
Specifications 25% Security of supply (of supply/demand)	Supply: 6 TWh 3 GW electrolyser (renewable H_2)* Wind 70%, profile = low Solar 30%, profile = low Grid 0%. Deficit (total – RES H_2) 100% Import	Developed hydrogen backbone, equivalent pipeline lengths of PL+CZ+SK Assumed 25% is available by 2030 60% transport by pipeline Pipeline ≈ 4,400 km 20% by ship (≈ 65 km) 20% by road (≈ 200 km)		Demand: 6 TWh 80% industry heat + feedstock 20% Mobility, profile = daily.

* In this archetype 3 GW electrolyser with chosen profiles produce ≈ 0.10 Mt/a renewable H_2
* Choice of wind or solar profile shifts the seasonal import need, but not the annual import or storage needs.

4.3.2 Asset and risk classifications per storage technology[210]

Main Take-aways of the section

- A storage project is deemed profitable if the net present value is positive when discounted at a rate representing the cost of capital
- The cost of capital should be equivalent to the sum of the risk-free rate and risk premiums reflecting all project risks (country, market, policy and regulatory, and technology risks)
  - **Country risks** are independent of the storage projects and specific to each country
  - **Market risks** to storage projects could arise e.g. from uncertainty on the development of the overall hydrogen market, electricity price evolutions or from competition with other storage projects
  - **Policy and regulatory risks** may arise from the lack of a regulatory framework for hydrogen storage, or the removal of hydrogen support policies, among others
  - **Technology risks** stem from the potential underperformance or higher costs, due to the current need for hydrogen storage technology development
  - Hydrogen storage **project-specific risks** could exist due to for example lack of access to a hydrogen network, permitting delays or issues with a reservoir site
- Future hydrogen storage projects should face non-negligible technology risk premiums. While storage of hydrogen in salt caverns is a proven technology (TRL 9), fast cycling of those storages is less mature (TRL 7). Also, storage in porous reservoirs is at a much lower maturity (around TRL 3).
- Salt cavern hydrogen storage projects could achieve technology risk premiums close to 3% by 2030. Future projects for storage in porous reservoirs could face TRPs of around 6%.
- Country risk premiums ranging from 0% to 5% should come on top of TRPs , leading to a combined risk premium ranging from 3% (salt cavern storage in Member States with a very low country risk premium) to 11% or more (porous reservoir storages in Member States with a high country risk premium).
- The absence of a clear and predictable regulatory framework should lead to policy and regulatory risks which would further increase total risk premiums. Interviewees indicate that hydrogen storage projects are CAPEX-intensive and that economic support will be required, at least initially, for investments to take place
- There is a lack of familiarity of the financial sector with hydrogen storage technologies and projects. EU and Member States can support not only technological innovation but also financial learning around hydrogen storage, in order to reduce risk premiums. This could involve for example co-financing and dissemination of best practices.

This section aims to conduct an analysis of hydrogen storage assets and classify it according to risks per storage technology. This should facilitate the development of policy measures targeted at reducing financial barriers to the investment in hydrogen storage assets due to high actual or perceived risks – with perceived risks meaning risks which arise from the lack of familiarity with a technology or context, rather than risks due to lack of technology maturity, regulatory instability or other factors which increase risk.

Investors in energy and specifically hydrogen storage assets balance the risks and expected returns of the investments when making decisions. In a simplified manner, expected returns, considering

[210] Theoretical aspects of this section are based on Trinomics (2020) Report on literature review and stakeholder interviews regarding the representation and implications of the financing challenge

the appropriate risks, should exceed all project costs (including the cost of capital) throughout its lifetime. In addition to risks and returns, other factors could be considered in the investment decision, such as the project size, portfolio considerations (as e.g. the project could help reduce the overall portfolio risk due to complementarities with other assets) and corporate social responsibility.[211] These factors could be ultimately represented as monetary or non-monetary benefits or risks of the project.

Risk can be understood to represent (positive or negative) deviations of returns from the expected value. Investors are generally risk averse, preferring a project with lower risk, all else equal. Therefore, investors will ask for a **risk premium** in order to invest in projects. The risk premium is added on top of the **risk-free rate** (which represents the cost of capital for an asset with no significant risk of financial loss) to determine the overall risk of the project, which is equivalent to the cost of capital of the project.[212] The sum of a project's revenues and costs throughout its lifetime discounted at the cost of capital should be positive (i.e. a positive net present value) in order for the project to be considered profitable. In other words, the cost of capital represents the minimum rate of return of a project required to make it profitable, considering the specific project risks.

This determination of the cost of capital of a project considers that investors will provide capital at a cost equivalent to the project's risk. However, for corporate finance projects (where a project is financed through a company's general funding and where the company's total assets serve as a collateral) the company will have a **weighted average cost of capital (WACC)** based on equity and loan interest rates. In this case, the project total risk should be equal or less than the WACC (and have a net present value with all cash flows discounted at the WACC).

The risk premium can represent different forms of risk, including country / market / policy and regulatory / technology / project-specific risks. Therefore, multiple risk premiums can contribute to the overall project cost of capital:

- The **country risk** represents the overall risk of doing business in a certain country, due to e.g. the political environment, or fiscal or monetary policy. While the country risk is unrelated to the characteristics of a specific project, it does affect the financing conditions for energy projects and vary across EU Member States, ranging in 2019 from 0% to e.g. Germany and Sweden to over 3% in a few other Member States;[213]
- **Market risks** arise from uncertainty regarding project sales and input costs. In the case of hydrogen storage, market risks would arise from uncertain revenues from the sale of storage services. The uncertainty of storage revenues may arise from uncertainties regarding the development of the overall hydrogen market, uncertainties in the electricity market such as price evolution, or competition with other hydrogen transport and storage options (e.g. distribution through trucks instead of pipelines). Policy measures which reduce uncertainty regarding sales and input costs (for example support mechanisms or a regulatory regime employing a regulated asset base) can help reduce market risks;
- **Policy and regulatory risks** represent the risks of unforeseen or retroactive changes in the legal and regulatory framework which can adversely affect the project profitability and which are contrary to the principle of regulatory predictability. For hydrogen storage projects, this could refer to unclear regulatory frameworks, or to including additional permitting require-

[211] Trinomics (2020) Report on literature review and stakeholder interviews regarding the representation and implications of the financing challenge

[212] The present analysis does not differentiate between the sources of capital (equity or debt) and the leverage ratio of the projects (i.e. the debt to equity ratio), with risks impacting the total risk premium as well as actions to reduce this premium being applicable to high or low leverage.

[213] Trinomics (2020) Report on literature review and stakeholder interviews regarding the representation and implications of the financing challenge

ments or changing the allowed regulatory regimes after the overall framework is defined. Another risk could be a reversal or restriction of hydrogen support policies due to the sustainability of hydrogen being lower than originally forecasted. Providing a clear and predictable regulatory framework for hydrogen storage assets (including elements which impact their profitability, such as energy taxation or support mechanisms) is a main measure to mitigate policy and regulatory risks;

- **Technology risks** refers to the possibility of underperformance or higher costs of a given technology, due to its characteristics and maturity. An indicator of technology maturity often used to assess associated technology risks is the technology readiness level (TRL). TRLs for hydrogen storage technologies are analysed in detail in section 1.1. Technology risks can also be associated with public acceptance issues for certain technologies, e.g. due to perceived safety risks or landscape impacts, or lack of workforce with sufficient technical expertise. While technology risks associated with the maturity of hydrogen storage technology exists, we do not identify particular risks associated with public opposition, and the market is not developed sufficiently for labour bottlenecks to exist;
- **Project-specific risks** regard the risks associated with the development, construction, commissioning, operation and/or decommissioning of individual projects and which cannot be classified in any of the other risk categories. This could include also risks associated with the specific project team and organisations, and risks associated with the borrower (in case of corporate financing of projects). Hydrogen storage project-specific risks could regard e.g. access to hydrogen networks in certain locations, potential delays in permitting and construction, and technical difficulties with certain reservoir sites.

Future hydrogen storage projects **should face non-negligible technology risk premiums.** Hydrogen storage technologies are in various stage of development, and thus exhibit different technology readiness level as discussed in section 1.1. While storage of hydrogen in salt caverns is a proven technology (TRL 9), fast cycling of those storages is less mature (TRL 7). Also, storage in porous reservoirs is at a much lower maturity (around TRL 3). Specific projects, including co-financed by the EU, aim at increasing the maturity of hydrogen storage technologies. The Hypster project aims to demonstrate the fast-cycling of salt cavern storage, and Hystories aims to increase the TRL of storage in porous reservoirs.[214]

Technologies with low deployment and high risk can have a technology risk premium (TRP) of up to 6% or more. Mature sustainable technologies such as solar PV can face a TRP of ~3% or lower - this can be seen as a lower bound for hydrogen storage technologies when they reach maturity. Moreover, technologies with a high risk perception due to public opposition, such as coal power plants, can face a higher technology risk premium, of 6% or above.[215]

Therefore, **salt cavern hydrogen storage projects could achieve technology risk premiums close to 3% by 2030,** similar to that of mature renewable energy technology. Future projects for storage in porous reservoirs could face TRPs of around 6% (i.e. the general TRP level for immature technologies with low deployment), due to the lower TRL level and the remaining need for technology demonstration, even by 2030. These TRPs do not consider other risks such as regulatory or market risks.

Country risk premiums ranging from 0% to 5% should come on top of TRPs[216], leading to a combined risk premium ranging from 3% (salt cavern storage in Member States with a very low

[214] https://hystories.eu/; https://www.storengy.com/en/medias/news/hypster-1st-demonstrator-H_2-green-storage

[215] Trinomics (2020) Report on literature review and stakeholder interviews regarding the representation and implications of the financing challenge

[216] Under currently practiced interest rates, which could change due to changes in monetary policy

country risk premium) **to 11% or more** (porous reservoir storages in Member States with a high country risk premium). The 3% TRP should be seen as a lower bound, and would need to be added on top of the risk-free rate and other risk premia (representing country, market or regulatory risks).

Even if fast-cycle hydrogen storage was a mature technology, other risk types would affect the overall risk premium and thus future project profitability. **The absence of a clear and predictable regulatory framework should lead to policy and regulatory risks** which would further increase total risk premiums. Also, most gas storage operators furthermore indicate that **a regulated tariff regime for hydrogen storages could increase revenue certainty,** thereby reducing market risks for the storage project developer and its associated premiums (by transferring the market risk to storage users and ultimately to the government, in case there is limited demand for storage). However, German gas storage operators do not favour a regulated tariff regime, preferring the ability to freely set access tariffs for future hydrogen storages. This likely reflects the current competitive landscape and regulatory approach for natural gas storages in the country, as well as the larger German salt cavern storage potential.

Interviews also indicate that **there is a lack of familiarity of the financial sector with hydrogen storage technologies and projects**. This applies to commercial banks, institutional investors such as pension funds, and other types of investors, and is driven by the lack of commercial hydrogen storage projects, as the financial sector has not had the opportunity to build expertise on the technology. This may increase risk premiums, potentially leading to a vicious circle which could impact the cost of capital for future hydrogen storage projects. Corporations could address this issue to some extent through initially financing projects themselves and later on selling stakes (at a profit) on it once project risks are lower. However, while corporate finance is thus an option, the lack of familiarity of the financial sector still will impact project finance. There is room for the EU and Member States to support not only technological innovation but also financial learning around hydrogen storage, in order to reduce risk premiums. This could involve for example co-financing and dissemination of best practices.

Governments can work towards reducing risk premiums, which should improve the cost of capital and thus bring projects closer to profitability. **Interviewees do indicate that hydrogen storage projects are CAPEX-intensive and that economic support will be required, at least initially, for investments to take place**. While the assessment of the need for public support may be left to Member States, it would be warranted to allow such support in case it can be demonstrated the storage projects are not commercially viable without it. This does not mean that such support should not be considered State Aid and thus be exempted from notification requirements. On the contrary, given currently support to electricity and gas storage constitutes State Aid,[217] any economic support should also require notification for State Aid assessment, in order not to distort competition between electricity, gas and hydrogen (unless Environmental and Energy Aid Guidelines and the General Block Exemption Regulation are revised in this matter). Eventual support to project revenues can be complemented with measures to reduce non-market risks and the overall cost of capital.

[217] European Commission (2020) Recovery and resilience facility (RRF) guiding templates - Energy and hydrogen infrastructure

4.4 Context and analysis of barriers for the development of hydrogen and derivatives storage

Main takeaways of the section

- This section details five contextual topics and barriers which shape the necessary policies and regulations to develop hydrogen storage
- While the section focuses on barriers related to hydrogen infrastructure and market design, other barriers not covered will need to be addressed in order for hydrogen storage to take off, including technical barriers and the need for economic support initially
- **Hydrogen markets will develop slowly**, starting with the substitution of grey hydrogen in industry, and with the market structure composed mainly of large producers and consumers
    - Hydrogen purchase agreements complemented with long-term network capacity bookings should provide the certainty for initial investments in hydrogen infrastructure. However, a development based on long-term bilateral agreements may initially restrict the liquidity of organised markets.
    - Low market liquidity may hinder the ability of hydrogen storage to profit from price differentials, especially if there are no incentives for market players to offer spare hydrogen supply and source additional needs (above contracted supply) in short-term markets. Moreover, underground hydrogen storage capacity may in the beginning largely exceed storage needs due to minimum project sizes
- **The need for regulation of storage will vary across Member States and storage types.** More detailed assessments will be required, but integrated storage markets of North-Western/Northern Europe and Iberia could be sufficiently competitive, while the South-Eastern Europe and Baltic markets could still require regulation for large-scale storage
    - Hydrogen storage capacity for all salt cavern formations in the EU provides a large storage potential, sufficient to meet future storage needs, but is unevenly distributed across Member States
    - Repurposed H_2 storage capacity may be limited for 2050 and even 2030 needs for certain Member States, and estimates on the storage potential of repurposed assets should be considered an (optimistic) upper boundary
    - Development of new reservoirs is likely to be necessary to meet the 2030 storage needs if the storage levels foreseen in the gas market package impact assessment modelling are to materialise
    - Each storage type and size may be more suitable to a specific storage need, and in specific cases and countries other storage forms than salt caverns could be more competitive or be the only available solution
    - A hydrogen storage market concentration analysis indicates that competitive storage markets may develop in Member States with relatively high storage needs, namely DE, FR, ES and NL. Without integration of markets, DK, GR, PL, PT and RO have lower storage needs and thus a lower number of operators, leading to market concentration
    - Integrating future hydrogen storage markets provides countries without salt cavern potential access to underground storage capacity and can decrease market concentration.
- Energy sector planning may not consider fully storage needs & benefits, potentials and interaction with other sectors. This potential failure in recognising appropriately the system and security of supply value of hydrogen storage might lead to supporting unnecessary investment in electricity or natural gas networks or lead to under- or overestimation of the hydrogen storage needs for future hydrogen systems, among other issues

- There has been some progress in the recent years in integrating the hydrogen sector into network planning. However, electricity and (natural) gas system projects are still assessed separately in the TYNDP process, with hydrogen supply and demand being considered only on the `boundaries` of the system. The lack of common planning scenarios may also not adequately reflect the development of hydrogen demand.
- There is also no EU requirement to consider hydrogen systems and the benefits of hydrogen storage on the national level. There is also no EU requirement for the NECPs being considered in developing the NDP scenarios. The possible consequence of this situation is divergence of national energy and climate policy and the plans of network operators for network development
- Increasing temporal and locational granularity of the system planning as well as of market design would allow to better reflect the market and system flexibility of storage

- **Market design and network tariffs may not reward the benefits of hydrogen storage.** While the market value may be adequately rewarded, that may not occur for the system (flexibility) and security of supply values.
  - Inadequate consideration of the system value may occur due to a lack of integrated systems planning, entry barriers in wholesale or ancillary services markets, lack of incentives for network users to minimise imbalances, and other barriers
- The storage contributions to security of supply may not be properly valued due to, among others, an inability of market players to adequately estimate the probability of rare supply disruption or infrastructure outage events, or due to the absence of incentives for them to do so (if for example energy-only markets do not allow to recover fixed costs, or if suppliers have limited liability to disruptions in supply)
- **There is regulatory uncertainty concerning the conversion of currently regulated gas storages,** since the current EU and most national regulatory frameworks for natural gas do not cover hydrogen
  - Projects need to be started soon if storage capacity is to be available by 2030, as from a technical point of view, repurposing hydrogen storages can take anywhere from 1 to 7 years, and developing new storage assets can take from 3 to 10 years. The underlying hydrogen regulatory framework should be also ready to enable this conversion.
- Future regulatory frameworks will need to address issues such as providing certainty for investments, ensuring cost-reflectivity, avoiding distortion of competition of the internal energy market due to different regulatory regimes, and others

This section presents the overall context shaping the future development of hydrogen and derivatives storage, as well as the main barriers for this development. The list of barriers presented is not exhaustive, focusing on the barriers which can be addressed by policy and regulatory measures (presented in section 4.4).

The approach for developing the analysis of barriers and policy & regulatory measures for developing hydrogen storage combined desk research with interviews of 10 gas infrastructure operators or operator associations. Textbox presents a summary of the main relevant opinions gathered in the interviews.

Textbox 6 Opinions of gas infrastructure operators on barriers and necessary measures for the development of hydrogen and derivatives storage

The opinions of the gas operators were critically assessed and are explicitly indicated whenever they are used in the analysis. They do not necessarily represent the opinion of Trinomics, who has considered eventual interests from the interviewees in the analysis.

Gas storage operators generally agree that:

- 4 main conditions are necessary for developing hydrogen storages
  - Certainty regarding the regulatory framework
  - Correctly valuing the contributions of storage to the market (e.g. increased value capture by electrolyser operators), system (reduced total system costs) and SoS, for the entire energy system (not only hydrogen) through enhanced integrated planning, market and tariff design
  - Long-term certainty regarding storage use, preferentially through regulated regimes or alternatively through long-term contracts
  - Subsidisation due to the high CAPEX and limited number of users in the beginning. OPEX is not significant in comparison and thus subsidisation can focus on CAPEX (or total costs)
- New H_2 storage investments will be necessary, even if some gas storages are repurposed
- H_2 storage in salt caverns is technically feasible
- Unbundling between gas and hydrogen networks needed, as otherwise gas storages could be penalised for financing H_2 investments

Furthermore, relevant individual opinions (not shared by all operators) include:

- German storage operators do not favour regulated TPA, as German gas storage market is highly competitive, including with multiple salt caverns in operation
- Allowing H_2 network operators to own and manage H_2 storages without regulation would lead to unfair competition towards other storage operators
- Several approaches may exist to value contributions of storage
  - (Minimal) network tariff discount
  - Tariff discounts based on calculated avoided network investments
- Transmission tariff structure as determined by TAR NC does not adequately provide locational signals nor temporal signals
- Long-term storage contracts should not represent a barrier as eventual repurposing will occur gradually and can be done for individual caverns

4.4.1.1 Hydrogen markets will mature slowly

Hydrogen markets are currently limited. Merchant hydrogen production (i.e. traded, whose production is not captive / dedicated to specific clients nor is a by-product of industrial processes) amounted in 2018 to around 15% of total production capacity. And the majority of the merchant production capacity was dedicated to serve large industrial customers on site. Therefore, the share of currently produced hydrogen which is offered to a broader base of customers is still limited,[218] and most merchant hydrogen is current traded on the basis of long-term supply contracts.

[218] Fuel Cells and Hydrogen Observatory (2020) Chapter 2 Hydrogen Supply & Demand

Hydrogen markets will grow slowly (despite a strong increase in the electrolysis installed capacity) as electrolytic hydrogen production first replaces fossil-based (mostly captive) hydrogen sources and also serves new end-uses. Renewable hydrogen production by 2030 may amount to up to 10 million tonnes (333 TWh_{LHV}) according to the Commission's Hydrogen Strategy, which is around the same magnitude of current GHG-intensive hydrogen production. Electrolyser capacity in Europe amounted in 2018 to around 10,000 tonnes.[219] Therefore the renewable electrolytic hydrogen production in the EU should increase by 80% every year in the 2018-2030 period (i.e. a constant average growth rate, CAGR, of 80%) to achieve the target of the EU Hydrogen Strategy.

Industry and potentially transport will be by 2030 the main end-use sectors. While part of the future hydrogen supply may be consumed on-site for large industries (as is currently often the case) and transport, a significant share in some Member States could be transported through dedicated networks. This would be a consequence of the distributed nature of renewable energy potential, including the fact that Member States with a significant renewable energy potential could become significant exporters. The Dutch government already making the first steps to developing a national hydrogen network.[220] By 2030, hydrogen markets may form in specific hydrogen clusters, potentially interconnected through a hydrogen transport backbone in certain regions and supplied also by international markets.

However, smaller hydrogen systems will exist, and even interconnected hydrogen systems may be dependent on variable hydrogen supply sensitive to renewable energy availability and variability. Smaller hydrogen systems may have higher balancing needs given the lack of interconnection with other systems which would provide additional flexibility resources and reduce variability of supply and demand given the correlation between producers or end-user profiles would decrease. This even if each individual hydrogen system is coupled to the larger energy system through interfaces with the electricity and methane gas sectors.

Initially, the structure of hydrogen markets should mainly comprise existing large hydrogen consumers (such as refineries and chemical industries) and suppliers with projects with a capacity of 100 MW or more (the average size of power-to-gas projects currently under consideration and due to be operational by 2030 is around 90 MW[221]). Eventual other large industries such as steel producers may also be early consumers. The hydrogen purchase agreements between these large market players, complemented with long-term network capacity bookings, should enable the necessary investments in hydrogen supply and transport infrastructure.

However, a development based on long-term bilateral agreements may initially restrict the liquidity of organised markets. Market liquidity may therefore be low, and hinder the ability of hydrogen storage to profit from price differentials, especially if there are no incentives for market players to offer spare hydrogen supply and source additional needs (above contracted supply) in short-term markets. Moreover, underground hydrogen storage capacity may in the beginning largely exceed storage needs due to minimum project sizes, especially in markets with limited hydrogen storage needs – see section 4.2 for a detailed analysis of the future market concentration in the EU. In the case of surface hydrogen storage, such issue with the lumpiness of storage assets would not exist, but surface storage is significantly more expensive than underground storage (see section 4.1).

Storage investments will therefore require long-term capacity bookings for investment certainty, as they will not be able to rely initially on revenues from short-term markets, and will face significant

[219] Fuel Cells and Hydrogen Observatory (2020) Chapter 2 Hydrogen Supply & Demand

[220] https://www.rijksoverheid.nl/actueel/nieuws/2021/06/30/staatssecretaris-yesilgoz-zegerius-zet-eerste-stap-voor-ontwikkeling-landelijk-waterstofnet

[221] Hydrogen Europe (2020) Clean Hydrogen Monitor 2020

upfront investments. Such long-term contracting can take place under negotiated or regulated regimes. Long-term agreements for supply could also foresee investments in storage, either by a cooperation of the trading parties, or by investments by the supplier (i.e. if the supplier has the responsibility to manage supply variability, it could itself invest in hydrogen storage).

Storage will serve two main functions: that of balancing the system (and individual imbalances of market players) in the short term, and providing flexibility in different timeframes (including seasonally) to matching variable supply of electrolytic hydrogen to the more constant demand of industry. Market players (or regulated ones if allowed) may realise investments in and contract storage services to meet both flexibility and balancing needs. Who realises the investments will depend on who is responsible for primary balancing and who should deal with supply variability, as well as the most economic hydrogen storage options. Given that underground salt cavern storage should be much more economical than tank storage and that the available linepacking storage capacity should be limited compared to storage needs, underground storage should be competitive and constitute a main source of flexibility. Given the limited availability of suitable underground storage sites in many Member States and the specific expertise required, it can be expected that hydrogen producers and consumers may resort to third parties to provide storage capacity (as opposed to developing their own capacity). Therefore, it can be expected that hydrogen storage operators will appear, offering storage services through long-term contracts as a main way to ensure revenue certainty, and gradually complementing the revenues from these long-term contracts with short-term storage services as the hydrogen market develops. Tank storage at producer or customer sites could complement underground storage sites, but as shown in section 4.3 should be a rather expensive storage option in comparison.

Therefore, policies and measures for developing hydrogen markets and storage through a flexible regulatory framework which at the same time provides the necessary certainty for investments will be necessary to develop hydrogen storage. These are detailed in section 4.6.

4.4.1.2 The need for regulation of storage will vary across Member States and storage types

This section demonstrates the reasons why different forms of large and small scale storage (with a focus on salt cavern storage) might have different economic characteristics and therefore warrant different regulatory approaches.

First, **repurposed H_2 storage capacity may be limited for 2050 and even 2030 needs, for certain Member States**. Only 6 MSs have currently salt cavern storages in operation or planned (DE, DK, FR, NL, PL, PT), with a combined natural gas storage capacity of 198 TWh. 75% of this capacity is located in Germany, which has 41 out of the 53 facilities in operation or planned in those Member States. The remaining countries have one to three facilities each.

Assuming the same derating factor of 23% (hydrogen to natural gas working gas capacity) as employed for the modelling of the impact assessment for the *hydrogen and decarbonised gas market package*, based on the volumetric energy density of hydrogen and natural gas, converting the 198 TWh of natural gas storage capacity in salt caverns could provide up to 45.5 TWh of hydrogen storage. Regarding other underground reservoir types (depleted gas fields and aquifers), a study for GIE estimates that repurposing gas storages in 13 MSs could provide an additional 213.8 TWh in hydrogen storage capacity. Until 2030, the maximum storage capacity from repurposed salt caverns (45.5 TWh) should be larger than the required storage capacity for all *gas market package* contexts (22.6 to 17.7 TWh). Estimates on the storage potential of repurposed assets should be considered an (optimistic) upper boundary, as in reality not all facilities will be available for repurposing (being still needed for storage of methane gases) or not financially attractive to repurpose.

Therefore, despite repurposing being more economical than developing new underground hydrogen storages, unless around half the existing salt cavern storages are repurposed to hydrogen by 2030, **development of new reservoirs is likely to be necessary to meet the 2030 storage needs**, if the storage levels foreseen in the *gas market package* impact assessment modelling are to materialise.

Hydrogen storage capacity for all salt cavern formations in the EU provides a large storage potential, sufficient to meet future storage needs, with 9 Member States (DE, DK, EL, ES, FR, NL, RO, PL, PT) having a storage potential within 50 km from shore[222] of more than 21,000 TWh, as detailed in section 4.2.

Therefore, in case there is a strong development of the hydrogen sector in the EU requiring storage capacities, **it is likely storage needs will be met by both repurposed and new assets**. The increasing storage needs up to 2050 will lead to further development of new fields, as the salt caverns for available repurposing are gradually used (unless storage in porous reservoirs becomes technically and economically feasible).

The hydrogen storage capacity market concentration across EU Member States and regions could be very different, with either highly concentrated or competitive environments depending on the hydrogen storage needs, the storage potential in the region and number of caverns managed by each operator, and the use of repurposed facilities.

Typical salt cavern can have a storage capacity of up to 0.15 TWh_{lhv} (reaching up to 4 TWh through the combination of caverns in a storage complex). Porous storage reservoirs can be 3-4x as large as salt caverns. Therefore, if they become technically and economically feasible, hydrogen storage in aquifers and depleted gas fields could significantly increase storage capacity concentration as fewer sites will be needed to meet the same storage need.

Each storage type and size may be more suitable to a specific storage need. Inter-seasonal underground storages require more compression as any hydrogen injected must be compressed to higher pressures[223]. If inter-seasonal storage needs are higher than the needs for flexibility in the weekly and daily timeframe, larger hydrogen storages would be used to meet inter-seasonal storage demand, with higher compression costs which would be compensated by the less frequent cycling – as occurs currently for natural gas. Short-term storage could be provided by smaller sites from different storage types with lower cycling costs, especially salt caverns.

Linepacking could cover a small share of storage needs, especially in the short-term, and linepacking capacity will increase once a backbone develops. However, while linepacking can be an economic way to provide short-term storage services, linepacking has a lower potential than in natural gas networks due to lower energy density of H_2. The analysis of section 4.3 indicates that linepacking can, for the archetypes analysed, provide only a marginal share of storage needs, with the bulk being satisfied by underground storage.

The competitiveness of other above-ground storage solutions will be affected by the levelized storage cost (generally much higher than underground solutions for pure hydrogen) and the use cases for hydrogen and its derivatives – for example, the competitiveness of ammonia or methanol storage would increase significantly in (port) industrial clusters if the derivatives could be directly used without needing to be re-converted to hydrogen first. Also given the higher costs associated with developing new salt cavern storages (compared to repurposing) and the limited salt cavern poten-

[222] The requirement of 50 km proximity to shore is chosen as brine disposal is too expensive otherwise.

[223] Leeds City Gate (2016) H_21

tial in certain member States, **in specific cases and countries other storage forms than salt caverns could be more competitive or be the only available solution**, especially if national hydrogen systems are not interconnected.

Therefore, in the future, competition should arise between various storage types and sizes. Each exhibiting characteristics which would warrant treatment as a competitive or regulated activity. These aspects may differ per Member State, depending on:

- Reservoir endowments, especially concerning salt formations
- Hydrogen storage needs, both concerning the overall needs in TWh as well as the type (short-term/seasonal), as different underground formations are best suited to provide storage at specific time frames
- The number of storage system operators and the number of storage sites each manage
- The end-uses and carrier of choice (hydrogen / ammonia / methanol or other), which would affect the competitiveness of different storage options
- The profitability of storage projects, influenced by the hydrogen market design and its ability to reward the different contributions of hydrogen storage
- The costs (especially CAPEX) of the different storage solutions

Smaller scale storage (above ground cylinders / spheres) could be considered a competitive activity, given the low entry barriers for developing it and the fact it is necessary for transhipment to/from trucks, barges and trains. Electrolysers / end-users may also want some storage on-site to deal with variability of supply, and could offer some of this storage capacity to the market through unbundled products, in order to tap into other revenue streams and improve the business case for hydrogen systems.

Salt caverns and other underground storage types (aquifers and depleted gas fields) may require regulation with negotiated or even regulated third party access, given limited availability of geological sites in some regions and the economic competitiveness compared to other solutions, which could make salt cavern storage an essential facility to enable the development of a hydrogen system. Moreover, regulating tariffs and revenues may lead to a lower cost of capital for hydrogen storage.

Linepack will also offer flexibility to some extent, and the capacity not needed for guaranteeing safe system operation should be made available by regulated hydrogen network operators to the market. Finally, LH_2 terminal storage may also be offered to the market through unbundled products, providing an alternative flexibility resource. This could take place especially in the short-term timeframes as LH_2 terminal storage would be needed first for bundled product offerings. In anyway, as shown in section 4.3 underground storage would meet the majority of hydrogen storage needs in 2030.

Therefore, it is likely that large-scale storage in some/several Member States will require regulation. Member States with large salt cavern potential (e.g. DE, ES) and sufficient storage needs may be competitive, with only minimum requirements on non-discriminatory access and transparency. In other **Member States, with low(er) salt cavern potential and lower hydrogen storage needs would require stronger regulatory measures to ensure non-discriminatory access, unless hydrogen markets were sufficiently integrated for shippers to access competitive storage capacity in neighbouring Member States.** Small-scale above-ground storage could remain a competitive activity, given 1) low barriers to entry; 2) lower relevance for system planning; and 3) that it will be required to some extent for end-users and rail / ship / transport. This analysis however focuses mainly on “bottom-up” market development, and to a certain extent omits the implications of slow hydrogen market development (at least in view of the 2030 policy ambitions), described in previous section. Another measure that will enable development of hydrogen storage as competitive activity is developing proper planning process that will clearly indicate the future storage needs. This is addressed in detail in the next section.

Nevertheless, a clear regulatory framework accounting for the differences across Member States and technologies will be necessary to develop hydrogen storage. This is detailed in section 1.6.

Textbox 7 Summary of the regulatory needs for different storage technologies and situation in MSs

Need for regulatory framework per storage technology and MS:

- **Salt caverns and other underground storage:**
  - In MSs with high storage potential, only minimum TPA and transparency rules could be required to ensure competitive markets, after confirmation through a market assessment;
  - In MSs with lower storage potential, the potential for market concentration is higher and therefore more stringent regulatory framework for TPA might be needed.
- **Surface storage:**
  - Low market entry barriers, few physical and spatial limitations and need for surface storage in e.g. transhipment from/to trucks, barges and trains make surface storage a competitive activity;
  - No differences in approach across MSs, except for storage in LH_2 terminals which will depend on the terminal regulatory regime.
- **Linepack:**
  - The limited storage potential in comparison to other technologies and expected storage needs does not result in need for strong regulatory framework;
  - However, in case of linepack in regulated hydrogen networks, regulation will be needed to ensure the regulated operators offer the linepack capacity (that is not needed for safe system operation) to the market in a non-discriminatory manner;
  - No differences in approach across MSs.

4.4.1.2.1 Hydrogen storage market concentration analysis

The natural monopoly characteristics of storage depend on the number of storages necessary to provide sufficient flexibility to match supply and demand in the different timeframes, and on the consequent market concentration.[224] Considering salt caverns are currently the most economical way to store hydrogen, if a sufficiently small number of storages (or storage operators in case those managed multiple storage units) were enough to meet the storage needs in a specific market, market concentration could arise - be it an isolated system, a Member State or a group of Member States.

This section estimates the 2030 market concentration for hydrogen storage in salt caverns, to attempt identifying whether highly concentrated markets could arise and which could justify regulation in order to ensure non-discriminatory access to hydrogen storage. Based on the salt cavern potential, it is assumed underground hydrogen storage could be developed only in 9 Member States (DE, DK, ES, FR, GR, NL, PL, PT, RO).

[224] Mulder et al. (2019) Outlook for a Dutch hydrogen market

The analysis is based on assumptions on the future hydrogen storage needs, the typical storage capacity of future individual hydrogen storage operators, and whether storage capacity would be provided through new or repurposed assets. Given the importance of these assumptions and the difficulty in forecasting actual developments in the hydrogen sector, the analysis must be seen only as providing an indication for the potential for market concentration.

The market concentration estimates are developed by:

1) Defining the typical salt cavern working gas capacity. Two typical capacities are analysed:
    a) 0.2 TWh_{hhv}, representing the typical capacity of a single salt cavern
    b) 0.6 TWh_{hhv}, representing storage operators managing 3 salt caverns simultaneously
2) Defining whether current gas storages would be available for repurposing (both cases where repurposing occurs and do not occur are analysed);
3) **Defining the storage capacity needs per Member State**, by directly employing modelling data for 4 different scenarios with different levels of cross-border hydrogen transport capacity, representing the level of integration between EU hydrogen markets:[225]
    a) Business as usual, without no new cross-border transport beyond existing private networks
    b) H_2-A constrained, with a low cross-border capacity
    c) H_2-A optimised, with a medium capacity
    d) H_2-B optimised, with a high capacity
4) **Defining clusters of Member States** representing integrated hydrogen markets, in order to assess the impact of integration of individual national markets;
5) Defining a 'merit order' of storage facilities for the (clusters of) Member States:
    a) Repurposed hydrogen storages (if available) are assumed to be deployed first, given repurposing is more economical than developing new salt caverns
    b) New salt cavern storages are then deployed
6) **Calculating the number of storages for the (clusters of) Member States** necessary to meet the storage needs per scenario;
7) **Calculating the Herfindahl-Hirschman Index** for each market.

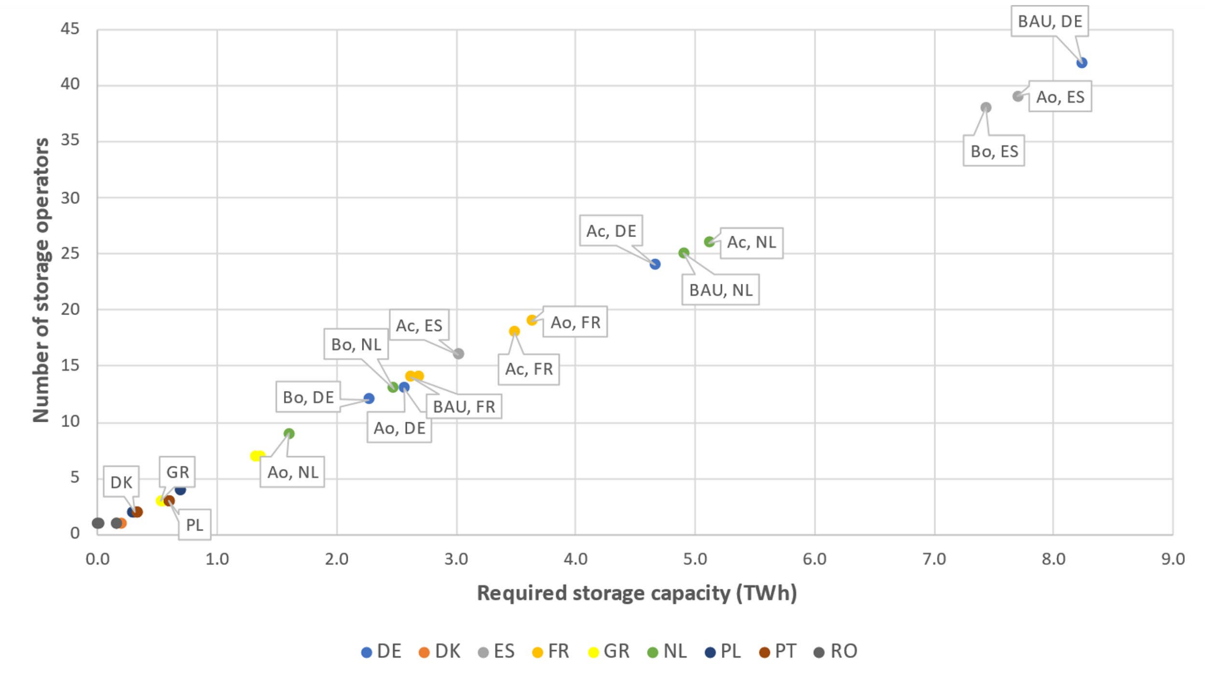
Based on this process, four cases are analysed, for all scenarios:

- **Case 1:** Operators each managing single salt caverns with a typical working gas capacity of 0.2 TWh_{HHV}, with no repurposing taking place, for each Member State
- **Case 2:** Operators each managing three salt caverns with a combined working gas capacity of 0.6 TWh_{HHV}, with no repurposing taking place, for each Member State
- **Case 3:** Repurposing taking place wherever gas caverns are available, and being prioritised over the development of new salt caverns, for each Member State
- **Case 4:** Grouping of Member States in 4 different clusters for H_2-B optimised scenario (operator working gas capacity of 0.6 TWh_{HHV}, with repurposing)

Therefore, in Case 1 market concentration is analysed per Member State, operators manage salt caverns with a capacity of 0.2 TWh_{HHV}, and no repurposing takes place. This leads to competitive storage markets with more than 10 operators for almost all scenarios in Member States with relatively high storage needs, namely DE, FR, ES and NL. In contrast, DK, GR, PL, PT and RO have lower storage needs and thus a lower number of operators (<5) is observed there for most scenarios. This is illustrated in Figure 44.

[225] Artelys (2021) METIS study on costs and benefits of a pan-European hydrogen infrastructure

Figure 44 **Case 1 - Number of storage operators assuming a storage capacity of 0.2 TWh_{HHV} and no repurposing**

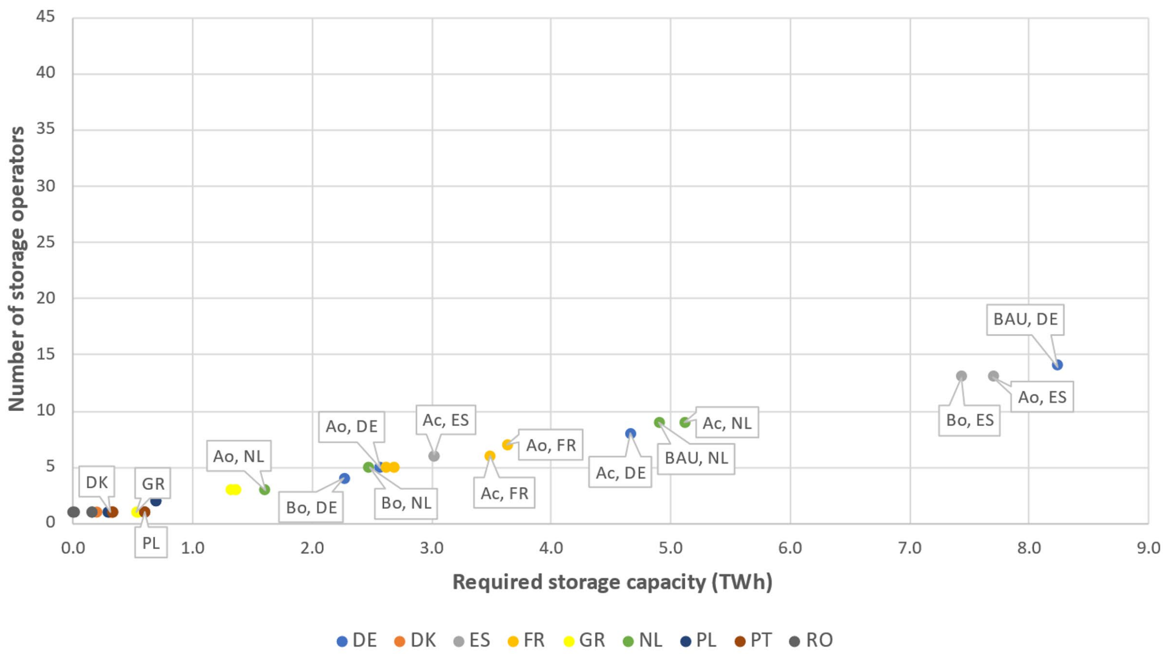


BAU: business as usual Ac: H_2-A constrained Ao: H_2-A optimised Bo: H_2-B optimised

In **Case 2** the storage capacities managed by each operators are greater (0.6 instead of 0.2 TWh). Results are shown in Figure 41. This leads to a significant increase in market concentration as can be expected, with only DE and ES having more than 10 operators, and that only in a few scenarios where storage needs are higher than 7 TWh. As indicated, it is very common for storage operators to manage multiple storage sites, and therefore it is probable that some future individual operators could manage a total storage capacity higher than the assumed 0.6 TWh. For example, the largest salt cavern complex currently in operation for gas storage in the EU is that owned by Uniper in Germany, whose 49 caverns total almost 43 TWh in storage capacity.[226] At the derating factor of 23%, this would be equivalent to a hydrogen storage capacity of 9.9 TWh, enough for a single operator to satisfy the entire 2030 German storage needs, in any of the METIS scenarios.

[226] Uniper - Our storage facilities in Germany https://www.uniper.energy/storage/what-we-do/where-we-operate/germany; Gas Infrastructure Europe (2018) Storage Map 2018

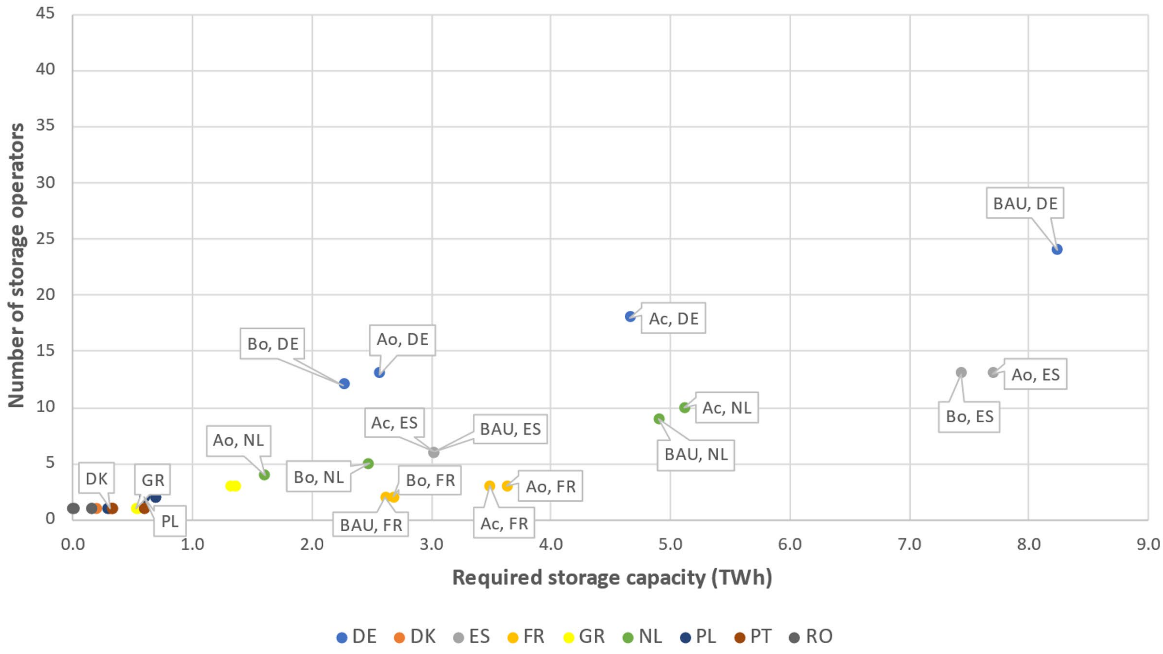
Figure 45 **Case 2 - Number of storage operators assuming a storage capacity of 0.6 TWh_{HHV} and no repurposing**



BAU: business as usual Ac: H_2-A constrained Ao: H_2-A optimised Bo: H_2-B optimised

Under **Case 3** repurposing of salt caverns currently used for gas storage is prioritised for meeting future hydrogen storage needs, given repurposing is expected to be more economical than developing new sites. The overall impact of allowing repurposing differs according to the size of the current storage facilities, as shown in Figure 46. In Germany, market concentration decreases compared to Case 2, as several existing storage sites have an equivalent hydrogen storage capacity below 0.6 TWh. Due to repurposing of large (virtual) grouping of caverns (*Storengy Saline*), French market concentration would increase – although gradual repurposing of some caverns would be more likely in reality, decreasing concentration as other operators could enter the market. For other Member States such as ES, GR, DK, PT or PL, repurposing has no significant impact as they do not have currently operating salt caverns or the forecasted hydrogen storage needs for 2030 is limited (below 0.6 TWh).

Figure 46 Case 3 - Prioritising repurposing of existing salt cavern gas storage sites

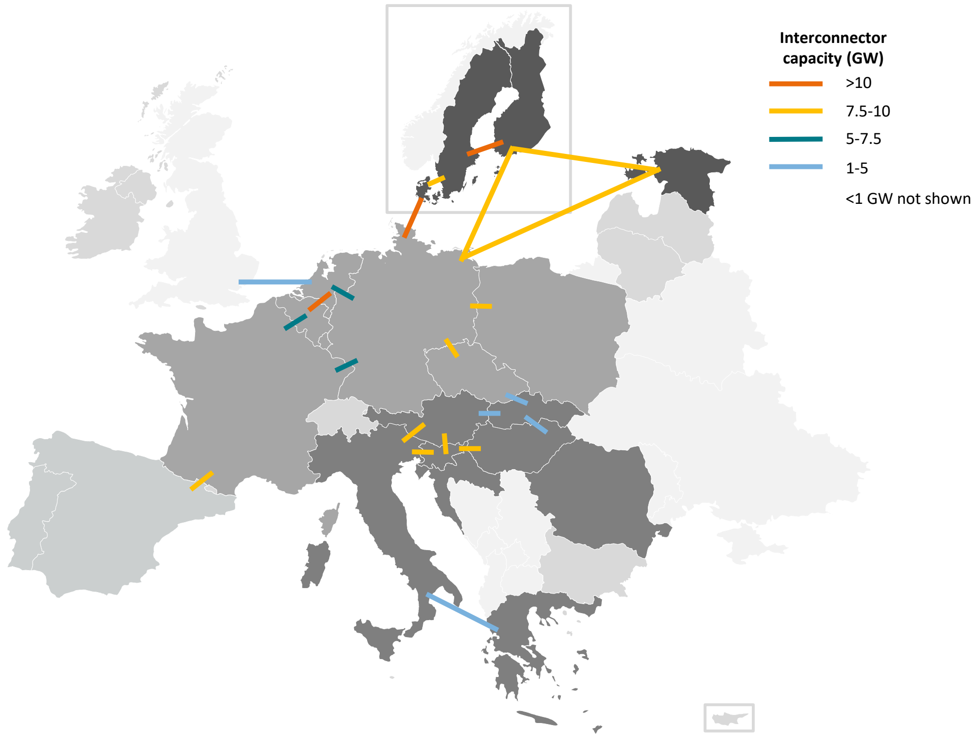


BAU: business as usual Ac: H_2-A constrained Ao: H_2-A optimised Bo: H_2-B optimised

Finally, in **Case 4** the impact of clustering the storage markets of several Member States is analysed, for the H_2-B optimised scenario only (as it is the scenario with the highest cross-border hydrogen transport capacity). The Member States are grouped according to storage needs and cross-border transport capacities through heuristics – the exercise does not warrant to represent the optimal or only possible grouping, but rather to illustrate the effects of storage market integration. The proposed clustering of Member States is presented in Figure 47. The clustering leads to 4 different clusters:

- **North-(Western) Europe** grouped as a main consumption centre, storage serves to address supply and demand variability;
- Exporting regions (**Iberian peninsula, Baltic**) each constitute a cluster -> storage serves to balance supply variability prior to exporting;
- **South-Eastern Europe** constitutes a separate cluster self-sufficient to some extent, with exports from IT and GR consumed in AT, HR, HU, SI.

Figure 47 Case 4 – Proposed clustering of Member States' storage markets



Source: own elaboration

Clustering storage markets leads to several impacts for cases 2 and 3, as illustrated in Figure 48 which indicates the storage market Hirschman-Herfindahl Index (HHI). The HHI serves to indicate the relative size of companies operating in a certain market and the level of market concentration, with a very low HHI (<100) indicating a highly competitive market and a 10,000 HHI indicating a monopolistic market. The figure indicates the HHI of the integrated markets of case 4 (NW/N Europe, SE Europe, Iberian Peninsula and Baltic) versus the HHI of isolated markets of case 2 and 3.

It can be observed that with hydrogen interconnectors and the consequent integration of storage markets, countries without salt cavern potential gain access to underground storage capacity, which also increases the total market size for storage services. This leads to significant decreases in market concentration, with the North-(Western) Europe and especially the Iberia cluster becoming more competitive. This benefits especially Member States with comparatively lower storage needs, particularly PL (lower needs compared to DE) and PT (lower needs compared to ES). in South-East Europe concentration decreases, although medium concentration remains due to low storage needs overall. Finally, in the Baltic cluster, Danish hydrogen storage maintains a monopoly due to the lack of salt cavern potential in the remaining Member States (EE, FI, SE) and due to low total storage needs by 2030.

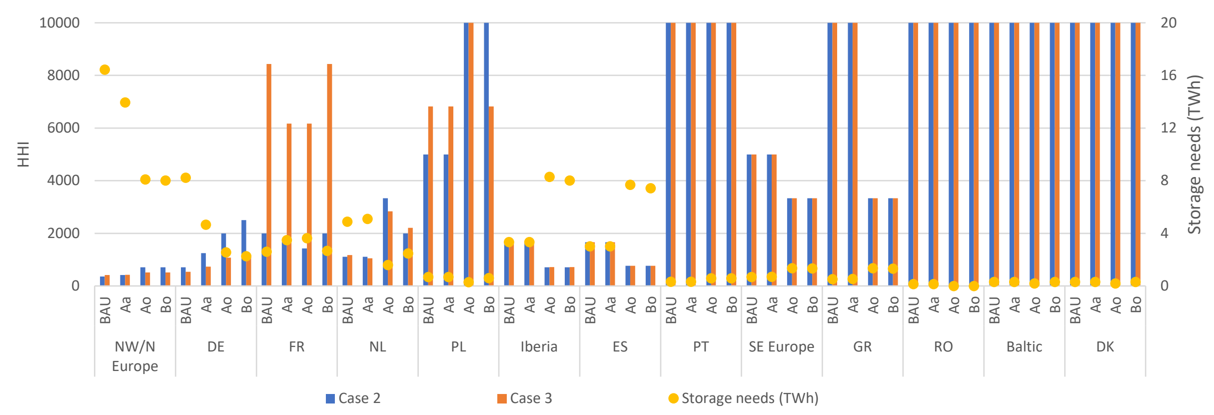
According to the 2004 Commission Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings:[227]

- "The Commission is unlikely to identify horizontal competition concerns in a market with a post-merger HHI below 1,000. Such markets normally do not require extensive analysis;
- The Commission is also unlikely to identify horizontal competition concerns in a merger with a post-merger HHI between 1,000 and 2,000 …".

[227] European Commission (2004) Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings

While developed for the assessment of horizontal mergers, the thresholds would indicate that the integrated storage markets of North-Western/Northern Europe and Iberia could be sufficiently competitive not to required strict (i.e. regulated) third-party access rules and other measures, while the South-Eastern Europe and Baltic markets would still require regulation. Albeit detailed assessments would be required by Member State/region, this already illustrates the different market conditions that could exist across the EU.

Figure 48 Hirschman-Herfindahl Index for individual and clusters of Member States



4.4.2 Energy sector planning may not consider fully storage needs & benefits, potentials and interaction with other sectors

As recognised by ACER and CEER, a more effective planning regulatory framework for infrastructure is needed to ensure level playing field, technology neutrality and fair competition between different technologies and market solutions. Existing network operators, responsible for network planning, are facing challenges from decentralised solutions[228] and therefore their neutrality in network planning cannot be fully taken for granted.[229]

There has been some progress in the recent years in integrating the hydrogen sector into network planning. Most significantly, hydrogen is now considered in the joint ENTSOs' TYNDP scenario[230], which defines the external conditions against whose proposed infrastructure projects are assessed.

However, electricity and (natural) gas system projects are still assessed separately in the TYNDP process, with hydrogen supply and demand being considered only on the `boundaries` of the system (electrolysers are only considered to use curtailed renewable electricity from the market). This issue is also highlighted in the ACER opinion on the ENTSOG draft TYNDP 2020, which states that the progress in implementing an interlinked model for infrastructure projects assessment (that would include also P2G and other direct linkages)is not progressing at the desired

[228] Such as moving part of the business to decentrally injected decarbonised gases

[229] ACER and CEER (2019). The Bridge Beyond 2025: Conclusions Paper. Available at: https://documents.acer.europa.eu/events/bridge-beyond-2025/default.aspx

[230] ENTSO-E and ENTSOG (2020). TYNDP Scenario Report. Available at: https://2020.entsos-tyndp-scenarios.eu/wp-content/uploads/2020/06/TYNDP_2020_Joint_ScenarioReport_final.pdf

speed.[231] Because of that, the optimal integrated functioning of the electricity and gas system is not assessed and the value of hydrogen infrastructure (including storage) for efficient energy system operation and investment cost optimisation is not captured properly.

This point on the need for integrated EU-level planning applies mainly to planning of infrastructure with cross-border relevance. **But there is also no obligation to consider hydrogen systems and the benefits of hydrogen storage on the national level**. The obligations for network operators to prepare network development plans (NDPs) are introduced separately in the gas[232] and electricity[233] market directives, and do not include any requirement to consider other energy sectors. This may lead to failure in recognising the system benefits of initial hydrogen developments up to 2030, in the form of hydrogen valleys not (yet) interconnected to other EU hydrogen systems. The most recent ACER assessment of national gas NDPs[234] found out that only 4 of 24 gas-specific NDPs include "hydrogen development aspects". According to the report, the praxis of consolidated cross-sectoral planning is also not common across MSs, with Denmark being practically the only MS to implement it (benefitting from the existence of a combined electricity and gas TSO). Moreover, as noted by ACER[235], none of the energy transition-related projects (covering, besides hydrogen, also biogas and biomethane projects) included in the ENTSOG 2020 TYNDP were included in the corresponding national NDPs. In countries where hydrogen production from (offshore) wind and solar PV is an important part of the energy strategy, hydrogen storage may be pivotal and with that also the integrated planning of electricity, methane and hydrogen systems. If the current situation will not change, up to 2030, the lack of integrated network planning will fail to account for the development of hydrogen valleys, and after that it may fail to account for the development of an interconnected EU hydrogen system.

The lack of common planning scenarios may also not adequately reflect the development of hydrogen demand. Initially, industry and potentially the transport sectors are the more likely end-users, but after 2030 hydrogen demand for electricity generation and potentially space heating might pick-up (although probably in lesser volume then the former applications), increasing the interactions between the electricity, gas and hydrogen systems.

Since most NDPs have been drafted before the National Energy and Climate Plans were available, most do not make use of the NECPs' scenarios[236] (on the other hand, it is likely that the NDPs were at least taken into account in the NECP itself). **There is also no EU requirement for the NECPs being considered in developing the NDP scenarios**. **The possible consequence of this situation is divergence of national energy and climate policy and the plans of network operators for network development**. This can potentially hinder the goal of increasing renewable production (if the infrastructure is not developed enough) or lead to delays in achieving the policy ambitions (if the infrastructure is not developed fast enough). However, the NECP scenarios are now the main guidance on energy system pathways on the national level, so they will probably be gradually introduced in the NDPs in most cases. Nevertheless, this process will take several years and might delay the hydrogen system development anyway.

---

231 ACER (2021). Opinion No 02/2021 on the ENTSOG draft Ten-Year Network Development Plan 2020. Available at: https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2002-2021%20on%20the%20ENTSOG%20draft%20Ten-Year%20Network%20Development%20Plan%202020.pdf.

232 Directive 2009/73/EC concerning common rules for the internal market in natural gas. Available at: http://data.europa.eu/eli/dir/2009/73/2019-05-23

233 Directive (EU) 2019/944 on common rules for the internal market for electricity. Available at: http://data.europa.eu/eli/dir/2019/944/oj

234 ACER (2020). Opinion No 09/2020 on the review of gas national network development plans to assess their consistency with the EU TYNDP. Available at: https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2020%20on%20the%20consistency%20of%20gas%20NDPs%20with%20EU%20TYNDP.pdf

235 ACER (2021). Opinion No 02/2021 on the ENTSOG draft Ten-Year Network Development Plan 2020

236 Moreover, several MSs introduced dedicated hydrogen strategies with greater details only after the final NECP submission.

The absence of consideration of hydrogen in national NDPs is especially consequential since it is probable that the initial hydrogen valleys will remain largely isolated within national borders or certain regions up to 2030 (and only become interconnected afterwards). **Therefore, in the short-term, NDPs have even more strategic role than the EU-level TYNDP, which considers mainly the development of cross-border infrastructure.** This consideration however applies mainly to the frontrunner countries that are planning to develop hydrogen valleys in this decade.

Furthermore, the level of detail of the energy system planning has a substantial impact on the possibility of capturing the real system value of hydrogen. **Increasing temporal and locational granularity of the system planning as well as of market design would allow to better reflect the market and system flexibility of storage** and other flexibility resources. A low granularity, e.g. not reflecting internal network or intra-day constraints may underestimate flexibility needs. It may also not properly account for the location of underground storage capacities, as e.g. salt caverns may be located in specific regions.

This potential failure in recognising appropriately the system and security of supply value might lead to supporting unnecessary investment in electricity or natural gas networks (e.g. additional flexibility sources for electricity system balancing), irreversible decommissioning of natural gas storage that could be repurposed for hydrogen use, or inefficient operational measures such as redispatching. The lack of integrated planning may also lead to under- or overestimation of the hydrogen storage needs for future hydrogen systems, leading to insufficient storage capacities and overall higher system costs. Furthermore, integrated infrastructure assessment is the best possible way to assess whether newly built or repurposed hydrogen will contribute to lowering overall energy system emissions.[237]

Moreover, depending on the regulatory framework and its degree of freedom to Member States, some NDPs would only be indicative for those storages (including some large-scale underground sites) that would remain unregulated. Strong involvement of market players in the TYNDP and NDP development process may to some extent mitigate these network-storage planning coordination challenges.

4.4.3 Market design and network tariffs may not reward the benefits of storage to flexibility and security of supply

In current EU gas markets, storage operators generally derive revenues by providing storage services to parties looking to arbitrage between periods of high and low commodity prices or parties looking to secure their own supplies for the future. This was historically a sufficient source of revenues for natural gas storage operators, who benefited from significant summer-winter price spreads. These price spreads were generally caused by increased demand for natural gas in winter (heating demand), while the import flows of natural gas remained rather stable during the whole year. This is true whether storage tariffs are regulated for certain storage operators or not.

The provision of storage services for arbitraging leads to a reduction in price spreads, reducing gas prices in winter and thereby providing a societal benefit which can be termed the **market value of storage** – reducing (mainly winter-summer) price spreads. Gas storage operators are able, through storage tariffs, to capture a portion of this market value, with the rest being allocated to shippers

[237] Trinomics and Artelys (2020). Measuring the contribution of gas infrastructure projects to sustainability as defined in the TEN-E regulation. Available at: https://op.europa.eu/en/publication-detail/-/publication/364d69a4-1744-11eb-b57e-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search.

and consumers. Besides market value, gas storage provides two other contributions to the energy system, which can be termed the **system value** and **the security of supply value.**[238]

The **system value** of storage comes from the avoided cost to the system, e.g., by reducing the need for congestion management or the capacity investment needs to meet peak demand. Specifically for hydrogen storage, it offers systemic benefits not only to the hydrogen networks, but also to electricity system, i.e., hydrogen storage may reduce the capital or operational costs of the electricity system as indicated in section 4.3.

The system value of storage may not be properly captured by storage operators if market design fails to value the least-cost solutions for satisfying demand across the entire energy system, leading to more expensive capital or operational costs. This may be the case due to a lack of integrated systems planning, entry barriers in wholesale or ancillary services markets, lack of incentives for network users to minimise imbalances, and other barriers.

Given the interlinkages between the electricity and hydrogen systems, the adequate valuation of flexibility provision to the former will require a level playing field to electrolyser operators and hydrogen-fired power generators. Part of the value captured by these market players can then be passed on to hydrogen storage operators for the provision of storage services. As a more concrete example, ancillary service markets and procurement mechanisms may not yet provide a level playing field for all technologies. Power-to-gas, for example, may not participate at the moment in all balancing markets to the same level as peak generators, pumped hydro electricity and even batteries as the pre-qualification and other market rules may not have been yet adapted. It must be noted that providing a level playing field will not automatically advantage hydrogen storage, as other energy technologies might become more attractive. But a level playing field should enable to value the contributions of hydrogen storage, whenever it is the most advantageous option from a system perspective.

The **security of supply (insurance) value** of storage originates from the fact that hydrogen storage can reduce the probability of demand curtailment in the event of a supply or other sort of system disruption. In a hydrogen system a number of occurrences may threaten supply:

- Long spells of reduced renewable electricity generation ("Dunkelflaute:")
- H_2 import disruptions due to e.g., geopolitical threats
- Disruptions in hydrogen supply routes
- Cold spells increasing (gas) heating demand

The storage contributions to security of supply may not be properly valued for a number of reasons:

- Market players may not adequately estimate the probability of rare supply disruption or infrastructure outage events. Markets are generally unable to fully value low probability-high risk events with significant systemic impacts.[239]
- Market players may not have incentives to internalise the negative externalities of supply or other disruptions. They may be incapable to fully recover fixed costs of investments from energy-only markets ('missing money' problem). Or suppliers may have limited liability to disruptions and thus fail to insure fully against supply disruptions, not buying the adequate volume of storage to ensure the adequate level of supply security.

Thus, energy-only markets may not capture the full value of hydrogen storage contribution to system flexibility and security of supply because the probability of supply disruptions may be hard to

[238] FTI Energy (2018). Measures for a sustainable gas storage market. Available at: https://ec.europa.eu/info/sites/default/files/gie-fti_study_-_measures_for_a_sustainable_gas_storage_market.pdf

[239] FTI Energy (2018). Measures for a sustainable gas storage market. Available at: https://ec.europa.eu/info/sites/default/files/gie-fti_study_-_measures_for_a_sustainable_gas_storage_market.pdf

foresee and market players may not have the incentive to hedge risks in the first place. At the same time, in future hydrogen markets policy makers may choose not to implement mechanisms to address eventual supply disruptions, even if duly justified through reliability assessments.

In the case of hydrogen, there is uncertainty about the future development of hydrogen markets overall, as discussed in section 3.10. Moreover, the character of hydrogen supply and demand and their fluctuations during time will depend on the prevailing supply options (whether domestic production or imports) and the particularities of end-use sectors where hydrogen is deployed. Given the expected importance of electrolytic hydrogen produced from intermittent renewables, there could be significantly variability of hydrogen supply (also as hydrogen producers respond to electricity prices). On the demand side, while initial industrial users may have a more predictable and stable demand profile, eventual hydrogen refuelling stations will have a more variable demand (albeit they should have some on-site storage). If hydrogen is used for power (co-)generation and providing flexibility to the electricity sector, this could increase the variability of overall hydrogen demand in certain Member States.

Therefore, there is still uncertainty on 1) the **market, system and security of supply value of storage** in future hydrogen and more broadly energy systems, and 2) the **ability of future hydrogen storage operators to capture this value.** Those factors lead to uncertainty on the business case of storage, strongly impacting investment decisions. While uncertainty regarding storage needs and its contributions to the energy system will remain, energy policy and regulation can allow storage operators to capture a greater share of the value of storage, thereby improving the business case of storage. Therefore, policies and measures to provide a clear regulatory framework and design hydrogen markets and network regulation which allows storage to capture the different contributions to the energy system will be necessary. These are detailed in section 4.6.

4.4.3.1 Regulatory uncertainty concerning the conversion of currently regulated gas storages

Since the current regulatory framework for natural gas does not cover hydrogen, **there are also no EU-level rules to guide the process of storage assets repurposing from natural gas to hydrogen**. The most relevant EU legislation for this case is the Offshore Safety Directive[240], which establishes rules for decommissioning of natural gas and oil offshore infrastructure. Although it concerns mainly the environmental impacts of decommissioning, it also contains provisions on identifying the parties responsible for the decommissioning and defining their liability.

The regulation of storage infrastructure repurposing is currently largely missing also on national level, with the exception of Germany, where a revision of the Energy Industry Act (EnWG-E)[241] was adopted recently (see Textbox 6). It contains the definition of hydrogen storage facility, as well as of hydrogen storage operators. However, the draft act only defines a mechanism for repurposing of hydrogen networks, not storage infrastructure (and this mechanism mainly concerns reacquiring permits).

[240] EC (2021). Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC. Available at: http://data.europa.eu/eli/dir/2013/30/oj

[241] Bundesanzeiger Verlag (2021). Gesetz zur Umsetzung unionsrechtlicher Vorgaben und zur Regelung reiner Wasserstoffnetze im Energiewirtschaftsrecht. Available at: https://www.bgbl.de/xaver/bgbl/start.xav#__bgbl__%2F%2F*%5B%40attr_id%3D%27bgbl121s3026.pdf%27%5D__1631886760865

Textbox 8 Hydrogen storage aspects in the German Energy Industry Act

In July 2021 the German Energy Industry Act (EnGW)[242] was amended by the "Law for the implementation of EU legal requirements and for the regulation of pure hydrogen networks in energy law".[243] The new provisions establish an 'opt-in' system for the regulation of hydrogen infrastructure, where operators may choose to be subject to regulation including aspects such as unbundling, third-party access and requirements on a demand assessment to demonstrate there is sufficient demand for individual hydrogen projects.

While many new provisions are focused on hydrogen networks, a number relate to hydrogen storage. The new EnGW includes now definitions for hydrogen systems and hydrogen storage operators (art. 3). If hydrogen storage operators declare to the regulator BNetzA they wish to be subject to regulation, then:

- Regulated hydrogen and storage operators "are **obliged to work together** to the extent necessary to implement cross-operator network and storage infrastructure for hydrogen and its use by third parties" (art. 28j(4));
- Regulated hydrogen and storage operators should publish by September 2022 a **joint report on the current state of the hydrogen network and the development plan to 2035**, including "possible criteria for the consideration of hydrogen projects as well as requirements for the determination of expansion measures". Criteria for consideration includes the rules for locating electrolysers, rules for determining hydrogen supply and demand, and interfaces with the gas and electricity NDPs;
- Storage operators are **subject to connection and third-party access rules** under conditions to be defined by the federal government (art. 28n);

If the hydrogen storage (or network) operators decide to not opt-in the regulatory framework, standard regulatory framework (based on EU law) still applies to them. This means that if they participate in other regulated activities (e.g. natural gas network operation), these activities have to be separated at least by accounts unbundling (to prevent cross-subsidisation).

Moreover, **regulated hydrogen network operators should be unbundled from hydrogen storage (and also hydrogen production and supply).**

From a technical point of view, repurposing hydrogen storages can take anywhere from 1 to 7 years and developing new storage assets can take from 3 to 10 years.[244] According to an interview with a gas storage operator, the minimal time to refurbish a salt cavern is 18 months from a purely technical perspective, but permitting issues might prolong it unnecessary (there is a need to obtain new permits even though nothing has changed in reality – e.g. land-use permits). Another problem is that a storage site typically consists of multiple caverns that cannot be converted at the same time. Although this can allow for the parallel exploitation of caverns for methane and hydrogen gas storage and gradual conversion, **given the estimated conversion time of 1-7 years, there is certain risk that it won't be possible to convert enough storage capacity to cover the system needs in 2030.**

For the storage operator, the conversion of natural gas facilities has an impact in terms of lost revenues while enduring significant capital investment costs at the same time. This claim

[242] https://www.gesetze-im-internet.de/enwg_2005/BJNR197010005.html

[243] Bundesanzeiger Verlag (2021). Gesetz zur Umsetzung unionsrechtlicher Vorgaben und zur Regelung reiner Wasserstoffnetze im Energiewirtschaftsrecht. Available at: https://www.bgbl.de/xaver/bgbl/start.xav#__bgbl__%2F%2F*%5B%40attr_id%3D%27bgbl121s3026.pdf%27%5D__1631886760865

[244] Guidehouse (2021) Picturing the value of underground gas storage to the European hydrogen system. https://www.gie.eu/gie-presents-new-study-picturing-the-value-of-underground-gas-storage-to-the-european-hydrogen-system/

is however specific for operators of salt cavern storages – given that the aim is to convert these facilities before 2030, it can be expected that the natural gas use (and demand for storage) will not decrease significantly by then and they will therefore lose the potential revenues if they decide to convert the storage. The demand for natural gas storage will probably decrease after 2030, in which case the storage might become a stranded asset and there would be no lost revenues during conversion. These market signals will however occur too late to influence the situation in 2030.

From an economic perspective, it is not clear whether the regulated revenues of natural gas storage owners could and should be used for investment in repurposed infrastructure. Network operators argue employing gas tariff revenues to finance repurposing to hydrogen would be a simple way to provide the necessary financing. A similar argument can be applied to regulated hydrogen storages.

Leaving the regulation of infrastructure repurposing on MSs carries a risk of different treatment and therefore uneven market conditions for potential storage operators. This could happen within a same Member State, but especially across borders, given the potential cross-border impacts[245] of storage facilities. For example, different rules on unbundling or on the use of gas network revenues across borders could result in significantly different investment opportunities for operators across borders.

Gas storage capacities are also significant for ensuring the security of supply. However**, there are no rules on assessing whether the repurposed gas storage would not pose a risk to natural gas security of supply**. The risk in this is that when repurposing natural gas storage assets, the impacts on natural gas security of supply will be assessed only ex-post, as a part of the national risk assessment under the Gas security of supply regulation.[246] This could be an issue especially for MSs where the salt caverns are concentrated, and therefore a more significant part of natural gas storage capacities would be potentially converted for hydrogen.

4.5 Policy and regulatory measures to address barriers to hydrogen storage

Main Take-aways of the section

- Three main recommendations are provided regarding policy and regulatory measures for the development of hydrogen storage and addressing the barriers discussed previously
- A **clear, predictable regulatory framework for large-scale hydrogen storage** should be set in place, comprising provisions for:
  - Third-party access rules when needed, based on a market assessment similar to Art. 33 of the Gas Directive also indicating the appropriate TPA regime (regulated or negotiated)
  - Horizontal accounts unbundling with methane gases activities to ensure cost-reflectivity and avoid cross-subsidisation, with EU rules allowing Member States to support storage investments when these are demonstrated to be commercially unprofitable
  - Some level of vertical unbundling between storage and competitive activities, when and if regulated access regime for storage is in place
  - Cost-benefit assessment for regulated hydrogen storage investments, to ensure the investments (new or from repurposing natural gas infrastructure) are aligned to energy & climate objectives

[245] Determined e.g. by the uneven geographical distribution of storage potential.

[246] Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply. Available at: http://data.europa.eu/eli/reg/2017/1938/oj

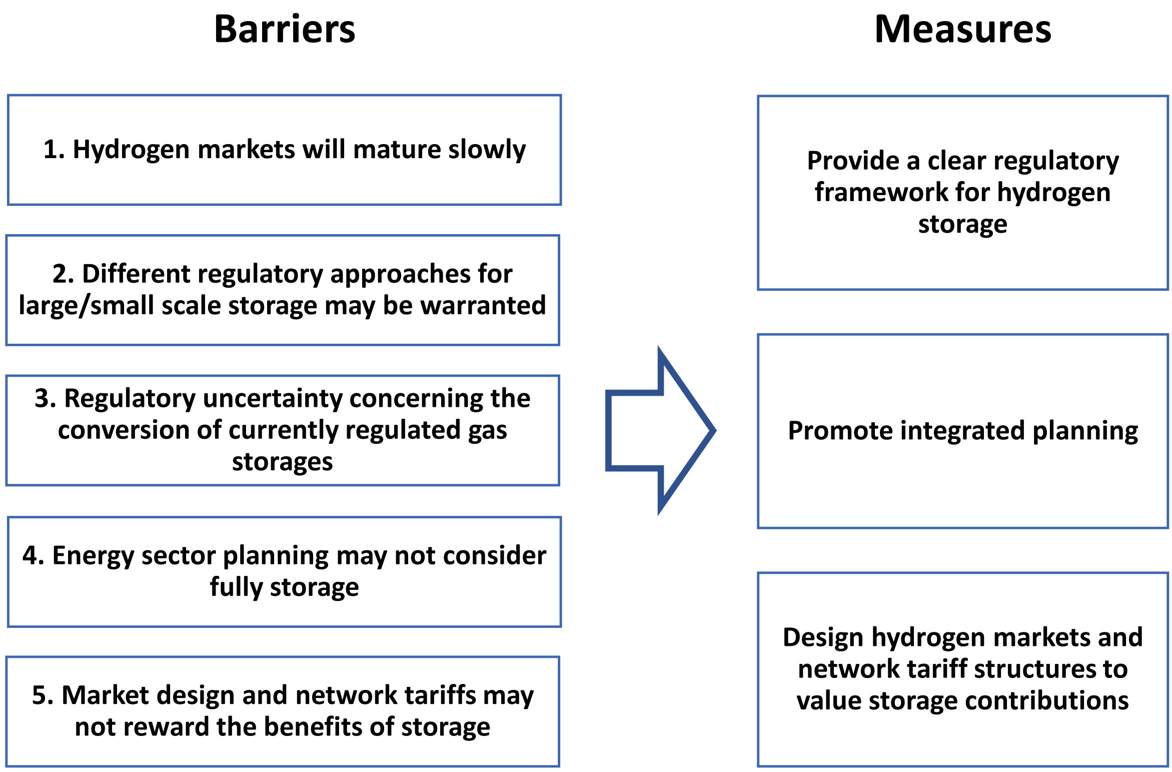
  - Rules regarding repurposing of existing gas storages, when beneficial from societal perspective
  - A potential role for the Commission disseminating best practices and providing guidance on permitting procedures
  - Designation of small-scale above-ground storage in tanks as a competitive activity given 1) low barriers to entry; 2) lower relevance for system planning; and 3) that end-users and rail / ship / transport operators will need to operate such storages.
- Integrated planning (of hydrogen, methane and electricity systems) should be promoted, including the following provisions:
  - Having minimal requirements for cross-sectoral planning in NDP processes carried out by the network operators, including the requirement for NRAs to assess or approve hydrogen NDPs and the involvement of electricity, gas and hydrogen storage system operators as well as market operators in the TYNDP and NDP processes
  - Requiring NDPs be based on hydrogen demand and supply forecasts defined or approved by policy makers or NRAs, in order to ensure planning is aligned to energy & climate objectives as well as on firm market need for hydrogen infrastructure
  - Increasing the time granularity of network models and CBAs for the TYNDP process (especially for electricity system modelling) to properly estimate the flexibility value of storage
  - Requiring hydrogen adequacy assessments to be conducted by system operators
- Design hydrogen markets design and network tariff structures to adequately value the contributions of storage and other flexibility resources, by:
  - Ensuring market parties bear their own balancing costs as much as possible as the hydrogen system develops. However, in the beginning hydrogen system operators may play a larger role in managing imbalances, being responsible potentially also for primary balancing. It will be particularly important to ensure the procurement of balancing services is conducted in a objective and non-discriminatory manner.
  - Requiring non-discriminatory market-based congestion management procedures. Initial hydrogen networks could be significantly over-dimensioned, but as the systems develops and become more interconnected, the importance of congestion management will increase
  - Adequate product characteristics such as temporal and locational granularity, especially based on interactions with electricity markets and the type and availability of hydrogen storage.
  - Gradually build the liquidity of hydrogen markets, including by assigning balancing responsibilities to market participants as much as possible
  - Setting hydrogen storage tariffs, if regulated, through market-based mechanisms like auctions
  - Ensuring network tariffs do not unduly burden storage, e.g. setting tariffs considering only marginal costs or using network discounts. However, any network tariffs designed to value storage should also value system contributions from other flexibility resources, to avoid negatively discriminating these

This section presents the main policy and regulatory measures designed to address the barriers identified in section 4.5. The measures presented focus on energy and hydrogen market design and infrastructure regulation – therefore, removing barriers to the development of hydrogen and derivatives storage will require complementary measures addressing e.g. taxation and technology standardisation issues which are out of scope of this chapter.

Figure 44 recaps the main barriers and presents the policy and regulatory measures to address them. All measures are designed to address several barriers simultaneously and therefore there is not a one-on-one relationship between the barriers identified. Nonetheless, the main effects of the measures on the barriers can be summarised as follows:

- **Providing a clear regulatory framework for hydrogen storage employing a target model for the gradual evolution of the framework should reduce regulatory uncertainty** (barrier 3), thus promoting storage investments by reducing regulatory risk. Storage investments should **enable a faster development of hydrogen markets** (addressing barrier 1). Moreover, A clear storage regulatory framework should be based on a clear regulatory need as proven by a market assessment, and account for the fact that **storage technologies, needs and potentials in EU Member States will vary considerably** (barrier 2);
- **Promoting integrated planning** should address barriers not only in the hydrogen sector, but the overall energy sector. It should allow to better value the contributions of storage - especially the system and security of supply contributions as indicated in barrier 3. Integrated planning should enable the development of the necessary infrastructure (not only storage, but also networks and import terminals) at least cost and aligned to energy and climate objectives, thus accelerating the development of hydrogen markets (barrier 1);
- **Designing hydrogen markets and network tariff structures** should ensure the **market, system and security of supply contributions of storage are adequately rewarded** (barrier 5). By better valuing the storage contributions, this (coupled with other measures) should increase the available revenue streams to storage and thus improve its business case, accelerating the deployment of hydrogen storage and thus also **accelerating development of the overall hydrogen market** (barrier 1).

Figure 49 Main policy and regulatory measures to address hydrogen storage barriers



4.5.1 Provide a clear regulatory framework for hydrogen storage

As shown in sections 1.5.2 and 1.5.5, it is critical to provide a clear, predictable regulatory framework for hydrogen storage, also in order to reduce perceived policy and regulatory risks presented in section 1.4. Such a regulatory framework would **provide certainty to the potential investors** in hydrogen storage, and could include provisions on the following aspects for large-scale storage in some or all markets:

- Third-party access rules based on a market assessment
- Horizontal accounts unbundling with methane gases activities
- Some level of vertical unbundling between regulated storage and competitive activities
- Rules regarding repurposing of existing gas storages
- Cost-benefit assessment for regulated hydrogen storage investments
- Permitting best practices dissemination and guidance by the European Commission

Small-scale above-ground storage in tanks could be designated as a competitive activity, without third-party access rules being in place, given 1) low barriers to entry; 2) lower relevance for system planning; and 3) that end-users and rail / ship / transport operators will need to operate such storages.

As shown in section 1.3.4, underground hydrogen storage in salt caverns is the most economical option for storing large hydrogen volumes. It is likely that large-scale storage in some or even several Member States will require third-party access regulation, as low storage needs in certain Member States, limited salt formations potential and/or the operation of several salt caverns by a single operator could lead to a concentrated storage market (see section 1.5.2). Member States, with low(er) salt cavern potential and lower hydrogen storage needs would require regulatory measures to ensure non-discriminatory access, unless hydrogen markets were sufficiently integrated for shippers to access competitive storage capacity in neighbouring MSs

Minimum requirements on non-discriminatory third-party access could be warranted also in Member States with large salt cavern potential (e.g. DE, ES) and sufficient storage needs, where storage markets may be competitive – but requirements could be less stringent).

Small-scale above-ground storage in tanks could be designated as a competitive activity, without third-party access rules being in place, given 1) low barriers to entry; 2) lower relevance for system planning; and 3) that end-users and rail / ship / transport operators will need to operate such storages.

The regulatory framework should also address linepacking and unbundled terminal storage products by regulated network and LH_2 terminal operators, so that that storage capacity is offered to the market in a non-discriminatory basis.

Given the national contexts will vary significantly, a market assessment similar to Art. 33 of the Gas Directive is warranted to determine the need for and the appropriate TPA regime. This should be done with the involvement of neighbouring Member States, given under some METIS scenarios there is significant cross-border integration of hydrogen systems. Member States will need to re-evaluate market circumstances with some periodicity (and to consider future developments), as these are likely to change for H_2 storage (e.g. with increasing storage needs, cross-border interconnections, and technological developments enabling storage in porous reservoirs). MSs can be given the choice to require regulated and/or negotiated TPA regimes depending on the technical/economic need for storage and market circumstances. Current gas storage operators' opinions vary, but many support regulation due to natural monopoly characteristics or benefits to facilitating business case (exception: DE)

Vertical unbundling would reinforce non-discriminatory access, where TPA is deemed necessary. For regulated TPA, associated revenue and tariff regulation would be in place in order to ensure cost recovery and non-discrimination of network users. Tariff regulation could also, in certain cases, increase the revenue certainty and thus facilitate storage investments, as discussed in section 1.4. Cross-border competition should arise, especially if significant cross-border interconnection capacity is developed and in case cross-border tariffs are eliminated or set according to marginal costs. In this case, harmonised requirements regarding e.g. setting tariffs for storage under regulated TPA regimes may be necessary in order to avoid market distortions. However, such risks of market distortion should arise only when hydrogen markets are sufficiently developed and integrated.

Therefore, the current gas regulatory framework may be adequate also for hydrogen storage, with transitional measures where necessary in order to account for the incipient development stage of the hydrogen sector.

The regulatory framework should also clarify the possibilities regarding repurposing of existing gas storages. Considering methane gas demand are forecast to decrease significantly by 2050, reducing the methane gas storage needs, while repurposing gas storages is an efficient way to develop hydrogen storage given the lower investments needed compared to developing new hydrogen storages, repurposing could be beneficial. Therefore, the regulatory framework for hydrogen storage should explicitly allow for the repurposing of gas storages.

However, there is a possibility regulated gas storage operators may want to realise investments in hydrogen storages in order to maintain their business activities, while these investments are not aligned to the future development of national energy systems and the EU and national energy & climate targets. Therefore, a cost-benefit assessment should be conducted by Member States or someone designated by them in order to ensure planned hydrogen storage investments by regulated operators are aligned to energy & climate targets. This cost-benefit assessment should be linked to a robust integrated planning process, as proposed in section 1.6.2.

In case repurposing is beneficial, policy makers and regulators could simplify permitting processes where possible and when gas and hydrogen storage exhibit similar characteristics – e.g., operator licenses land use permits could be considered valid for hydrogen storage automatically or through a simplified process. Once such practices start to develop in Member States, the European Commission could play a role in disseminating best practices, and providing guidance on which permits could qualify for such an approach and for which it would better to require storage operators to go through the entire permitting process.

Given the development and operation of hydrogen storages is similar in many aspects to that of gas storages, there would be benefits in allowing combined methane gases/hydrogen operators. This would also facilitate eventual repurposing of gas storages. However, accounts unbundling between gas and hydrogen operations should be required as a minimum to ensure cost-reflectivity and avoid cross-subsidisation. Moreover, re-evaluation of assets should be avoided during transfer of assets between operators in order to not unduly burden network users with increased tariffs.

4.5.2 Promote integrated planning

Based on the barriers in current regulatory framework, identified in section 4.4.2, **integrated planning (of hydrogen, methane and electricity systems) should be promoted** by employing the measures proposed in the following section. From a high-level perspective, it is also necessary to note that the principle of technological neutrality should be uphold, and therefore similar requirements should be employed also for planning in electricity and natural gas sectors, especially in case they are stricter than the current regulation.

On top of the existing combined-sector scenarios for the TYNDP, **minimal requirements for cross-sectoral planning should be introduced in national NDP processes carried out by the network operators**, as well as a requirement to consider the implication NECP's targets and scenarios. This should be introduced in EU law that defines the processes (Electricity and Gas market directives) and would apply to both transmission and distribution system operators. However, as in the existing legislation, MSs could have the ability to exempt DSOs with less than 100,000 customers (or other suiting threshold) from the obligation. The obligation for NRAs to monitor network development plans of network operators should be extended to hydrogen (including the possibility of issuing recommendations or amendments to the plans). The role of NRAs in development of NDPs could be also further strengthened by requiring an approval from the NRA on the final NDP. These measures would ensure that the plans of network operators remain aligned with the overall decarbonisation efforts and policy priorities. As a transitional measures for countries in which the hydrogen sector is expected to develop only in longer-term perspective, the obligation for gas network operators could be limited to identifying, which parts of infrastructure might become obsolete in the future and would therefore be suitable to hydrogen conversion.[247] Based on this, decommissioning of assets with potential to be used for future hydrogen networks could be avoided. Moreover, it could also limit the potential for investment in stranded assets.

Hydrogen demand and supply forecasts, used for the network planning process, should be defined or approved by policy makers or regulators also on the national level, to avoid over-investments in hydrogen assets. This would also reduce the risks related to the vested interest of natural gas network operators who are currently (and according to TEN-E revision proposal) in charge of network planning for hydrogen infrastructure. This requirement scenarios use in network planning should be however introduced step-wise, to avoid overburdening the potential investors.

[247] ACER and CEER (2021). When and How to Regulate Hydrogen Networks?. Available at: https://documents.acer.europa.eu/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf

As a first step, every new or repurposed hydrogen project could be required to demonstrate that there is a sufficient demand to be covered (e.g. with negotiated supply contracts).

Equal **involvement of electricity, gas and hydrogen storage system operators** in the TYNDP and NDP development processes should be ensured. This should, however, be part of a wider effort to ensure technology neutrality, so other stakeholders should be involved as well. The involvement could be ensured by introducing additional consultation requirements for ENTSOs and TSOs/DSOs. Furthermore, in the NDP process, the involvement of hydrogen storage operators could be part of a requirement for TSOs to consider innovative solutions[248] in network development (together with e.g. renewable hydrogen and derivatives operators).

The storage operators could be for example involved in the development of an **integrated electricity-gas-hydrogen market and network model**, to help accurately determine storage needs and contributions to the market and system. As the suitable storage sites are distributed unevenly in the EU territory, an additional layer of detail needs to be introduced to the network models to accurately model the potential benefits of hydrogen storage. When using zonal network models, a greater level of detail could be used in the areas with potential for hydrogen storage, to better capture the potential impacts. Furthermore, **especially on the EU TYNDP level the time granularity of network models and CBAs should be increased** (especially the electricity system modelling could move from hourly to 15 minutes time steps), to properly estimate the flexibility value of storage. However, deploying advanced modelling tools such as interlinked model or greater time granularity could be limited only to projects where there could be a reasonable expectation that the modelling will reveal additional benefits for the CBA. For that reason, the ENTSOs are proposing two-step approach to multi-sectoral planning. In the first step, it would be determined which projects actually need the multi-sectoral assessment (and for which sector), while in the second step the network modelling and assessment would be conducted for the selected group of specific projects.[249]

A requirement for **hydrogen system operators to conduct an adequacy assessment** could be introduced to identify potential scarcity situations, due to e.g. disruptions of renewable electricity supply or hydrogen imports. Besides contributing to the overall security of hydrogen supply, the adequacy assessment would help identify the need for hydrogen storage (among other measures). This exercise could take place at the system or national level (considering the size of the system and types and size of network users in order to determine the need for such an assessment), and be later expanded to the EU level once hydrogen systems became sufficiently interconnected. **Hydrogen and natural gas supply issues should be also considered more in electricity system adequacy assessments** to better reflect the integrated nature of energy systems (pilot integration of renewable hydrogen and derivatives should be introduced in the electricity ERAA from 2023 onwards[250]).

248 As proposed in EC (2019). Do current regulatory frameworks in the EU support innovation and security of supply in electricity and gas infrastructure? Available at: https://ec.europa.eu/energy/studies_main/final_studiesdo-current-regulatory-frameworks-eu-support-innovation-and-security-supply_en

249 ENTSO-E (2020). ENTSO-E Roadmap for a multi-sectorial Planning Support. Available at: https://eepublicdownloads.azureedge.net/clean-documents/Publications/Position%20papers%20and%20reports/l_entsoe_RM_MSPS_09.pdf

250 ENTSO-E (2021). European Resource Adequacy Assessment: 2021 Edition. Available at: https://www.entsoe.eu/outlooks/eraa/.

4.5.3 Design hydrogen markets and network tariff structures to ensure the contributions of storage are adequately rewarded

Given the different contributions of hydrogen storage to the future energy system (with market, system and security of supply values as discussed in section 4.3), a large number of measures can be implemented in order to allow hydrogen storage to capture a larger share of this value.

A number of policy and regulatory elements will affect the costs and revenue streams of storage services. Taxation aspects are not addressed further here. Also, the measures indicated here focus on hydrogen market rules and network tariff design. However, the design of other energy markets (especially electricity) should also be very important for valuing the contributions of hydrogen storage, although that is not addressed here further.

Measures should aim to provide a level playing field for all market participants and technologies, rather than being focused at energy storage per se. Therefore, some measures may rather negatively affect the business case for storage, especially those which (also) promote other flexibility resources such as demand response or the participation of aggregators in cases where those technologies are a more cost-efficient flexibility resource. Nonetheless, overall, the measures below, by fostering a level playing field, should enable to better value the contributions of hydrogen storage.

Given the various measures that can be recommended, they are categorised according to the whether they are general measures or whether they aim to enable storage to capture the market, system or security of supply values.

Ensuring market parties bear their own balancing costs as much as possible as the hydrogen system develops will increase the incentives for those market parties to develop or contract hydrogen storage services as the parties would need to deal themselves with supply or demand variability, therefore promoting a more liquid hydrogen storage market. However, especially in the initial development phases of each hydrogen system, parties may have a reduced capacity to manage their imbalances, given that wholesale, balancing and storage markets will be less developed. Therefore, in the beginning hydrogen system operators may play a larger role in managing imbalances, being responsible potentially also for primary balancing. In this case, it will be important to ensure the procurement of balancing services from market operators by system operators is conducted in a objective and non-discriminatory manner. Given the economic advantages of underground salt cavern storages and the possibility of renewable hydrogen of providing also (upward) balancing services, there could be from the start significant competition between technologies for the provision of balancing services, which reinforce the need for non-discriminatory rules.

Ensuring non-discriminatory market-based congestion management procedures will also be required. Initially, due to economies of scale and especially where repurposing of gas pipelines is significant, hydrogen networks could be significantly over-dimensioned, reducing the needs for congestion management. However, as the systems develops and become more interconnected, the importance of congestion management will increase.

Adequate product characteristics such as temporal and locational granularity in all markets will be essential to value the contributions of storage. This applies not only to hydrogen markets, but also to electricity markets. For example, locational granularity may not be as relevant initially for hydrogen, as hydrogen systems may be rather small at the start, but adequate locational signals to electricity wholesale prices and tariffs will foster the optimal localisation of electrolyser capacities. Thus, adequate definition of pricing zones reflecting any (future) structural network will be important. The right temporal granularity of hydrogen market products will be determined especially by the interactions with electricity markets (as gaseous hydrogen and derivatives variability will be a major driver of overall hydrogen system flexibility needs, at least initially, given the less variable demand profiles of the initial industrial consumers) and the type and availability of hydrogen storage.

In order to promote the market value of storage, it will be important to gradually build the liquidity of hydrogen markets. Initially, as discussed in section 4.5.1, bilateral long-term supply contracts will play a central role in providing the certainty necessary for investments in hydrogen supply, transport, storage and demand. However, short-term hydrogen wholesale markets can play a complementary role to these long-term supply contracts, by enabling suppliers to sell hydrogen surpluses and consumers to contract additional hydrogen needs. Hydrogen storage could increase the liquidity of this wholesale market by increasing arbitrage possibilities. However, as initially hydrogen storage development will also depend on long-term contractual agreements, storage requirements such as use-it-or-lose-it could maximise storage utilisation and gradually develop short-term markets, while still allowing long-term contracting of storage services.

To adequately value the system contributions of storage, hydrogen storage tariffs (if regulated) should be set through market-based mechanisms, such as capacity auctions. This should allow tariffs to be set according to the true value of storage, and avoid that storage be 'outpriced' by other flexibility solutions due to the setting of storage tariffs at levels that do not reflect storage costs. This would better enable the participation of storage not only in ancillary services procurement processes, but also wholesale markets. Eventual revenue gaps for regulated storage can be recovered through means such as charges to network users or direct subsidies.

Hydrogen network tariffs should also not unduly burden hydrogen storage given its system contributions. Therefore, it could be considered to require or allow that network tariffs for storage are set considering only marginal costs, or that, alternatively, network tariffs discounts for storage are implemented. Especially in the initial phases of development of the hydrogen sector, this could be an issue as the storages would not be depreciated. Moreover, initially hydrogen networks could be over-dimensioned for the existing demand, leading to high tariffs on a EUR/MWh base, even if only variable costs are to be recovered through tariffs. However, any network tariffs designed to value storage should also value system contributions from other flexibility resources.

Coupled with the high investment costs, these are main reasons for existing gas infrastructure operators to argue that subsidies (for capital expenditures) would be necessary to develop hydrogen storage. However, to avoid distorting the energy market and discriminating other energy technologies, if any subsidies are made available to hydrogen storage, these should focus on RD&I projects (including large-scale demonstration) or use non-discriminatory financing mechanisms open to other infrastructure projects which also potentially contribute to energy & climate goals, such as the Connecting Europe Facility. Planning for the development of hydrogen infrastructure could, based on the estimated necessary investments and storage utilisation, assess the tariff impact on the initial customer based and the need for recovering part of the investment costs from hydrogen network users in general or taxpayers more broadly.

Regarding the valuation of the security of supply contributions of storage, as hydrogen markets develop measures can be investigated so that market prices better reflect hydrogen value at times of scarcity. This could be done by requiring Member States to conduct a hydrogen adequacy assessment (in coordination/integrated with similar assessments for the electricity and gas systems) and allow them to implement market-based measures in case adequacy risks are identified. Measures so that suppliers ensure supplies in scarcity moments could be explored if warranted to protect small consumers (if such consumers eventually are connected to hydrogen networks), in case curtailment measures are not foreseen in contractual arrangements with customers.

5 Prospective analysis 'domestic' vs. 'external' H_2 production

The aim of this chapter is to combine the findings and data from the previous chapters in order to build complete pathways from production to end-use, and assess and compare these pathways. It connects EU H_2/derivatives demand and H_2/derivatives supply, being domestic or import.

The first step is therefore to fix the demand scenario, based on chapter 1 research and ongoing workstreams within the EC. The second step assesses all steps and elements along the supply chain (infrastructure, transport, production, ….), to connect supply to demand. The third step describes plausible and potential supply pathways to comply with the demand. Several supply pathways are explored, to allow qualitative and quantitative comparison.

5.1 Demand scenario

Renewable hydrogen and derivatives will be likely deployed firstly for replacing existing hydrogen use in the industry, and then extend to the transport sector. Looking at the current use in the different industrial sectors, ideally by MS will help identify where the demand for "green" hydrogen use will be pulled.

The demand scenario will ensure it reaches at least 10 million metric tons renewable H_2 per year[251] as demand across EU27. To facilitate the comparison between different fuels and carriers, we convert this target of 10Mt H_2 into 28,600 ktoe[252].

Regarding the future demand for renewable hydrogen and derivatives, it is important to consider:

1) The demand per sector, as each sector would probably be localised differently across the EU.
2) The demand per fuel type, as each fuel has different cost along its entire value chain (including infrastructure and conversion).
3) The maritime sector (alternative fuels) will be an important player in developing the demand for the transport sector.
4) The aviation sector is easily supplied from the main oil industries (e.g. the CEPS[253] pipeline is supplying most of the airports in Western Europe, mainly from the ARA[254] area).
5) The existing infrastructure will most likely be partially repurposed:
   - for the transport of gaseous hydrogen, using the existing gas infrastructure;
   - for PtL, repurposing petroleum products handling infrastructure will be at very low cost[255];
   - for ammonia and methanol, the first potential consuming sectors would be those replacing fossil-based ammonia by imported renewable-based ammonia. New terminal infrastructure would be required.

[251] H_2 strategy "In a second phase, from 2025 to 2030, hydrogen needs to become an intrinsic part of an integrated energy system with a strategic objective to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10 million tonnes of renewable hydrogen in the EU"

[252] 1 metric ton of hydrogen contains 2.86 toe

[253] https://www.nspa.nato.int/about/ceps

[254] ARA = Amsterdam, Rotterdam and Antwerp is a major cluster of oil industries, supplying large part of the region

[255] https://fetsa.eu/wp-content/uploads/2021/07/Implications-of-energy-transition-FINAL-REPORT.pdf

5.1.1 Current situation

According to the FCH JU Observatory, total hydrogen production capacity in the included countries (EU27) at the end of 2019 has been estimated at 10.8 Mt per year.[256] The corresponding consumption of hydrogen has been estimated at 8.4 Mt (~280 TWh_{HHV}), which means an average capacity utilization of 80%. The biggest share of hydrogen demand comes from refineries, which were responsible for 49% of total hydrogen use, followed by the ammonia industry with 31%. About 13% was consumed by the chemical industry including methanol production constituting 5%. Emerging hydrogen applications, like the transportation sector comprised a small portion of the market at 0.02% as of 2019.

These data come from the FCH JU Observatory and as such are not considered official statistics, but give a clear baseline and understanding of the current hydrogen market. These data cover hydrogen use of only 2019 (and does not take into account a yearly average).

Metric tons H2	Refinery	Ammonia	Other chemicals	Other	Methanol	Energy	H2O2	Transport	Total metric tons/y
EU27	4.080.239	2.580.520	688.062	444.376	417.461	103.367	61.463	1.545	8.377.033
	49%	31%	8%	5%	5%	1%	1%	0%	

Source: https://www.fchobservatory.eu/observatory/technology-and-market/hydrogen-demand[257]

The location of demand will be a key consideration for industrial clusters and valleys to deploy, while connecting large demand centres to supply, which can be either local or imported.

The following figures show the location of fertilizer plants and refineries across the EU.

[256] https://www.fchobservatory.eu/sites/default/files/reports/Chapter%202%20Hydrogen%20Supply%20and%20Demand%202021.pdf

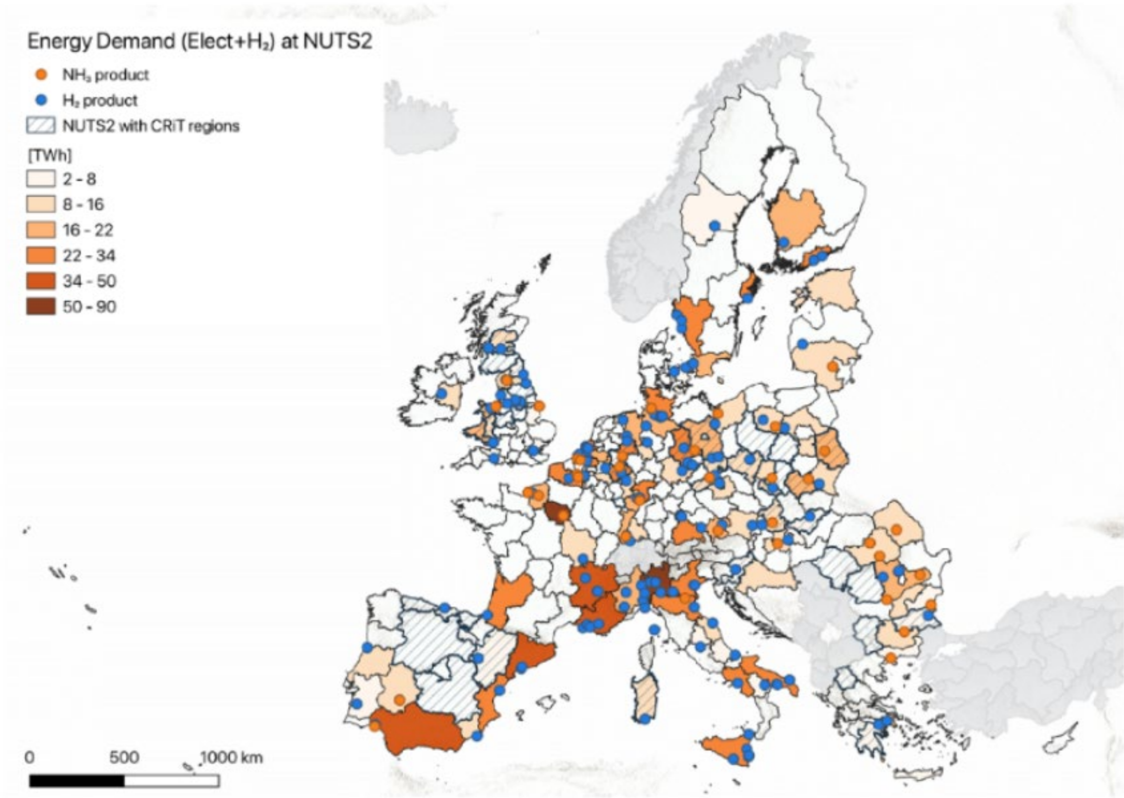
[257] Specific 2020 data are available in the followoing report https://www.fchobservatory.eu/sites/default/files/reports/Chapter%202%20Hydrogen%20Supply%20and%20Demand%202021.pdf

Figure 50 Location of major fertiliser plants in Europe

Source: https://www.fertilizerseurope.com/fertilizers-in-europe/map-of-major-fertilizer-plants-in-europe/

This map illustrates that an important number of fertiliser industrial plants are located near coastal areas, especially in North-Western Europe. In order to complement this, the next map illustrates the distribution of main hydrogen production hubs in EU27 (and UK).

Figure 51 Main hydrogen production hubs

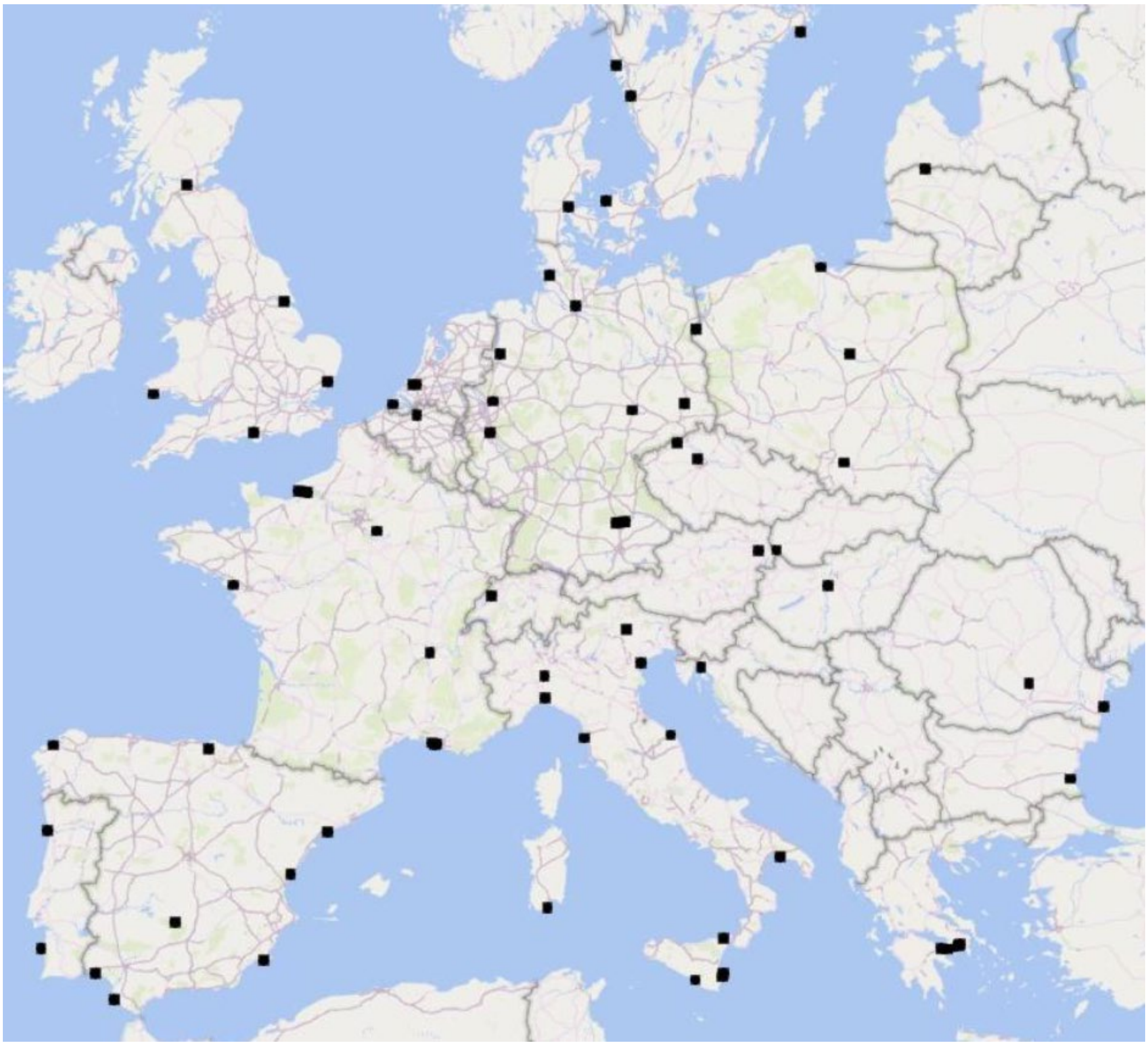


Source: Green Hydrogen in Europe – a regional assessment: substituting existing production with electrolysis powered by renewables, JRC 2021[258]

These coastal areas, showing an important hydrogen demand, could become EU trading points, also due to their proximity to some refineries (as illustrated by the next map).

[258] The article is available at https://reader.elsevier.com/reader/sd/pii/S0196890420311766?token=E9E1E898831361E14F4040D1F693B4B60CECC74A6AF70377EADE07CF7D87175AB21D1B17272D75174435A6113E08E88A&originRegion=eu-west-1&originCreation=20220118044338

Figure 52 Captive hydrogen production units at refineries in Europe



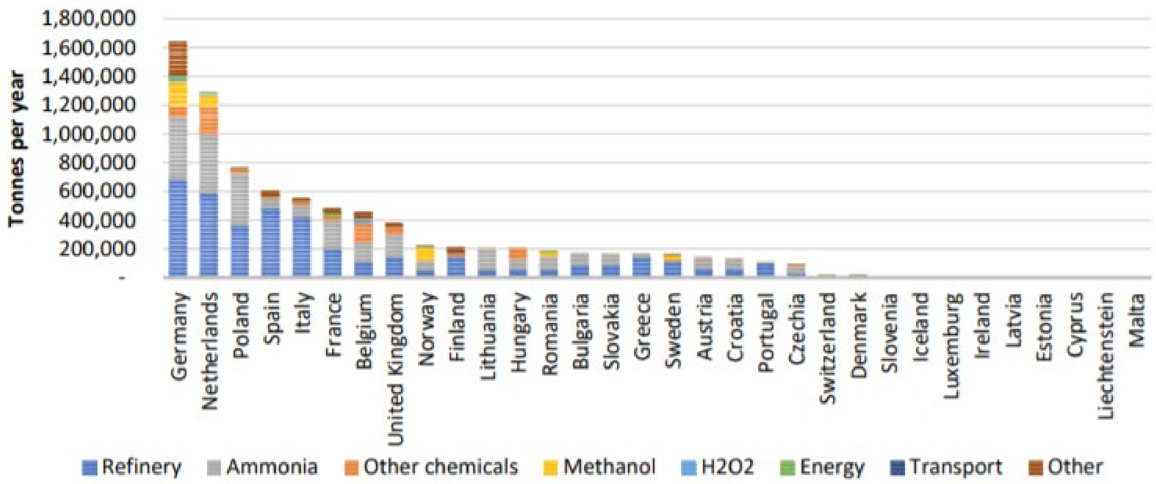
Source: https://www.fchobservatory.eu/sites/default/files/reports/Chapter%202%20Hydrogen%20Supply%20and%20Demand%202021.pdf

This map illustrates that many of the refineries are located near coastal areas, which can be considered as EU entry points. A well-developed pipeline network (especially in Western Europe) connects the inland refineries to the current costal import terminals (entry points).

These maps will be used when addressing the regions and areas where renewable hydrogen could be supplied, via pipelines and shipping.

5.1.1.1 Current demand per MS

Figure 53 Total demand for hydrogen in 2019 by country



Source: Fuel Cells and Hydrogen Observatory (2021 Hydrogen supply and demand, September 2021[259])

This gives a broad view on where the current hydrogen consumption spots are located across the EU, and where a possible switch to renewable hydrogen could happen first.

5.1.2 Renewable hydrogen demand scenario

The demand scenario is based on the literature review, and especially on the different studies analysed under chapter 1, including the MIX-H2 scenario.

One 2030-2035 scenario is fixed as baseline, comprising

- The direct use of hydrogen (13,400 ktoe), consumed locally (on-site) or transported via pipeline (gaseous) or via tanks (liquefied);
- The conversion of 4,400 ktoe (1,500 kt H_2) of renewable hydrogen to 8,630 kt e-ammonia[260];
- The conversion of 4,800 ktoe of renewable hydrogen to e-diesel, of 1,500 ktoe of renewable hydrogen to e-fuel oil, 1,100 ktoe of renewable hydrogen to e-gasoline, and 2,500 ktoe of renewable hydrogen to e-kerosene, to be transported via the existing (repurposed) liquid infrastructure, for the use in transport;
- The conversion of 800 ktoe of renewable hydrogen to synthetic methane (or SNG) for injection in natural gas networks.

259 https://www.fchobservatory.eu/sites/default/files/reports/Chapter%202%20Hydrogen%20Supply%20and%20Demand%202021.pdf

260 On average, 1 ktoe H_2 produces 1.96 kt NH3 (or 0.51 kt H_2 are needed to produce 1 kt NH3)

Table 30 Hydrogen demand scenario

kt H_2	2030-35							
	Hydrogen direct use	Ammonia	PtL diesel	PtL fuel oil	PtL gasoline	PtL kerosene	SNG	Total
H_2 production for the se/conversion of…	4.700	1.500	1.700	500	400	900	300	10.000
H_2 production (in ktoe)	13.400	4.400	4.800	1.500	1.100	2.500	800	28.500

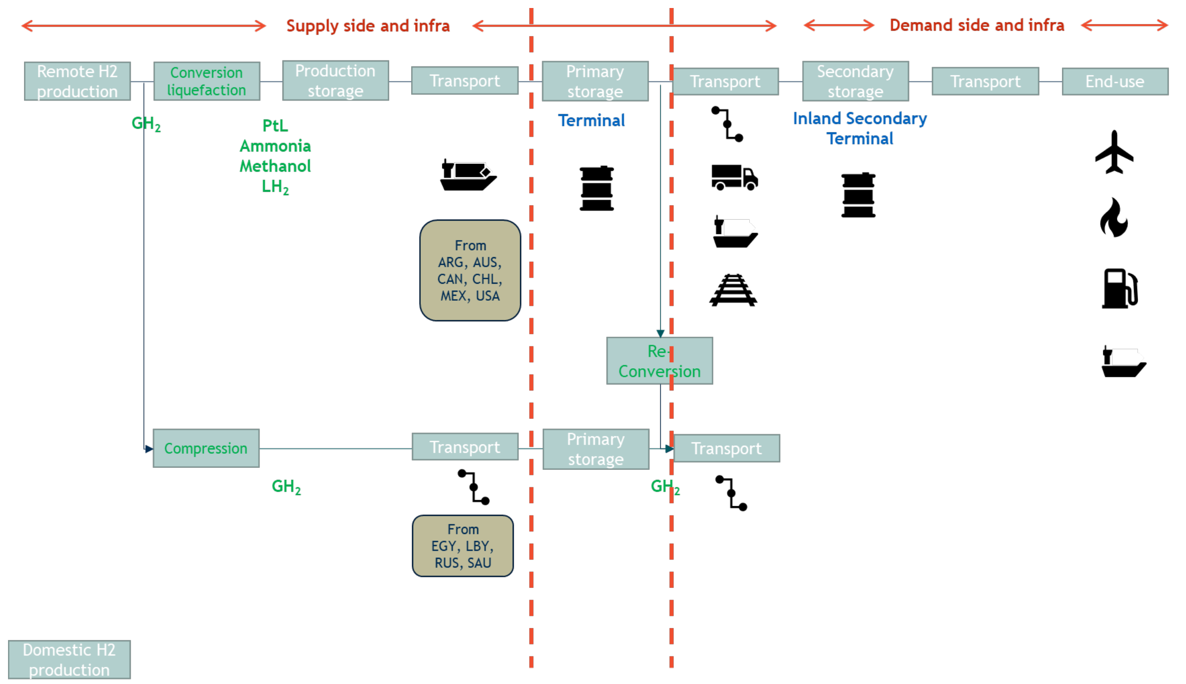
Source: own elaboration, based on several scenarios (cf. chapter 2)

A total of 28,500 ktoe (or 10,000 kt H_2[261]) of hydrogen must be produced to supply the direct use of 13,400 ktoe of renewable hydrogen, to convert 4,400 ktoe of renewable H_2 to ammonia, and to convert 10,700 ktoe H_2 into 7,700 ktoe PtL & SNG (4,800 ktoe H_2 to 3.400 ktoe e-diesel; 1,500 ktoe H_2 to 1,100 ktoe e-fuel oil; 1,100 ktoe H_2 to 800 ktoe e-gasoline; 2,500 ktoe H_2 to 1,800 ktoe e-kerosene; 800 ktoe H_2 to 600 ktoe SNG).

5.2 Supply chain description

The supply chain from production to delivery to the final consumer can be decomposed according to the steps depicted in the following figure.[262] As the aim is to compare different supply pathways, the focus will be on primary storage which can be a terminal or a storage facility. The downstream of the chain, from primary storage to end-use, would be similar between the different supply configurations.

Figure 54 Supply chain steps and scope



[261] Conversion factor: 1 kt hydrogen contains 2.8571 ktoe of energy, but figures in this study are rounded

[262] https://fetsa.eu/wp-content/uploads/2021/07/Implications-of-energy-transition-FINAL-REPORT.pdf

The 4 steps covered in this section are

- **Production** of hydrogen, based on local electricity cost; **including conversion** in the case **derivatives** are considered;
- **Exporting infrastructure**, including production storage, to store products before loading ships;
- **Transport**, by ships;
- **Import infrastructure**, such as terminals and import storage facilities. These entry points to EU when imported from non-EU are located
  - Mainly in seaports (when supplying countries are ARG, AUS, CAN, CHL, MEX or USA)

In Chapter 3, the cost of producing hydrogen and its derivatives was calculated for the top 10 countries with the greatest renewable hydrogen and derivatives potential. The calculations in chapter 3 are based on the PtX Atlas of Fraunhofer IEE, which provides a cost-optimized system design and cost-optimized fuel production cost. It includes the following components and assumptions:

- Electricity production by wind, solar or hybrid (wind and solar)
- Intermediate storage of electricity
- Transport of electricity
- Water treatment (sea water desalination and/or purification system)
- Hydrogen production by electrolysis
- Buffer for hydrogen
- Heat storage system
- DAC for CO2 generation
- Derivatives production and
- Transport cost.
- Country specific WACC

These data from PtX Atlas should enable comparability between imported hydrogen and hydrogen produced within the EU, as the latter one is calculated with completely different tools (based on METIS). Results from these two different calculation tools cannot be compared directly. This is why, for the purpose of this chapter 5, a very simplified tool was developed that calculates LCOE and LCOH, using specific EU and non-EU data with the same simplified tool.

The calculations are carried out using the same assumptions on CAPEX, OPEX, WACC, efficiency and lifetime of the system. The simple tool only considers the electricity generation and the hydrogen production. The varying factors are the full load hours of renewable energies (wind) and the resulting full load hours of electrolysis. In the following, the differences in the hydrogen production costs thus result exclusively from the resources of the countries considered. The following EU assumptions are based on REF2020 - technology assessment.

The results in chapter 3 are a lot more precise, specific and realistic than the following figures, which have only been calculated to compare European renewable hydrogen and derivatives production to imports.

5.2.1 Production cost of renewable H_2 and its derivatives

Hydrogen production cost calculated using the simplified tool comprises

- CAPEX and OPEX of wind turbines

- CAPEX and OPEX of electrolysers[263]
- FLH of wind and resulting FLH of electrolysis (varies depending on the country considered)

With the simplified tool it is not possible to calculate the production costs for derivatives, because the design is very complex. The configuration of hydrogen storage, partial load capability of synthesis, capacity ratio of electrolysis to synthesis, etc. must be taken into account, which the tool cannot represent.

The calculation of the LCOE and the LCOH is made based on a simplified modelling. The tool created for the comparison of European production with imports of hydrogen is based on the annuity method[264]. The LCOE is calculated according to the following formula:

$$LCOE = \left(\frac{i \, * (1+i)^n}{(1+i)^n - 1} + O\&M\right)\frac{CAPEX}{FLH}$$

The parameters are valid for wind energy and come from REF2020 - technology assessment. For the generation of electricity only wind energy was considered, because in this case no further storage or design optimization (for hybrid plant configuration) is required. The electricity can be fed directly into the electrolyser.

Table 31 LCOE calculation parameters (EU data at 2030)

Parameter	Value
i (interest rate)	0,07
life of system n (a)	30
CAPEX of wind (€/kW)	1,000
O&M (% of CAPEX)	0,0165
FLH of RE (h)	depending on the resources of the country considered (~2,300h)

The hydrogen production costs are then calculated according to the following formula:

$$LCOH = \frac{LHV}{\eta}\left(\left(\frac{i \, * (1+i)^n}{(1+i)^n - 1} + O\&M\right)\frac{CAPEX}{FLH} + LCOE\right)$$

The parameters are based on REF2020 - technology assessment:

263 Purification costs are included in the CAPEX of the electrolyser. These are typically higher for alkaline electrolysers than for PEM (PEM ~ 99,995 % purity; AEL ~ 99,999 % purity)

264 With the annuity method, the non-periodic payments and periodic payments with changing amounts are transformed over an observation period T into constant periodic payments, by use of the annuity factor a. The annuity as the determined common constant periodic payment can be allowed for as an interest share or repayment share for capital to be repaid up to the amount of the capital value.

Table 32 LCOH calculation parameters (EU data at 2030)

Parameter	Value
LHV (kWh/kg)	33,3
Efficiency of Electrolysis η	0,81
i (interest rate)	0,07
life of system n (a)	30
CAPEX of electrolysis (€/kW)	670
O&M (% of CAPEX)	0,022
FLH of electrolysis (h)	depending on the resources of the country considered

The results from this simplified model deviate from the numbers calculated from the PtX-Atlas. The assumptions on CAPEX, OPEX, interest rate, efficiency and lifetime are different and this leads to lower LCOH using the simplified model. This approach is only introduced in order to compare the cost for hydrogen production within the EU with the LCOH from other countries in the world.

The results for hydrogen production within EU and for the countries where there are wind sites are listed in the following table.

Table 33 LCOH for different regions, EU and non-EU

	LCOH from simple tool [€/MWh]	Feedstock
EU	*85,7*	*Wind only*
ARG	*34,4*	*Wind only*
AUS	*42,4*	*Wind only*
CAN	*41,1*	*Wind only*
CHL	*31,8*	*Wind only*
MEX	***45,7***	***Wind only***
RUS	***40,2***	***Wind only***

The results in chapter 3.3 are based on much more precise and specific analyses with the PtX Atlas. The following statements are made based on optimized system configurations at specific sites. In addition, statements on derivatives and transport costs based on detailed analyses are also made in the following. These are not representable with the simple tool.

The following table shows the production cost for hydrogen, based on the simple tool calculating hydrogen production costs for EU and non-EU countries (imported renewable hydrogen and derivatives). In addition, hydrogen, methanol, liquid derivatives and SNG production costs are presented based on the PtX Atlas from chapter 3.

Table 34 Fuel production cost

Fuel cost (€/MWh)	Hydrogen (1 kg = 33.33 kWh)	Methanol	PtL (diesel, kerosene)	SNG
from EU countries (simple LCOH model)	86			
from non-EU countries (simple LCOH model)	32 - 46			
from non-EU countries (PtX Atlas)	66 - 105	132 - 198	140 - 208	126 - 190

Source: DG ENER for DE, NL, PL, GR, PT, DK, FR, ES, RO and Task 2-3, for ARG, AUS, CAN, CHL, EGY, MEX

5.2.2 Transport cost

Transport cost comprises

- Investment in assets (ships and pipelines, possibly trucks)[265]
- Operation of the assets (opex and fuel costs), depending on the average distance
- Conditioning of renewable hydrogen and derivatives product for transport (liquefaction, compression)

The following table shows the transport cost for hydrogen, methanol, liquid derivatives and SNG based on the figures for "Pipeline" and "Storage" of scenario B_optimised from DG ENER (production within EU) and the calculations carried out in chapter 3 (imported PtX products). The transport of ammonia and its cost is described in chapter 3.2.2.1, but not considered in the PtX atlas. In addition to the transport costs from the PtX Atlas and the data from DG ENER (based on METIS), figures for pipeline-bound imports of renewable hydrogen and derivatives from Africa and Asia are provided below.

For transport cost, it is assumed that PtX Atlas (non-EU), Hydrogen Backbone (pipeline-bound) and METIS (EU) costs can be compared as their calculations are simpler than for the production, where a simple tool was used for the comparison and less influential in terms of total cost.

Table 35 Fuel transport cost

Transport costs (€/MWh)	Hydrogen	Methanol	PtL (diesel, kerosene)	SNG
from EU countries (from METIS)	gaseous: 7 - 29		1.0 – 1.5	
Shipping from Top 10 countries to EU (from PtX Atlas)	liquefied: 11.2 - 39.2	4.6 - 15.3	2.3 - 7.6	liquefied: 3.7 - 12.3
Pipeline transport from Africa / Asia to EU (3 000 km)[266]	gaseous: 6.3 – 13.5	-	0.8	gaseous: 5.2 - 7.7

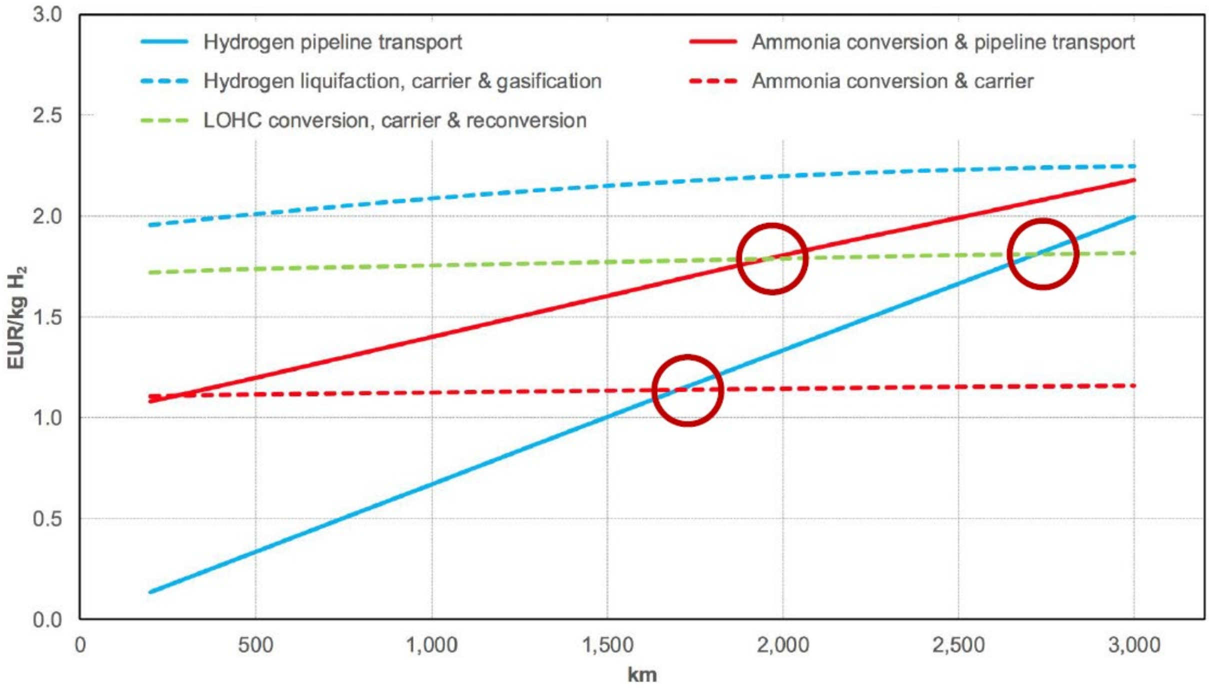
Source: T2-3, for ARG, AUS, CAN, CHL, EGY, MEX; DG ENER, for DE, NL, PL, GR, PT, DK, FR, ES, RO; European Hydrogen Backbone and Energy Brainpool

[265] The cost for quality adaption after transport is not taken into account

[266] Adapted from Hydrogen Backbone

A generic overview of the options for transporting hydrogen and the associated costs depending on the transport distance are provided in the following figure.

Figure 55 Costs of different options for the long-distance transport of hydrogen depending on transport distance

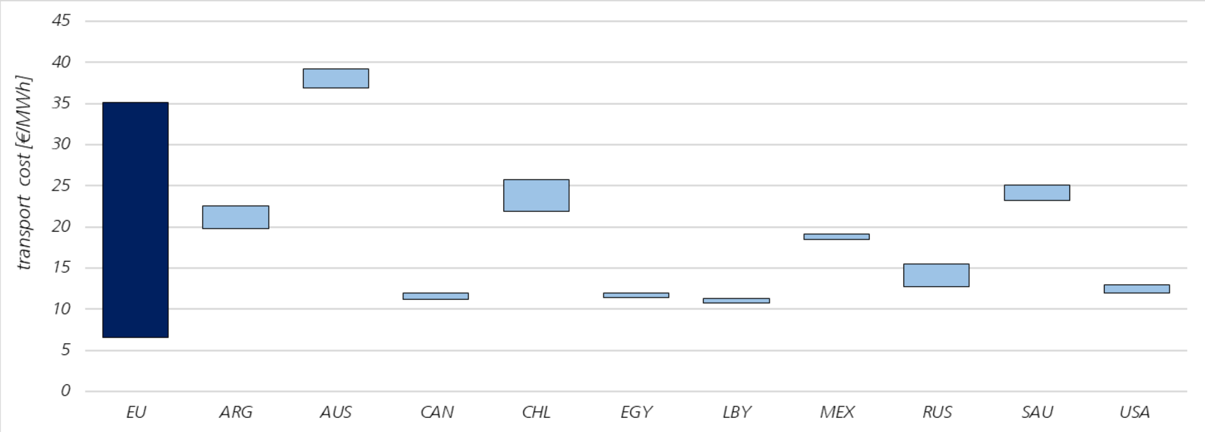


Source: Ökoinstitut; 2020; Wasserstoff und wasserstoffbasierte Energieträger bzw. Rohstoffe

The transport cost for different end products increase depending on the transport distance, but also depending on the derivative under investigation. While the cost of hydrogen transport by pipeline increases with the distance, mainly because of intermediate compression, for LH_2 transport liquefaction is the cost-intensive part of the chain. Once the hydrogen is liquefied, it can be transported over long distances with few boil-off losses. Transporting ammonia is less expensive than transporting liquid hydrogen. Conditioning of the end product is less complex and boil-off losses are lower.

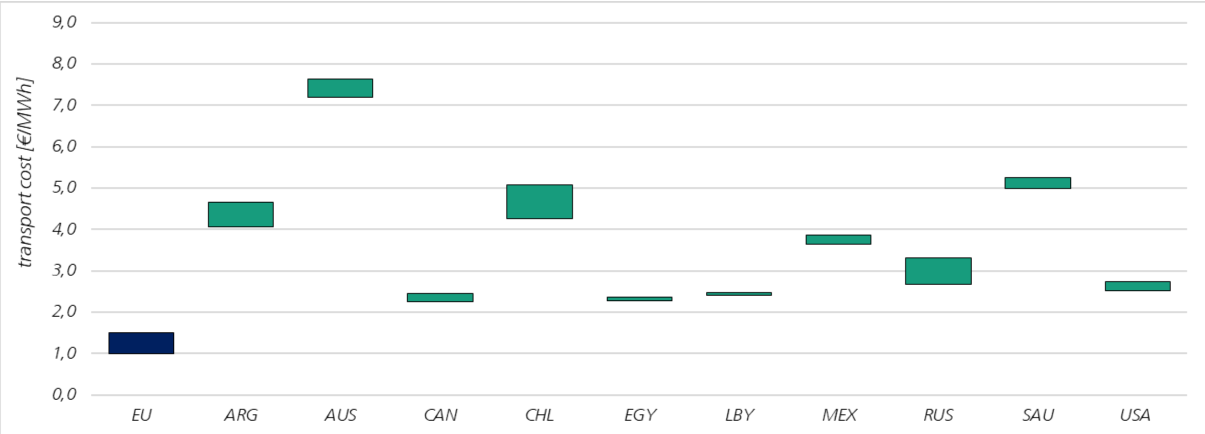
The transport costs in the following chart are based on data from the PtX Atlas and from DG ENER. A direct comparison is not possible, since the costs for imported hydrogen are based on liquefaction and the intra-European transport is pipeline-bound, i.e. compression was taken into account.

Figure 56 Hydrogen transport cost



The transport costs for liquid derivative products are cheaper than the costs for hydrogen transportation. The results of the transport cost analysis and a comparison between imported liquid derivatives and liquid derivatives produced within the EU are presented in the following figure.

Figure 57 Liquid derivatives transport cost (Fischer Tropsch)



5.2.3 Importing infrastructure

Importing infrastructure would comprise especially handling infrastructure (offloading) and terminal storage infrastructure (usual medium scale storage, whose costs are presented in the following section). Typical sizes which can be expected for importing terminals is presented in the next table.

Unfortunately, due to the significant differences in terminal construction costs and the lack of concrete examples, cost information for H_2 and derivatives import terminals is scarce. Information gathered in chapter 2 indicates that the CAPEX for ammonia terminals, including storage and cracking, would amount to 1,400 – 2,150 €/t NH_3.

5.2.4 Storage infrastructure

Regarding storage costs for hydrogen and derivatives, the table below presents a comparison of the costs and sizes of new storages, based on the overview of chapter 4 as well as additional sources for PtL and SNG. These primary storage infrastructure (located upstream prior to distribution to final consumers) would be located at import terminals, EU production sites or, in the case of underground storage, in available locations connected by a hydrogen backbone.

Table 36 EU *storage infrastructure costs*[267]

Storage infra costs	Hydrogen (salt caverns)	Liquid hydrogen (tanks)	Methanol (tank)	Ammonia (refrigerated tank)	PtL (diesel, kerosene - tanks)	SNG (underground)
Average storage size	0.263 TWh	0.009 TWh	0.165 TWh	0.328 TWh	0.45 TWh[268]	> 5 TWh[269]
Costs of new storage (CAPEX)	200 €/MWh	2,700 €/MWh	113 €/MWh	194 €/MWh	Stored in existing infrastructure	Stored in existing underground facilities

5.2.5 Production and transport cost comparison

The comparison of production and transport cost is a mixture of production cost from the simple tool and transport cost from the Atlas as well as from the data provided by DG ENER.

Table 37 Production, Transport and Total cost for European-produced Hydrogen

[€/MWh]	Production Cost	Transport Cost	Total Cost
EU	86 €	7-35 €	95 - 123 €

Source: Simple tool and DG ENER

The cost of imported hydrogen are based on the simple tool (production) and the Atlas (transport). The more realistic cost for imported renewable hydrogen and derivatives products are presented in chapter 3.

Table 38 Average Production, Transport and total cost for imported hydrogen (up to EU border)

[€/MWh]	Production Cost	Transport Cost	Total Cost
ARG	34,4	21,2 €	55,6 €
AUS	42,4	38,1 €	80,5 €
CAN	41,1	11,6 €	52,7 €
CHL	31,8	23,9 €	55,7 €

267 DNV GL study, 2020-09-09 - DNV GL - GIE database Liquid Renewable Energy (draft final).xlsx

268 Assuming an average tank size of 50 000 m^3, based on https://www.vopak.com/terminals/vopak-terminal-europoort-rotterdam?language_content_entity=en

269 Based

[€/MWh]	Production Cost	Transport Cost	Total Cost
MEX	45,7	18,8 €	64,5 €
RUS	40,2	14,1 €	54,3 €

Source: simple tool and PtX Atlas

The direct comparison of hydrogen production cost using the simplified model leads to far lower production cost of hydrogen in non-EU-countries because of better resources. The transport costs for imported hydrogen are in turn higher than the costs for intra-European transport. European hydrogen costs 95 to 123 €/MWh and imported hydrogen costs 53 to 81 €/MWh at the import terminal. However, the hydrogen landed at the terminal also still has to be distributed in the EU, which leads to additional distribution costs.

Compared to the import cost figured out in Chapter 3, the range of hydrogen costs from European production is quite similar.

In summary, it can be stated that the costs for imported hydrogen is lower than for hydrogen produced within the EU. There are countries in the world where the derivative products can be produced at lower cost because of outstanding wind and PV resources, as highlighted within the EC Long Term Strategy[270]. However, as the cost of the products increases with increasing transport distance, products from the EU can remain competitive. To ensure that all options are available in the long term, the relevant import infrastructures as well as the European ramp up of derivatives production facilities should be considered at an early stage. Furthermore, the factor of additionality of renewable energies is decisive for the advantageousness in terms of climate effectiveness. Thus, derivative production can only succeed sustainably on a large scale if it is accompanied by a massive expansion of renewable.

Therefore, the availability of renewable sources becomes a key factor for the massive production of renewable hydrogen. The recent IRENA study[271] illustrates the technical potential of producing renewable hydrogen under 1.5USD/kg H_2 in 2050, showing the main regions.

Textbox 9 Geopolitics of the Energy Transformation: Hydrogen Factor, IRENA 2021

Geopolitics of the Energy Transformation: Hydrogen Factor – main takeaways

Driven by the climate urgency and countries' commitments to net zero, IRENA estimates hydrogen to cover up to 12 per cent of global energy use by 2050.

"It is green hydrogen that will bring new and diverse participants to the market, diversify routes and supplies and shift power from the few to the many. With international co-operation, the hydrogen market could be more democratic and inclusive, offering opportunities for developed and developing countries alike.", Francesco La Camera, Director-General of IRENA said;

IRENA estimates that over 30 per cent of hydrogen could be traded across borders by 2050, a higher share than natural gas today. Countries that have not traditionally traded energy are establishing bilateral energy relations around hydrogen.

[270] See the LTS page 64, footnotes 187, 188, available at https://ec.europa.eu/clima/system/files/2018-11/com_2018_733_analysis_in_support_en.pdf

[271] Geopolitics of the Energy Transformation, the Hydrogen Factor, IRENA, 2022, available at https://irena.org/publications/2022/Jan/Geopolitics-of-the-Energy-Transformation-Hydrogen

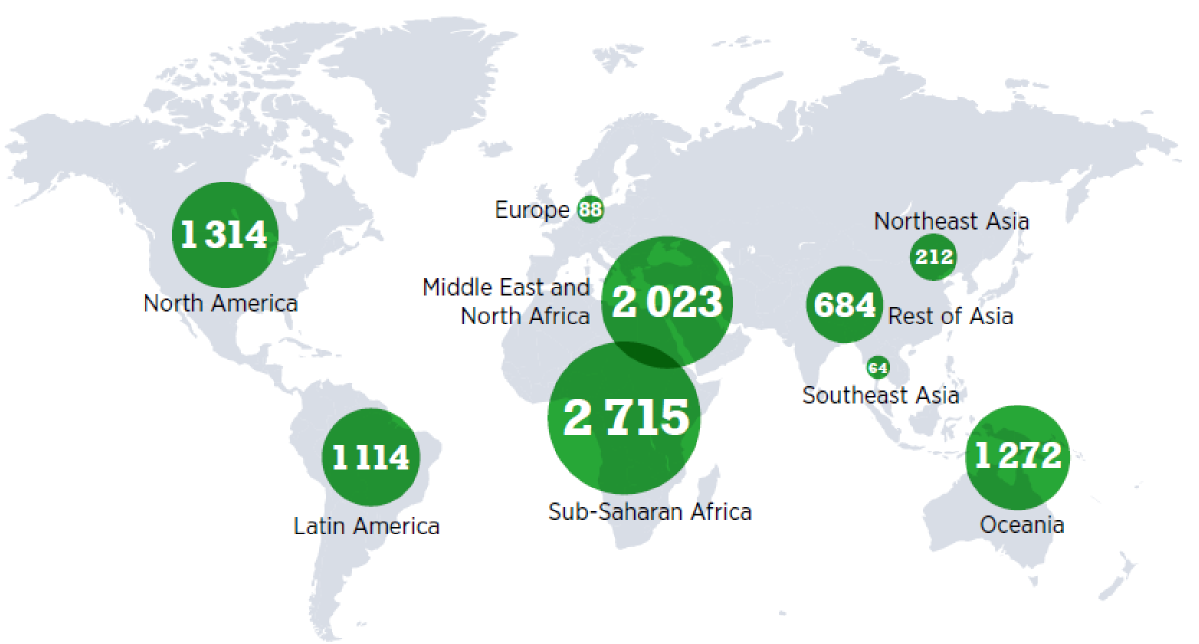
Cross-border hydrogen trade is set to grow considerably with over 30 countries and regions planning for active commerce already today. Some countries that expect to be importers are already deploying dedicated hydrogen diplomacy such as Japan and Germany. Fossil fuel exporters increasingly consider clean hydrogen an attractive way to diversify their economies for example Australia, Oman, Saudi Arabia and the United Arab Emirates.

Countries most able to generate cheap renewable electricity will be best placed to produce competitive green hydrogen. While countries such as Chile, Morocco, and Namibia are net energy importers today, they are set to emerge as green hydrogen exporters. Realising the potential of regions like Africa, the Americas, the Middle East, and Oceania could limit the risk of export concentration, but many countries will need technology transfers, infrastructure and investment at scale.

The geopolitics of clean hydrogen will likely play out in different stages. The report sees the 2020s as a big race for technology leadership. But demand is expected to only take off in the mid-2030s.

Countries and regions with high renewable potential and low levelised cost of electricity can use their resources to become major producers of renewable hydrogen. The ability of different regions to produce large volumes of low-cost renewable hydrogen varies widely, as illustrated by the figure.

Figure 3.4 Technical potential for producing green hydrogen under USD 1.5/kg by 2050, in EJ



Source: IRENA (forthcoming-a). Map source: Natural Earth, 2021

5.3 Plausible supply pathways

5.3.1 Selection of plausible supply pathways

To supply the forecasted EU demand for hydrogen and derivatives, several options are possible, through domestic production (with intra-EU trade) and/or by importing from non-EU countries and regions. Production and transport costs have been extensively assessed under chapter 3, but the assessment was isolated and not addressed in potential pathways considering all parts of the hydrogen value chain.

The different supply pathways described in this section are first defined based on the following considerations:

- Transport over very long distances (around 2,000 km and above) through ships can often be economically more advantageous (and sometimes the only alternative) to transporting gaseous hydrogen through pipelines, leading to imports of liquefied hydrogen and/or derivatives being favoured over imports of gaseous hydrogen. Depending on aspects such as the availability for repurposing and quality of existing natural gas pipelines, pipeline transport over 2000 km could be considered. Therefore, a gaseous hydrogen import pathway is considered only from Northern Africa (e.g. Algeria, Morocco) or Eastern Europe (Ukraine, Russia);
- The re-conversion (from any derivative back to (gaseous) hydrogen) significantly decreases the total efficiency, and is therefore currently not considered as a plausible pathway (this does not mean such configuration will not happen or does not make sense, but rather that it would probably not be deployed at large scale). Therefore, the PtL and ammonia supply pathways (in the case of imports) are seen as delivering final products to the EU (e.g. replacing fossil ammonia, or delivering PtL to the transport sector).

The baseline for the pathways is to comply with the EU Hydrogen Strategy, meaning a total demand of 10 Mt H_2, and a domestic production with 40 GW of electrolysis capacity (producing ~5Mt H_2[272]). The gap will be covered by import of renewable hydrogen or its derivatives, or a mix of both. The different pathways vary on the basis of the imported H_2 form, to compare the impacts on the system.

The following 4 plausible supply pathways are assessed.

	Hydrogen	**Ammonia**	**PtL (diesel, kerosene)**	**SNG**
Pathway 1 – imported liquids	EU	Non-EU	Non-EU	EU
Pathway 2 – NH_3 domestic	EU & non-EU	EU	Non-EU	EU
Pathway 3 – PtL domestic	EU & Non-EU	non-EU	EU	EU
Pathway 4 – NH_3 & PtL domestic	non-EU	EU	EU	non-EU

The assessment aims to describe and compare the following aspects for each supply pathway:
- All steps until hydrogen or the derivative is available in the EU (i.e. production in the case of domestic production, or production, conversion and shipping in the case of import pathways);
- Terminal infrastructure (import/export infrastructure in maritime ports), when applicable;
- Impact on storage and transport infrastructure (pipelines, but also trucks equipment, and even barges and rail), with entry points in EU (localisation of primary storage infrastructure);
- Summary description of the pathways;
- Advantages and disadvantages.

5.3.2 Overall plausible supply pathways description focusing on 2030/2035

Figure 58 details the supply volumes of hydrogen and derivatives for the different plausible pathways according to the origin (domestic or imported).

[272] Each electrolysis GW is expected to produce around 250 kt of H_2 per year, therefore 40GW would produce 10Mt H_2, https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Figure 58 Hydrogen and derivatives supply pathways to 2030/2035

(kT H2-equivalent)	Hydrogen	Ammonia	PtL diesel	PtL fuel oil	PtL gasoline	PtL kerosene	SNG	Total
				Pathway 1 – Imported liquids				
Domestic	4 690						282	**4 971**
Import		1 543	1 652	562	390	883		**5 029**
				Pathway 2 - NH3 domestic				
Domestic	3 176	1 543					282	**5 000**
Import	1 514		1 652	562	390	883		**5 000**
				Pathway 3 - PtL domestic				
Domestic	1 233		1 652	562	390	883	282	**5 000**
Import	3 457	1 543						**5 000**
				Pathway 4 – NH_3 & PtL domestic				
Domestic		1 543	1 652	562	390	883		**5 029**
Import	4 690						282	**4 971**

The following table summarises the main characteristics of each plausible pathway, and their impacts on all supply chain steps.

Table 39 Summary of the supply pathways characteristics

		Pathway 1 - imported liquids	**Pathway 2 - NH_3 domestic**	**Pathway 3 - PtL domestic**	**Pathway 4 – NH_3 & PtL domestic**
High-level description		Renewable hydrogen produced in the EU to supply the direct use of hydrogen, produced close to end-use, transported through the hydrogen backbone or through ships (intra-EU) to main ports. A small share of the domestic renewable H_2 is converted to methane (SNG), close to gas network infrastructure, for injection. Alternatively, the hydrogen could be blended directly in gas networks. Derivatives (PtL and NH_3) are produced close to H_2 production in partner countries and exported to the EU.	Renewable hydrogen is mainly produced in the EU, but with some imports (1.5 Mt) of hydrogen. Renewable ammonia is fully produced in the EU, close to chemical plants mainly in Central-Western and Eastern Europe. A small share of the domestic renewable H_2 is converted to SNG, close to gas network infrastructure. PtLs are produced close to H_2 production in partner countries and exported to the EU.	Domestic renewable hydrogen is used mainly for power-to-liquids production. A small share is used for production of synthetic natural gas, which is injected in gas networks. Up to 1.2 Mt of domestic hydrogen is used in pure form, especially close to end-uses in coastal areas or distributed through local/regional networks, trucks or barges. Most of the hydrogen used in pure form is imported from partner countries.	Domestic renewable hydrogen is used fully for ammonia and power-to-liquids production. All hydrogen used in pure form is imported. Part is consumed near entry points while the rest is distributed through the hydrogen backbone. A small quantity of SNG is imported through existing LNG terminals.
Cost competitiveness of imported hydrogen/ derivatives		As stated above, the costs for imported H_2 is lower than for H_2 produced within the EU, and the same cost difference would apply to derivatives. However, import cost does not include the cost of import infrastructure (terminal & storage), and transport cost increases with increasing transport distance, both leading to situations where EU production would remain competitive. For liquid derivatives, the existing import infrastructure would be used with very limited or no investments. Therefore, for those products, the import (production & transport) cost difference will certainly remain an important factor,			
Import routes	Hydrogen	N/A	H_2 transport via pipelines (from Eastern Europe or North Africa) and/or ships from other countries (liquefied H_2). Lower pipeline transport costs from neighboring regions potentially counterbalanced by lower production costs in other regions.		
	Derivatives	NH_3 imports via ships to use existing infrastructure. PtL import via ships due to limited volumes for pipeline transport & to use existing infrastructure.	PtL import via ships due to limited volumes for pipeline transport to use existing infrastructure.	NH_3 imports via ships to use existing infrastructure.	Limited SNG imports through existing gas infrastructure (pipelines and/or LNG terminals).

	Pathway 1 - imported liquids	**Pathway 2 - NH_3 domestic**	**Pathway 3 - PtL domestic**	**Pathway 4 – NH_3 & PtL domestic**
Entry points	Imports of ammonia through ships to any of the coastal MSs using existing facilities. Imports of PtLs distributed in current fuel terminals.	Import of CGH_2 through pipelines from Eastern Europe / North Africa – 1 to 2 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE. Imports of PtLs distributed in current fuel terminals.	Import of CGH_2 through pipelines from Eastern Europe / North Africa – 3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Imports of ammonia through ships to any of the coastal MSs using existing facilities.	Import of CGH_2 through pipelines from Eastern Europe / North Africa - 3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Minimal imports of SNG injected into existing gas infrastructure or liquefied in terminals.
Impact on import infrastructure	Hydrogen trade mainly between EU Member States, no need for LH_2 terminals or import pipelines. Ammonia imported via ships using existing port facilities, likely only limited new infrastructure needed. Imports of PtLs distributed in current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Import through pipelines would use 1-2 pipelines. Otherwise, 1-2 LH_2 terminals (less likely). Imports of PtLs distributed over current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Import through pipelines would use 4-5 pipelines. Otherwise, 5-6 LH_2 terminals (less likely). Ammonia imported via ships using existing port facilities, likely only limited infrastructure needed. No PtL imports, thus no terminals required.	Import through pipelines would use 3-6 pipelines. Otherwise, 7-8 LH_2 terminals (less likely). SNG injected in existing NG infrastructure
Impact on storage	No need for additional NH_3 or PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. At least 1.25 TWh of liquefied H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 3 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional NH_3 storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H_2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 4 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No additional need for SNG storage in existing LNG terminals.

5.3.2.1 Possible entry points

Until 2030, entry points for imported hydrogen and derivatives through ships will most likely be located at the main existing consumption areas for hydrogen and derivatives near the coast. On the mid-term horizon of the pathways this seems realistic:

- Among the industry to switch from fossil-based H_2 to electricity-based H_2, the refining industry is heavily present along the coasts[273]
- In Western European countries (DK, DE, NL, BE, FR, ES, PT), the fertiliser sector[274] (incl. ammonia-based) is often localised nearby the same ports as refineries (see section 5.1.1)

Next to existing hydrogen demand, new demand would be driven by the following sectors:

- Steel (map of production sites[275] and producers announcing H_2 use[276]): in Sweden, the Netherlands, Belgium, France, Germany, Spain
- Cement: Norway[277], Germany[278], Spain[279] & others expected
- Transport: regions with significant users, mostly likely serving heavy duty or public transport. More distributed use than industry

The new demand for these sectors could require additional transport infrastructure for hydrogen and derivatives. However, it is likely that the plants located close to shore would first use hydrogen. Thus, industry would probably deploy H_2 near existing clusters (also close to the coast), while others that are far from clusters with existing demand would probably be connected via a direct pipeline (e.g. HYBRIT project).

Section 5.2 indicates that there is an overlap in the supply price ranges between domestic and imported hydrogen, as well as between domestic and imported derivatives. Therefore, there is still uncertainty regarding what the actual supply routes for liquefied hydrogen imports will be. Nonetheless, chapter 3 indicates that for imports, due to the ease and lower cost of transport derivative imports could have an advantage over liquefied hydrogen imports. Therefore, in case hydrogen imports take place in the future, these could happen through pipelines from neighbouring regions.

Intra-EU, for transport distances of up to even 3,000 km, pipelines could remain more attractive for H_2 transport, and will be deployed by then. In case the development of a hydrogen backbone is too slow due to e.g. coordination and planning issues, lack of gas infrastructure to be converted, or would appear unattractive from an economic point of view for intra-EU trade for very long distances, H_2 trade could take place through terminals (either repurposed LNG or new). Given the scope of the study, the development of a domestic hydrogen backbone is not discussed further, but several recent studies address it, among which the one supporting the impact assessment of the Hydrogen and Decarbonised gas Market Package.[280]

[273] See map of refineries: https://www.concawe.eu/refineries-map/

[274] See map of fertilisers in EU: https://www.fertilizerseurope.com/fertilizers-in-europe/map-of-major-fertilizer-plants-in-europe/

[275] https://www.eurofer.eu/assets/Uploads/Slide1.PNG

[276] https://bellona.org/news/climate-change/2021-03-hydrogen-in-steel-production-what-is-happening-in-europe-part-one

[277] https://www.hc-ne.com/en/hydrogen-suppliers-selected-to-the-worlds-first-zero-emission-bulkship

[278] https://www.h2bulletin.com/cemex-announces-plans-for-its-european-cement-plant/

[279] https://www.cemex.com/-/cemex-successfully-deploys-hydrogen-based-ground-breaking-technology

[280] Artelys (2021) METIS study on costs and benefits of a pan-European hydrogen infrastructure

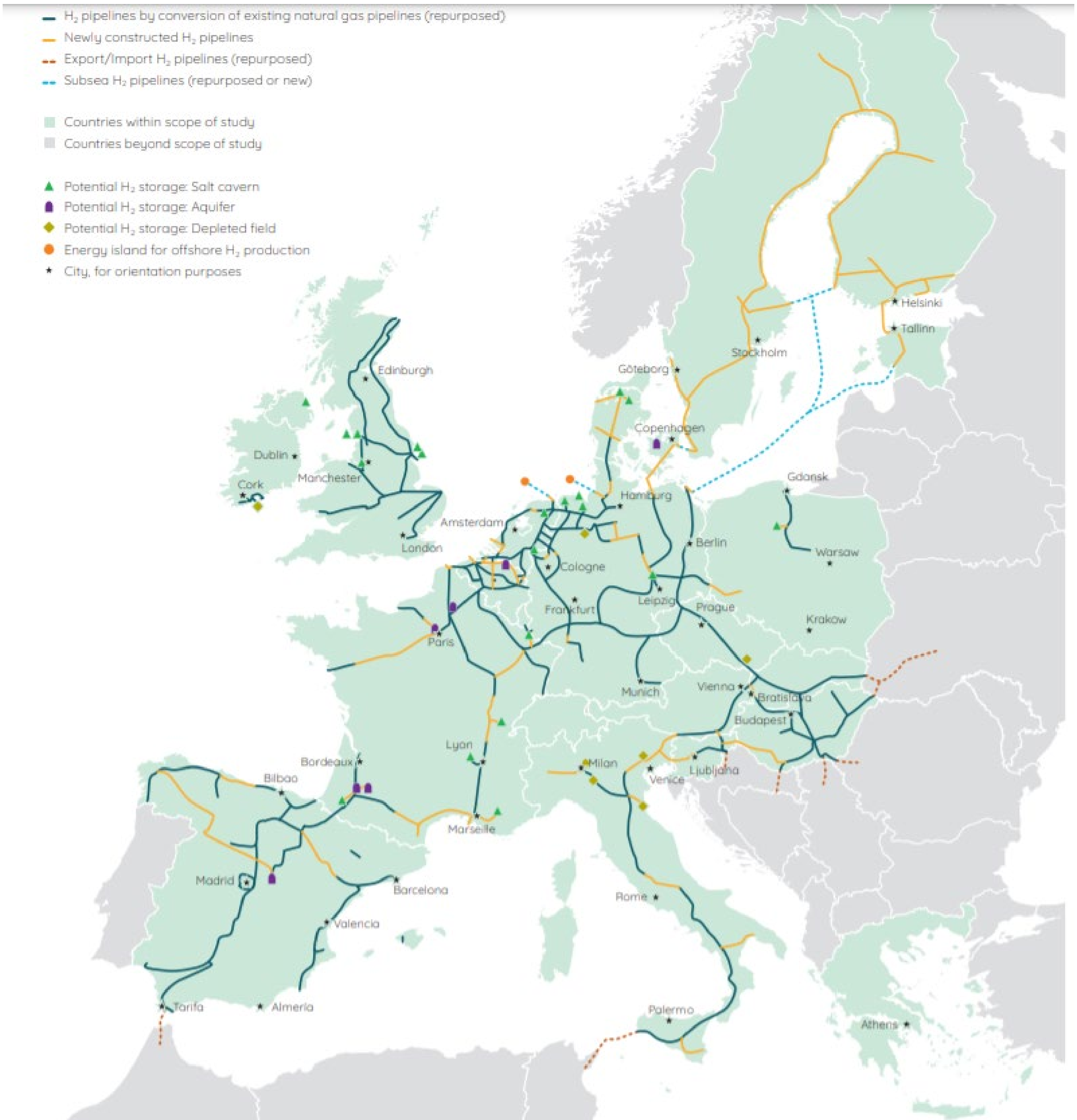
For gaseous hydrogen through pipelines from non-EU Eastern European or North African countries, the entry points should be in the majority of cases the nearest Member State. Repurposed pipeline would provide gaseous hydrogen to the Member States they currently supply, for example Slovakia or Germany.

The European Hydrogen Backbone[281] and the METIS hydrogen[282] studies can be a starting point to identify possible terminal or import pipeline entry points from where the hydrogen could be further distributed inland through dedicated pipelines. Here, several European ports and inland entry points could be used to import liquefied hydrogen, while gaseous hydrogen could be imported through Slovakia, Hungary, Italy or Spain. Small import volumes could be delivered to the main consuming regions such as CWE, while in case of more significant hydrogen imports these could be supplied to a larger number of Member States.

[281] https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/

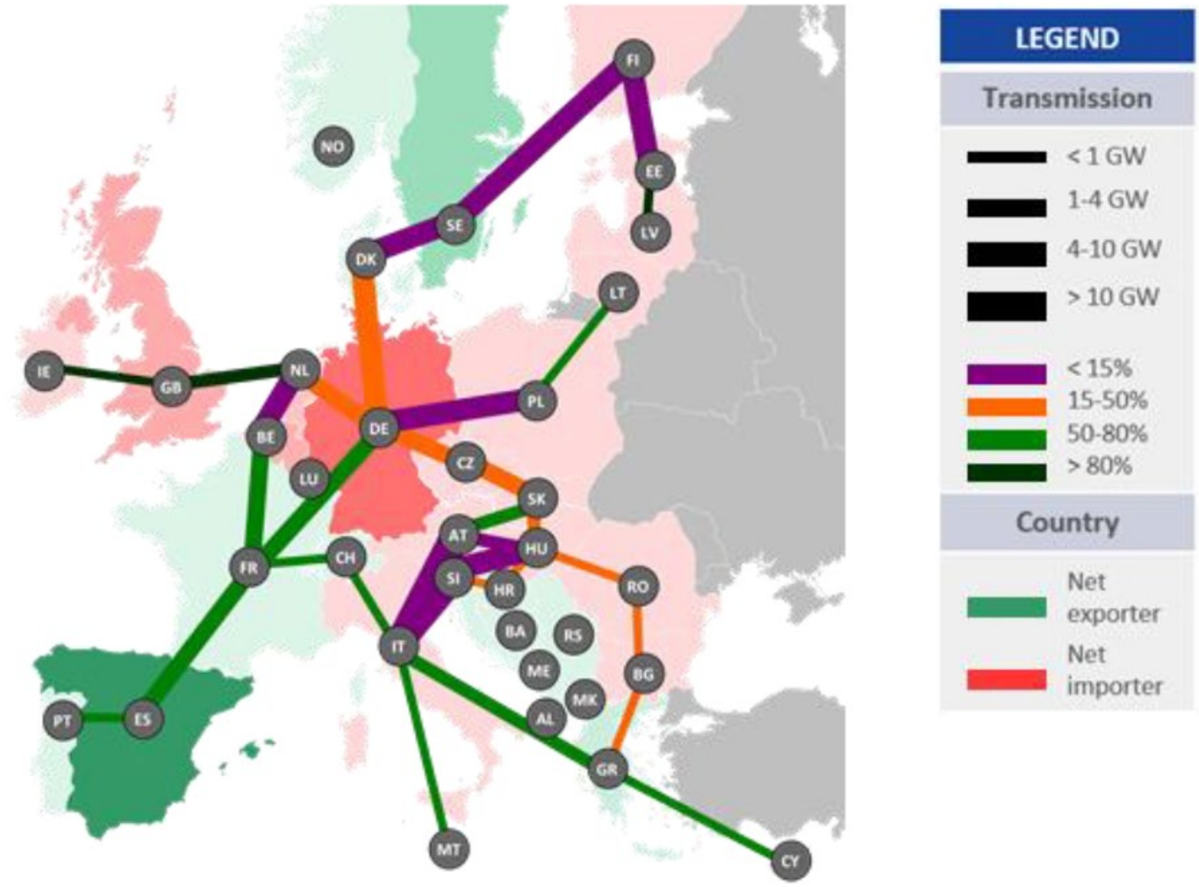
[282] Artelys (2021) METIS study on costs and benefits of a pan-European hydrogen infrastructure

Figure 59 Possible European Hydrogen Backbone study configuration by 2035



Source: https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/

Figure 60 Optimised cross-border hydrogen interconnection capacities in 2030 of the METIS hydrogen study



Source : Artelys (2021) METIS study on costs and benefits of a pan-European hydrogen infrastructure

Therefore, the entry points for the different pathways could be as follows:

Table 40 Pathways assessment regarding possible entry points

Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
Imports of ammonia through ships to any of the coastal MSs using existing facilities. Imports of PtLs distributed in current fuel terminals.	Import through pipelines from Eastern Europe / North Africa – 1 to 2 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE. Imports of PtLs distributed in current fuel terminals.	Import through pipelines from Eastern Europe / North Africa – 3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Imports of ammonia through ships to any of the coastal MSs using existing facilities.	Import through pipelines from Eastern Europe / North Africa - 3 to 6 pipelines to be repurposed. Alternatively (but less likely), import of liquefied H_2 in CWE, ES, IT. Minimal imports of SNG injected into existing gas infrastructure or liquefied in terminals.

5.3.2.2 Expected impact on import infrastructure

This section analyses the expected impact of this pathway on the import infrastructure.

The need for import infrastructure depends on the following factors:

- The type of carrier (CGH_2, LH_2, SNG, PtL, NH_3)
- The demand/supply volume gaps at MS level
- The trade route (ship/pipeline), which is based on the existence of infrastructure and the distance
    - for shipping the chain is complete and comprises export terminal, transport and import terminal;
    - for pipelines, there is no import terminal, nor export terminal, but only storage on production side, and/or on demand side (primary storage).

Existing gas pipelines from Eastern Europe and North Africa (see the Hydrogen Backbone figure above) can be repurposed for gaseous hydrogen imports in pathways where these are anticipated. The average capacity for a typical pipeline of 36 inch diameters is 42 TWh / year (4.7GW at LVH) at 100% utilisation[283], which means that there are at least 3 pipelines needed per ~100 TWh of demand, assuming that utilisation is less than 100%. **In high pure hydrogen import pathways (pathways 3 & 4), 3 to 6 hydrogen pipelines would need to be repurposed or built from scratch.**

If hydrogen imports take place through ships rather than pipelines, around 4 terminals would be needed to import 100 TWh of liquefied hydrogen. Currently operating LNG terminals across the EU have a send-out capacity of 89 TWh/year,[284] which translates into ca. 29 TWh/year of hydrogen send-out capacity considering the density properties of hydrogen (one third of that of LNG). Given that the send-out capacity at these terminals might not be fully utilized, 4 terminals at least might be needed to import each 100 TWh of LH_2.

The terminals identified in, or close to the potential importing countries that are best situated to import the needed quantities are the following:

- Belgium: Zeebrugge
- Netherlands: Gate
- Germany: Wilhelmshaven, Brunsbuettel (both potentially built directly as H_2/derivative import terminals)
- France: Dunkerque

These terminals are located in 'first-mover' regions given the existence of projects for renewable hydrogen (domestic and imported), existing hydrogen network and (fossil) hydrogen consumption. As renewable hydrogen consumption develops in other regions there will be an opportunity to establish import capacities more distributed throughout the EU in the pathways with significant hydrogen imports.

Developing hydrogen terminals through the repurposing of LNG terminals should be more advantageous compared to new builds, but not as much as in the case of pipelines, due to the differences in (re)conversion and transport of hydrogen vs LNG (see chapter 2). Below we show a map of where existing and planned LNG terminals are located in Europe, as indication for where import infrastructure could be developed and repurposed for H_2 imports.

[283] Guidehouse & Gas for Climate (2021): Analysing future demand, supply and transport of hydrogen

[284] TYNDP 2020 Annex C.1 – Capacities per IP of TYNDP 2020

Figure 61 LNG terminals in Europe in 2019

Source: European Commission

For ammonia imports, existing import facilities located throughout the EU could be used, although some investments in additional import capacity might be needed. Ammonia can be imported via ships in semi-refrigerated or refrigerated gas carriers to existing import facilities, or terminals that are part of ammonia/fertilizer plants and are located at the coast and are equipped for transhipment of fertilizers and ammonia. Ammonia imports to Europe in 2019 amounted to around 4.4 Mt, or 0.8 Mt-H_{2eq}.[285] Several Member States already have terminals capable of importing ammonia, with Figure 62 showing over 15 ammonia import facilities in Europe. This means that it is possible no new infrastructure would be needed to receive ammonia volumes of up to 1.5 Mt-H_{2eq} in 2030, depending on the distribution of imports. But in reality, some investments in new import capacity are already being considered, for example in the port of Rotterdam.[286]

[285] Ammonfuel – An industrial view of ammonia as a marine fuel (2020)

[286] https://www.portofrotterdam.com/en/news-and-press-releases/horisont-energi-and-port-of-rotterdam-sign-memorandum-of-understanding

Figure 62 Ammonia terminals in Europe[287]

[287] Ammonfuel – An industrial view of ammonia as a marine fuel (2020)

Southern Europe

Source: Alfa Laval et al. (2020) Ammonfuel – an industrial view of ammonia as a marine fuel, based on Fertecon IHS Markit

For PtLs, 3-4 terminals could satisfy the needs in any pathway. An average capacity of ca. 2 million cubic meters per liquid fuels terminal (based on the VOPAK terminal's size in Rotterdam which has a capacity of 4 million m^3) [288] would lead to a capacity of around 1.6 Mtoe[289]. There would be no adaptations or refurbishments needed besides the purging of pipelines and containers for the PtLs in these terminals.

There are only few concrete plans laid out for new H_2 and derivatives terminals to date, one is for the port of Wilhelmshaven in Germany which is intended to be a national hub for hydrogen. The terminal will be equipped with an ammonia cracking facility for renewable H_2 production and will be connected to the planned German Hydrogen network[290].

For PtLs, pipeline imports would likely not take place to a significant extent. Figure 63 presents the existing crude oil and oil product pipelines in operation in Europe in 2017. It shows there are no pipelines for imports of oil products from non-EU Member States, except for a Hungary-Ukraine pipeline. Moreover, there are three oil pipeline entry points to the EU for importing Russian crude oil. However, while some of the crude oil import pipelines could be repurposed for the import of PtLs, their capacity is significantly higher than the highest PtL import demand in any pathway (10 Mtoe, or 116 TWh, in pathways 1 and 2). In comparison, the main oil import pipeline to the EU (the Druzhba pipeline) has a capacity of over 600 TWh.

[288] Vopak Terminal Europoort (Rotterdam) | Royal Vopak. https://www.vopak.com/terminals/vopak-terminal-europoort-rotterdam?language_content_entity=en

[289] Assuming an energy density of 0.79 toe/m^3 for synthetic gasoline, similar to fossil gasoline

[290] Uniper Plans to Make Wilhelmshaven a Hub for Climate friendly Hydrogen

Figure 63 Crude oil and oil products pipelines in Europe[291]

Nonetheless, research and initial technical screening shows that oil infrastructure and existing off-shore and onshore pipelines could also be reused for derivatives imports after a requalification process[292].

Based on these aspects and the fact that under any scenario the quantity of hydrogen or derivatives imported is limited, the number of terminals necessary to enable the imports will remain limited. The types of terminals will depend on which specific energy carrier is imported.

Table 41 Pathways assessment regarding expected impacts on import infrastructure

Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
Hydrogen trade mainly between EU Member States, no need for LH_2 terminals or import pipelines.	Import through pipelines would use 1-2 pipelines. Otherwise, 1-2 LH_2 terminals (less likely).	Import through pipelines would use 4-5 pipelines. Otherwise, 5-6 LH_2 terminals (less likely).	Import through pipelines would use 3-6 pipelines. Otherwise, 7-8 LH_2 terminals (less likely).

[291] CIEP (2017) The European Refining Sector – a Diversity of Markets?

[292] DNV (2021): Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe

Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
Ammonia imported via ships using existing port facilities, likely only limited new infrastructure needed. Imports of PtLs distributed in current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Imports of PtLs distributed in current fuel terminals, no adaptations necessary. 3-4 terminals could satisfy needs.	Ammonia imported via ships using existing port facilities, likely only limited new infrastructure needed. No PtL imports, thus no terminals required.	SNG injected in existing NG infrastructure.

5.3.2.3 Expected impact on storage infrastructure

Each pathway impacts not only the need for import infrastructure, but also storage. This section summarises the need for hydrogen and derivatives storage, be it underground, in import/export terminals through tanks, or other above ground storage (for example, located on-site at electrolyser plants or end-consumers). More details on hydrogen and derivative storage can be found in chapter 4.

The localisation of primary storage depends on a number of factors, namely:

1) **The hydrogen supply source,** as e.g. hydrogen and derivative imports through terminals will require storage at the terminal, while pipeline imports or domestic supply may require only underground storage or located at end-user / transhipment (modal exchange) sites;
2) **The demand for different hydrogen storage services:** as shown in chapter 4, the need for storage may arise from the need to manage the supply (and in later development stages also the demand) variability, but also storage may be directly needed for modal exchanges;'
3) **The deployment of (gaseous hydrogen) interconnectors** connecting various industrial clusters and other H_2 consumption areas: as more hydrogen supply and demand is interconnected, there will be lower correlation between supply and demand profiles reducing flexibility needs. Moreover, interconnection will allow for integration of a greater number of flexibility resources, including storages.
4) The **potential for underground hydrogen storage,** which, as demonstrated in chapter 4, is the most economical storage option for gaseous hydrogen but whose potential varies across the EU;

To analyse the impact on storage infrastructure, it is important to differentiate the different possible storage types and locations. Storage of hydrogen could be located first **at dedicated underground storage facilities** connected to hydrogen networks nearby (industrial) demand sites in Central-Western Europe, which also has most of salt caverns used for gas storage currently.

Storage would also be **located at import terminals**, serving primarily to store hydrogen and derivatives after off-loading. Any spare storage capacity not needed for the bundled product offerings could be offered separately, i.e. as an unbundled product. Hydrogen and derivatives stored in import-focused terminals could be shipped by networks, used to fuel ships, be distributed on site for consumption in industry or distributed by trucks, barges and rail. These ports could be located in Central-Western Europe (e.g. Germany, the Netherlands, Belgium, France).

Storage could also be located at **transhipment facilities**, i.e. whenever hydrogen and derivatives are loaded into a different transport mode (e.g. into and off trains). Finally, storage could be located at **hydrogen and derivatives supply locations**, for example in electrolysis plants, to manage the variability of supply prior to shipping the hydrogen products, or **at end-user sites,** to match demand and supply, reduce own imbalances and increase security of supply, in case those responsibilities are not placed elsewhere.

The **need for gaseous hydrogen storage** within the EU will depend on the level of interconnection between national hydrogen systems, as well as availability of other flexibility sources. In the METIS scenarios, **storage capacities range from 20.8 TWh in the BAU scenario (with the lowest hydrogen interconnection level) to 17.7 TWh in the H2-B optimised scenario** (with the highest interconnection level). With the typical salt cavern hydrogen storage capacity used in chapter 4 of 0.2 TWh_{hhv}, this means almost 90 salt caverns would be needed across the EU27 to meet the storage needs from domestic production in the H2-B optimised scenario. This figure could be lower with somewhat higher average salt cavern storage capacities, but tens of caverns would likely be needed. These would be concentrated in the Member States with the highest storage needs due to being significant exporters or consumers (DE, ES, FR, GR, NL, PL, PT).

Higher hydrogen systems interconnection levels decrease the total domestic storage needs, as shown in the METIS results**.** The utilisation of the storages[293] is rather constant, of around 2 full-load cycles per year, for all scenarios). Given it is unlikely the storages would be simply fully filled and emptied twice a year, the actual number of storage cycles per year would be higher, indicating that the storages satisfy not only the need for seasonal flexibility, but also for shorter-term (weekly and daily) flexibility.

In none of the pathways the underground hydrogen storage needs should surpass the estimates of the METIS scenarios. The METIS scenarios assume a domestic production and consumption of 6 Mt of pure hydrogen. In no pathway the sum of pure hydrogen domestic production and imports surpasses this volume. Assuming the domestic production of derivatives from hydrogen would to a large extent be conducted on-site, there would be limited need for underground storage capacities for this hydrogen purposed for transformation. Therefore, underground storage capacity needs should not surpass the 20.8-17.7 TWh estimated. If imports of gaseous hydrogen from Eastern Europe or North Africa take place, this could change the localisation of the storages, with more storages located near entry points to the EU. However, this would be constrained by the availability of salt cavern potentials in those countries. Based on chapter 4, possible hydrogen pipeline entry points which dispose of salt cavern potential comprise Romania, Poland, Spain and Portugal. Other candidate entry points such as Italy, Austria, Slovakia and Bulgaria do not have potential for deployment of salt caverns.

In case of liquefied hydrogen imports, storage would be needed at import terminals. Assuming a LH_2 terminal storage utilisation rate of 50% and a storage/send-out capacity ratio of 2.5% (i.e. a terminal has 2.5 TWh of storage for every 100 TWh/y of send-out capacity)[294], a hydrogen terminal with an annual send-out capacity of 29 TWh (same assumption as for section 5.3.2.3) would have a storage capacity of 0.36 TWh. This would be equivalent to over 40 LH_2 tanks with an individual storage capacity of 9 GWh[295], at a total cost (per terminal) of over 900 M€.

For the import of derivatives (PtLs or ammonia), the existing storage available in import terminals and in the distribution supply chain could be used. Therefore, and considering the limit volumes of PtLs compared to overall fossil-based liquid fuel consumption in the EU**, there should be no need for additional PtL storage capacity in the EU in any pathway.** Likewise, given the limited

293 Calculated dividing the total hydrogen stored per the storage capacity in each Member State

294 The average LNG storage utilisation rate in 2017/2018 was 47-48% for EU LNG terminals. Source: GIE (2021) Aggregated LNG Storage Inventory; TYNDP 2020 Annex C.1 – Capacities per IP of TYNDP 2020

295 See chapter 4 storage technology overview fiche

amounts of renewable ammonia imports under the scenarios and the assumption that ammonia-consuming industry and other end-uses would be located near terminals, **the existing ammonia import terminals' storage capacity should be sufficient.**

Table 42 Pathways assessment regarding potential impacts on storage infrastructure

Pathway 1 - imported liquids	Pathway 2 - NH_3 domestic	Pathway 3 - PtL domestic	Pathway 4 – NH_3 & PtL domestic
No need for additional NH_3 or PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H2 imported by pipelines. At least 1.25 TWh of liquefied H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional PtL storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 3 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No need for additional NH_3 storage in import terminals or downstream of the value chain (besides existing storage for fossil derivatives).	No additional need for H_2 underground storage capacity compared to domestic pathway in case H2 imported by pipelines. Localization might change with higher number of salt cavern storages in ES/PT, RO, PL. Around 4 TWh of H_2 tank storage capacity in terminals if H_2 imports supplied by ship. No additional need for SNG storage in existing LNG terminals

5.3.3 Advantages and disadvantages of the pathways

This section identifies the advantages and disadvantages of the different pathways in terms of (mitigating) risks and the import and storage needs expected under each pathway. This should provide indications of the likelihood of pathway materialising, although there is still high uncertainty for all pathways. **In summary, in regions where a hydrogen backbone is developed in the EU by 2030/2035, pathways importing derivatives such as ammonia or PtLs could be more advantageous due to avoided investment costs in import infrastructure and storage**, as the existing value chain for fossil-based ammonia and liquid fuels could be largely used. **In areas where the hydrogen backbone is inexistent, hydrogen import pathways could be interesting as the hydrogen could then be used in industry and other end-uses near coastal areas**, while domestic PtLs are transported through domestic oil product pipelines or other modes. In the case of **ammonia, imports could also be relevant for supplying industry in coastal areas**, although there are also industries such as fertiliser plants located inland.

Table 43 Advantages and disadvantages of the pathways

<table>
<tr><th></th><th>Pathway 1 - imported liquids</th><th>Pathway 2 - NH_3 domestic</th><th>Pathway 3 - PtL domestic</th><th>Pathway 4 – NH_3 & PtL domestic</th></tr>
<tr><td rowspan="2">Advantages</td><td colspan="4">By opening the possibility to import hydrogen and derivatives, allows access to competitive non-EU supply sources and facilitates development of end-use at lower cost and public support, which may decrease the overall cost of the energy transition
No additional underground H_2 storage needs expected compared to purely domestic pathway due to distribution of end-use consumption across hydrogen and different derivatives</td></tr>
<tr><td>Uses the most economical forms of transport according to carriers and distances
Would facilitate the integration of EU hydrogen markets
Import infrastructure is focused on NH_3 and PtLs, for which terminals already exist
NH_3 import entry points could be focused on existing end-uses</td><td>Does not require additional import infrastructure for PtL imports
Moderate H_2 imports could be focused to supply areas unserved by hydrogen backbone waiting for its expansion
By relying on both domestic and imported H_2, leads to diversification of sources with SoS benefits</td><td>NH_3 import could be focused on existing end-uses
In case EU hydrogen backbone is delayed or some areas unserved, could facilitate H_2 and NH_3 end-use in coastal areas, while domestic PtLs are transported across EU
By relying on both domestic and imported H_2, leads to diversification of sources with SoS benefits</td><td>SNG imports can utilise existing NG infrastructure
In case EU hydrogen backbone is delayed or relevant areas unserved, could facilitate H_2 end-use in coastal areas, while domestic PtLs and NH_3 are transported across EU</td></tr>
<tr><td rowspan="3">Disadvantages</td><td colspan="4">Risk of importing products with high carbon footprint in case of inadequate certification mechanism
Less secure investment climate for imports (compared to sourcing hydrogen and derivatives from EU countries), potentially increasing cost of capital
Lower guarantee of a level playing field for the energy products, possibly hindering investments and security of supply compared to EU supplies</td></tr>
<tr><td>Dependence on development of an EU H_2 backbone</td><td>Dependence on development of an EU H_2 backbone</td><td colspan="2">Focus on domestic PtLs could require larger share of EU renewable electricity production, due to conversion losses</td></tr>
<tr><td></td><td colspan="3">Would require new or repurposed H_2 terminals or import pipelines investments, to different extents. Although this could represent the opportunity to use existing assets.</td></tr>
</table>

6 List of figures

7 List of tables

A.1 Annexes

A.1.1 Annex 1 - Scenario description

European Commission (2021): Impact Assessment Report

Published by: the European Commission (EC), 17.07.2021

Developed by: the European Commission (EC)

Background: To implement the Paris Climate Agreement, the European Commission initiated the European Green Deal (EGD) and, on this basis, the Renewable Energy Directive (RED) and REDII. This report is a revision of the REDII. The overall ambition of this initiative is to ensure that the revised REDII is fit to contribute to the target of a minimum GHG emissions reduction of 55% in 2030, in a cost-effective and sustainable way. This must be done in complementarity with the other initiatives in the "Fit for 55" program and in accordance with other EGD targets and initiatives.

Modelling: The impact assessment builds on a well-established and proven analytical framework for the revision of Effort Sharing Regulation (ESR), Emission Trading Scheme (ETS), CO_2 Standards, land use, land-use, change and forestry (LULUCF), RED and Energy Efficiency Directive (EED). The core models used are PRIMES and PRIMES-TREMOVE for energy, transportation, and CO_2 emission projections. The characteristic of the PRIMES models is the combination of behavioural modelling (based on microeconomic principles) with technical aspects covering all energy sectors and markets. For all non-greenhouse gas emissions and air pollution, the simulation-based model GAINS is implemented. This also covers the health and ecosystem sectors. For LULUCF emissions, the GLOBIOM-G4M model is used, while the CAPRI model is used for agricultural activity protection. For the analysis, interactions between the individual models have been taken into consideration. The geographical scope of the model is the EU-27 plus the UK, while the focus of the analysis is the EU-27.

Scenario description: This assessment focuses on three core scenarios (REG, MIX and MIX-CP), which all achieve the target of 55% GHG reduction in 2030 and result with the cost-effective range for renewable energy sources (RES) shares of 38-40% in 2030 (already established in the Climate Target Plan impact assessment). These core scenarios are intended to provide consistency among the various impact assessments for the "Fit for 55" package. Variant scenarios are developed for the assessment of specific options, one of which is selected for the analysis in this study:

- **EC MIX-H_2 scenario:** It is one variant building on the MIX scenario, a core and central scenario relying on carbon price signal extending to road transport and buildings and strengthening energy and transport policies. The MIX-H_2 scenario helps to assess policy options regarding the promotion of renewable fuels of non-biological origin (RFNBOs) in industry and transport. In comparison to the core scenarios, MIX-H_2 illustrates a high uptake of hydrogen in final energy demand sectors in 2030. The scenario aligned with the goal of 40 GW electrolyser capacity in the EU in 2030 set in the Hydrogen Strategy and takes into account the national hydrogen strategies and "Opportunities for Hydrogen Energy Technologies considering the NECPs"[296].

Hydrogen assumptions: Only green hydrogen production is considered and is produced exclusively in the EU (including UK) with the electrolyser capacity of 47 GW in 2030. Carbon capture and storage (CCS) is only implemented to a very limited extent and not for hydrogen production.

[296] https://www.fch.europa.eu/publications/opportunities-hydrogen-energy-technologies-considering-national-energy-climate-plans

Climate Action Network Europe (2020): Building a Paris Agreement Compatible (PAC) energy scenario

Published by: Climate Action Network (CAN) Europe, June 2020

Developed by: Climate Action Network (CAN) Europe and European Environmental Bureau (EEB)

Background: The PAC Scenario is the first comprehensive climate and energy roadmap for European policymakers drafted by a broad range of civil society organisations. It reflects non-government organisations (NGOs´) priorities for an ambition yet credible pathway towards the 1.5°C target of the Paris Agreement. The scenario illustrates a pathway for the transition of the European energy system that is in line with the EU's commitment to the Paris Agreement.

Modelling: This study refers to a summary of an open learning process, in which the reported statistics are based on secondary research figures from a variety of studies and models. The PAC scenario reflects a collective bottom-up research process in which the different studies were compared with each other. Up to 150 representatives from organizations, industry and science collaborated in this process, especially regarding the key assumptions. The Priorities of the individual NGOs for the 1.5°C target of the Paris Agreement were considered. The geographical scope of the study is the EU-27 plus the UK.

Scenario description: The present study assesses one scenario that illustrates a roadmap for the transition of the European energy system and is in line with EU leaders´ commitment to the Paris Agreement. The PAC scenario shows that the current level of ambition can be raised substantially.

- **PAC scenario:** The results of the scenario show that the EU 2030 targets can be more ambitious. Compared to 1990 the EU target of reducing GHG emissions can be adjusted to 65%. The current EU energy efficiency target of 32.5% is suggested to be raised to 45%. As for the current EU renewable energy target, the share of renewable energy sources in gross final energy consumption can be increased from 32% to at least 50%, of which very limited bioenergy potential is predefined following the feedbacks from members and experts.

Hydrogen assumptions: Exclusively green hydrogen and its derivative are considered in the study, which is produced within the EU. Although no information regarding electrolyser capacity is given, the supply of renewable hydrogen and its derivatives of 566 TWh discloses an electrolyser capacity of more than 40 GW in 2030. It is assumed that neither CCS nor carbon capture and utilization (CCU) technologies is introduced.

ENTSO-E and ENTSO-G (2020): TYNDP 2020 Scenario Report

Published by: ENTSO-E and ENTSOG, in June 2020

Developed by: ENTSO-E and ENTSOG

Background: According to the Regulation (EU) 347/2013, ENTSO-E and ENTSOG are obligated to use scenarios as the basis for the bi-annual official publication of Ten-Year Network Development Plan (TYNDP). The scenarios are also used for the calculation of the cost-benefit analysis, which is used to determine EU funding for electricity and gas infrastructure Projects of Common Interest. The European and global perspectives for these scenarios enable the user to track supply and demand developments geographically as well as the temporally and to gain greater insight into challenges facing energy infrastructure during the Energy Transition.

Modelling: A core element of the ENTSO-E and ENTSOG scenario development process has been the use of supply and demand data, collected from both gas and electricity transmission system operators, through a bottom-up approach. By considering national and EU climate targets, in particular the National Energy and Climate Plans (NECPs), these strategies are used for the National

Trends (NT) scenario, the central policy scenario of this report. With a view to the 1.5°C target of the Paris Agreement, the ENTSOs have also developed the Global Ambition (GA) and Distributed Energy (DE) scenarios that take a top-down approach based on historical energy balance data with a comprehensive energy perspective. The geographical scope of the report is the EU-27 plus the UK.

Scenario description: The TYNDP 2020 scenario analysis is built based on three scenarios, with two main drivers in the storyline development being decarbonisation and centralised or decentralised innovation. One scenario, National Trends (NT), focuses on the NECPs and further national policies and climate targets through a bottom-up approach. The other two scenarios, Global Ambition (GA) and Distributed Energy (DE), are compliant with the 1.5°C target of the Paris Agreement with consideration of the EU's climate targets for 2030. These two scenarios are differentiated by their focuses of centralised generation (GA) and decentralised energy transition approach (DE). For the short- and mid-term development, the scenarios include a so-called "Best Estimate" scenario. For the long-term development, they are based on different storylines to reflect the increasing uncertainties. Only one of these three scenarios is selected for the analysis, as the other two have less than 40 GW electrolyser installed in 2030:

- **ENTSO DE scenario:** The scenario is compliant with the 1.5°C target of the Paris Agreement and considers the EU´s climate target for 2030. A key feature for the decentralised approach to the energy system is the role of an energy consumer, who actively participates in the energy market and helps to drive the decarbonisation of the system by investing in small-scale solutions and circular concepts. Most of the parameters used for the scenario refer to the 1.5 TECH/LIFE scenarios from the European Commission.

Hydrogen assumptions: Both green and blue hydrogen production is considered for the scenario, which implies the implementation of CCS technology. Beside hydrogen supply within the EU, import of hydrogen and its derivative (most likely in form of LNG from Russia and Norway) was taken into account. The installed electrolyser capacity in 2030 in the DE scenario amounts to 41 GW.

Joint Research Centre (2021): Global Energy and Climate Outlook 2020: A New Normal Beyond Covid-19

Published by: Joint Research Centre (JRC) of the European Commission, in 2021

Developed by: Joint Research Centre (JRC) of the European Commission

Background: This report is the sixth edition of the Global Energy and Climate Outlook (GECO). It contributes to the JRC work in the context of the United Nations Framework Convention on Climate Change (UNFCCC) policy process and Intergovernmental Panel on Climate Change (IPCC) assessment reports. The report also considers the impact of the Covid-19 pandemic for the global energy demand, the related GHG emissions and how it changed the efforts for the transition towards a low-carbon economy in the coming decades.

Modelling: The GECO analysis is built on the JRC-POLES and JRC-GEM-E3 models. In addition to the results on all energy sources, sectors, and GHG emissions, the models estimated of the trends in international energy prices and trade used in the EC energy modelling. JRC-POLES covers the entire globe, divided into 66 regions, including the EU-27 and the UK. GHG emissions from agriculture and LUFUCF are derived from GOBIOM-G4M lookup tables. Although it is a global model, detailed breakdown of data to the EU-27 is available.

Scenario description: Four scenarios are developed in this report. A baseline scenario (Base_noC19) focusing the development would have been, if no Covid-1919 pandemic did happen. Secondly, a "New Normal" scenario is built from the GECO 2019 Reference scenario, reflecting mainly the immediate effects on key macroeconomic parameters caused by of the Covid-19 pandemic. Lastly, the 2°C and 1.5°C scenarios are departing from the New Normal with additional climate policies, aiming at the compliance with the Paris Agreement. The 1.5°C scenario was selected for the analysis in this study, as it is in line with the climate neutrality target in the EU and considers the EU Hydrogen Strategy.

- **JRC 1.5 scenario:** It includes policies from the New Normal scenario and an economy-wide carbon price. Therefore, the country-specific policies of the New Normal scenario from the 2019 GECO Reference scenario were removed to provide a homogeneous policy driver to which all countries are subjected.

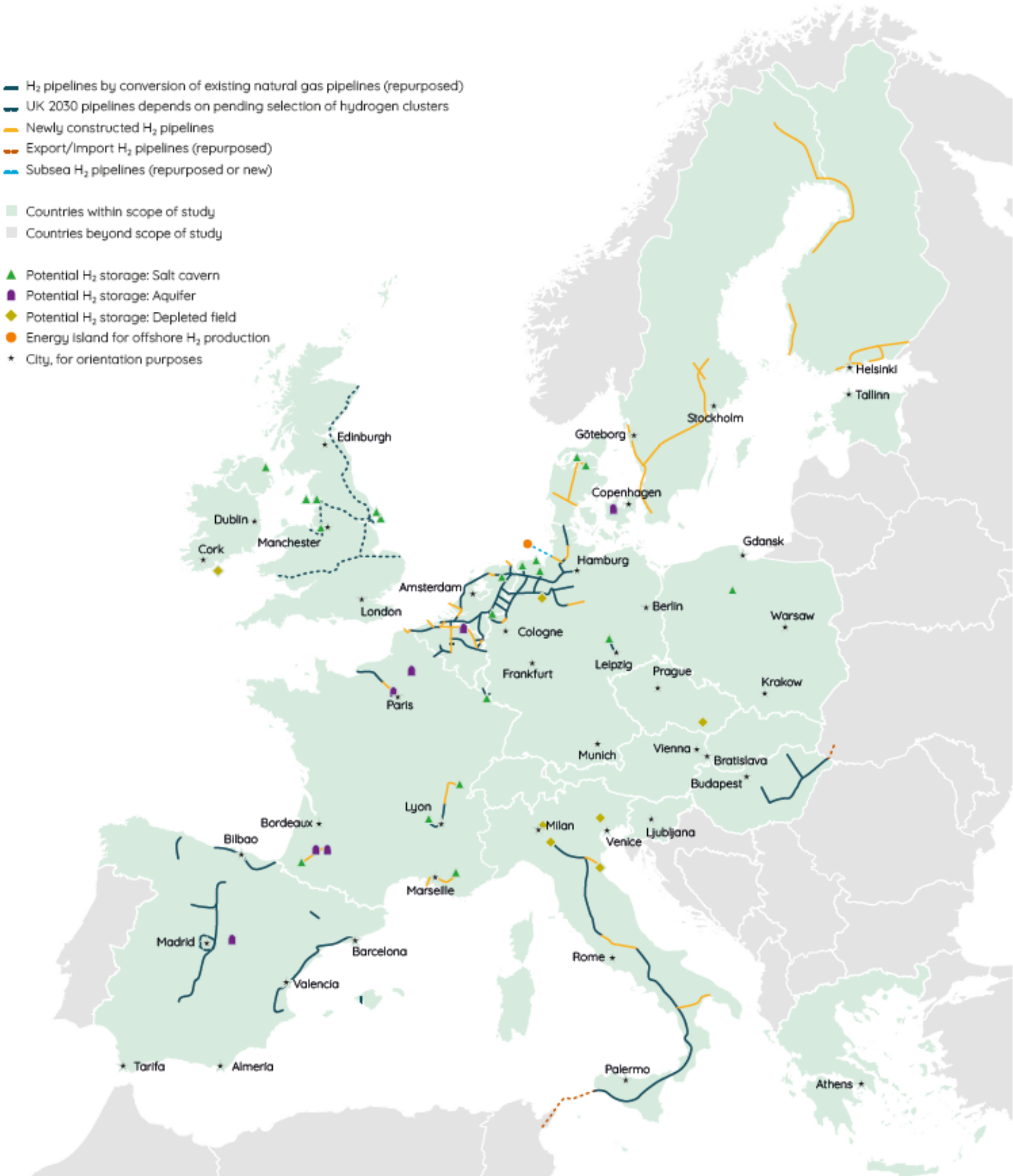
Hydrogen assumptions: The considered shade of hydrogen does not limit to green. The CCS technology is implemented mainly in the field of power generation of coal, gas and biomass. Since it is a global model, information regarding domestic production and import of hydrogen and its derivative is not specified. As mentioned, the selected scenario considers the EU Hydrogen Strategy and therefore it can be assumed that the installed electrolyser capacity fulfils the target of 40 GW in 2030.

A.1.2 Annex 2 - Development a European Hydrogen Backbone

In the following the development of a pipeline-bound infrastructure for hydrogen in the EU as well as for import from neighboring countries is presented. It is based on a publication by European gas network operators.

The hydrogen Backbone connects industrial clusters to an emerging infrastructure by 2030. Separated hydrogen networks can develop, consisting mainly of repurposed existing natural gas pipelines. The initial stretches include the proposed Dutch and German national backbones. The initial hydrogen grid provides only two repurposed Export/Import H_2 pipelines.

Figure 64 Emerging European Hydrogen Backbone in 2030



Source: [European Hydrogen Backbone 2021]

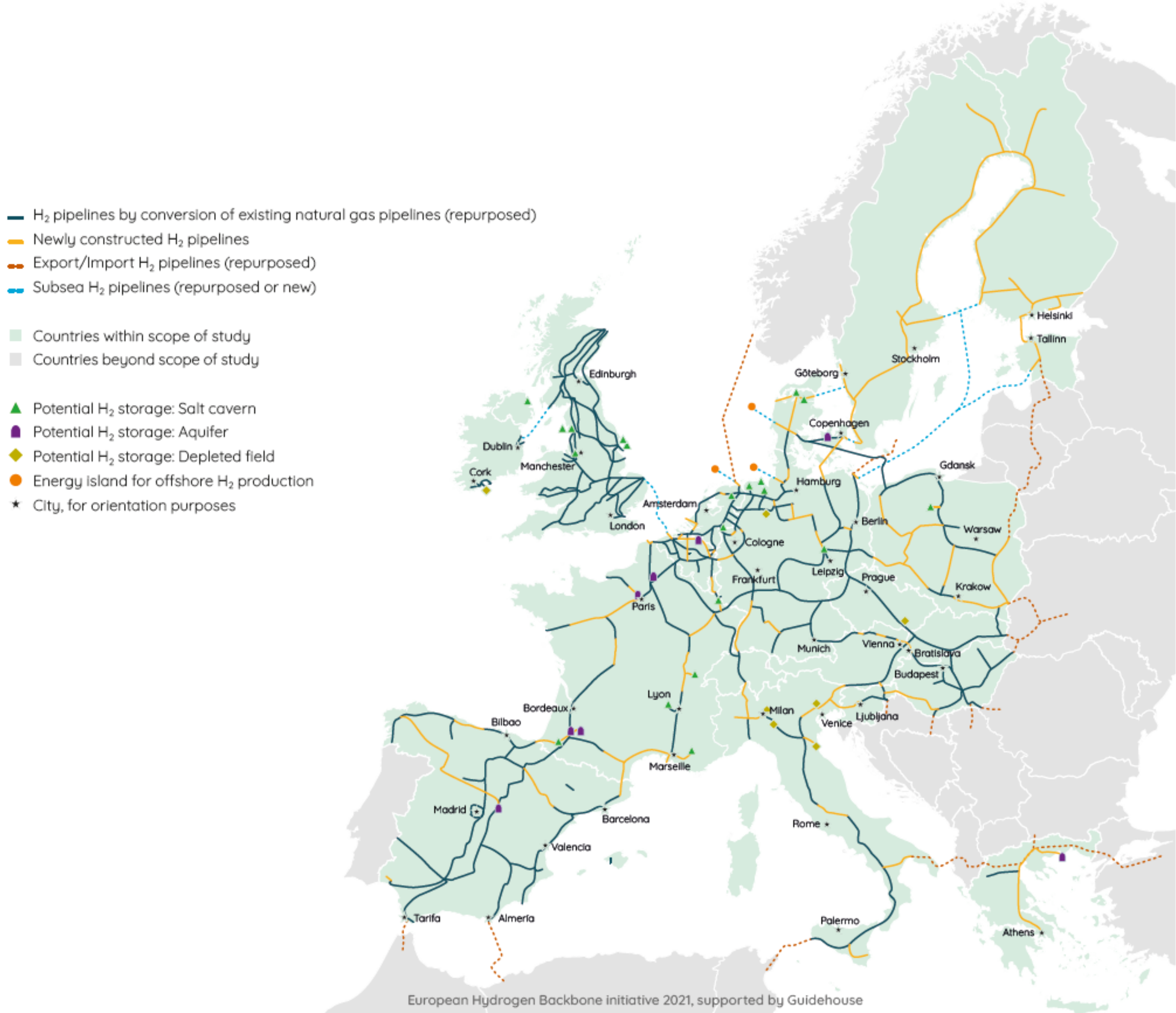
The growing network covers more countries and enables imports by 2035. It is covering more regions and developing new interconnections across Member States. Pipeline transport will be valuable to connect regions with abundant solar PV and wind potential with energy demand centres, including areas which are out of reach for power transmission infrastructure. In 2035 the backbone provides several import/export H_2 pipelines.

Figure 65 Growing network covering more countries in 2035

Source: [European Hydrogen Backbone 2021]

The “Mature infrastructure stretching towards all directions” by 2040. Pan-European dedicated hydrogen transport infrastructure can be envisaged with a total length of around 39,700 km. The grid consists of 69% repurposed existing infrastructure and 31% of new hydrogen pipelines. It would also allow pipeline imports from Europe’s eastern and southern neighbours, as well as imports of liquid hydrogen from other continents via Europe’s main ports.

Figure 66 Mature European Hydrogen Backbone can be created by 2040



Source: [European Hydrogen Backbone 2021]

The following figures refer to those published in Hydrogen Backbone. Cost estimates for CAPEX and OPEX of the H_2 transport infrastructure in the 2040 scenario in three variants (depending on input data) are presented.

Table 44 **Cost input ranges for estimating total investment, operating, and maintenance costs for hydrogen infrastructure. Adapted from the original European Hydrogen Backbone Report (2020)**

Cost parameter				Unit	Low	Medium	High
Pipeline Capex, new	Small	< 700 mm	< 28 inch	M€/km	1.4	1.5	1.8
	Medium	700-950 mm	28-37 inch		2.0	2.2	2.7
	Large	> 950 mm	> 37 inch		2.5	2.8	3.4
Pipeline Capex, repurposed	Small	< 700 mm	< 28 inch		0.2	0.3	0.5
	Medium	700-950 mm	28-37 inch		0.2	0.4	0.5
	Large	> 950 mm	> 37 inch		0.3	0.5	0.6
Compressor station Capex				M€/MW_e	2.2	3.4	6.7
Electricity price				€/MWh	40	50	90
Depreciation period pipelines				Years		30-55	
Depreciation period compressors						15-33	
Weighted average cost of capital				%		5-7%	
Operating & maintenance costs (excluding electricity)				€/year as a % of Capex		0.8-1.7%	

Source: [European Hydrogen Backbone 2021]

Table 45 **Estimated investment and operating cost of the European Hydrogen Backbone (2040)**

		Low	Medium	High
Pipeline cost	€ billion	33	41	51
Compression cost	€ billion	10	15	30
Total investment cost	**€ billion**	**43**	**56**	**81**
OPEX (excluding electricity)	€ billion/year	0.8	1.1	1.8
Electricity costs	€ billion/year	0.9	1.1	2.0
Total OPEX	**€ billion/year**	**1.7**	**2.2**	**3.8**

Source: [European Hydrogen Backbone 2021]

MJ-01-22-112-EN-N

ISBN 978-92-76-48847-7

Publications Office
of the European Union