ISSN 1831-9424

European Commission

JRC TECHNICAL REPORT

Assessment of Hydrogen Delivery Options

Feasibility of Transport of Green Hydrogen within Europe

Ortiz Cebolla, R.

Dolci, F.

Weidner, E.

2022

Joint Research Centre

EUR 31199 EN

This publication is a Technical report by the Joint Research Centre (JRC), the European Commission's science and knowledge service. It aims to provide evidence-based scientific support to the European policymaking process. The contents of this publication do not necessarily reflect the position or opinion of the European Commission. Neither the European Commission nor any person acting on behalf of the Commission is responsible for the use that might be made of this publication. For information on the methodology and quality underlying the data used in this publication for which the source is neither Eurostat nor other Commission services, users should contact the referenced source. The designations employed and the presentation of material on the maps do not imply the expression of any opinion whatsoever on the part of the European Union concerning the legal status of any country, territory, city or area or of its authorities, or concerning the delimitation of its frontiers or boundaries.

Contact information
Name: Francesco Dolci
Address: Westerduinweg 3, 1755-LE Petten, The Netherlands
Email: francesco.dolci@ec.europa.eu
Tel.:

EU Science Hub
https://joint-research-centre.ec.europa.eu

JRC 130442

EUR 31199 EN

PDF ISBN 978-92-76-56421-8 ISSN 1831-9424 doi:10.2760/869085 KJ-NA-31-199-EN-N

Luxembourg: Publications Office of the European Union, 2022

© European Union, 2022

The reuse policy of the European Commission documents is implemented by the Commission Decision 2011/833/EU of 12 December 2011 on the reuse of Commission documents (OJ L 330, 14.12.2011, p. 39). Unless otherwise noted, the reuse of this document is authorised under the Creative Commons Attribution 4.0 International (CC BY 4.0) licence (https://creativecommons.org/licenses/by/4.0/). This means that reuse is allowed provided appropriate credit is given and any changes are indicated.

For any use or reproduction of photos or other material that is not owned by the European Union must be sought directly from the copyright holders.
The European Union/European Atomic Energy Community does not own the copyright in relation to the following elements:

- Cover page illustration, © stock.adobe.com
- Figure 2: O. Kruck, F. Crotogino, R. Prelicz, and T. Rudolph, *HyUnder Proj. Deliv. 3.1*, 2013

How to cite this report: Ortiz Cebolla, R., Dolci, F. and Weidner, E., *Assessment of Hydrogen Delivery Options*, Publications Office of the European Union, Luxembourg, 2022, doi:10.2760/869085, JRC130442.

Contents

Abstract

The RePowerEU plan [1] and the European Hydrogen Strategy [2] recognise the important role that the transport of hydrogen will play in enabling the penetration of renewable hydrogen in Europe. To implement the European Hydrogen Strategy it is important to understand whether the transport of hydrogen is cost effective, or whether hydrogen should be produced where it is used. If transporting hydrogen makes sense, a second open question is how long the transport route should be for the cost of the hydrogen to still be competitive with locally produced hydrogen. JRC has performed a comprehensive study regarding the transport of hydrogen. To investigate which renewable hydrogen delivery pathways are favourable in terms of energy demand and costs, JRC has developed a database and an analytical tool to assess each step of the pathways, and used it to assess two case studies. The study reveals that there is no single optimal hydrogen delivery solution across every transport scenario. The most cost effective way to deliver renewable hydrogen depends on distance, amount, final use, and whether there is infrastructure already available. For distances compatible with the European territory, compressed and liquefied hydrogen solutions, and especially compressed hydrogen pipelines, offer lower costs than chemical carriers do. The repurposing of existing natural gas pipelines for hydrogen use is expected to significantly lower the delivery cost, making the pipeline option even more competitive in the future. By contrast, chemical carriers become more competitive the longer the delivery distance (due to their lower transport costs) and open up import options from suppliers located, for example, in Chile or Australia.

Preface

The European Hydrogen strategy recognises the important role [2] the transport of hydrogen will have in enabling the penetration of renewable hydrogen in Europe in the future, and explicitly mentions the import of hydrogen from outside Europe. Moreover, the RePowerEU plan [1] sets a target of 10 million tonnes of renewable hydrogen imports by 2030. JRC is assessing the costs and energy demand of hydrogen transport and distribution for various volumes and distances, allowing for a semi-quantitative ranking of transport options for hydrogen within the chosen set of assumptions [3]. The study considers transport of compressed or liquefied hydrogen, but also by means of liquid hydrogen carriers such as ammonia, methanol or liquid organic hydrogen carriers (LOHC). Each option offers different advantages, for example a good hydrogen storage density (e.g. NH_3, MeOH or LOHC) or better round-trip efficiency (e.g. compressed or liquefied gas). The assessment covers the transport of hydrogen to the demand location through various means, the main options being pipelines, ships, trains or trucks.

The goal of this study is to answer the question whether it is more convenient to produce renewable hydrogen close to the demand location or to transport it from a location where renewable hydrogen production is cheaper. A second point we looked into is how long the transport route can be for the cost of hydrogen to still be cost competitive. To provide these answers a comprehensive analysis of the energy demand and costs involved in the delivery chain for the supply of renewable hydrogen has been performed.

Acknowledgements

The authors would like to thank Christian Weinberger for inspiring this study, and for the guidance and advice provided. The discussions with Paul Hodson and his encouragement have helped to shape and moreover complete this report. Jonathan Davies' scientific proof-reading skills are much appreciated.

We are grateful for the information provided by our contacts in industries developing or selling hydrogen technologies. Comments and suggestions received from experts at IEA, IRENA and SINTEF are gratefully acknowledged.

Authors

Rafael Ortiz Cebolla

Francesco Dolci

Eveline Weidner

1 Introduction

The RePowerEU plan sets an ambitious target of 10 million tonnes of renewable hydrogen imports by 2030 [1]. Already the European Hydrogen strategy [2] had foreseen that hydrogen may have to be transported within Europe, or even imported from the EU's eastern and southern neighbours, which are seen as potential exporters of clean hydrogen to Europe. It is therefore important to understand whether it is cost effective to produce renewable hydrogen where renewable electricity is cheap and then transport it to the customer, or it is better to produce the renewable hydrogen close to the demand location. If transporting hydrogen makes sense, a second open question is how long the transport route should be for the cost of the hydrogen to still be competitive with locally produced hydrogen. The development of an infrastructure connecting areas rich in renewable energy with areas with high demand for hydrogen will need significant investment and should therefore be planned in a coordinated manner, at a European level. As there are multiple options available, it is necessary to investigate their advantages and disadvantages, in order to guide infrastructure development along the most effective path.

JRC has performed a comprehensive study regarding the transport of hydrogen. To investigate which renewable hydrogen delivery pathways are favourable in terms of energy demand and costs, JRC has developed a database and an analytical tool to assess each step of the pathways, and used it to assess two case studies. The first case study is for a simple point A to point B delivery route, assessing shipping and pipeline transport, whereas a second case analyses a more complex distribution route. This report analyses several options for hydrogen delivery in order to provide relevant insights and techno-economic information to stakeholders, and to provide support to policymakers in the implementation of the hydrogen strategy.

1.1 Policy context

The European Commission (EC) adopted a new hydrogen strategy on 8 July 2020 with the communication 'A hydrogen strategy for a climate-neutral Europe' [2]. Renewable hydrogen is recognised as a key component for the decarbonisation of the energy sector, which is responsible for over 80% of European Greenhouse Gas (GHG) emissions [4]. The strategy sees the multiple roles of hydrogen in a decarbonised energy system, to provide energy storage, to provide fuel for heavy-duty transport, and to provide heat and feedstock to industries. The Hydrogen Strategy recognises the important role that the transport of hydrogen will play in enabling the penetration of renewable hydrogen in Europe. In the timeframe up to 2024, the strategy proposes that infrastructure needs for transporting hydrogen will remain limited as demand will be met by on-site production. However, planning of infrastructure should begin. After 2025, there will be a need to deploy an EU-wide infrastructure to supply hydrogen. A pan-European hydrogen grid will need to be planned, and a network of hydrogen refuelling stations is to be established. The transport of hydrogen from areas with large renewable potential to demand centres across borders is mentioned in the strategy. It proposes that the transport of renewable hydrogen over longer distances can be enabled through repurposing of parts of the existing gas grid. Moreover, according to the strategy, there could also be international trade, in particular with the EU's neighbouring countries in Eastern Europe and in the Southern and Eastern Mediterranean countries.

The RePowerEU plan sees the necessity to accelerate efforts to deploy the hydrogen infrastructure for producing, importing and transporting 20 million tonnes of hydrogen by 2030. In order to facilitate the import of up to 10 million tonnes of renewable hydrogen, three major hydrogen import corridors will be supported: via the Mediterranean, the North Sea area and, when possible, the Ukraine.

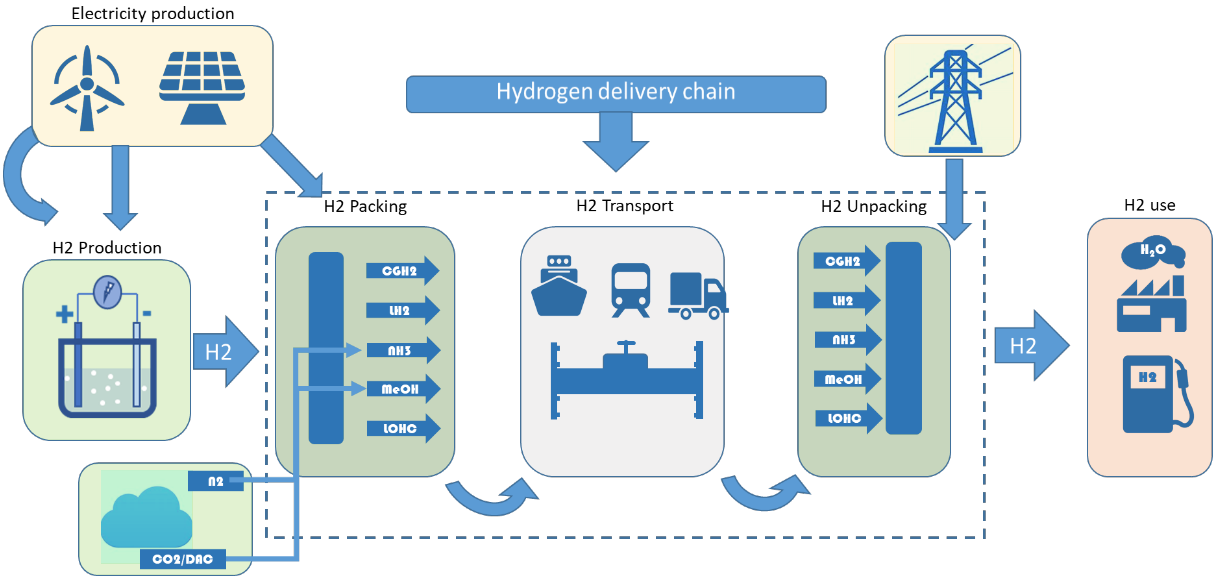
Several Member States have published national hydrogen strategies, with some of them contemplating the importation of hydrogen. The German hydrogen strategy considers that the country will continue to source much of its energy from abroad, including hydrogen. It proposes that Germany will foster and intensify international cooperation and partnerships on hydrogen [5]. In March 2021, a Memorandum of Understanding on German-Saudi hydrogen cooperation has been signed [6], and a bilateral agreement was signed recently to investigate the scope for Germany to import hydrogen produced from solar power in Australia [7]. The Dutch hydrogen strategy recognises the key role of hydrogen imports once there is a global market [8]. It also mentions that part of the hydrogen demand of Germany may have to be transported through the Netherlands. In general, the Netherlands aims to continue to act as an energy hub, as it has an extensive gas grid, ports and storage facilities [8]. The Spanish Hydrogen Roadmap foresees that Spain will become an exporter of renewable hydrogen to the rest of Europe [9]. Italy has not yet published its hydrogen strategy, but it is likely to mention Italy's role for the importation of hydrogen from North Africa, given the existing pipelines [10]. In recent years, many countries outside Europe published hydrogen strategies or deployment roadmaps. At international level, the strategies of Australia, Chile and Canada focus on the exportation of hydrogen [11][12][13]. Countries such as New Zealand and Saudi Arabia, as well as the region of North Africa, have also expressed interest in the production and exportation of hydrogen [14][15][16]. Norway's strategy also clearly positions the country as one of the potential exporters of low carbon gas. Whether this would be in the form of hydrogen, or natural gas with the CO_2 being transported back to Norway, is still open [17]. Regions are also active, for example in Flanders, the hydrogen strategy sees importation of hydrogen as a necessity in the future [18]. Pilot projects are foreseen, and the first imports through Flemish ports should take place by 2030. The Hydrogen Import Alliance has recently published a study on the importation of hydrogen for this region [19].

1.2 Goal and scope

The goal of this study is to answer the question whether it is more convenient to produce renewable hydrogen close to the demand location or to transport it from a location where renewable hydrogen production is cheaper. If transporting hydrogen makes sense, the second question that this study tries to answer is how long the transport route can be for the cost of hydrogen to still be competitive. To provide these answers, JRC has performed a comprehensive analysis of two key parameters, namely the **energy demand** and **costs** involved in the delivery chain for the supply of renewable hydrogen.

This study considers that the delivery chain comprises the key processes and equipment necessary for the delivery of hydrogen from the production site to the demand/use location(s) (see **Figure 1**). The delivery chain can be divided into three main segments: i) the "packing", where hydrogen is prepared for its transport; ii) the transport itself; and iii) the "unpacking", where hydrogen is prepared for its final use. Across each step of the delivery chain, a storage facility is assumed to enable a smooth transition. Since the focus of this study is the delivery stage, the production of hydrogen and its final use are considered to be outside of the scope. Nevertheless, a cost for hydrogen production had to be assumed to account for the economic value of hydrogen losses (see Section 4). Hydrogen is assumed to be fully renewable, in line with the long-term ambitions set out in the Hydrogen Strategy [2], the RePowerEU plan [1] and the Clean Planet for All [20] communications. Although quantification of CO_2 emissions is not part of the scope of this study, the specific technical options selected have been singled out for their potential to offer the lowest possible GHG emissions while at the same time having a reasonable technological maturity. Fossil fuel based approaches were avoided as much as possible and circularity solutions (such as direct air capture) for feedstock streams such as CO_2, were privileged.

Figure 1 depicts the delivery chain elements considered in our study. Our analysis refers only to the elements within the dotted line.



Source: JRC, 2022

The delivery chain options considered for this study are strictly related to the form in which hydrogen is transported (i.e., the ‘packaging’ mode). Five packaging modes are considered: compressed hydrogen (CGH_2), liquefied hydrogen (LH_2), ammonia (NH_3), methanol (MeOH), and Liquid Organic Hydrogen Carriers (LOHC) in the form of dibenzyltoluene (DBT). Formic acid or other chemical carriers have been excluded due to their low technical maturity. Synthetic natural gas was also not covered among the packaging options; although it has been mentioned as a suitable means of transporting hydrogen in previous studies (e.g. [21]), a pathway involving synthetic natural gas was deemed to not be in line with the decarbonisation strategy of the EC, given the potential emissions of methane along the delivery chain. In fact, unlike the other pathways, leakages of this carrier would substantially increase the global warming potential of the H_2 delivery[1]. In this study, the blending of hydrogen with natural gas is also not considered a means for the bulk delivery of hydrogen. In the view of the authors it could not be ensured that the hydrogen supplied by the hydrogen producer would reach the hydrogen consumer over long distances in the required quantities and at comparable cost with other transport options. The costs for hydrogen separation are currently still high, and it should be assumed that the amount of hydrogen contained in a blend with natural gas will vary, in particular over longer distances. Therefore guaranteeing the delivery of a specific large amount of hydrogen to a customer would be very difficult.

As mentioned above, for this study, packaging options were selected which do not involve greenhouse gas emissions directly and intrinsically linked with the hydrogen carrier, even if there are fossil fuel based state of the art alternatives. For example, for methanol the CO2 necessary for its production was sourced using Direct Air Capture (DAC). However, it is important to underline that direct and indirect greenhouse gas emissions occurring along the delivery chain are not further assessed in this study. These could emissions arise, for instance, from transport or from the generation of the electricity used in the transformation plants, even though an attempt was made to reduce emissions as far as possible. An in-depth assessment of this aspect is currently underway, to be published end 2022.

The rough timeline considered in this study is 2030-2035, assuming that there is a large demand for green hydrogen both for industrial and mobility end uses.

The various technologies involved in transporting large quantities of hydrogen over long distances are currently at different stages of maturity. For the study, established existing technologies were used as far as these were available, and compatible with the objective to enable low CO2 emissions overall. All of the packing/unpacking technologies considered, even if already used in real-world installations, are at a much lower technology readiness level than the usual industrial installations currently employed for fossil fuels. Therefore all the technological development needed to implement these technologies at the required scale (as well as cost and energy demand) is assumed to have taken place.

In some cases, existing established technologies are considered as perfectly suitable for the transport cases considered in our study. For instance, LOHC has similar properties as crude oil, therefore ships, pipelines and storage facilities for crude oil could easily be used. This had been considered in the cost assumptions. However, both packing and unpacking plants for LOHC have only been realised at small, prototype scale. For LH_2, liquefaction plants exists, but as explained in Section 5.5.2.1, a significant cost reduction due to upscaling of plant capacity, and an increase in efficiency have been considered. For MeOH and NH_3, packing plants exist at large scale, but are often based on the use of fossil fuels as feedstock and process fuel. Unpacking plants still need further development, in particular for NH_3 cracking. Hydrogen compressors could also be considered to be at high TRL, although further improvements in efficiency and upscaling have been assumed. For pipelines, the maturity of the technology can be considered high, even if there no example of hydrogen pipelines covering the distances and the volumes considered in our study.

The different delivery chain options are presented in detail in Section 2. The methodology and general approach of the report are outlined in Section 3. Two case studies inspired by plans of the hydrogen industry are presented, considering the amount of hydrogen transported and the distances. More details regarding the case studies are given in Section 4. The assumptions are explained in Section 5, and the key data underlying the assessment per transport pathway can be found in the Annex 2. In Section 6 the key findings are presented, and in Section 7 the conclusions that can be drawn from these findings are discussed. Section 8 provides recommendations and discusses policy implications.

---

[1] To investigate the potential environmental impacts of the different delivery options, a comparative life cycle assessment is being performed.

2 Hydrogen delivery packaging options and pathways

As explained in the previous Section, the hydrogen delivery pathways considered are compressed hydrogen, liquefied hydrogen, ammonia, methanol and LOHC. The latter three will be labelled generally as 'chemical carriers'. As hydrogen has a low density, it can be advantageous to process it before delivery. In this study, 'packaging' is used when referring to the form in which hydrogen is being delivered. 'Packing' refers to the compression or liquefaction of hydrogen or its conversion to a chemical carrier. 'Unpacking' means reversing that process in order to have purified, gaseous hydrogen at a defined pressure and purity at the use site.

2.1 Compressed hydrogen (CGH_2)

At present, compressed hydrogen is the preferred option for storing and transporting hydrogen. This packaging option has a low technological complexity, however, it also has a low gravimetric and volumetric density. The low density represents a challenge when delivering large amounts of hydrogen.

2.1.1 Packing

Hydrogen is compressed in order to increase its density and therefore, to reduce the volume necessary for its storage and transport. Hydrogen can be compressed up to different final pressures. The higher the pressure, the higher the density of the hydrogen, but also the higher is the energy required for its compression up to the chosen final pressure. Final pressure is defined by the application; while compressors for hydrogen refuelling stations may require pressures up to 100 MPa, compressors for pipelines can operate at far lower pressures (below 10 MPa).

The most commonly used technologies for the compression of hydrogen are based in mechanical compression and include reciprocating, diaphragm and centrifugal compressors. Although they are well-established technologies, the presence of moving parts in mechanical compressors usually leads to high maintenance costs. Moreover, this technology poses the risk of contaminating the hydrogen with oil (except in the case of diaphragm compressors). Ionic compressors are reciprocating compressors working with an ionic fluid. The use of ionic liquid improves the efficiency of the compression while reducing maintenance costs and contamination of the hydrogen.

The choice of a particular type of mechanical compressor depends on the requirements of the application (e.g., underground storage, pipelines). Reciprocating compressors show the best performance for high pressure ratios. Centrifugal compressors are limited in this aspect, but in applications requiring high flows they may be the preferred choice. Diaphragm compressors supply hydrogen with a higher purity than other mechanical compressors, thanks to their design that reduces the contact of hydrogen with the compressor's oil. Applications where purity is a key parameter may prefer this compression technology.

Alternative compression technologies such as electrochemical [22] and metal hydride [23] compression systems are under development, or in an early commercial stage. These technologies do not have moving parts, which in principle should increase their reliability and eliminate contamination problems due to the presence of lubricant oil. This also reduces their noise level, which can be a relevant factor in certain applications. Nevertheless, it is not yet clear whether these alternative technologies can be scaled up sufficiently (e.g. flow-rate) to play a relevant role in a hydrogen economy, or if they will be limited to small niche markets.

It is not possible to provide a simple representative value for the energy necessary for compressing hydrogen. The energy consumption value depends not only on the compression technology, but also on the pressure ratio and flowrate delivered by the compressor. This can be seen in **Table 1**, where several references of compressor energy and cost are collected.

Table 1 Compressing energy (MJ/kg H_2) for different hydrogen compressors.

Inlet pressure (MPa)	Outlet pressure (MPa)	Flowrate (kg H_2/h)	Energy (MJ/kg H_2)	Technology	Reference
2	10	8 333	3.0	Centrifugal	[24]
2	50	4.2	13.0	Diaphragm	[25]
1-4	45	62	9.7	Diaphragm	[26]
1-4	45	125	9.0	Diaphragm	[26]
3	45	95	6.8	Reciprocating	[27]
3	45	190	6.1	Reciprocating	[27]
3	45	550	4.7	Reciprocating	[27]
0.8	50	18	10.4	Ionic	[28]
2.5	50	18	7.9	Ionic	[28]
0.6	90	28	11.9	Ionic	[29]
0.3	90	0.4	30.2	Electrochemical	[22]
0.3	95	5	23.8	Electrochemical	[22]
2-3	100	4.2	15.8	Diaphragm	[25]

Compressor costs also depend on technology, flowrate and pressure ratio. According to [24], compressors delivering 300 kgH_2/h with an inlet/outlet pressure of 10/55 MPa have a capital cost of M$[2] 0.27, while the capital cost of a compressor with a nominal flow-rate of 8 300 kgH_2/h and 2/10 MPa as inlet/outlet pressure is around M$ 6.

2.1.2 Storage

Once compressed, hydrogen must be stored in a suitable system able to withstand the storage pressure and with materials compatible with hydrogen under those storage conditions. This storage system can be located either aboveground or underground. Underground storage can involve salt caverns, depleted gas fields, aquifers, or other underground formations. Hydrogen can be stored aboveground either in pipelines or in vessels. These storage systems can also be used as underground storage.

Among underground storage solutions, salt caverns are considered as the most promising means of storing hydrogen in large quantities [30]. The advantages consist of good leak tightness, high pressure resistance (up to 20 MPa), and flexible operation. Moreover, the inert nature of the cavern material and the lack of

---

[2] Unless noted otherwise, costs have been adjusted for inflation (May 2020), for more details see Section 3.

microbiological activity reduce the probability of hydrogen depletion and contamination. Currently, there are a few examples of hydrogen storage in salt caverns (located in the USA and the UK); their main parameters can be found in **Table 2** [31]. Capital costs for salt caverns can range between 35-38 $/kgH$_2$ stored [32], depending on the storage pressure. Other underground storage solutions present higher costs, as in the case of lined rock caverns, where they can range between 56-116 $/kgH$_2$ stored [32] The potential for hydrogen storage in European salt caverns (onshore and offshore) has been estimated at 2.5 billion tonnes of hydrogen, with the largest potential in Germany (42%) [33]. Nevertheless, salt caverns require specific geological formations, which may not always be available. The distribution of salt deposits in Europe can be seen in [34].

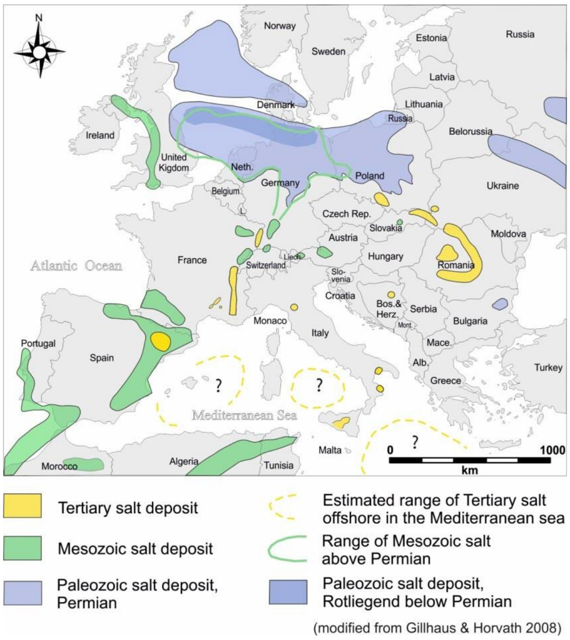
Table 2 Operational parameters of existing hydrogen salt caverns. Source [31]

Company	Chevron Phillips Chemical Company	Air Liquide	Praxair	Sabic Petrochemicals
Location	Texas	Texas	Texas	Teesside (UK)
Volume (m^3)	580 000	906 000	566 000	210 000
Max operating pressure (MPa)	13.5	20.2	13 (estimated)	4.5
Storage (t H$_2$)	2 500	5 800 (estimated)	2 400	750

Energy requirements for hydrogen storage in salt caverns are divided between the energy needed to compress the hydrogen, and the energy necessary to dry the hydrogen before its delivery. While the latter has a value of 0.374 MJ/kg-H$_2$, according to [35], compression energy is defined, mainly, by the pressure difference between the storage and the delivery pressure (see **Table 1**).

Pipelines or vessels can also be used for aboveground hydrogen storage. These storage systems are easier to deploy than underground solutions but they are more than one order of magnitude more expensive than underground storage options, at between 930-2 200 $/kgH$_2$ stored [24]. Therefore, aboveground stationary storage of hydrogen it is not seen as an optimal solution when storing large amounts of hydrogen. This type of storage can be more suitable in applications with smaller storage needs (e.g., hydrogen refuelling stations) or where underground storage is not available.

Figure 2 Salt deposits in Europe



(modified from Gillhaus & Horvath 2008)

Source: [34]

2.1.3 Transport

Nowadays, compressed hydrogen gas is mostly transported by road, using systems known as Multiple Element Gas Containers (MEGCs). These systems consist of bundles of gas cylinders. MEGCs can be designed to match the dimensions and features of ISO standard containers, facilitating their use in intermodal transport. Basic dimensions and permissible gross weights of intermodal containers are largely determined by two ISO standards, ISO 668:2013 [36] and ISO 1496-1:2013 [37].

Gas cylinders comprising the MECG are either metallic or made of a combination of internal liner (metallic or plastic) wrapped with a carbon fibre based composite material. Metallic cylinders have been extensively used to transport and to store compressed hydrogen, usually up to 30 MPa. Composite cylinders are lighter, but more expensive. Nevertheless, they allow for higher transport pressures, which increase the payload of the MEGC, reducing the transport costs (more hydrogen can be transported in one shipment). Storage pressure of MEGCs can range from pressures below 20 MPa [38] up to 50 MPa [39]. At the highest pressure (50 MPa), the payload of a MEGC can reach values above 1 tonne [39]. The cost of MEGC systems ranges between 790 $/kg H_2 for systems at 25 MPa [24] and 1 100 $/kg H_2 for transport at 50 MPa [40].

Gas cylinders, in particular when their design matches ISO container dimensions, may be used to transport compressed hydrogen by rail, sea, or inland waterways.

A recent announcement by GEV shows a design of compressed hydrogen tanker ship storing the whole hydrogen cargo in two big tanks of a cylindrical shape. This compressed hydrogen tanker ship can transport a total amount of 2 000 tonnes of hydrogen at 25 MPa [41]

Compressed hydrogen can also be transported by pipelines. More than 4 500 km of hydrogen pipelines are deployed worldwide [42], however, they are limited to industrial applications, where the customers (e.g., refineries, fertilizer plants, steel plants) are supplied via pipeline, usually from a natural gas steam reforming plant located nearby. Transmission system operators (TSOs) of natural gas grids foresee a hydrogen economy where hydrogen transport via pipeline will play a relevant role [43].

Two options are considered in the case of pipelines for hydrogen delivery: either deployment of newly built hydrogen pipelines or repurposing of pipelines and components currently used in the natural gas transmission network [44]. While the second option can be several times cheaper, it also requires a careful analysis of the current state of the pipeline to be repurposed (i.e. possible damages) and of its suitability to transport hydrogen (i.e. material compatibility). Other components of the network to be repurposed, such as compressors, valves, or flowmeters, must also undergo a thorough compatibility analysis.

A range of operating pressures for transport of hydrogen has not yet been established. Currently deployed industrial pipelines can have operating pressures of up to 10 MPa [45]. On the other hand, the typical operating pressure in natural gas transmission pipelines in Europe ranges between 6.7-8 MPa [43], meaning that repurposed pipelines may not be able to exceed that pressure when transporting hydrogen.

Optimisation of the design of a hydrogen pipeline network is not a straightforward process. From an energy point of view, the larger the diameter, the more efficient the transport of hydrogen, as the pressure drop is lower. However, from an economic point of view, the smaller the pipeline, the cheaper it will be but also the higher the pressure drop of the hydrogen transported. This higher pressure drop will require a larger number of compressor stations and, therefore, more compression work (energy costs) than in the case of a pipeline with a larger diameter.

A similar trade off occurs when choosing the operating pressure of the pipeline: the higher the pressure, the higher the density of the transported gas; therefore, for the same pipeline diameter, more gas is transported. However, higher pressures requires thicker pipeline walls and more compression work, both of which will increase the costs.

Hydrogen pipeline materials include plastic, metallic and composite materials. Current standards for hydrogen pipelines recommend the use of metallic pipelines (carbon steel alloys) [46]. Regarding compressors, gas transport by pipeline usually operates at high flows and low/medium pressure ratios. Reciprocating and centrifugal compressors seem the most suitable compressor technologies for this application [43].

In [44], costs for pipelines and compressors are estimated. For newly built pipelines, depending on size and the scenario considered, they range from 1.4 to 3.4 M€/km. If natural gas pipelines are repurposed, the costs can drop down to between 0.2 and 0.6 M€/km. Capital costs for compressor stations are estimated to be in the 2.2 to 6.7 M€/MW range.

Pipelines themselves can act as temporary storage by increasing pressure. This feature provides a certain degree of flexibility to a hydrogen delivery network based on pipelines, facilitating its adaptation to a changing supply or demand. Nevertheless, additional storage may be required, depending on the variability of supply and demand. Storage can be placed at the production site and/or the demand site, and also in a suitable location along the pipeline. These storage solutions will be similar to the ones described in the previous section.

2.1.4 Unpacking

Once arrived at the consumption site, the compressed hydrogen should be delivered to the local storage system of the end-user (except in the case of hydrogen delivered by pipeline). Usually, the hydrogen pressure during transport is higher than the storage pressure at the end-user. Therefore, initially, the delivery of hydrogen is performed without additional energy input. However, there is a point during this delivery where the pressure in the storage of the transport system is not enough to deliver the hydrogen to the end-user storage. From this point onwards compression work is necessary. This additional work is defined by the pressures and volumes of the end-user storage and of the storage of the transport system. This delivery work is performed by compressors similar to the ones described in the packing section, however, the energy needs for compression during unpacking are, generally, much lower than the ones in the packing step.

2.2 Liquefied hydrogen (LH$_2$)

At atmospheric pressure, hydrogen reaches the liquid state at 20 K (-253 °C). Under these conditions, the hydrogen density is 70.85 g/l [47], which is 2.3 times higher than the density of compressed hydrogen at 50 MPa and normal conditions (around 30 g/l). This is the main reason why this packaging option, despite the technical and economic challenges involving the use of cryogenic temperatures, may be preferable to the use of compressed hydrogen. This advantage becomes more relevant the larger the amount of hydrogen to be stored and transported.

2.2.1 Packing

Hydrogen is liquefied by means of liquefaction plants. The first such hydrogen plants were built in the USA to supply the demand of the petrochemical and aerospace industries. The working principle of large liquefaction plants is usually based on the (pre-cooled) Claude cycle [48]. This cycle consists of two stages. In the first stage, called the hydrogen refrigeration loop, the hydrogen is first compressed, and then cooled down by means of heat exchangers and expansion in turbines. The refrigerant commonly used in the heat exchangers is liquefied nitrogen, and the hydrogen is recirculated after expansion in the turbines. The second stage of this cycle is where the hydrogen liquefaction process takes place. Here, gaseous hydrogen is fed, at a pressure of around 5 MPa, into heat exchangers, where it is cooled down using the refrigerated hydrogen coming from the refrigeration loop as a cooling agent. Finally the feed hydrogen gas is liquefied at 0.1 MPa and 20.4K by expansion when passing through a valve (Joule-Thomson effect) [49],[50].

An alternative hydrogen liquefaction cycle is the helium Brayton cycle, where the hydrogen refrigeration loop is substituted by a helium cooling cycle. This cycle uses cheaper compressors than the Claude cycle, reducing its investment costs, but it has a lower energy efficiency. This cycle is used in small hydrogen liquefaction plants where economics are more sensitive to capital investment than to operating costs [50].

Additionally to the processes described above, an ortho to para hydrogen conversion process is necessary during the liquefaction of hydrogen. Hydrogen molecules exist in two forms, para and ortho (depending on the electron configurations). At room temperature the equilibrium concentration is 25% para-hydrogen and 75% ortho-hydrogen, but in the case of liquefied hydrogen the equilibrium concentration is 99.79% para-hydrogen and 0.21% ortho-hydrogen. However reaching this equilibrium is a slow process if no catalysts are used [51].

Conversion from ortho to para hydrogen releases heat (527 kJ/kg) [51], therefore, it is required that liquefied hydrogen reaches its para-ortho equilibrium before storage, otherwise the heat release during the ortho to para conversion that will take place until reaching equilibrium, will evaporate part of the hydrogen stored. This conversion can take place at an initial rate of 1% per hour, leading to the evaporation of 18% of the stored hydrogen in just one day [52]. For this reason, catalysts to accelerate the ortho to para conversion are introduced in the heat exchangers during the liquefaction of hydrogen [51]. These catalysts are commonly based on iron oxide or chromium oxide doped silica [53].

Due to the low temperatures of the liquefaction process, impurities in the feed gas need to be removed to avoid their condensation or solidification in the heat exchangers. Otherwise, blockage or damage of this equipment could take place. Additionally, oxygen has to be removed to avoid the presence of solidified oxygen in the liquefied hydrogen, which could lead to hazardous situations [52]. This purification of the feed gas takes place before it is supplied to the liquefaction plant (e.g. by means of PSA), but also during the liquefaction process, either by cryogenic absorption or adsorption. Impurity levels in the liquefied hydrogen after liquefaction is below 1 ppm [52].

While ideal liquefaction work is below 14.4 MJ/kg H_2 [54], the energy requirement of current liquefaction plants is in the order of 36-43 MJ/kg H_2 [55]. It is expected that with larger scale plants (>50 tonnes/day), the power requirements could be reduced by up to 50% (18-22 MJ/kg H_2) [55]. This will be reached not only by scaling-up but also with technological and operational improvement of the equipment used in the liquefaction process, such as recycle gas compressors, closed refrigeration loops for pre-cooling, improved turbine designs and adjusted concepts for the main refrigeration loop [50].

Today, the capacity of a conventional hydrogen liquefaction plant in Europe ranges between 4.4-10 tonnes/day, while in the US higher capacities are found, up to 32 tonnes/day [55]. Japan has a similar total liquefaction capacity as Europe, and Japanese plant capacities range from 0.3 to 11.3 tonnes/day [48][56].

The capital investment for a liquefaction plant is $2.5-5 million per hydrogen tonne/day [57]. Hydrogen liquefaction cost is mostly driven by operational costs, where the energy cost of the liquefaction represents the main part [57]. Scaling up may bring prices down to 50% (including CAPEX and OPEX) [55]. Alternative technologies (e.g. magnetocaloric liquefaction [58]), with expected lower operational costs, are still under development..

2.2.2 Storage

Liquefied hydrogen storage systems are usually double-hulled cryogenic tanks, with both inner and outer metallic walls, and the space between walls filled with a thermally insulating material (e.g. perlite) at low-vacuum pressure [54]. One of the main challenges when storing and transporting liquefied hydrogen is the evaporation of part of this hydrogen, which is known as boil-off. Boil-off is a consequence of the heat transfer from the storage tank surroundings, to the stored hydrogen. Evaporated hydrogen will progressively build up pressure inside the storage tank up to levels that can endanger the structural integrity of the storage tank. Pressure safety valves are placed in liquefied hydrogen storage systems to vent the evaporated hydrogen and reduce the pressure. The maximum allowable pressure in liquefied hydrogen tanks can reach up to 1.2 MPa [59]. The vented hydrogen represents a loss, from both an energetic and economic point of view.

The boil-off rate is proportional to both the difference between stored hydrogen and environmental temperatures, and to the heat transfer coefficient. This coefficient is mainly defined by the materials and design of the storage systems. For instance, a storage tank with a spherical design will offer a lower evaporation rate, due to a more favourable volume-surface ratio than other tank geometries (e.g. cylindrical).

Since mid-1960s, the two largest liquefied storage tanks (around 212 tonnes of liquefied hydrogen each) have been operating at NASA facilities (liquefied hydrogen has been historically used in aerospace applications). These tanks were designed to have boil-off rates below 0.075 %/day of the total volume of the tank [60]. In 2019, CB&I Storage Solutions began construction of a storage tank of 4 700 m3 (300 tonnes of liquefied hydrogen, considering 10% ullage) to be operated at NASA Kennedy Space Center [61]. It includes improvements such as better insulation (glass bubbles instead of perlite) and integrated refrigeration and storage (IRAS) heat exchanger that should reduce the boil-off to a maximum of 0.048%/day. Smaller tanks (20-145 tonnes of liquefied hydrogen) show a higher boil-off rate (0.1-0.3 %/day) [59]. Costs for liquefied hydrogen storage for big tanks can range between 150-300 €/kgH_2 [62], [63].

In addition to the boil-off described above, there is also a part of the stored hydrogen that is evaporated for operational purposes. Current techniques for the transfer of liquefied hydrogen between storage systems are based on a pressure difference between the delivering and receiving tanks, and this pressure difference is achieved by boiling-off hydrogen in the delivering tank [64]. The boil-off increases the pressure in the delivering tank, allowing its transfer to the receiving storage system. In certain conditions, boil-off during a single transfer can reach values above 15% of the hydrogen transferred [64], however, this amount can be drastically reduced if the right operational conditions are set (e.g. filling method [64]). Moreover, boil-off can also be reduced by means of low pressure cryogenic pumps [64]. These pumps can be used to transfer the liquefied hydrogen between tanks, avoiding the boil-off pressure build-up necessary for operational purposes.

Boil-off does not necessarily mean a loss of hydrogen. The evaporated hydrogen may either remain inside the storage tank, or be redirected back to the liquefaction plant, or to an intermediate gas storage buffer, or directly to a final user. These measures may require additional equipment, such us compressors, or tanks with higher operational pressures than the current state of the art; therefore, the economic benefit has to be assessed on a case by case basis. An alternative solution to reduce boil-off losses when liquefied hydrogen is stored in a tank, is the inclusion of a system able to re-liquefy the boil-off gas within the liquefied hydrogen storage system [65], similar to the systems used in LNG carriers [66] or in the new liquefied hydrogen tank being deployed at NASA Kennedy Space Center [61].

2.2.3 Transport

Liquefied hydrogen transport is currently limited, with few exceptions, to road transport by means of insulated tanks placed on top of trailers (tankers). These tankers can hold up to 4 tonnes of hydrogen (3.3 t in EU) [59]. The cost of these tankers is in the order of 200 $/kg$H_2$ [24]. Their boil-off rate can reach up to 1% volume per day [59]. Additional boil-off losses occur when transferring the liquefied hydrogen from storage to tanker and vice versa. Cryogenic tanks are not filled up to their full capacity, to avoid a quick build-up of pressure due to boil-off of the liquefied gas. The free volume left in the tank is called the ullage volume. It usually ranges from around 5-10 % of the total volume.

An alternative transport system to road tankers are containerised/portable storage solutions. The system HYLICS (Linde [59]), which follows the HELICS system tank designed to transport helium [67], is one example. This system can store up to 3 tonnes of hydrogen and it has the dimensions and features of an ISO 40 ft container

[59], making it suitable for intermodal transport. Kawasaki has a similar system based on a 40 ft container with a capacity of 46 cubic meters (around 3 tonnes of liquid hydrogen) and with a boil-off rate ≤1% per day [54]. Uralcryomash (УРАЛКРИОМАШ) has an ISO 30ft container model able to store up to 1 270 kg of liquified hydrogen (20 m^3) [68].

No commercial solutions for railway transport are currently available according to the inquiries performed by the authors. Systems such as the rail car ЖВЦ100М2 [69] by Uralcryomash (УРАЛКРИОМАШ) have been discontinued. This rail car had a boil-off rate of 0.8-1% per day and it was able to store up to 7 350 kg H_2, in a volume of 119 m^3, giving an ullage volume of 13% (According to US regulations for cryogenic liquid in tank cars [70], the minimum ullage volume is 7%). Another past example can be found in [71], where a dewar-type tank on a railway wagon was used to transport liquefied hydrogen.

Nevertheless, cryogenic rail tank cars transporting cryogenic liquid, at temperatures as low as 77 K are commercially available [72]. Similar systems could be used to transport liquefied hydrogen, bearing in mind the lower temperature of liquid hydrogen (20 K), which may require better insulation and/or alternative materials. Containerised storage solutions such as those presented in [54], [59] or [68] could be viable options due to their design. However, the applicability of the HYLICS system to this transport is not clear, since its design is based on the HELICS system, and this system it is currently not certified for rail transport [67], but only for road and maritime transport.

To the knowledge of the authors, transport of bulk liquefied hydrogen by sea (or inland waterways) has only been undertaken by NASA, using barges with a capacity of around 1 000 cubic meters (almost 65 tonnes of liquid hydrogen) [73]. Containerised solutions for the transport and storage of liquefied hydrogen (e.g. HYLICS) could be used in combination with container ships for the delivery of hydrogen. However, the transport of large amounts of hydrogen would probably need more optimised solutions, similar to the ones of LNG carriers. In this type of carrier several cryogenic tanks are integrated inside the ship. These carriers can transport up to 266 000 m^3 of liquefied gas [74], but typical sizes are in the range of 125 000-175 000 m^3 [75]. This capacity range would translate into 8 500-12 000 tonnes of liquefied hydrogen. Capital costs for LNG carriers are in the 1 000-1 200 $/$m^3$ range [21], [76]. Currently, a prototype for a liquid hydrogen carrier developed by Kawasaki Heavy Industries, the Suiso Frontier [77], is under trial, transporting liquefied hydrogen from Australia to Japan. It has a capacity of 1 250 cubic meters (around 85 tonnes of liquid hydrogen).

Containerised solutions could be more suitable for the transport of liquefied hydrogen along inland waterways, since smaller ships are expected to navigate in these waterways.

2.2.4 Unpacking

As mentioned above, liquefaction plants provide hydrogen with a very low content of impurities (below 1ppm). This should eliminate the need for a purification step as part of the unpacking. Therefore, the last step in the liquefied hydrogen delivery chain is usually the regasification of the hydrogen, which could be provided directly to the demand point (e.g. fuel cell electric vehicles (FCEVs)) or stored in an intermediate buffer.

This regasification is performed by means of an evaporator and a cryogenic pump, which is placed at the inlet of the evaporator. The cryogenic pump pushes the liquefied hydrogen through the evaporator, where the liquid hydrogen transform into gas, and provides the pressure required for the final user. These pumps are able to reach up to 100 MPa, allowing direct refuelling of FCEVs. Hydrogen cryogenic pumps have lower energy consumption (4.3 MJ/kg H_2 at 100 MPa, [59]) than hydrogen compressors. According to [24], the cost of a cryogenic pump able to deliver 100 kg/h at 90 MPa is around 650 000 $.

2.3 Ammonia

Ammonia is a chemical commodity traded worldwide and a fundamental building block used in fertiliser production. In 2019 its global production capacity was of the order of 218 Mt and growth in demand is forecast for the future [78]. European ammonia production is of the order of 20 Mt/yr [79].

Traditionally, ammonia is usually produced via the Haber-Bosch process, reacting hydrogen and nitrogen at 400–550°C and at pressures of 10–25 MPa over an iron-based catalyst. The hydrogen feedstock can be supplied by electrolysers, as has already been demonstrated [80]. Alternative designs are possible, but have not yet been proven at scale [81], [82].

Ammonia cracking is an endothermic process and can be regarded as the reverse of the synthesis reaction. In order to achieve high conversion rates (>99%), ammonia cracking has to operate at temperatures higher than 400°C. Conversion equilibria decrease by increasing pressure and kinetic limitations require high temperatures in order to achieve a significant hydrogen yield. The catalytic decomposition is promoted by the same metals active in ammonia synthesis, even if the different reaction conditions for synthesis and decomposition entail a different optimal catalyst for the two processes. Purification of the produced hydrogen has to be guaranteed and purification steps have to be implemented in the process [83]–[87]. Some new ammonia cracking designs exploiting Group I amide-imide properties are showing promising results [88], [89].

Both electrochemical ammonia synthesis and decomposition options seem to be at a much earlier development stage and they still have to be considered as being at relatively low technical maturity [90]. Therefore they will not be considered any further in this report.

2.3.1 Packing

The only reference process for ammonia synthesis which will be considered in this document and the analysis it contains, is a fully electrified Haber-Bosch, without any natural gas consumption The Haber-Bosch process, which is currently the most widespread method for ammonia synthesis, is using natural gas as feedstock and as fuel in most of plants worldwide. The low cost of natural gas drove the widespread deployment of this process. The energy consumed by the process considered in this report consists mainly of electricity used to compress the synthesis gases to the required pressure. A non-negligible amount of electricity is also required for the air separation unit process which is providing nitrogen feedstock. Due to the exothermic nature of the reaction, no significant steady heat supply to the synthesis loop is expected.

Depending on the Air Separation Unit (ASU) design considered, energy consumption varies from 1.1-1.2 GJ/tNH_3 for Pressure Swing Absorption (PSA) [81], [91]–[93] to around 0.3-0.72 GJ/tNH_3[3] for cryogenic distillation [94] [95], [92], [93].

Literature estimates for the compression energy consumption required, for achieving the pressure level needed for the ammonia synthesis, vary significantly. In a conventional fossil fuel fed Haber-Bosch process, compressors are steam powered turbine compressors, mainly powered by waste heat from the SMR process. The use of electrically driven compressors would make the process much more efficient [81]. Therefore the energy required for ammonia synthesis from green hydrogen cannot be directly derived from a conventional natural gas fed process. The energy used in driving a fully electrical ammonia synthesis is in the range 1.2-2.7 GJ/tNH_3 [81], [92], [94], [96]–[98], with a significant outlier giving a value of 5 GJ/tNH_3 [99]. The discrepancies present in literature values can be explained by different starting and final pressures of feedstock gases, by differences in the considered compression efficiency, or by different process designs. The presence of an outlier value could be due to the assumed use of a steam turbine compressor rather than an electrical one.

The expected heat production from the exothermic ammonia synthesis reaction in an all-electric process is 2.7 GJ/tNH_3. This high grade heat (around 500-550°C) could, in principle, be used for other applications [81], [96]. According to Morgan, the pumping power needed for cooling the synthesis loop of an all-electric ammonia plant with a capacity of 300 tons per day, is around 112 kW and it circulates around 9.5 tons of water per minute [94]. The electricity consumption of such a system is negligible in comparison with compression and the ASU.

---

[3] The final pressure of these values varies.

Table 3 Cost estimates for an ammonia plant taken from literature.

Plant Capacity - tNH$_3$/d	Haber-Bosch Synloop	Air Separation Unit	Total	Source
10	$\$_{2007}$7.4 m	$\$_{2007}$5.6 m	$\$_{2007}$13 m	[97]
20	$\$_{2007}$11.5 m	$\$_{2007}$8.7 m	$\$_{2007}$20.2 m	[97]
50	$\$_{2007}$20.9 m	$\$_{2007}$15.8 m	$\$_{2007}$36.7 m	[97]
100	$\$_{2007}$32.9 m	$\$_{2007}$24.8 m	$\$_{2007}$57.7 m	[97]
200	$\$_{2007}$51.6 m	$\$_{2007}$38.9 m	$\$_{2007}$90.5 m	[97]
300	$\$_{2007}$67.1 m	$\$_{2007}$50.7 m	$\$_{2007}$117.8 m	[97]
400	$\$_{2007}$80.9 m	$\$_{2007}$61.1 m	$\$_{2007}$142 m	[97]
600	$\$_{2007}$105. 3 m	$\$_{2007}$79.5 m	$\$_{2007}$184.8 m	[97]
800	$\$_{2007}$126.9 m	$\$_{2007}$95.9 m	$\$_{2007}$222.8 m	[97]
1 000	$\$_{2007}$146.8 m	$\$_{2007}$110.8 m	$\$_{2007}$257.6 m	[97]
1 200	$\$_{2007}$165.2 m	$\$_{2007}$124.8 m	$\$_{2007}$290 m	[97]
1 400	$\$_{2007}$182.6 m	$\$_{2007}$137.9 m	$\$_{2007}$320.5 m	[97]
1 600	$\$_{2007}$199.2 m	$\$_{2007}$150.4 m	$\$_{2007}$349.6 m	[97]
1 800	$\$_{2007}$215 m	$\$_{2007}$162.4 m	$\$_{2007}$377.4 m	[97]
2 000	$\$_{2007}$230.3 m	$\$_{2007}$173.9 m	$\$_{2007}$404.2 m	[97]
2 200	$\$_{2007}$245 m	$\$_{2007}$185 m	$\$_{2007}$430 m	[97]
2 400	$\$_{2007}$259.3 m	$\$_{2007}$195.8 m	$\$_{2007}$455.1 m	[97]
2 600	$\$_{2007}$273.1 m	$\$_{2007}$206.2 m	$\$_{2007}$479.3 m	[97]
2 800	$\$_{2007}$286.6 m	$\$_{2007}$216.4 m	$\$_{2007}$503 m	[97]
3 000	$\$_{2007}$299.7 m	$\$_{2007}$226.3 m	$\$_{2007}$526 m	[97]
3 200	$\$_{2007}$312.6 m	$\$_{2007}$236 m	$\$_{2007}$548.6 m	[97]
3 400	$\$_{2007}$325.1 m	$\$_{2007}$245.5 m	$\$_{2007}$570.6 m	[97]
2.4	$\$_{2019}$33 m	-	-	[81]
240	$\$_{2020}$33 m	$\$_{2020}$12 m	$\$_{2020}$45 m	[100]
300	$\$_{2010}$55.2 m	$\$_{2010}$15.8 m	$\$_{2010}$71 m	[94]
667	EUR$_{2019}$103.9 m	EUR$_{2019}$10.9 m	EUR$_{2019}$114.8 m	[21]
1 840	$\$_{2019}$42.4 m	$\$_{2019}$13 m	$\$_{2019}$55.4 m	[93]

2.3.2 Storage

Cryogenic temperatures can enable large-scale storage of ammonia at atmospheric pressure with capacities up to 50 000 tonnes [101]. Detailed techno-economic information on the design of a cryogenic storage tank with insulated double containment is given by Morgan [94]. The same source quantifies boil-off as less than 0.04% per day. This boil-off can be re-liquefied by a compression-refrigeration loop and pumped back again into the storage vessel. According to Bartels, a low-temperature and large-scale storage system can store about 41-45 tonnes of ammonia per tonne of steel [97]. A detailed description of a large-scale installation of an ammonia tank is given by Turi [102].

A summary of CAPEX estimates available for large-scale ammonia storage is given by Nayak-Luke et al. [103][4] and Elishav et al. [104][5].

---

[4] The authors consider a value of 0.81 USD/kgNH3 based on a 25,000-tonne tank, for their analysis.

[5] The ranges provided in the review are between 0.32 and 0.84 USD per kg of ammonia and depends on the size of the storage and the location of the storage facility.

2.3.3 Transport

The use of ships, trains and trucks for transporting ammonia is well-established [97], [101].

Shipping of ammonia is currently performed on a regular basis and requires partial or full refrigeration (ammonia liquefies at -33°C) in order to keep the ammonia cargo in liquid form around atmospheric pressure. It is possible to retrieve precise information on very large, dedicated gas carriers able to transport large amounts of ammonia [105]. The amount of ammonia transported can be as much as 50 000 tonnes (around 75 000 m^3), but this amount could be even higher since cryogenic, fully-refrigerated LPG transport (which requires lower temperatures than ammonia) can already reach volumes of 100 000 m^3 [101] Due to the similarities with LNG carrier designs, even higher capacities are possible, in principle [106]; see also Section 2.2.3. A newly-built, fully-refrigerated ammonia tanker with a capacity of around 80 000 m^3 should have a cost in the order of USD (2020) 80 m [106], [107]. Boil-off is quantified in the order of 0.03-0.04% per day [108], [109] and should be re-liquified if no losses are to be incurred.

Details on ammonia transport by rail can be found in documents providing information for the US and Europe [101], [110], [111]. The rail cars are pressurised (lower than 2.03 MPa) in order to have liquid ammonia and usually have capacities in the range of 50-110 m^3. However, the volume of the car can only partially be filled due to the thermal expansion of ammonia. In Europe, a filling density of 530 $kgNH_3/m^3$ should be used for calculating the tank capacity. Tanks usually have a wall thickness of 1.75 cm and are covered with a 0.32 cm jacket. At least one detailed design for a European manufacturer is publicly available [112]. A reference for the cost of a rail car able to transport ammonia is given by Hattenbach [113].

Ammonia is regularly transported in pressurised liquid form through pipelines over distances which can span thousands of kilometres and using trucks for distances around or below 150 km [101].

2.3.4 Unpacking

Ammonia cracking energy requirements depend strongly on the process design considered. It should be noted that the design for commercial ammonia crackers is based on small outputs in the order of less than 100 kgH_2/h [100].

There appear to be few recent reports providing a design (later than 2010) for a large-scale ammonia cracker [32], [89]. The proposed large-scale design by Fothergill et al. [89] uses a firebox in which the heat necessary for the process is provided by a mix of 85% ammonia and 15% hydrogen, used as a fuel. The energy required for the process can be quantified as around 52 GJ/tH_2 with a conversion of 98.5%[6].

The purchased equipment cost for a large-scale ammonia cracker, able to produce 200 $tonH_2$/day at 25 MPa and with a 99.97% purity, is estimated by the authors to be around £74.85 m.

The value reported by Fothergill et al. [89] is in line with those reported by Papadias et al. [32][7], but seems lower than the ones reported by Cesaro et al. [100], which are based on extrapolation of the cost of small-scale ammonia crackers, using the expected cost-size correlation of SMR firebox units.

2.4 Methanol

Methanol is a commodity chemical, with almost the whole European production located in Germany [114], [115]. Methanol is used as a fundamental chemical precursor in many industrial syntheses (e.g. formaldehyde, chloromethane, methyl tert-butyl ether[8] and acetic acid) and can be blended with petrol as a fuel additive. Methanol can also be used as a precursor in the methanol-to-olefins process. In Europe the majority of methanol production is absorbed by formaldehyde synthesis (2014 data) [114].

---

[6] The values of energy consumption of Giddey et al. (ACS Sustainable Chemistry & Engineering; 2017; 5; 11; 10231–10239) seem to be based on an error in their calculations and do not match with other values available in literature.

[7] Their analysis involves heat partially produced through use of natural gas.

[8] An antiknock agent.

2.4.1 Packing

Conventional, fossil-based methanol production is based on syngas (a mixture of carbon monoxide and hydrogen) used as a synthesis precursor and obtained from fossil fuels. More details on this process can be found elsewhere [116], [117]. In recent years there has been a growth in interest in pursuing methanol synthesis using CO_2 and hydrogen mixtures. Methanol synthesis from CO_2 and hydrogen is kinetically limited at low temperatures and thermodynamically disfavoured at high temperatures. By increasing pressure, methanol yield increases and heat management is crucial since the CO_2 hydrogenation reaction to methanol is strongly exothermic.

Pressures in the range 5-15 MPa and temperatures around 250°C are needed for methanol synthesis using CO_2 and hydrogen as precursors [114], [118][9]. These parameters are not much different from those of a conventional methanol process based on syngas conversion.

The catalyst used for CO_2 hydrogenation is usually the same relatively cheap zinc/copper catalyst as the one used in conventional methanol synthesis based on syngas. The direct hydrogenation of CO_2 has the drawback of producing significant amounts of water and has reaction equilibria which are not as favourable as those of CO hydrogenation; it nevertheless has the advantage of facilitating the overall reaction kinetics and reducing by-product formation, since CO_2 and not CO is the species reacting with hydrogen and producing methanol; moreover its hydrogenation reaction is less exothermic. For industrial-scale methanol syntheses, a moderate content of CO is necessary, since it keeps the catalyst in a reactive reduced state [114], [116], [118].

The development of pilot plants for methanol synthesis through direct CO_2 hydrogenation has started in the nineties and to date, the biggest and only commercial production plant is the one operated in Iceland by Carbon Recycling International with a capacity of 4 000 tMeOH per year [114], [118]. New designs with an increased capacity have been announced recently.

The industrial process of converting CO_2 and hydrogen into methanol is not yet largely deployed and proposed designs can be grouped around two main solutions [119]: direct CO_2 hydrogenation, or a combination of a reverse water gas shift (RWGS) step producing syngas, followed by methanol synthesis (CAMERE process) [114], [118], [120], [121][10].

In the available literature, it is usually reported that the two step process is more energy intensive than the direct hydrogenation of CO_2 and should require more CO_2 per unit-mass of methanol produced [119], [122]. Nevertheless some sources cite the CAMERE process as having higher efficiency (higher methanol yields, lower operating costs) in comparison with the direct hydrogenation route [123]. Available information does not seem to show a remarkable advantage in the production efficiency of the CAMERE process compared to available data from direct hydrogenation pilot plants [118].

The feedstock requirements reported for the direct synthesis of methanol from CO_2 and H_2 mixtures do not vary much from a 3:1 stoichiometric minimum ratio with a range of 0.1887-0.204 $kgH_2/kgMeOH$ and 1.375-1.484 $kgCO_2/kgMeOH$ [124]–[128].

The electricity consumption of a plant based on a double conversion step is estimated by some authors to be in the order of 2.03 GJ/tMeOH [122]. This is in contrast with other published values which are as high as 7.56 GJ/tMeOH [129]. The highest reported heat requirement is 52.9 GJ/tMeOH [129], but was reported to be almost zero for a process combusting a fraction of the output gases [122].

The published values for the total electricity needed in a direct CO_2 hydrogenation process with heat integration are in the range of 0.63–5.4 GJ/tMeOH [98], [137], [138], [130], [125], [132], [133], [134].

Heating and cooling needs vary significantly among published sources. Pérez-Fortes et al. [125], [130] mentions a total heating need of 1.58 GJ/tMeOH and a total cooling need of 3.1 GJ/tMeOH; while de Jong gives a total heating need of 1.04 GJ/tMeOH and a total cooling need of 1.71 GJ/tMeOH [127]. Kiss et al. [126] quantify a need of 0.48 tons of steam per tonne of methanol, if the reboiler and the reactor are thermally coupled. Nieminen et al. quantify the cooling need as 10.7 GJ/tMeOH and does not mention any heating duty [133]. No necessary external heat or cooling loads are mentioned in Van-Dal et al. [132].

---

[9] Temperature should be maintained below 300°C in order to avoid catalyst deactivation.

[10] The CAMERE (CAtalytic MEthanol synthesis via Reverse water gas shift) process developed by the Korean Institute of Science and Technology.

A precise explanation of the origin of the discrepancies between literature values is impossible without a specific in-depth analysis, nevertheless some differences can be justified by the dissimilar input/output pressures used in the synthesis, varying degrees and different configurations of heat integration, different reactor designs and target temperatures, and overall non-homogeneous process design choices.

Quantifying an exact capital cost is quite difficult, but literature values are summarised in **Table 4**.

All equipment cost are provided excluding electrolyser costs.

Table 4 Methanol production plant CAPEX estimates taken from literature

Reference	Capacity [t MeOH/d]	Total capital cost[11]	Cost definition in the reference
[125]	1 320	€$_{2014}$220 m	Total fixed capital cost (TFCC)[12] + working capital
[133]	54.6	€$_{2018}$10.5 m	Installed equipment cost
[21]	635	€109 m	Total installed cost (ISBL)
[133]	12 30 150	€$_{2015}$0.81 m €$_{2015}$2.2 m €$_{2015}$6.0 m	Capital cost Capital cost Capital cost
[119]	690 608	\$$_{2012}$21.3 m \$$_{2012}$38.2 m	Capital cost (direct methanol synthesis) Capital cost (two-step methanol synthesis)
[133]	1 000	€$_{2016}$650 m	CapEx
[133]	1 190	\$$_{2016}$305 m	Total capital cost
[133]	195	€11 m	Capital cost
[135]	756	€$_{2015}$63.6 m	Total Fixed Investments

OPEX costs for running a methanol production plant should include the cost for sourcing CO_2.

2.4.2 Storage

Large-scale storage of methanol is usually performed in carbon steel or 300-series austenitic stainless steel tanks much like flammable oil products such as currently used fuels [136]. Special care should be given to

---

[11] Excluding H_2 production and CO_2 capture

[12] TFCC = ISBL (inside battery limits) + OSBL (outside battery limits) + engineering + contingency

safety, since methanol is a flammable volatile liquid, whose vapours have a higher flammability range than gasoline (the flammable range of methanol is 6-36 vol% while that of gasoline 1.4-7 vol%).

2.4.3 Transport

Methanol is a chemical commodity with a large market [114]. Methanol transport can be performed using ships, trains and trucks suitable for transporting hazardous chemicals.

Several examples of bulk chemical carriers able to transport large quantities of methanol can be found (e.g.: see [137]). Their size can already be as large as 50 000 DWT (dead weight tonnage). Since methanol is defined as a Low Flashpoint Liquid (LFL), methanol cargo has to be transported according to the safety requirement for such goods. It is possible that the cargo needs to be protected with a gas blanket such as nitrogen.

There is also a growing interest in using methanol as an alternative and more sustainable fuel in the shipping industry [138].

A newly-built, coated chemical tanker with a capacity of around 50 000 DWT should have a cost in the order of $(2020) 60m [106].

Transport of methanol in railcars is carried out using rail-tanks compatible with toxic substances and flammable liquids. An example of a suitable car is provided by a European manufacturer [139].

2.4.4 Unpacking

Methanol steam reforming is the reference process for obtaining hydrogen back from methanol. Together with hydrogen, CO_2 is also produced. The produced H_2/CO_2 stream should be purified and the emitted CO_2 should be captured again (on-site, or from the atmosphere) if methanol is to be considered a carbon neutral fuel. While literature is available on designs for small scale applications targeted especially at fuel cells [140]–[142], it is difficult to find designs and specifications for the production of large amounts of hydrogen [143], [144].

Methanol steam reforming can already occur at temperatures as low as 150-350°C and is an endothermic process. Methane formation occurs at lower temperatures, while higher temperatures favour increasing equilibrium amounts of CO [145]. High pressures shift the reaction toward the reagents. Group VIII metal-based catalysts, palladium in particular, can be used as catalysts and are compatible with processes exploiting higher temperatures [141], [146], [147], [148], [149], [150], [151]. Cu/Zn catalysts active for methanol synthesis can also be used for methanol steam reforming [141].

Purification from CO and methane, and separation of CO_2 and hydrogen from the product mixture are necessary steps and are strongly dependant on the type of application hydrogen is needed for. Balance of Plant of a methanol steam reformer has to include water supply and thermal management.

Not much information is available on large–scale methanol reforming installations.

The expected theoretical minimum thermal energy requirement for methanol reforming is quantified as 28 GJ/tH_2 [152], without the energy needs for purification[13]. Another source considers an ATR process and claims a minimum ideal consumption of 4.3 GJ/tH_2 of electricity and 43.2 GJ/tH_2 of heat [153]. The electricity consumption of a methanol steam reforming plant is quantified as 1.8 GJ/tH_2 by an industrial plant supplier [143].

The only available data on cost for a methanol steam reforming plant is from a presentation of Papadias et al. [154], reporting a capital cost of 662k$ for a production of 50 tons-per-day hydrogen and 396 k$ for a production of 350 tons-per-day hydrogen. Purification is included in the considered system [32][14].

OPEX costs for running a methanol steam reforming plant should include water consumption.

---

[13] A thermodynamic minimum work for extracting all of the hydrogen from a mixture with a constant concentration of 75 mol%H_2 at 298K, should be around 0.93 GJ/tH_2.

[14] The boiler used for producing heat is using natural gas as fuel.

2.5 Liquid Organic Hydrogen Carriers (LOHC)

Liquid Organic Hydrogen Carriers (LOHC) are molecules able to release or accept hydrogen under specific temperature and pressure conditions. Ideally the hydrogen carrier is liquid at ambient conditions, non-toxic, easy to handle, and has a sufficient hydrogen storage capacity [155]. These molecules have a hydrogen-poor and hydrogen-rich form (e.g. toluene / methylcyclohexane (MCH)). Aromatic hydrocarbons and heterocyclic compounds can be used as LOHCs, for example carbazoles, pyridines or pyrroles. An overview of the properties of several LOHC systems can be found in [156] or [157], among many others. Hydrogen is stored by catalytic hydrogenation of a LOHC molecule through an exothermic reaction and released in an endothermic reaction by catalytic dehydrogenation. Given processing with the appropriate catalyst material, both hydrogenation and dehydrogenation yield can be close to 100%, on the other hand, the kinetics of the dehydrogenation step might be low (e.g. [158]). The hydrogen-poor form typically has a high boiling point in order to facilitate the separation of the hydrogen from the liquid carrier material.

LOHCs are easy to handle as they are typically liquid at room temperature and atmospheric pressure. Their physical properties are similar to fossil fuels, therefore existing infrastructure can be used, such as crude oil tankers for shipping. They can be charged and discharged several times, but most LOHC systems will experience some degradation associated with cycling. Depending on the system, the losses range from 2.5% to 0.015% per cycle [159], [160]. It should be noted that the dehydrogenated carrier has to be transported back to the hydrogenation plant. LOHC have advantages over other options of hydrogen delivery in terms of safety. Storage in these types of compounds offers intrinsic safety, as the release of hydrogen requires heat and a specific catalyst. These systems also enable long-term, loss-free storage of hydrogen with a reasonable volumetric and gravimetric density.

The LOHC concept was first proposed by Exxon researchers back in 1975, and a patent was filed in Canada a few years later by a different research group for the benzene/cyclohexane system [161]. This system has some major drawbacks as benzene is highly toxic, and the enthalpy for release is high at -68.7 kJ/mol H_2. Moreover, the reactants are gaseous at reaction conditions, which makes it difficult to separate the hydrogen. Beginning in the 1990s with researchers at the PSI in Switzerland, research has been conducted into the toluene/MCH system. This system has a similar enthalpy of –68.3 kJ/mol, and a gravimetric storage capacity of 6.1 wt% H_2 [157]. Catalyst materials based on Pt for dehydrogenation and Ru for hydrogenation have been tested successfully [157]. The Japanese company Chiyoda is developing large-scale hydrogen transport via ships based on the toluene/MCH system. This LOHC system has many advantageous properties, however the decomposition temperature is high at 350 °C, and for each cycle toluene has to be replenished (2.52% due to dehydrogenation losses) [154], necessitating hydrogen purification. Many other possible LOHC compounds have been investigated, but most systems have drawbacks such as high cost, energy demand or toxicity. N-ethylcarbazole has been the object of a high number of investigations due to its low dehydrogenation temperature of 128 °C [162]. Unfortunately, the dehydrogenated form has a high melting point of 69 °C, making it rather impractical in terms of handling.

In Europe, the SME Hydrogenious was developing a hydrogen transport solution based on dibenzyltoluene (DBT) and its perhydrogenated counterpart (H18-DBT). This system has a hydrogen storage capacity of 6.2 wt%. DBT is a commercial product used as a heat-transfer fluid (with commercial names such as Marlotherm SH, amongst others). As it has a high thermal stability, low volatility and a viscosity similar to diesel (in the hydrogenated form), it is seen as one of the more promising hydrogen carrier systems [160]. Due to the high cycling stability and dehydrogenation temperature of 250 °C, this system was selected for this study, rather than the toluene/MCH system. In terms of safety, Marlotherm SH is not classified as being an oral or dermal toxicity hazard, but is a Category 1 aspiration hazard and chronic hazard to the aquatic environment, Category 4[15], according to the safety data sheet [163]. It is not a dangerous good according to the ADR[16] [162]. There is no data available about the toxicity of H18-DBT [164].

---

[15] Category 4 being the lowest level of hazard.

[16] ADR stands for Accord européen relatif au transport international des marchandises dangereuses par route, which translates as The European Agreement concerning the International Carriage of Dangerous Goods by Road.

2.5.1 Packing

Hydrogenation of aromatic hydrocarbons is a standard process often used in the chemical industry, and is carried out at Mt scale [162]. Costs for a plant for the hydrogenation of toluene have been estimated at USD 16 000 per tpd MCH [165]. A plant able to process 100 000 tH_2/year would therefore cost around USD 80 m.

2.5.2 Storage

LOHC can be stored in large quantities at ambient conditions in double-walled containers, as used for crude oil or diesel. LOHC has been proposed for seasonal energy storage, as there are no losses during storage.

2.5.3 Transport

It is expected that, due to its similarities with crude oil or chemical products, LOHC will be transported using the same transport solutions as the ones used for those products. This represents an advantage for this type of packaging mode since there is no need for development of new transport technologies.

The high viscosity, in particular of the hydrogenated compounds of some of the LOHC options, might require heating or suitable pumps for handling. The HYSTOC project has been investigating the potential of a mixture of DBT and BT, which would lower the viscosity. Experiments showed that the kinetics were improved as well [166].

Transport by sea / inland waterways could take place using oil tankers or, if the toxicity of the LOHC is an issue, in chemical tankers. Oil tankers' capacities usually range between 10 000 and 320 000 DWT per ship, going up to 550 000 DWT for ultra-large carriers [167]. Chemical tankers are usually smaller than oil tankers and their average cargo capacity is around 30 000 tonnes [168]. In the case of oil tankers, prices for newly-built ships range between 350-800 USD/tonne of cargo [169]. Transport by road or railway of LOHC can be performed in an analogous way to oil or chemical products [170], [139]. Railcars for these products have capacities above 70 cubic meters per unit, and their price is estimated to be around USD 135 000 [171]. In the case of transport by road, LOHC could be stored in tanks that can be placed on top of trailers suitable for road transport. A 40 tonne tanker truck could transport between 1.5 - 2 tonnes of hydrogen.

Moreover, it is also possible to use intermodal tank containers that would allow its use in road, railway and waterways transport. These intermodal tank containers are usually T11 UN portable tanks [172] (T14 if the material to be transported falls under the category of hazardous chemicals). Finally, LOHC can be transported by pipelines, as is done with crude oil.

One disadvantage of LOHC compared to other hydrogen packaging modes is that the dehydrogenated LOHC must be transported back to the hydrogenation plant. This is applicable to any LOHC transport option and particularly relevant in the case of transport by pipelines. In this case, since LOHC physical properties change with the level of hydrogenation [173], it is possible that dehydrogenated LOHC is more viscous than hydrogenated LOHC (e.g. in the case of DBT) and would require more pumping work and probably larger diameter pipelines than that needed for transporting hydrogenated LOHC.

2.5.4 Unpacking

The dehydrogenation of LOHCs has a high energy demand as the strong C–H bond has to be broken. Typically, a dehydrogenation temperature ranging from 150-400°C is needed to reach reasonable hydrogen release rates [174]. This endothermic reaction is catalysed by a PGM catalyst and usually takes place at pressures below 1 MPa [175]. The heat for the dehydrogenation reaction can be supplied either by electricity, combustion of hydrogen or natural gas, or by waste heat, if available.

Even if not directly consumed when hydrogen is released, LOHC will likely experience a decline in storage efficiency due to degradation associated with cycling. The number of cycles that a LOHC molecule can endure can be determined by measuring the amount of by-products produced during each charge/discharge cycle [65]. The cycling stability of DBT is likely to be high, with 750 – 1 000 cycles reported in literature [176]. For the toluene/MCH system, hydrogen will need a further purification step due to the decomposition of the carrier during dehydrogenation, and the number of cycles is limited, with assumed toluene losses of 0.84% per cycle [32].

3 Methodology

The starting point of this analysis is retrieving a set of information regarding **costs** and **energy demand** from public literature and in some cases private companies (section 5). Literature data was carefully reviewed, and for some technologies and processes, considerable discrepancies between various sources were found. References were selected in which more detailed and well-founded justifications were given. For several components and technologies of the hydrogen delivery chain, industry experts were consulted to provide information regarding costs and other key parameters. Detailed information regarding the assumptions for each of the transport options is given in Section 5 and Annex 2.

Due to the large variation in assumptions found in literature, discussions were held with the authors of two studies on this topic, namely the 'Future of Hydrogen' report by the IEA [177] and a paper by Ishimoto et al. [178]. This dialogue helped to clarify some of the differences in the outcomes between the studies. More detail is provided in Section 6.6.

The figures from literature sources are complemented by assumptions and extrapolations required to model large capacities, or a technology not characterized well enough by the sources collected. Calculations have been performed when the information available in literature was insufficient. One example is pipelines, where literature sources were often in disagreement and provided a wide range of costs. For pipelines, this study describes the operation of the pipeline by using a simple pressure-drop model. The pipeline was considered as a straight line with no changes in altitude. A bottom-up calculation of costs was performed, based on material use and other cost components such as right-of-way and operation and maintenance, with data compiled from a large set of sources (see Annex 2).

The collected information is summarized in a database, which is then used to assess specific case studies (see section 4). A summary of the key assumptions for each pathway can be found in section 5.5 and Annex 0. The database allows for the modification of the transport distance and the amount of transported hydrogen. Any hydrogen delivery pathway is broken down into simple constituent individual steps (**Figure 1**, i.e. hydrogen storage, hydrogen transport, conversion plants at production and delivery points, purification, compression), and the energy demand and costs assessed for each. For conversion plants, costs can be calculated for various capacities (see the description of case A and B in section 4), whereas the energy demand is deemed constant irrespective of scale. For transport segments, the size and number of ships assumed was adapted to the yearly transported hydrogen capacity; for pipelines their size was adjusted according to the amounts of hydrogen transported.

For cost data taken from literature, the domestic inflation rate was used to adjust for inflation, as given by reference [179] and [180]. Historical exchange rates were taken from [181]. A final conversion from non-Euro currency was applied and a May 2020 rate was used (e.g.: 1 USD=0.919456 EUR). No geographical localisation factors were considered for our analysis. Due to the intrinsic uncertainties present in the starting data and our scaling method, it is deemed that this decision does not significantly impact the viability of the obtained results.

No parameters other than distance and amount of hydrogen transported are required as inputs and geographical specificities for the production and delivery points are implicitly taken into account through the definition of an electricity price (see section 5.3). For the considered conversion technologies, information on costs and energy demand were especially scarce, or based on not yet established technologies. The relevant available information was typically found for much lower capacities than those needed to process the amounts of hydrogen considered in this study (see section 4). A scaling factor methodology has therefore been applied, to provide a rough order-of-magnitude estimate for plant cost [182]. This approach is based on the use of the known costs for a plant of smaller capacity, which is then scaled up using an exponential factor. The capital costs of two plants using the same technology, but having different scales are linked by the equation: $C_1 = C_2 (S_1/S_2)^n$; where C_1 is the ISBL[17] capital cost of the plant with capacity S_1 and C_2 the ISBL capital cost of the plant with capacity S_2 [182]. The exponent n depends on the type of process considered and is often around 0.6 ('six-tenth rule') (see e.g. [182]). For this study, typically an exponent of 0.67 was used, up to a specific maximum plant capacity, which differs for each pathway due to the varying maturity of the technologies. This maximum capacity assumed is in the region between 200-350 tH_2/day, for plants larger than this maximum capacity, no further cost savings from upscaling are considered.

---

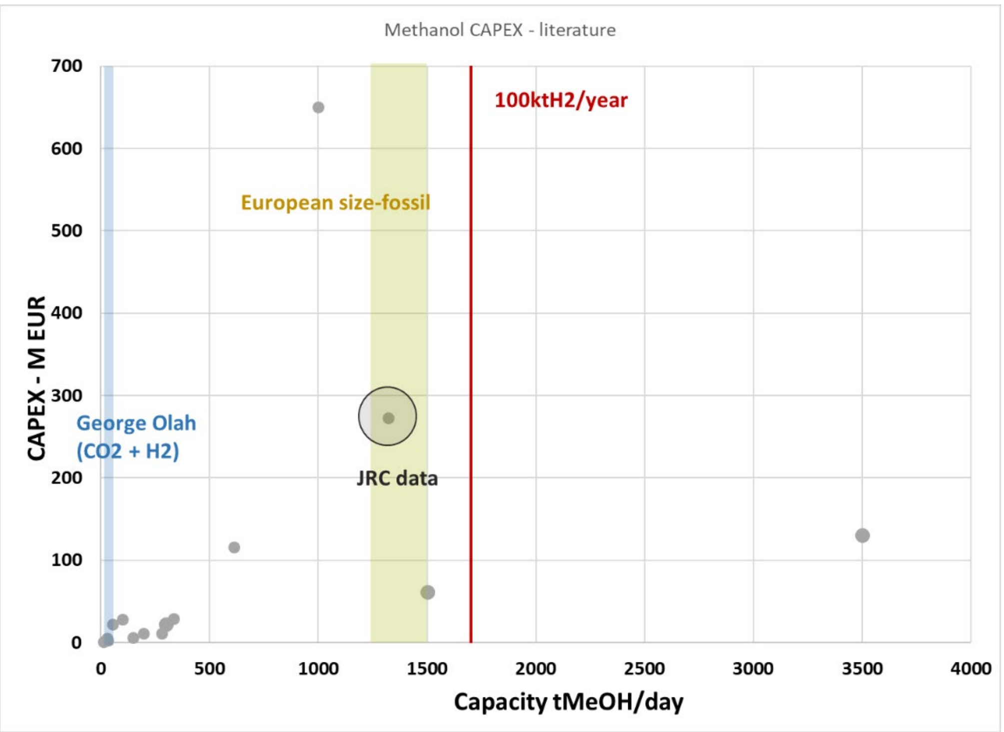
[17] Inside battery limits

In some cases a different exponent was used, as described in section 5.5, if indicated in literature, or if the available information on a particular process is deemed to imply a different scaling factor. The limits of this method have been extensively highlighted in literature [182], but it offers a quick way for roughly assessing the approximate order of magnitude of the costs expected for building packing, unpacking and transport infrastructure powered by electricity and dedicated to renewable hydrogen transport. As information on the CAPEX of various technologies, in particular for the packing and unpacking plants was scarce, the uncertainty for this aspect of the cost calculations is high. Also many references were not clear whether the CAPEX stated referred to ISBL or the complete costs for the plant. In case of doubt we decided to assume the latter.

OPEX, unless noted otherwise, does not include energy costs.

It should also be noted that all of the packing/unpacking technologies considered, even if already used in real-world installations, are at a much lower technology readiness level than the usual industrial installations currently using fossil fuels. Moreover, several of the technologies have never been deployed at a scale even close to the ones considered in this study, even considering the maximum plant capacity limitation as specified above. This situation is illustrated using methanol as an example in **Figure 3**. In this figure it is possible to observe how the literature data available for CO_2 hydrogenation to methanol plants do not achieve the scale required for transporting the largest hydrogen volumes. More research is needed to be able to quantify the maximum economically reasonable and technically achievable conversion plants dimensions able to exploit savings from economies of scale (as expressed by the 'six-tenth rule' described above), see also section 8.3.

Figure 3 Methanol plant capacities



Source: compiled by JRC from available literature data, see section 2.4.1

The size and type of the required transport fleet depends on the packaging mode. As outlined in section 4, the means of transport used to deliver hydrogen are at different stages of technological readiness depending on the type of carrier considered. DBT and ammonia can be transported in already available conventional oil tankers and refrigerated chemical tankers, respectively. By contrast, liquefied hydrogen will need to be transported in large carriers with a new, but similar design, to liquefied natural gas (LNG) carriers. Compressed hydrogen will be delivered in tanker ships analogous to those transporting compressed natural gas (CNG). The latter two have not yet been fully developed, although efforts are already underway, see for example Section 2.2.3 for LH_2.

Ships were scaled according to the volumes of hydrogen considered, up to a maximum capacity limit defined by available information on existing ships. Restrictions imposed by shipping routes, such as the maximum ship size for a particular passage were considered. Once the maximum ship size was reached, the number of shipping units were increased if needed. For trucks and trains the maximum transport capacity is regulated, and these limitations have been taken into account. For trains, when available, information on technical specifications for European markets was given preference and a rail convoy length of 750 m coupled with a locomotive was taken as the maximum rail single transport unit.

It should be noted once more, that there is a significant level of technical uncertainty in the assessment presented in this study. Firstly, there are, to date, few working examples of some of the processes examined and actual field data are extremely scarce. Most of the used sources are based on results coming from chemical process simulations. Secondly, the scale of the considered processes is often small compared with the volumes considered. In order to improve the accuracy of this type of assessment, more data will be needed, in particular on plant costs (see Section 8.3).

Nevertheless, this study allows for a semi-quantitative ranking of costs for hydrogen transport options within the technological boundaries defined by the chosen set of assumptions.

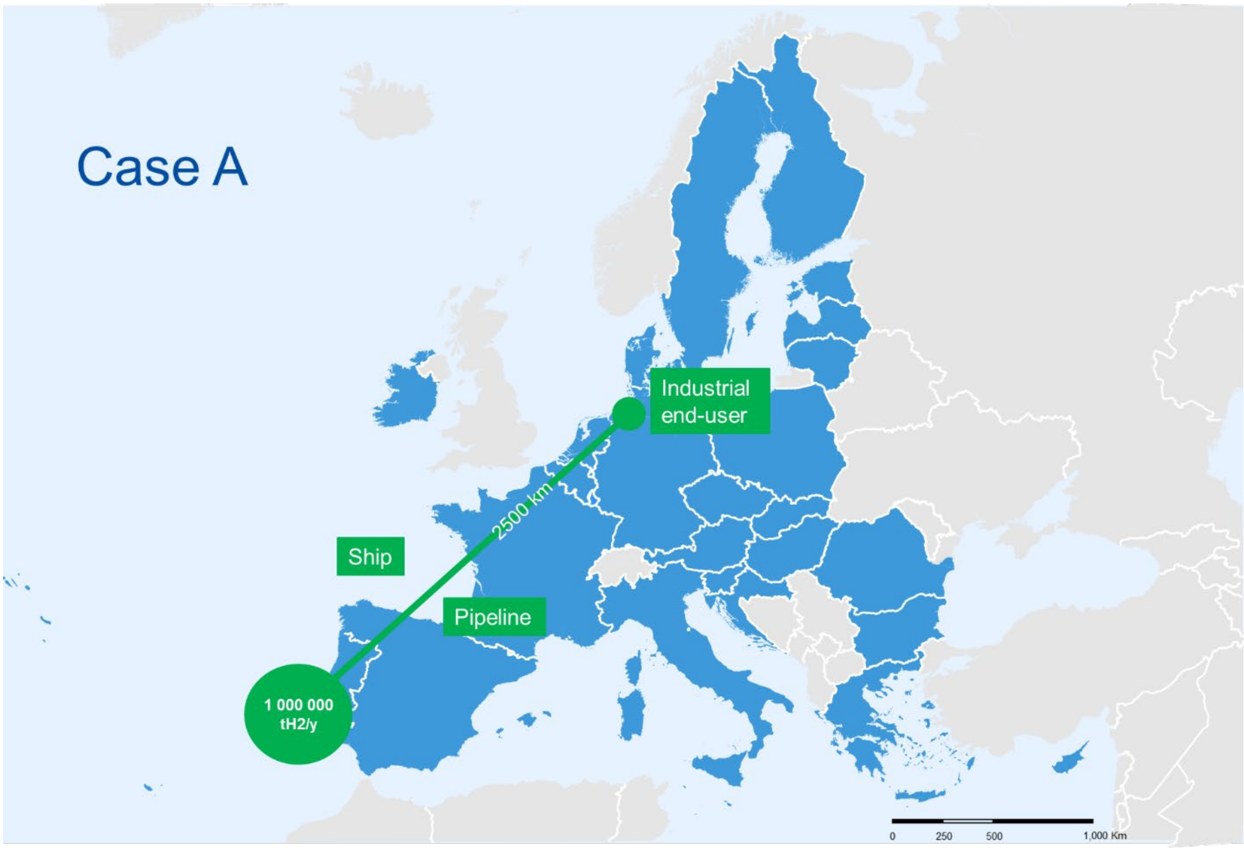
4 Case studies

To investigate which renewable hydrogen delivery pathways are favourable in terms of energy demand and costs, JRC has developed a database and an analytical procedure to assess each step of the pathways, under the assumptions defined for two case studies. These case studies were inspired by plans of the hydrogen industry in 2020, as expressed in proposed projects for the hydrogen IPCEI (Important Projects of Common European Interest) [183]. The case studies as described below are loosely based on project ideas put forward by the industry.

The database developed (see section 3) was used to model two hypothetical cases:

Case A is based on the delivery of 1 million tons of renewable hydrogen per year to a single industrial customer, via a direct transport pathway, using a dedicated pipeline or shipping route. The transport distance considered is 2 500 km for shipping and pipelines (see **Figure 4**). No further distribution is assumed, the hydrogen end-user site is presumed to be close to the port. One million tons of hydrogen would be sufficient, for instance, to supply a very large steel plant (15 Mt steel/year) using direct reduction of iron ore with hydrogen, or a large industrial cluster. The final hydrogen purity is considered to be compliant to ISO 14647, although it should be noted that for this type of customer, the hydrogen purity requirements are possibly less stringent. For more detail on Case A, see section 5.2.

Figure 4 Schematic representation of Case A

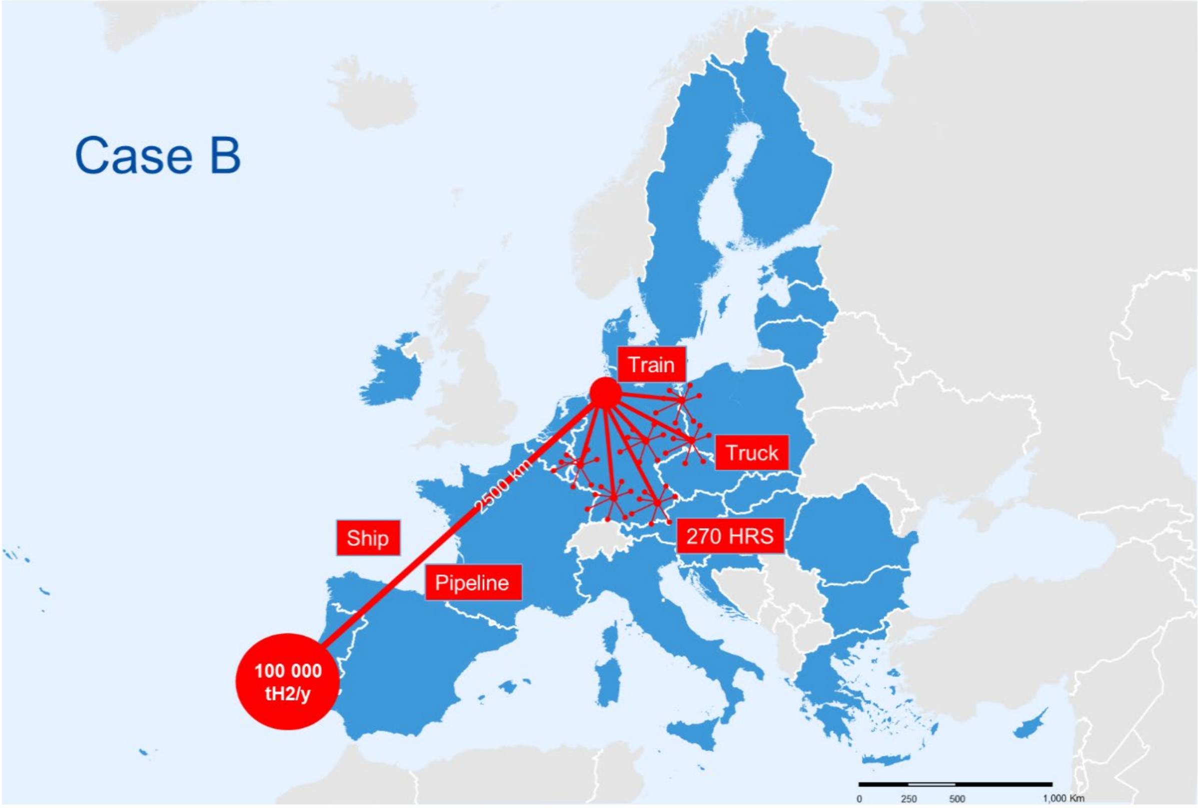


Source: JRC, 2022

Case B aims to represent a more complex delivery route with 100 000 tons of renewable hydrogen delivered every year to a network of 270 hydrogen refuelling stations (HRS), each with a dispensing capacity of 1 tH_2/day (see **Figure 5**). The first leg of the transport route is similar to Case A (2 500 km) and consists in a single dedicated delivery route to a port. Both shipping and pipelines were assessed for this part of the delivery route. However, as pipelines were much more costly than shipping for all options, due to the low volume being transported, the results are not shown in Section 6.2. Hydrogen is then further distributed within a radius of 500 km through a combination of railway (400 km) and road transport (100 km). In this case, the hydrogen delivered at the refuelling station should comply with the hydrogen purity and pressure levels required for mobility applications (ISO 14647 and 50 MPa delivery pressure). For all pathways, except for LOHC, the last segment of the distribution route is presumed to be in the form of hydrogen, CGH_2 or LH_2. The chemical carriers are converted to hydrogen at the railports. For LOHC, the dehydrogenation at the site of the HRS was also assessed.

For Case B, the scenario where hydrogen is distributed only by pipelines is not included in the analysis presented here. It requires a more complex analysis, which is part of ongoing work.

Figure 5 Schematic representation of Case B



Source: JRC, 2022

5 Assumptions

5.1 General assumptions

This study's objective is to determine the cost and energy demand related to the transport of large amounts of green hydrogen over long distances.

For packing/unpacking often the technologies are existing and commercially available, but currently not developed at the scales needed, or with the process efficiency assumed in this study. The values used are based on the closest existing technological application (e.g. LNG for LH_2). As explained below, in terms of technological development, likely, but not overly optimistic assumptions were made, based on literature and information from experts. A similar approach was taken regarding hydrogen storage (gaseous and liquid).

Supply of hydrogen as input for the delivery chain is considered as always available and provided at a pressure of 3 MPa. The supply of hydrogen is assumed to be provided from an underground storage facility, as the electrolysers are operating at 50% capacity. The price of electricity is considered as constant, defined only by location. A well-defined difference between electricity costs in the production and the delivery points is assumed.

The hydrogen lost along the transport chain, either to provide energy (e.g. use of the carrier as fuel for ammonia cracking), or to compensate hydrogen losses that may happen along the transport chain[18] is quantified and accounted for. The hydrogen capacities for the pathways experiencing losses are scaled up accordingly, to ensure that the amounts specified for each case are delivered to the end-user.

The authors of this study believe that not only the production of hydrogen, but also the whole delivery chain, including both the conversion and reconversion of the hydrogen, as well as its transport, should have as low GHG emissions as possible. When technically possible, the approach of our analysis considers electricity-powered options for the conversion and reconversion processes as the most suited to reduce carbon emissions[19]. Therefore, we assume that the energy required for the packing and unpacking processes is provided by either green electricity, or combusted renewable hydrogen (directly in its molecular form, or in the form of a carrier such as ammonia or methanol), or waste heat in the case of LOHC. For the latter, hydrogen and electricity for the provision of energy for the dehydrogenation process are also assessed.

If available, the transport means used in this study for transporting hydrogen on sea, or land, are considered to be based on currently available technologies that rely on biofuels for their propulsion (see also section 1.2.). The use of electricity, synthetic fuels or hydrogen as transport fuels would imply the use of technologies that are in their early stage of deployment (e.g. fuel cells, or electric trucks), or which do not exist yet (e.g. big ships propelled with hydrogen, or ammonia), increasing significantly the final cost of the hydrogen delivered and the technical uncertainties already present in our analysis. However, 50% of the rail lines are considered to be electrified.

In general, transport logistics have been optimised as far as possible, in terms of transport time, capacity and storage size. The time allocated to the loading/unloading process depends on the carrier.

Unless it is indicated otherwise, the utilisation factor of equipment is defined at 90%.

More details are provided in the following section.

5.2 Case study assumptions

5.2.1 Packing/Unpacking

The scale of installations for Cases A and B are defined based on the amount of hydrogen to be delivered to the final user in a year (1 MtH_2 and 100 ktH_2). All the packing and unpacking plants are assumed to be operated

---

[18] Such as the hydrogen need for replacing the boil-off of liquefied hydrogen, or the cushion gas that remains in compressed hydrogen underground storages.

[19] The carbon footprint of the used electricity will influence the actual GHG footprint of the process.

for 333 days in a year. Extra packing (and transport) capacity is added where necessary, to account for losses across the delivery chain (e.g.: fuel use for unpacking). A lifetime of 30 years is used for most[20] industrial installations and a discount rate of 5% is used to calculate the annualised capital costs [155].

The energy demand for compressors used in the packing and unpacking processes is assumed to be met by electricity. Heat, such that required for the ammonia cracking process, is assumed to be met using a mix of ammonia and hydrogen as fuel; for LOHC dehydrogenation can use heat supplied by electricity, or hydrogen, or employ a source of waste heat (the latter examined only in Case A). For ammonia cracking, the high temperature needed is not deemed suitable for electrical heat (see section 5.5.3.4). In the case of LOHC, the availability of waste heat would enable lower costs for the dehydrogenation process (see section 5.5.5.4).

It is assumed that hydrogen is delivered at the same conditions in each pathway, i.e. CGH_2 at 7 MPa in Case A or at 50 MPa in Case B.

Due to potential contamination of hydrogen during its delivery, and depending on the requirements of the final application, a purification step may be required. Nowadays, most hydrogen purification systems are based on Pressure Swing Adsorption (PSA) technology. Alternative purification systems to PSA can be based on technologies such as cryogenic distillation or membrane technology. Purification was assumed for all chemical carrier based delivery pathways.

5.2.2 Storage

Storage sizes are dimensioned to provide a certain degree of security of supply, in case some part of the delivery chain fails (due to maintenance or unexpected events). Storage capacity at import and export terminals of the ports is defined as two times the capacity of the ship connecting both terminals. At HRS, the storage systems hold at least 3 tonnes of hydrogen (i.e. supply for 3 days). For pipelines, carrier storage was considered at the point of packing and unpacking.

Storage technology depends on the carrier to be stored and therefore are different in each pathway. However, all pathways include an underground (salt cavern) compressed hydrogen storage located between the hydrogen production facility (i.e. electrolyser plant) and hydrogen packing plant (e.g. ammonia synthesis plant). Capacity of this underground storage is defined to cover the hydrogen packing plant demand for 3 days.

5.2.3 Transport

Logistics have been optimised to minimize CAPEX and storage needs. It is assumed that, in the ports, specific new infrastructure needs to be built for LH_2 and CGH_2, but not for chemical carriers, (this study considers that infrastructure is already available for these chemical carriers).

Biodiesel is the fuel choice for ships, diesel trains, and trucks. This choice aligns with a more decarbonised hydrogen delivery chain. Biodiesel price is defined at 780 EUR/t [184] for ships and trains. In the case of trucks, biodiesel price is assumed to be double (1 460 EUR/t), to account for additional taxes and intermediary costs (refuelling stations). Lower heating value of biodiesel used in calculations is 37 MJ/kg [185]. Fuel consumption is calculated assuming that the return trip is performed empty (except for LOHC pathways).

Each type of transport has a set of individual assumptions, which are described below:

Ship:

The type of ship is chosen according to the carrier considered (e.g. chemical tanker in the case of ammonia). Ship capacity is optimised and scaled according to the needs of the particular pathway and case. Due to this, relevant data on ships is found in the correspondent pathway assumptions section. They are assumed to navigate at full speed, which is between 14-19 knots, (26-35 km/h), depending on the type and size of the ship.

---

[20] For some as yet unproven technologies a lifetime of 20 years is assumed (dehydrogenation of LOHC, liquefaction).

If not available in literature, the fuel consumption of the ship considered is calculated considering an engine efficiency of 40%.

Train:

A train is formed by a locomotive pulling a convoy of either flat platforms carrying containers or carrier-specific rail cars (e.g. rail car chemical tanker [139]). Locomotive size is determined based on the weight of the cargo they are meant to carry, following [186]. Length and weight of the train convoy, as well as the type of wagons, changes depending on the pathway, therefore relevant assumptions on locomotive and wagons is provided in the respective pathway assumptions section. Nevertheless, the maximum length of a train convoy is set at 750 metres. CAPEX for locomotive and flat wagons (for containers) is calculated from [187].

Two train technologies are considered, diesel and electric. Final costs for this transport mode is obtained as an average value between the two technologies. Train energy average consumption is defined at 0.19 MJ/t km in the case of (bio)diesel trains and 0.07 MJ/t km in the case of electric trains, both according to [188]. An average speed of 50 km/h is assumed [189].

No railway transport fees have been included in the total costs.

Trucks:

When transporting containerised solutions, trucks considered are comprised of a tractor head and a platform (where the container is placed). CAPEX of a tractor head is around 115 000 EUR, as provided by [190] For the platform CAPEX, a value of 60 000 EUR [40] is used. If the road transport is by truck tankers, then the truck is comprised of a tractor head and the tanker trailer. Relevant data on tanker trailers are given in the assumptions section related to their correspondent pathway, since they are specific to the carrier they transport (e.g. ammonia).

Truck average energy consumption is estimated at 0.8 MJ/t [188]. Truck operational costs (not including fuel costs) are obtained from [191]. An average speed of 50 km/h is also assumed for trucks [189].

Time for unloading and loading depends on the type and the amount of cargo, therefore, this is specified for each pathway in their corresponding section.

5.2.4 Case A

For Case A it is assumed that the industry customer demand is for hydrogen at a pressure of 7 MPa and purity according to ISO 14647[21]. For the three pathways involving chemical conversion at the end-user site, an underground salt cavern hydrogen storage facility with a capacity of 8 and 12 kt is included in the costs, to account for the fact that the processing plants only operate 333 days out of the year. This storage amount is equal to 3 days of demand of the industrial customer.

Specific assumptions for each pathway are listed below.

CGH_2

- Shipping at 25 MPa pressure.
- Pipeline pressure up to 7 MPa.

LH_2

- Re-liquefaction of boil-off produced during transfer to the ship.

---

[21] Many industrial applications will not need this purity level of hydrogen, and costs for some of the delivery routes can be reduced.

- Boil-off during transport is considered as lost.

Ammonia

- Purification of hydrogen with PSA.
- Cracking/purification process results in a final pressure of 25 MPa, and an energy/cost bonus is considered for the overpressure of 18 MPa.

Methanol

- Purification of hydrogen with PSA.

LOHC

- Purification of hydrogen with PSA.

5.2.5 Case B

For Case B, the HRS customer demand is assumed to be for hydrogen delivered at a pressure of 50 MPa and purity according to ISO 14647. In this case, containerised solutions for hydrogen transport by ship are also considered.

From the ports, the hydrogen or chemical carriers are transferred to rail. The unpacking is assumed to take place at the railport, as smaller scale plants at the HRS sites did not seem feasible, except for LOHC. No underground hydrogen storage is deemed to be needed at the railport. The last segment of the delivery route is per truck, either CGH_2 at 50 MPa or LH_2. For LOHC, the option to dehydrogenate the carrier at the HRS was also considered.

Specific assumptions for each pathway are listed below.

CGH_2

- Shipping at 25/50 MPa pressure.
- Pipeline pressure up to 7 MPa.
- Train and truck delivery pressure of 50 MPa.

LH_2

- Re-liquefaction of boil-off produced during transfer to the ship.
- Boil-off during transport is considered as lost.
- Train and truck delivery as LH_2.

- Boil-off during liquid hydrogen transport by train and truck is not accounted for.
- Compression to 50 MPa at HRS

Ammonia

- Ammonia cracking at railport location, truck distribution as CGH_2 (at 50 MPa).
- Purification of hydrogen with PSA.

Methanol

- Methanol reforming at railport location, truck distribution as CGH_2 (at 50 MPa).
- Purification of hydrogen with PSA.

LOHC

- Case B-1 Dehydrogenation at railport location, truck distribution as CGH_2 (at 50 MPa).
- Case B-2 Dehydrogenation at HRS.
- Purification of hydrogen with PSA.
- Compression to 50 MPa at HRS

5.3 Energy price assumptions

In our model, energy prices play a relevant role in the final cost of hydrogen transportation. This study considers different electricity prices depending on the location considered. Electricity price at the hydrogen production site is assumed to be cheaper than the one at the demand point; otherwise green hydrogen production would reasonably take place at the demand site.

As key fundamental assumption of our model is to consider that a nearby renewable power plant provides, by means of an isolated electric grid, all the electricity required for hydrogen production and conversion into the hydrogen transport carrier. In this way, the direct supply of electricity to the hydrogen production and packing plants will avoid the taxes and tariffs usually related to electricity provided via a national grid. Therefore, electricity price in the production site is closer to a LCOE (Levelised Cost of Electricity) than to an actual electricity price.

It is assumed that hydrogen production, packing and shipment sites will be located close to renewable electricity generation, benefiting from relatively low electricity prices which will not be much above their generation cost. By contrast, the cost of electricity used during transport (e.g. pipeline compressors) and for unpacking at the delivery site, is assumed to be higher, i.e. the local retail price for large European industrial consumers. To assess the impact different electricity price have, two scenarios are explored (see Table 5):

(1) Low price (**Lo**), with a production site electricity price of EUR 10/MWh and a consumption site electricity price of EUR 50/MWh;

(2) High price (**Hi**), with a production site electricity price of EUR 50/MWh and a consumption site electricity price of EUR 130/MWh.

The low electricity prices are an estimation of future electricity prices (2030+) based on renewable electricity cost trends [192] and the recent announcement of a record low price for renewable electricity of EUR 11.14/MWh [193]. The high electricity price scenario is based on the current electricity prices, as 50 EUR/MWh from renewables have been reported to be feasible today [194], and the demand side prices are those typical for an industrial customer in Germany today [195].

For Case A (industrial use of hydrogen), it is assumed that in the delivery site there is the option to source waste heat at 300°C, since in this type of industrial setting waste heat may be available. Information on the cost of waste heat is not readily available, so the price was set to a value considerably lower than that of heat provided by NG, at a price of EUR 20/MWh.

For the hydrogen demand site, the (local[22]) electricity grid provides the electricity required for the extraction of hydrogen (in the case of carriers) and/or the conditioning of the hydrogen before the final use (e.g. compression, purification, regasification etc.). The same assumption is made for the electricity used during the transportation of hydrogen (e.g. electric trains or pipeline compressors).

As mentioned in section 5.2.3, biodiesel is the fuel choice for ships, diesel trains, and trucks. For ships and trains, a biodiesel price of 780 EUR/t is defined from [184]. In the case of trucks, biodiesel price is assumed to be double (1 460 EUR/t), to account for additional taxes and intermediary costs (refuelling stations).

The two chosen sets of electricity prices are shown in **Table 5**.

Table 5. Electricity prices depending on location and scenario. Source: literature data, see text.

Scenario	Production site	Demand site
High electricity price (Hi) (EUR/MWh)	50	130
Low electricity price (Lo) (EUR/MWh)	10	50

5.4 Hydrogen production assumptions

The cost per kilogram of hydrogen is used to account for the cost of any additional hydrogen lost across the delivery chain and not delivered to the final user. Additional hydrogen is needed due to boil-off, or if part of the hydrogen is used to provide heat necessary for cracking or de-hydrogenation of carriers.

Based on the two scenarios for electricity price outlined in the previous section, two different hydrogen costs have been established, 3.5 EUR/kgH_2 for the high price scenario and 1.5 EUR/kgH_2 for the low price scenario To calculate these values we have considered two main electrolyser technologies: PEM and alkaline. The final hydrogen cost is based on an average between the values obtained for each of the two technologies, as they are assumed to be deployed equally. The electrolysers are assumed to be operating at 35% capacity, coupled to a solar renewable energy production plant. To buffer the intermittency of the hydrogen output, a salt cavern hydrogen storage facility is assumed. This salt cavern is scaled according to the demands of the pathway. The relevant electrolyser parameters used for the hydrogen cost calculation are presented in Annex 2, **Table 16**.

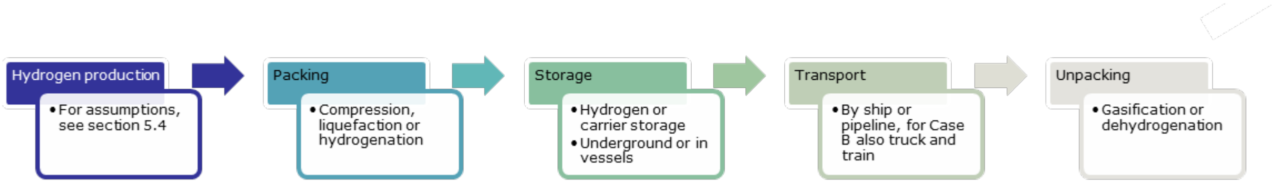
---

[22] Assuming that this electricity can be provided without, or with low tariffs, or grid fees.

5.5 Pathway assumptions

The hydrogen delivery chain has been divided into several steps (see **Figure 6**). Specific assumptions for each of the delivery options are summarized below. Hydrogen or carrier storage is necessary at the ports, also referred to as import and export terminals, and at the site of the packing and unpacking plants. Unpacking includes a compression and purification step, where needed.

Figure 6 Hydrogen delivery steps



Source: JRC, 2022

5.5.1 Compressed hydrogen

5.5.1.1 Packing

It is assumed that compressors operate for 50% of the time. This means that installed compressor capacity is double that which is strictly necessary. Compressors are designed considering a pressure output 2 MPa higher than the delivery pressure, to compensate for pressure losses that might exist between the compressor and the system receiving the CGH_2. The CAPEX and energy demand for the compressors depends on the capacity and compression ratio and are calculated based on information from industry experts, and the authors' own calculations based on fundamental gas equations or simple physical assumptions in the case of liquids (see Annex 2 **Table 17**). For the calculation of energy demand it is considered that compressors have an isentropic efficiency of 85% and an engine efficiency of 95%.

Compression at the production site takes place in two stages, with an intermediate underground storage at 10 MPa. In the first stage, the compressor system connects the electrolyser plant to the underground storage. Compressor capacity is defined by the flow-rate of the hydrogen production plant. The second compressor stage is used to supply hydrogen from the underground storage to the CGH_2 ship tankers. The delivery pressure of this compressor is defined by the storage solution chosen for the transport by ship, either bulk at 25 MPa or container solutions at 50 MPa. Compressor capacity is defined by the ship storage capacity and the loading/unloading time, which is assumed to be 24 hours for each process. An additional 6 hours are included to account for preparatory operations necessary for the transfer of hydrogen (e.g. connection/disconnection between compressor and tanker or mooring of the tanker).

For Case B, where the transport by sea is performed with CGH_2 ship tankers (25 MPa), a compressor system is necessary at the port to bring the pressure level up to the 50 MPa needed for further transport by rail and truck (in MEGC).

5.5.1.2 Storage

Storage of compressed hydrogen is done in underground salt caverns, near the export terminals. It should be pointed out that in real conditions, local geology might not allow this. Underground hydrogen storage pressure is assumed to be 10 MPa. The volume of the storage caverns is defined summing up the capacity of two hydrogen ship tankers plus the volume of cushion gas considered (30% of total volume). Therefore, the volume of an individual underground storage system considered in this study is around 585 000 m^3 (for both Case A and B). CAPEX of these salt caverns have been estimated from formulas provided in [32], obtaining a value of almost 65 MEUR per cavern.

In Case B, as transport by train and truck is already done with MEGC, there is not the need for dedicated CGH_2 storage at railports and HRS, since the MEGC serves as storage. If CGH_2 is transported in containerised solutions from the point of origin, then the same applies to the storage of hydrogen at export and import terminals. The MEGC considered is based on the X-STORE® system developed by Hexagon Purus GmbH [39]. It stores hydrogen at 50 MPa with a total capacity of 1 115 kg of hydrogen. It is considered that this MEGC would be emptied down to 2 MPa, providing a real capacity of 1 058 Kg of hydrogen. The dimensions of these systems are equal to those of a 40 ft ISO container. Cost of these units is based on [40], obtaining a CAPEX of around 0.9 MEUR per unit.

5.5.1.3 Transport

. For Case A, it is assumed that compressed hydrogen is transported by sea with hydrogen gas tankers. Alternatively, compressed hydrogen can also be transported by pipelines. For Case B, transport by sea is performed either in bulk (hydrogen gas tanker) or in the containerised solutions (MEGC) described in section 5.5.1.2 by container ships.

A compressed hydrogen gas tanker ship is defined as a bulk carrier ship transporting CGH_2 storage systems based on CNG storage system [196]. The hydrogen is assumed to be transported at 25 MPa on this type of ship. The CGH_2 tanker has a capacity of 1 370 tonnes of hydrogen (150 000 DWT), however, it is considered that hydrogen tanks on board these tankers can only be emptied down to 2 MPa. Therefore, the real ship capacity is around 1 245 tonnes of hydrogen. Fuel consumption is estimated from [197].

Container ships (Case B) considered can transport up to 5 800 Twenty-foot equivalent units (TEU). This is equivalent to 2 900 units of 40 ft containers, providing a hydrogen capacity of around 3 000 tonnes. Fuel consumption and relevant costs for this type of ship are calculated combining data from [198], [199], [200], [201].

The train convoy comprises 48 wagons (i.e. 48 MEGC systems), with a total hydrogen capacity of around 50 tonnes per train. It is considered that a (full) MEGC convoy is delivered at the railport, where another (empty) MEGC convoy is ready to be transported back to the import terminal (port). In this way, the train does not need to wait for the full MEGCs to be removed from the rail car platforms [202] and the empty MEGCs to be relocated back. Despite the investment on additional rail car platforms that this solution requires, the improvement on logistics (less loading/unloading time) reduces the final cost of the hydrogen delivered. The time considered to disconnect the locomotive from one train convoy (e.g. full convoy) and to connect it to the other (e.g. empty convoy) is 4 hours. CAPEX is 2.8 MEUR in the case of a diesel locomotive, and 2.1 MEUR if the locomotive is electric.

It is assumed that a truck can carry a single MEGC unit between railport and HRS. CAPEX is calculated at 175 000 EUR, for the tractor head and trailer (excluding the MEGC). A full MEGC is left at the HRS and an empty MEGC is loaded on the truck. This operation is assumed to last 1.5 hours.

5.5.1.4 Unpacking

For the unloading of CGH_2 ship tankers in Case A, it is considered that there is a first stage where the transfer is done by pressure difference between ship and storage at port, so the compressor is by-passed. Once this pressure difference is not enough to maintain the required flow (2 MPa pressure difference has been considered), the remaining amount is transferred from the ship to the storage system with the help of the compressor. Worst case scenario (storage full at 65% capacity) has been considered to determine the amount of ship load that has to be transferred with the use of compressors (around 45% of the ship capacity).

No purification step has been considered in this pathway.

5.5.2 Liquefied hydrogen

5.5.2.1 Packing

Current efficiencies for liquefaction plants are between 36-43 MJ/kg H_2 [55]. However, it is expected that increasing plant capacity will lead to higher process efficiency (21.6 MJ/kg H_2 for 150 tpd plant capacity [55]). As the capacities of the liquefaction plants defined in this assessment are several orders of magnitude larger than current liquefaction plants, the efficiency assumed for the liquefaction process is 21.6 MJ /kg H_2.

A liquefaction plant is assumed to be operative 90% of the time. Liquefaction plant size is defined based on annual hydrogen demand and hydrogen losses along the delivery chain. Two types of hydrogen losses are considered; hydrogen vented due to boil-off and the hydrogen evaporated but not vented. The latter does not bring additional hydrogen costs but it is considered to be re-liquefied in the liquefaction plant. The energy demand assumed for re-liquefaction is around 14.4 MJ/kg H_2, calculated from data provided in [54].

For Case A, the liquefaction plant size is 3 375 tpd, which is two orders of magnitude larger than any liquefaction plant currently in operation (32 tpd, [48]). Liquefaction plant size in Case B is almost 390 tpd. Considering this and the data on liquefaction costs given in [190], liquefaction plant CAPEX is calculated assuming that the liquefaction plant comprises as many liquefaction plants units of 200 tpd as necessary to cover total demand (i.e. CAPEX plant X tpd = X/200 * CAPEX plant 200 tpd). Based on [190], the CAPEX of a 200 tpd liquefaction plant is around 390 MEUR. For smaller sizes of plant (<200 tpd), the equation provided in [190] is used. Liquefaction plant capacity and CAPEX for Case A and B are collected in Table 6 (for more information, see Annex 2, **Table 19**).

Table 6. Capacity and CAPEX of liquefaction plants for Case A and B. Source: literature data, see text.

Capacity (tpd)			CAPEX (MEUR)		
Case A	Case B (bulk)	Case B (ISO container)	Case A	Case B (bulk)	Case B (ISO container)
3 375	390	315	6 600	755	640

5.5.2.2 Storage

Total storage capacity at the importing and exporting terminal is calculated based on the capacity of the LH_2 ship tanker (2 times ship capacity) and the boil-off downstream in the delivery chain. It is assumed that the maximum capacity of a single liquefied hydrogen tank is 15 000 m^3 (around 1 000 tonnes LH_2). In the case of bulk storage at railports (Case B), the volume assumed at this location is two times the capacity of the LH_2 train. At HRS, storage solutions as described in [59] have been used as reference. Storage volume at this location is 55 m^3.

For tanks with volumes bigger than 3 500 m^3, CAPEX is calculated from the value provided in [24]. For smaller tanks, values provided by industry experts have been used to determine the CAPEX. LH_2 storage in containerised solutions is based on the Linde HELICS system [67]. CAPEX is calculated from various sources, including industry information. Operational costs of LH_2 storage tanks are taken from [190]. In the case of containerised solutions, there is an operational cost associated to the use of liquid nitrogen. This is used to reduce the heat transfer from the environment to the liquid hydrogen. The amount of hydrogen necessary is estimated from [67], while the cost of liquid nitrogen considered is 0.15 EUR/kg [203], [204].

Volume and CAPEX data of storage facilities are summarised in **Table 7**.

Table 7. Liquefied hydrogen storage volume and CAPEX along delivery chain. Source: literature data and JRC assumptions, see text.

Storage facility at:	Volume (m^3)		CAPEX (MEUR)	
	Case A	Case B	Case A	Case B
Importing terminal	250 000	125 000	290	145
Exporting terminal	235 000	115 000	275	135
Railport	N/a	5 000	N/a	8.5
HRS	N/a	55	N/a	0.35
Container	44	44	0.8	0.8

Assessment results of this pathway will strongly depend on the assumptions made on boil-off losses. The analysis presented here assumes a scenario where the hydrogen losses due to boil-off are minimised. The boil-off management assumed for this pathway would not be possible without the use of cryogenic pumps. They are used for the hydrogen transfer of LH_2 from storage sites to transport mode and vice versa. Dimensioning of cryogenic pumps is defined by the loading/unloading times. Data of energy consumption and cost for this equipment is obtained from [205].

For Case A, boil-off in storage located at importing and exporting hydrogen terminals is not considered as a hydrogen loss but it is assumed to be re-liquefied at the liquefaction plant. The same assumption is made with the boil-off generated during LH_2 transfer operations.

For Case B it is assumed that boil-off at importing terminal storage (including boil-off during transfer operations) is re-liquefied, similarly for the boil-off generated during transfer between LH_2 tanker ship and exporting terminal storage. The rest of the boil-off generated at the exporting terminal location (due to storage and transfer for train transport) is considered a hydrogen loss. For storage at railports and HRS, all boil-off is treated as hydrogen loss.

In the case of containerised solutions for the storage of liquefied hydrogen (e.g. HELICS [67]), no hydrogen losses are considered during storage or transport. Therefore, all boil-off generated during transfer from the liquefaction plant to storage, and from storage to pump in the HRS, as well as the boil-off produced during its storage and transport, is assumed to be re-liquefied.

Boil-off rates are summarised in **Table 8**. Reference values for boil-off rates of LH_2 during storage are found in [59], [67] and [60]. Boil-off rates during transfer operations are obtained from [64].

Table 8. Boil-off rates of LH_2 storage systems. Source: literature data, see text.

Storage system at:	Boil-off rate during tank filling (%)	Boil-off rate during storage (%/day)	Boil-off rate during tank emptying (%)
Importing terminal	2	0.08	2.5
Exporting terminal	2	0.08	2.5
Railport	2	0.10	2.5
HRS	2	1	2.5
ISO Container	2.5	0.2	2.5

5.5.2.3 Transport

Liquefied hydrogen can be transported either in bulk, or in containerised solutions. However, unlike in the compressed hydrogen pathway, bulk transport of liquefied hydrogen by train and truck is also considered. Unlike containerised solutions, bulk transport requires hydrogen transfer between transport modes (through intermediate storage), increasing the boil-off losses.

Bulk transport by sea is done by means of liquid hydrogen tankers. As mentioned in the previous section, there are no examples of this type of ship existing (only one prototype [77]). Therefore, some of the data for liquid hydrogen tankers are calculated from data available on liquid natural gas carriers. For Case A, liquid hydrogen tankers are defined to hold a cargo of around 125 000 cubic meters (~8 700 tonnes of hydrogen per ship). This size is equivalent to a medium size LNG ship [75]. In Case B, LH_2 tankers have a capacity of 60 000 cubic meters (~4 200 tonnes of hydrogen per ship). The ullage volume considered in both cases is 1.5% of the ship capacity. When the transport of LH_2 is performed using containerised solutions, the container ship considered has a capacity of 2 200 TEU (above 3 000 tonnes of hydrogen).

CAPEX for LH_2 tankers is calculated from data provided in [62] and [21]. In the case of container ships, CAPEX is calculated combining data provided in [206], [201], [198], [199], and [207]. The same references have been used to estimate the fuel consumption of container ships. For LH_2 tankers, the fuel consumption has been calculated from data available on LNG tankers [208]. Capacity, CAPEX and fuel consumption of the ships considered in the different cases are summarised in Table 9.

Table 9. Data on ships transporting LH_2. Source: literature data and JRC assumptions, see text.

	Case A	Case B	
		Bulk	ISO container
Capacity (t H_2)	8 700	4 200	3 300
CAPEX (M EUR)	380	265	25
Fuel consumption (t/d)	135	64	75

The boil-off produced during the trip is considered as hydrogen losses, therefore, an additional amount of hydrogen has to be produced to cover the demand at the consumption site. The hydrogen boil-off rate on board ships is defined at 0.2% of the total storage volume per day. This pathway does not consider using this boil-off to fuel the ship.

In the case of bulk transport by train, cryogenic rail cars are assumed to be leased. A leasing cost is estimated at 210 EUR per day and rail car, based on [209]. Dimensions and capacity of the rail car is taken from [69]. In order to improve logistics, the same approach is taken as in the case of CGH_2 transport by train, where the number of rail cars are duplicated. This approach is used for both, bulk and containerised transport.

Bulk road transport is performed by LH_2 truck tankers. CAPEX for a 3.3 t LH_2 tanker is 630 000 EUR, not including the associated tractor head [24]. For transport of LH_2 in container solutions, truck CAPEX includes CAPEX of tractor head and trailer (175 000 EUR, see section 5.2.3).

To simplify calculations, the boil-off produced during transport of liquefied hydrogen in LH_2 rail cars and LH_2 truck tankers (bulk transport) is not considered. It is estimated that, due to the short trip duration (less than one day) hydrogen losses during these journeys should be less than 1% of the hydrogen transported.

In the case of containerised solutions, an average trip duration time of 20 days has been estimated for Case B (from production site to final use at the HRS). A constant boil-off rate is considered during this trip (0.2 %/day, see **Table 8**). Considering the holding time specified by the technology provider (HELICS, [67]), it is assumed that when liquefied hydrogen is transported in containerised solutions no hydrogen is lost due to boil-off[23], and that all the hydrogen evaporated is re-liquefied.

5.5.2.4 Unpacking

It is assumed that LH_2 does not require any additional purification step prior to its final delivery. Therefore, the only process considered during the unpacking is the regasification of the hydrogen and its compression up to the delivery pressure, which is 7 MPa for Case A and 50 MPa for Case B. This is done by means of cryopumps (as described in section 5.5.2.2) and evaporators (costs obtained from [190]).

5.5.3 Ammonia

The hydrogen delivery chain based on ammonia considered here, takes into account the extra capacity needed because of the use of ammonia as a fuel for the unpacking step. This will be discussed more in detail in section 2.3.4 (unpacking) and will imply a required packing (ammonia production) capacity of about 21 864 tNH_3/d (7 280 694 tNH_3/year) for Case A and 2 186 tNH_3/d (728 069 tNH_3/year) for Case B.

5.5.3.1 Packing

CAPEX for ammonia packing (Synloop and ASU) has been extracted from Morgan [94]. This source has been used as the main source due to an extensive description provided by the author.

Morgan gives a very detailed account of a fully electric ammonia plant and provides a precise description of its different components. It is straightforward to extract CAPEX information for the synloop and the Air Separation Unit (ASU) and derive the relationships used for scaling. Unfortunately, CAPEX data are only given for the synloop capacity range of 100-500 tNH_3/d and ASU capacities of 60-420 tN_2/d[24]. The EUR_{2020} 118.76m CAPEX of a 500 tNH_3/d capacity plant was used as a basis for our cost assumptions.
Bartels [97] provides a full CAPEX table which uses a scaling factor of 0.67 for covering the range of capacities from 10 to 3 400 tNH_3/d (see **Table 3**). This exponential factor was used to scale CAPEX up to a plant dimension of 4 700 tNH_3/d [210]; from this scale upwards it is assumed that costs grow linearly.

---

[23] 40 days, which is longer than the maximum time that the LH_2 is expected to be stored at less than 30 days, from production site to final use at the HRS.

[24] Considering a constant ratio of 0.833 tN_2 required per ton of ammonia this translates in about 70-500 tNH_3/d.

This implies that Case A (1 MtH_2/y) would have a packing plant CAPEX of about EUR_{2020} 2369 m. Case B (100 ktH_2/y) would have a packing plant CAPEX of EUR_{2020} 309.7 m. Annual OPEX (including workforce) is assumed to be 3% of total CAPEX, while electricity consumption is calculated based on the assumed electricity requirements.

The energy required for the packing process is estimated to be around 2.3 GJ/tNH_3 for the synloop and 0.6 GJ/tNH_3 for the ASU unit (total of 2.9 GJ/tNH_3). These values are a reasonable, yet conservative, assumption based on a cryogenic ASU and the literature values given in section 2.3.1. The ratio of nitrogen and hydrogen used in the process is close to an ideal stoichiometry and can be considered to be around 0.18 $kgH_2/kgNH_3$ and 0.83 $kgN_2/kgNH_3$ [21], [92]. These values deviate slightly from a perfectly stoichiometric ratio, but are conservative and take into account possible process losses and incomplete conversion.

5.5.3.2 Storage

Costs for storage have been extracted from the detailed description offered by Morgan [94]. Storage is assumed to be performed in liquid form and the maximum possible storage capacity is fixed at 50 000 tNH_3. The CAPEX of such an installation would be EUR_{2020} 32.5 m and it is derived by extrapolating the values given in the reference paper used [94]. The yearly OPEX for such a facility is calculated assuming a liner scale-up relationship for the workforce costs and extrapolating the costs given by Morgan for the 9 000 tNH_3 storage facility[25]. The power requirement for driving compressors used to re-liquefy boil-off is considered negligible with respect to the electric power requirements of the packing and unpacking plants.

5.5.3.3 Transport

Ammonia shipping is modelled according to the detailed information provided for Clipper Sirius, Clipper Victory and Clipper Sun [105]. The maximum capacity of the ammonia carrier ship is considered to be 50 000 tNH_3, even if, in principle, bigger cargo capacities could be possible. The CAPEX for a ship with a capacity of 50 000 tNH_3 is fixed at EUR_{2020} 70 m [106]. Yearly OPEX is around 4.7% of ship CAPEX for a ship able to carry 50 000 tNH_3 and sailing 90% of the year [106]. The speed of the ship is taken as constant at 16 knots (about 29.6 km/h). Loading and offloading operations are considered to last for a total of three days. The fuel consumption is taken as equivalent to about 36 tonnes of Heavy Fuel Oil (HFO) per day including loading/offloading operations and cruising [105]. All boil-off is considered as re-liquefied and no losses due to boil-off are accounted for.

Transport of ammonia using trains is based on the specifications of a VTG Aktiengesellschaft design [112]. It was considered that an ammonia rail tank car can carry a maximum of 55.12 tNH_3[26], has a tare weight of 35 t and a trailer length of 17.16 m. For a convoy of 750m this would translate to a capacity of around 2 370 tNH_3. The CAPEX for a single rail tank car is estimated at around EUR_{2020} 160 k [113].

An electric locomotive with a power of 2.9 MW should be able to provide traction for the convoy and should have a CAPEX quantified around EUR_{2020} 2.7 m. The yearly OPEX includes maintenance and workforce and can be quantified as around 2.4% of CAPEX[27].

5.5.3.4 Unpacking

The most detailed public reference available on a large scale ammonia cracker is by Fothergill et al. [89]. Other references are available in literature, but, to the best of our knowledge, none provides the same level of technical detail and addresses challenges associated with large scale facilities. Therefore, despite its shortcomings outlining some plant components, it was used as the only reference for unpacking.

The mass ratio of produced hydrogen to consumed ammonia (both as feedstock and fuel, and including recycling of recovered ammonia) is 0.137 tH_2/tNH_3. The electricity requirement is around 17.5 GJ/tH_2[28], while the fuel

---

[25] These corresponds to about 13.7% of the CAPEX cost.

[26] Calculated using a filling density of 530 kg/m^3 for a nominal volume of 104 m^3.

[27] It is assumed that a train can be available 90% of time.

[28] According to our interpretation of the reference used, this is the value required to obtain hydrogen at 25 MPa with a 99.97% purity.

requirement is 51.9 GJ/tH_2[29]. The reference used estimates CAPEX for the cracking plant as EUR_{2020} 369 m for a plant with a capacity of 200 tH_2/d[30]. Even if this value is at least a factor of four higher than that provided by another source providing some information on large scale ammonia cracking [100], it was kept as it presents a conservative estimation. Scaling of plant CAPEX was performed using a power law with scaling factor 0.67 up to a capacity of about 350 tH_2/d, and then scaled up linearly. The obtained CAPEX for Case A (1 MtH_2/y) is then about EUR_{2020} 4 606 m, while Case B (100 ktH_2/y) would have an unpacking plant CAPEX, for a single unpacking plant, of EUR_{2020} 145.8 m. Yearly OPEX is assumed to be 3% of CAPEX.

5.5.4 Methanol

As for ammonia, a hydrogen delivery chain based on methanol needs to account for the use of methanol as fuel for processing steam reforming, which is providing hydrogen (see section 2.4). This translates to a packing (methanol production) capacity of about 21 168 tMeOH/d (7 048 979 tMeOH/year) for Case A and of 2 117 tMeOH/d (704 898 tMeOH/year) for Case B.

5.5.4.1 Packing

It is difficult to find consistent CAPEX values for methanol production plants performing direct CO_2 hydrogenation. The work of Pérez-Fortes [125], was used as a reference, since it is precise in its plant description and considers a plant with a capacity comparable to that currently available in Europe.

The plant design used requires about 1.46 tCO_2 and 0.199 tH_2 per tonne of methanol produced [130], [211].

The energy required for the synthesis consists of 0.64 GJ/tMeOH of electricity. The heating needs of 1.6 GJ/tMeOH can be provided by 0.92 tonnes of steam per tonne of methanol and 3.1 GJ//tMeOH of cooling needs can be covered by circulating 92.3 tH_2O/tMeOH. Considering an electric boiler efficiency of 95% the electricity required for steam generation would be around 1.7 GJ/tMeOH. By using the assumptions on pump power used by Morgan [94], it is possible to quantify the electricity associated with the pumps providing the necessary cooling as 0.09 GJ/tMeOH. The total electricity requirements will then become 2.3 GJ/tMeOH if utilities like cooling water and steam are factored in.

According to the reference used, a plant with capacity of 1 320 tMeOH/d has an Inside Battery Limits (ISBL) investment of EUR_{2020} 114.2 m[31]. This can be transformed into an actual CAPEX by using the methodology outlined by Towler and Sinnott [182]. A CAPEX of EUR_{2020} 254.5 m is then obtained. The capacity of the plant is then scaled using an exponent of 0.67 up to a capacity of 5 400 tMeOH/d [212] and then linearly after that. This implies that Case A (1 MtH_2/y) would have a packing plant CAPEX of about EUR_{2020} 2 564 m. Case B (100 ktH_2/y) would have a packing plant CAPEX of EUR_{2020} 349.2 m. Annual OPEX (including workforce) is assumed to be 3% of total CAPEX, while electricity consumption is calculated based on the assumed electricity requirements.

Carbon dioxide is assumed to be coming from a Direct Air Capture (DAC) plant with a pressure of 0.1 MPa and with a suitable purity for the CO_2 hydrogenation process. The CAPEX for the DAC installation is not considered in our model due to the uncertainties associated with its deployment. Nevertheless, the work of Keith et al. [213] was used as a reference for the cost of CO_2 sourced through DAC and for the energy requirements of the process. The price for a tonne of CO_2 is assumed to be EUR_{2020} 145 for the low cost electricity assumptions and EUR_{2020} 242 the high cost electricity assumptions; the associated DAC process requires 0.28 GJ/tCO_2 (77 kWh/tCO_2) of electrical energy and 5.25 GJ/tCO_2 of thermal energy[32].

---

[29] The fuel composition is 85% NH_3 and 15% H_2.

[30] ISBL was considered to be £ 312.8 m and the CAPEX calculated according to [125].

[31] Excluding the requirements for CO_2 purification.

[32] A range of $\$_{2018}$ 94-97 is given in the reference work used. This energy is considered to be provided by natural gas with a cost of 3$/GJ. In our case it is provided by burning hydrogen. This translates into a need of 48.7 kilograms of hydrogen (lower heating value) per tonne of CO_2 captured (using a boiler efficiency of 90%).

5.5.4.2 Storage

It is not straightforward to obtain specific information for the storage of methanol. The available detailed information for ammonia [94] have been used also for obtaining relevant storage information for methanol. The available volume has been quantified using a methanol density of 790 kgMeOH/m^3. Only the cost of a single wall internal floating roof tank made of steel was considered. No losses due to evaporation were considered. A methanol tank with a capacity of approximately 11 500 tonnes is expected to have a cost of EUR$_{2020}$ 4.9 m and a scaling exponent of 0.67 is used. The maximum tank capacity is assumed to be about 58 000 tMeOH with a CAPEX of about EUR$_{2020}$ 14.6 m. The yearly OPEX (maintenance and workforce) for such a facility is calculated assuming a similar linear relationship as the one used for ammonia and amounts to about 23.6% of CAPEX.

5.5.4.3 Transport

Shipping of methanol is based on the data available for an actual deep sea tanker used for transporting methanol: the 'Taranaki Sun' [214]. Based on the available volumetric capacity of the cargo tanks, and using a methanol density of 790 kgMeOH/m^3, it was calculated that the maximum capacity of the ship is around 41 500 tMeOH. The average speed of the ship was extracted from [215] and taken as 16 knots (about 29.6 km/h). Loading and offloading operations are considered to last for a total of three days. The amount of HFO used by the ship in a cruising day (about 33.4 tHFO/d) is calculated from the EEDI[33] reported in the THETHIS-MRV database [216] and assuming an emission factor of 3.11 kgCO$_2$/kgHFO. The total average consumption considering cruising and loading/unloading operations is assumed to be 24 tHFO equivalent per day. The CAPEX of the reference ship was estimated from Tijdgat [106] and expected to be around EUR$_{2020}$ 42 m. OPEX is estimated to be around 8 % of CAPEX for a ship carrying 41 500 tMeOH and sailing at a maximum of 90% of the year.

Transport of methanol using trains is based on the specifications of a VTG Aktiengesellschaft design [139]. It was considered that a methanol rail tank car can carry a maximum of 63.2 tMeOH[34], has a tare weight of 26 t and a trailer length of 16.24 m. For a convoy of 750 m this would translate to a capacity of about 2 900 tMeOH. The CAPEX for a single rail tank car is estimated around EUR$_{2020}$ 109 k [171]. An electric locomotive with a power of 3 MW should be able to provide traction for the convoy and should have a CAPEX quantified around EUR$_{2020}$ 2.8 m. The yearly OPEX includes the cost of maintenance and workforce and can be quantified as around 3% of CAPEX[35].

5.5.4.4 Unpacking

As stated in section 2.4.4, it is very difficult to obtain relevant accurate information for a large scale methanol steam reformer.

The thermal energy required for steam reforming is fixed at its thermodynamic minimum of 28 GJ per ton of hydrogen produced [152]. The fuel used for thermal needs is a mixture of methanol[36] and hydrogen[37] which is not extracted from the purification step. It is assumed that a boiler with 90% efficiency is used, bringing the overall fuel consumption up to 31.1 GJ/tH$_2$. The calculated mass ratio of produced hydrogen to consumed methanol (both as feedstock and fuel) is 0.142 tH$_2$/tMeOH. This value is in line with information provided by Mahler AGS [143]. The electricity consumption is taken from the information given by Mahler AGS and is 1.8 GJ/tH$_2$ [143]. The water used for steam reforming can be calculated considering the proportion of 3.8 kgH$_2$O/kgH$_2$[38] [143].

Despite a different set-up than the one used by Brown et al. [152], data on cost were extrapolated from Papadias et al. [165] since this is the only reference found providing costs for a large-scale methanol steam reforming plant. The scaling curve presented (with an exponent of about 0.67) was up to a capacity of about 350 tH$_2$/d; CAPEX was scaled linearly after that threshold capacity. It is not clear whether the cost provided in the reference used is an actual CAPEX, or more similar to an ISBL [182]; it was, however, treated as a full CAPEX.

---

[33] Is it assumed that cargo capacity is 70% of DWT.

[34] Calculated using a filling density of 790 kg/m^3 for a nominal volume of 80 m^3.

[35] It is assumed that a train can be available 90% of time.

[36] The lower heating value of methanol of 19.9 MJ/kgMeOH was used.

[37] The lower heating value of hydrogen of 119.9 MJ/kgH$_2$ was used.

[38] The stoichiometric ratio is 3 kgH$_2$O/kgH$_2$.

This favourable assumption is taken as a best case scenario. In this way it is possible to benchmark the methanol option against other options and immediately check if this less developed technology has the possibility to be competitive against other hydrogen transport options. The obtained CAPEX for Case A (1 MtH_2/y) is then about EUR_{2020} 1 088 m, while Case B (100 ktH_2/y) would have an unpacking plant CAPEX for a single unpacking plant of EUR_{2020} 145.8 m. Yearly OPEX is assumed to be 3% of CAPEX.

5.5.5 LOHC

As DBT has many advantageous properties, this LOHC system is assumed for the study. The main source of cost and energy data for the DBT LOHC pathway has been the FCH 2 JU funded project HYSTOC though publically available deliverables ([160], [176], [217]). During the project HYSTOC, the cost and energy demand of the hydrogenation and dehydrogenation process has been investigated further, and these references are assumed to contain current information on DBT as LOHC.

For this pathway, three different scenarios are considered for the provision of heat for dehydrogenation. The options are electricity, waste heat and hydrogen. In the latter case, more hydrogen needs to be produced and transported, in order to end up with the required amount.

DBT is produced from toluene and benzyl chloride and currently costs around 4 EUR/kg [218]. The HYSTOC project has performed a cost calculation for the production of DBT, up to large production volumes of 100 000 t/year, in this case with a total production cost estimated to be in the range of 1.42 – 1.80 EUR/kg [160]. 1.5 EUR/kg DBT were assumed in this study to determine the CAPEX for LOHC.

The amount of LOHC necessary has been estimated based on the shipping volume. CAPEX for the purchase of DBT is potentially a substantial cost contribution. In order to estimate the amount of DBT needed, the following assumptions were made:

- Case A: 2 shiploads being transported[39] and 2 shiploads being processed (hydrogenated or dehydrogenated) at any given time, storage of 2 shiploads, for a total of 8 shiploads LOHC needed;
- Case B railport[40]: 4 shiploads being transported on board a ship, 2 aboard trains and 2 shiploads being processed at any given time, storage of 2 shiploads, for a total of 10 shiploads LOHC needed.
- Case B HRS: 4 shiploads being transported on board a ship, 2 aboard trains, 2 aboard trucks and 2 shiploads being processed at any given time, storage of 2 shiploads, for a total of 12 shiploads LOHC needed.
- Case A Hydrogen: 4 shiploads being transported[41] and 2 shiploads being processed (hydrogenated or dehydrogenated) at any given time, storage of 2 shiploads, for a total of 10 shiploads LOHC needed;
- Case B Hydrogen railport[42]: 3 shiploads being transported on board a ship, 2 aboard trains and 2 shiploads being processed at any given time, storage of 2 shiploads, for a total of 9 shiploads LOHC needed.
- Case B Hydrogen HRS: 3 shiploads being transported on board a ship, 2 aboard trains, 2 aboard trucks and 2 shiploads being processed at any given time, storage of 2 shiploads, for a total of 11 shiploads LOHC needed.

---

[39] This figure is based on the number of ships operating.

[40] For Case B two scenarios were investigated, conversion of the carrier at the railport or alternatively at the HRS. In the latter case 270 small scale de-hydrogenation plants would be deployed.

[41] This figure is based on the number of ships operating.

[42] For Case B two scenarios were investigated, conversion of the carrier at the railport or alternatively at the HRS. In the latter case 270 small scale de-hydrogenation plants would be deployed.

The assumed capacity of the ships and the number of ships operating therefore has a direct relation to the investment for purchasing DBT, the cost of which can be considerable. Whereas in terms of shipping costs it would be preferable to have large capacity ships with fewer roundtrips, this is increasing the purchasing costs of the DBT. Smaller ships enable an optimisation of the amount of LOHC in circulation. As an example, if only one ship is traveling back and forth, the amount of DBT in circulation would be the highest. The storage sizes have to be increased proportionally, and storage times are also high due to the small number of trips of the ship. The number of (de-)hydrogenation cycles would be lower, compared to using more ships, however this has less impact on the final cost than the purchase of the DBT. The ship capacity was therefore set to a value that minimises the overall costs.

As for other investments, an interest rate of 5% was assumed, and the DBT given a lifetime of 20 years (notwithstanding replenishment and upgrading, as explained below).

In addition, the operational costs for DBT were calculated according to the formula given in [219]. A small fraction of DBT decomposes during cycling. The decomposition reaction also releases methane, toluene, benzene, MCH and cyclohexane [174]. However, a recent study found that prior purification of the DBT may circumvent this issue [175]. According to the outcomes of the HYSTOC project, it is assumed that regeneration of DBT is needed after 750 cycles [219]. Fresh DBT also has to be purchased to replace the decomposed material. According to [176], 0.013% of DBT is assumed to be lost per cycle. The cost can be calculated by adding the amount of LOHC needed per kg of hydrogen to the assumed 10% loss of DBT for every 750 cycles. 15.3 kg of LOHC are needed to store 1 kg of hydrogen, which is a gravimetric storage capacity of 6.13%, somewhat lower than the theoretical maximum of 6.2%, as it is assumed that the (de-)hydrogenation rate will not reach 100%. The number of cycles have to be calculated according to the amount of DBT and the number of cycles per shipload of DBT.

The energy demand for the production of DBT has been estimated at 42.1 kWh electricity and 2.7 MJ steam in [35]. The project HYSTOC, as described in detail in a public deliverable [160] arrived at a lower value assuming 4 840 kW for a plant with 3 500 t/year capacity (8 040 h operating hours considered). This would amount to 10.41 MJ/kg DBT based on the assumed output of the plant, where 26% of the total energy demand is attributed to DBT, the rest to the production of MBT. As the report by the HYSTOC project provides more information than [35], the energy demand for DBT production is based on the former reference. According to [160], 12 950 tons of toluene are needed to produce 3 500 tons of DBT[43], which is a ratio of about 3.7 : 1. The energy demand for chlorine and for toluene as the base materials has been added[44]. The energy demand for the production of toluene from biomass is assumed to be 0.45 GJ/ton, according to [220]. This would amount to 1.67 MJ/kg DBT. For chlorine, the production process delivers 1 ton chlorine and 1 ton caustic soda, plus hydrogen, which is referred to as the electrochemical unit (ECU). The energy demand of the chlor-alkali process is 11.88 GJ per ECU [221], of which 33% is attributed to chlorine, based on the value of the final products[45]. 1.29 t chlorine is needed to produce 1 t DBT. In total, the energy demand per kg DBT is assumed at 17.2 MJ.

5.5.5.1 Packing

The enthalpy of reaction of DBT is 65.4 kJ / mol H_2 [145]. Hydrogenation takes place via the intermediate compounds H6- and H12-DBT, to the fully hydrogenated H18-DBT storing 9 moles of H_2 [164]. Heterogeneous metal catalysts, such as Ru or Ni are needed for hydrogenation, which is an exothermic process and takes place at 1-5 MPa [147]. Hydrogenation at a pressure of 1.5 MPa has been reported in the range of 74-98% [148]. The degree of hydrogenation is determined by the temperature, pressure and reaction time. During decompression, some hydrogen degasses, leading to process losses of around 0.1 wt% [218].

---

[43] The plant also produces 10 000t MBT for which a market is assumed, and by-product HCl is sold.

[44] Energy demand for other components than toluene and chlorine was not estimated in this study

[45] Main inputs: 1.75 kg sodium chloride, 10.69 MJ. Main outputs: 1 kg chlorine [0.141 EUR/kg], 0.028 kg H_2 [2.68 EUR/kg], 1.13 kg caustic [0.191 EUR/kg] [281]

The energy demand for hydrogenation was assumed to be 1.33 MJ/kg H_2, in line with Reuss et al. [222], for compression and pumping. In the literature, values between 0.79 MJ/kg H_2 [176] and 3.48 MJ/kg H_2 [223] are stated. The reaction itself is exothermic, so it is assumed that there is no further energy demand for hydrogenation. Excess heat could be recovered in principle, however, for this study it was not seen as a viable option due to the unlikelihood of a suitable heat sink close to the hydrogenation facility.

The costs for the hydrogenation plant have been estimated based on Reuss et al [222]. It is assumed that a facility with a capacity of 100 000 tH_2/year would cost EUR 60 m [222]. No scaling factor was used for a plant size with a capacity above 100 000 tH_2/year, as these types for plants have not yet been implemented at large scale, so a more conservative cost estimation was used. For both the hydrogenation and dehydrogenation plants, CAPEX is calculated assuming that the plant comprises as many units of 100 000 tH_2/year as necessary to cover total demand. For LOHC, the option to use hydrogen for the provision of heat for dehydrogenation was also assessed. In this case, the volume of hydrogen to be transported is higher in order to be able to supply this energy demand, which is assumed to be 45 MJ/kg H_2 (see section 5.5.5.4). This means that additional LOHC has to be processed and transported. Hence, the plant capacities for Case A and Case B are 1.63 times larger compared to the scenarios where the energy demand is met by electricity or waste heat.

The plant assumptions are similar to those used for ammonia and methanol, with an utilisation of 333 days per year, an interest rate of 5%, and a 20 year[46] lifetime. The O&M costs are estimated to be 3%, including replacement of catalyst material.

5.5.5.2 Storage

Storage costs have been estimated based on those for crude oil and LOHC storage for various capacities, based on [224], [176], [225]. The values were interpolated assuming an exponential relation between cost and storage capacity, with reference values per m^3 ranging from 122 EUR to 550 EUR. In [226], a cost of USD 466 per m^3 is given for underground stockpiling, with the remark that this is 20% higher than aboveground storage. Therefore the assumed cost range seems to be reasonable.

Energy demand for storage was not considered.

5.5.5.3 Transport

Due to the similar properties of DBT to diesel and crude oil, it is assumed that existing infrastructure and technology can be used.

For shipping for Case A, the round-trip duration, including (off-)loading is set to 12 days. A Suezmax size ship with a capacity of 158 000 DWT was chosen; for Case A there would be 5 ships operating. If hydrogen is used to provide the heat for dehydrogenation, a higher amount of hydrogen, and consequently LOHC, needs to be transported, increasing the amount of hydrogen to 1.63 mt/year. For this scenario, 7 ships with the same capacity would be in operation. The cost for the Suezmax size ships is assumed to be EUR 65 m according to [106], which is stated as an average value for this ship capacity. At 15 knots speed the fuel consumption is set at 55t/day, which is an estimate based on [227]. For fuel costs, biodiesel is assumed to cost EUR 782 per ton. For pumping operations, 30% of the fuel consumption for cruising is considered. Loading/off-loading operation is considered to take 24 h [228] with the ship staying at the harbour for a total of 4 days.

OPEX is calculated in line with the function provided in Tijdgat [106], and amounts to around 5% of CAPEX for the Suezmax size tankers, and around 10% for the smaller tankers.

For Case B Hydrogen, ships with a capacity of 35 000 DWT were assumed, and for Case B, a smaller ship capacity of 16 000 DWT resulted in an overall lower cost (see above, related to the amount of DBT in circulation). For Case B, 4 ships are used to transport the LOHC, and for Case B Hydrogen, 3 of the larger ships. The ships are cruising at a speed of 15 knots, with a fuel consumption of 28 t/day (small oil tanker) and 22 t/day (very small oil tanker) [227]. Loading/unloading is performed in 12 hours, and the ships remain in the port for 2 days.

---

[46] As this is a technology yet unproven at this scale, a 20 year lifetime has been assumed, rather than 30 years.

The costs of the ships were taken from [106] and [229], whilst information on fuel use was found in [227] and [230]. As for the other options, the ships are assumed to be consuming biodiesel as fuel, with a cost of 782 EUR/t. OPEX was calculated according to [106]. The energy demand was calculated by assuming an energy content of 37.5 MJ/kg biodiesel. The number of operating hours were calculated for cruising and pumping operations. The energy demand for pumping was set to 30% of that for cruising.

More information on the assumptions can be found in the Annex 2, **Table 22**.

Transport by train takes place through the use of oil rail cars [170], with a DBT capacity of 23.6 tonnes. CAPEX for an oil rail car is around EUR 128 000 [171]. The size of train convoy, as well as the number of trains, is defined by LOHC demand. This changes depending on the energy source for the dehydrogenation step. Table 10 summarizes these values, as well as the correspondent CAPEX. The number of rail cars is duplicated, in order to improve logistics. CAPEX represented is the average value between diesel and electric train.

Table 10. CAPEX, size and number of trains transporting DBT. Source: literature data and JRC assumptions, see text.

	Electricity / Waste heat	Hydrogen
Train convoy size	38	41
Number of trains	2	3
Train CAPEX (MEUR)	8.2	8.8

For Case B, there are two scenarios, one where the LOHC is dehydrogenated at the railport, and the second where dehydrogenation takes place at the HRS. For the latter, it is assumed that DBT is transported by truck using portable tanks [172]. The portable tank considered can hold 25 000 litres of DBT (22,8 tonnes) [231]. Tare weight of these portable tanks is around 3500 kg [231]. Two 20 ft portable tanks are transported per truck, however there is a limitation in cargo weight (40 tonnes). Therefore, it has been decided to limit the amount of cargo transported by truck to 33 tonnes of DBT. Truck CAPEX is 175 000 EUR (excluding portable tanks), as explained in section 5.2.3. Portable tank CAPEX is around 20 000 EUR [231].

As for trains, the number of trucks is defined by the energy source for DBT dehydrogenation. In the case of electricity or waste heat, the number of trucks considered is 51, while for hydrogen as energy source the number of trucks goes up to 81.

If dehydrogenation takes place at the railport, transport of hydrogen to HRS is performed by trucks similar to the ones described in section 5.5.1.3.

5.5.5.4 Unpacking

The energy demand for dehydrogenation is assumed to be 45 MJ/kg H_2, with 41.2 MJ/kg H_2 for provision of heat and 3.6 MJ/kg H_2 electricity requirement, in line with information given in various sources [232], [223], [222], [233]. In case of dehydrogenation using hydrogen, the total energy requirement was set to 49.6 MJ/kg H_2 to account for the efficiency of the combustion process (assumed to be 90%). If waste heat is available, then 3.6 MJ/kg H_2 electricity was assumed, and the rest of the energy demand provided by the waste heat. The cost for hydrogen was set as described in Section 5.4. Waste heat costs were assumed to be EUR 20 per MWh.

Hydrogen recovery is assumed to be 99.9%, as reported in [233].

For Case A, the costs of the dehydrogenation plant was assumed to be EUR 669 M, based on the cost estimate given in Reuss et al. of EUR 60 M for a plant with a capacity of 100 000 t H_2/year. A linear scaling factor was used, as plants of this scale have not yet been realized. For the option of using hydrogen for provision of heat, the capacity of the plant increases to 1.64 Mt H_2/year, and the costs of the plants increase accordingly.

For Case B, the unpacking of the LOHC takes place either at the railport or at the HRS.

For the railport option, dehydrogenation takes place in 6 separate plants, one at each railport. The costs of each plant is assumed to be EUR 20 m for the electricity case, and EUR 28 m for the hydrogen case. For the HRS case, these dehydrogenation plants need a capacity of 1.12 tH_2/day based on an availability of 333 days per year. The cost for the plant was set to EUR 4.0 m, based on the cost estimate provided in [176] for a plant capacity of 1t H_2/day of EUR 3 - 4 m.

At the HRS, hydrogen needs further compression, from 0.7 MPa to 52 MPa. The energy demand was assumed to be 7.7 MJ/kg H_2. CAPEX is set around EUR 400 000 [234], and OPEX to 4% of CAPEX [24].

Hydrogen purity following dehydrogenation is high for DBT, with impurities in the ppm range of toluene and other hydrocarbons [235]. A recent paper suggests that even higher purity is possible, largely complying with the ISO standard for PEMFC vehicles, if the DBT is purified prior to use [74]. This is a promising development, as further purification would be unnecessary for most end-use applications.

Purification was considered necessary for both Case A and Case B, although it should be noted that many industrial customers would not need further purification. Due to the high initial purity, either membrane or PSA purification with a recovery rate of 99% is assumed to enable PEMFC grade hydrogen [233]. According to a study by Papadias et al., the cost of a PSA is USD 286 per kgH_2/day for a capacity of 350t/H_2 per day, and USD 452 per kg H_2/day for a capacity of 50 tH_2/day [236]. These figures were used to calculate the costs of purification for Case A and Case B. The cost of the purification plant is therefore set to EUR 229 m for Case A, and for Case B EUR 6 m (for each individual plant, in total 6 PSA are needed) for the railport case and EUR 500 000 for the HRS case. The energy demand for the PSA process is assumed to be 3.6 MJ/kg H_2, according to [237]. The loss of 1% of hydrogen during purification is taken into account by increasing the amount of hydrogen to be transported.

5.5.6 Pipelines

Pipelines as transport options were modelled for compressed hydrogen, ammonia, methanol and DBT for Case A and Case B (results for Case B are not shown, see Section 4).

Pipelines are assumed to be newly built, and to connect the hydrogen production site directly to the consumption location. Pipelines are considered straight and without change in altitude level (total length of 2 500 km). This assumption simplifies calculations but underestimates the final cost.

5.5.6.1 Compressed hydrogen

Maximum allowable pressures in pipelines considered is 7 MPa and temperature is assumed to be constant at 12°C.

In the case of compressed hydrogen, the pipeline has been dimensioned optimising final cost, which consists of both pipeline and compressor costs. Pipeline costs are obtained in two different ways, either following formulas provided in [190], or using the material costs provided by [190] and considering that material costs represent 20% of the total pipeline cost. Following a conservative approach, the value used as pipeline cost is the higher of the two.

Compressor costs are determined based on industry information[47]. The pipeline compressor located at the production site is supplied with low price electricity (price at production site, see **Table 5**) while the rest of the compressors that are part of the pipeline network are assumed to use electricity at demand site prices.

Evolution of pressure along the pipeline is calculated using Darcy's equation, and the Darcy friction factor is calculated using the Churchill correlation [238].

Additionally, two compressor operational configurations were assessed: 1) pressure in the pipeline ranges between 6-7 MPa or 2) pipelines operate in the 3-7 MPa range. The first option would require more compressors than in the second configuration, but those compressors will be cheaper and they will require less power (per

---

[47] Private communication

unit) than compressors in configuration 2. Although configuration 2 has led to lower costs, the costs presented in this report are related to configuration 1, as it appears more realistic in terms of allowed pressure drop.

The CGH_2 pipeline is fed from an underground storage (at 7 MPa) with a capacity of 10 days, costs of this storage are calculated from [32]. Pipeline hydrogen leaks have been considered, assuming a value of 0,4% of the hydrogen transported, according to [24].

Following the dimensioning strategy described above the following values were obtained for pipeline diameter and compressor station distance (see **Table 11**). In these cases, the values obtained were independent of the electricity price scenario.

Table 11 Dimensioning of pipeline network. Source: JRC assumptions.

	Pipeline diameter (inches)	Compressor station distance (km)
Case A	34	220
Case B	14	200

5.5.6.2 Ammonia and methanol pipelines

Ammonia and methanol pipeline designs were based on the same assumptions. All information available for long-distance ammonia pipelines was also used to model methanol pipelines since, to the best of our knowledge, there are no equivalent methanol long-distance pipelines to the NuStar, Magellan and Togliatti-Odessa pipelines [101].

Pressure drop is calculated using the Darcy-Weisbach equation with a Colebrook–White relation friction coefficient obtained using an online calculator [239].

For Case A the internal diameter of the pipeline is taken to be 439.1 mm since this diameter gives a flow velocity of about 2.44 m/s, which Bartels suggests as ‘safe’ [97] and should not cause excessive heating. The chosen diameter is larger than most of the data available for ammonia pipelines, but does not seem to be unreasonable [97]. It is assumed that the pipeline can work 365 days in a year and has a lifetime of 40 years. The chosen interest rate is 5%.

The distance between pumping stations was selected to avoid a pressure drop above 4.3 MPa and ensure that ammonia will remain liquid. It is assumed that ammonia and methanol always remain liquid and their density does not change throughout the pipeline[48]. Given these assumptions, an 80 km distance between pumping stations was chosen and found to be compatible with the details of a Magellan pipeline (US) map [240]. A pipeline surface roughness of 0.05 mm was considered.

The material prices used are based on those of an 18 inch seamless X46 steel[49] pipe and were estimated to be about 1 320 EUR/t-steel [241].

Other details chosen for the pipeline design were based on the information retrieved from a 2016 accident report [242]. A maximum operating pressure of about 8.3 MPa was used in the equation for calculating thickness outlined in Knoope et al. [243]. A wall thickness of about 8.3 mm was obtained. This is in line with ammonia pipeline thicknesses reported in literature [101].

---

[48] This is an approximation, especially for ammonia, but it helps in obtaining rough approximations which are accurate enough for the purpose of our analysis.

[49] The steel density was assumed to be 7 850 kg/m^3.

The cost of the pipeline is obtained using the simple approximation that the cost of material is just a fraction of total pipeline costs. For the diameters considered, this crude approach does not seem to cause uncertainties inappropriate for the level of accuracy of our analysis [243]. Material costs are considered to be 20% of total costs (including right-of-way, labour and miscellaneous other costs). This rough approximation seems to be conservative, but reasonable, as confirmed by available pipeline literature [243], [244], [245], [246].

It was not possible to retrieve detailed information on actual pumps able to manage the flows considered. The only available information was obtained from a presentation by Leighty [247]. It is estimated that an electric ammonia pump with a capacity of 150 tonnes per hour has a cost of EUR_{2020} 600 000. A scaling factor of 0.6 was used. This decision seems to be in agreement with available cost information [248]. The lifetime of a pump is taken as 20 years and two pumps are used per pumping station. The pump efficiency is considered to be 90% and the obtained energy requirements seem to be in line with available technical data on ammonia plunger pumps [249]. Yearly OPEX (excluding fuel) is considered to be 0.04% of CAPEX for pipelines and 4% for pumps.

Based on the assumptions outlined previously, the final CAPEX for Case A will be an overall 626 300 EUR_{2020}/km for both the ammonia and methanol case. Methanol pumps need about 60% of the electricity necessary for pumping ammonia across the pipeline length of 2 500 km (about 515 GWh).

5.5.6.3 DBT pipelines

DBT transport by pipeline is an exceptional case. It requires the construction of two different pipelines, one to send the hydrogenated DBT to the demand location and the other to return the dehydrogenated DBT to the hydrogenation plant. It should be noted that hydrogenated DBT and dehydrogenated DBT are fluids with different physical properties (e.g. density, viscosity). These different physical properties have been considered when dimensioning their respective pipelines. DBT is reasonably easy to handle in terms of its kinematic viscosity of 16.5 mm^2/s at 40°C, however the hydrogenated compound is more highly viscous at 82 mm^2/s at 40°C (for comparison, honey has a kinematic viscosity of 73.6 mm^2/s) [250]. At 20°C, a value of 425 mm^2/s is reported [251].

Pipeline costs are also calculated considering the most conservative value between the costs obtained following formulas provided in [190], and the ones obtained using the material costs provided by [190] and considering that material costs are 20% of the total pipeline cost.

Pipelines are assumed to operate between 1-7 MPa. As in the case of compressed hydrogen, evolution of pressure along the pipeline is calculated using Darcy's equation, and the Darcy friction factor is calculated using the Churchill correlation [238]. Pumping energy demand is calculated considering the pressure drop between pumping stations, and a pump efficiency of 80% [252]. Pump CAPEX is estimated at around 1 700 EUR/kW, according to [253]. Pump annual maintenance costs are 68 EUR/kW, following [252] and [254]. The cost of the DBT held in the pipelines is also considered when dimensioning the pipeline. Summary of dimensions of pipelines for pathway (electricity or hydrogen for dehydrogenation) and energy price scenario are collected in **Table 12** (for Case A) and in **Table 13** (for Case B).

Table 12 Dimensions of DBT pipelines for Case A. Source: JRC assumptions.

Electricity Scenario	Energy source for DBT de-hydrogenation	DBT status	Pipeline diameter (inches)	Total pumping power (MW)	Distance between pumping stations (km)
High	Hydrogen	De-hydrogenated	32	110	125
High	Hydrogen	Hydrogenated	34	200	85
High	Electricity	De-hydrogenated	28	70	130
High	Electricity	Hydrogenated	32	95	110
Low	Hydrogen	De-hydrogenated	30	150	95
Low	Hydrogen	Hydrogenated	34	200	85
Low	Electricity	De-hydrogenated	26	100	95
Low	Electricity	Hydrogenated	28	165	75

Table 13 Dimensions of DBT pipelines for Case B. Source: JRC assumptions.

Energy Scenario	Energy source for DBT de-hydrogenation	DBT status	Pipeline diameter (inches)	Total pumping power (MW)	Distance between pumping stations (km)
High	Hydrogen	De-hydrogenated	12	25	60
High	Hydrogen	Hydrogenated	14	45	40
High	Electricity	De-hydrogenated	10	20	50
High	Electricity	Hydrogenated	12	40	30
Low	Hydrogen	De-hydrogenated	12	25	60
Low	Hydrogen	Hydrogenated	12	65	30
Low	Electricity	De-hydrogenated	10	20	50
Low	Electricity	Hydrogenated	10	95	20

6 Results

The outcomes of the study are based on assumptions, some of which have a high degree of uncertainty, as many of the technologies involved have not been deployed at scale, and information on costs is scarce. Some simplifications have been made, for example pipelines are assumed to be in a straight line, at constant temperature and with no elevation changes. More complex approaches were not deemed to be reasonable, given the overall lack of data, but in general, the error margin on all of the outcomes is likely to be high.

6.1 Case A

As explained in section 5.2.4, Case A is based on the delivery of 1 million tons of renewable hydrogen per year to a single industrial customer, via a direct transport pathway, using a dedicated pipeline or shipping route. The transport distance considered is 2 500 km for shipping and pipeline.

Figure 7 and **Figure 8** show the hydrogen delivery costs in Case A, for the two energy price scenarios. While **Figure 7** focuses on transport by ship of the different carrier options considered, **Figure 8** depicts the case of transport by pipeline. These figures also show the share of costs for specific parts of the delivery pathway (packing, unpacking, carrier costs, hydrogen losses and transport and storage) for each of the options considered and the two energy price scenarios.

One of the objectives of this study is to understand the economic advantage of importing hydrogen from places with lower renewable energy costs/prices, with a particular focus on the internal EU hydrogen market. From the results shown in **Figure 7** it can be concluded that, for distances of 2 500 km between hydrogen production and hydrogen demand locations (compatible with a potential internal EU hydrogen market), imports of hydrogen can economically be competitive if the renewable electricity generation cost differences are above EUR 20/MWh, considering the boundary conditions for this scenario (Case A, low electricity price).

Comparing **Figure 7** and **Figure 8** it can be concluded that transport of compressed hydrogen by pipeline is the cheapest delivery option in Case A, independent of the energy price scenario. Transport by ship of pure forms of hydrogen (i.e. compressed gas and liquefied hydrogen) also appear as a competitive solution. LOHC, if waste heat is available at the consumption site at the assumed price, could also be a low-cost option for hydrogen delivery.

Therefore, chemical carriers, despite their very low transport costs, are identified as less cost effective options for hydrogen delivery. The analysis shows how the cost related to packing and unpacking more than negate the advantages of the very low transport costs. Packing and unpacking costs for chemical carriers are however strongly influenced by energy costs, meaning that lower energy prices would make them more competitive, as can be observed in the figures later in this Section.

In the case of compressed hydrogen delivered by ship, it can be seen that the final cost is dominated by the transport costs. Due to its lower density, transport of compressed hydrogen requires a bigger and more expensive fleet than any other packaging mode. However, the packing and unpacking costs (i.e. compression costs) are low enough to compensate for the higher transport costs. This makes compressed hydrogen by ship an attractive option, for Case A, with a delivery distance of 2 500 km (for other distances, see Section 6.4). As for this pathway costs are dominated by transport costs (i.e. ship fleet plus fuel), final delivery costs do not show a remarkable difference between energy price scenarios for this pathway (see **Figure 7**).

LH_2 can be seen as an intermediate step between compressed hydrogen and chemical carriers. Whereas, owing to its higher density, its transport costs are lower than for compressed hydrogen, (but higher than for chemical carriers), its packing costs (i.e. liquefaction) are considerably higher than in the case of compressed hydrogen (but lower than that of chemical carriers). The latter is explained by the lower packaging (packing and unpacking) energy requirements for LH_2 compare to chemical carriers, and also because most of its packaging energy demand is covered in the location where the energy prices are lower (exporting terminal), contrary to chemical carriers, where most of energy demand happens close to the final use location (i.e. higher energy prices).

Due to the assumption made in this study (LH_2 losses only occur during shipping), costs related to H_2 losses in the LH_2 pathway are relatively low. However, the influence of boil-off on the final costs goes beyond the cost related to H_2 losses. For instance, a bigger liquefaction plant is required to cover the delivery chain demand. H_2

losses and boil-off also requires higher energy demand, since additional hydrogen has to be liquefied (due to H_2 losses), and some additional hydrogen is re-liquefied (the amount boiled-off but not lost).

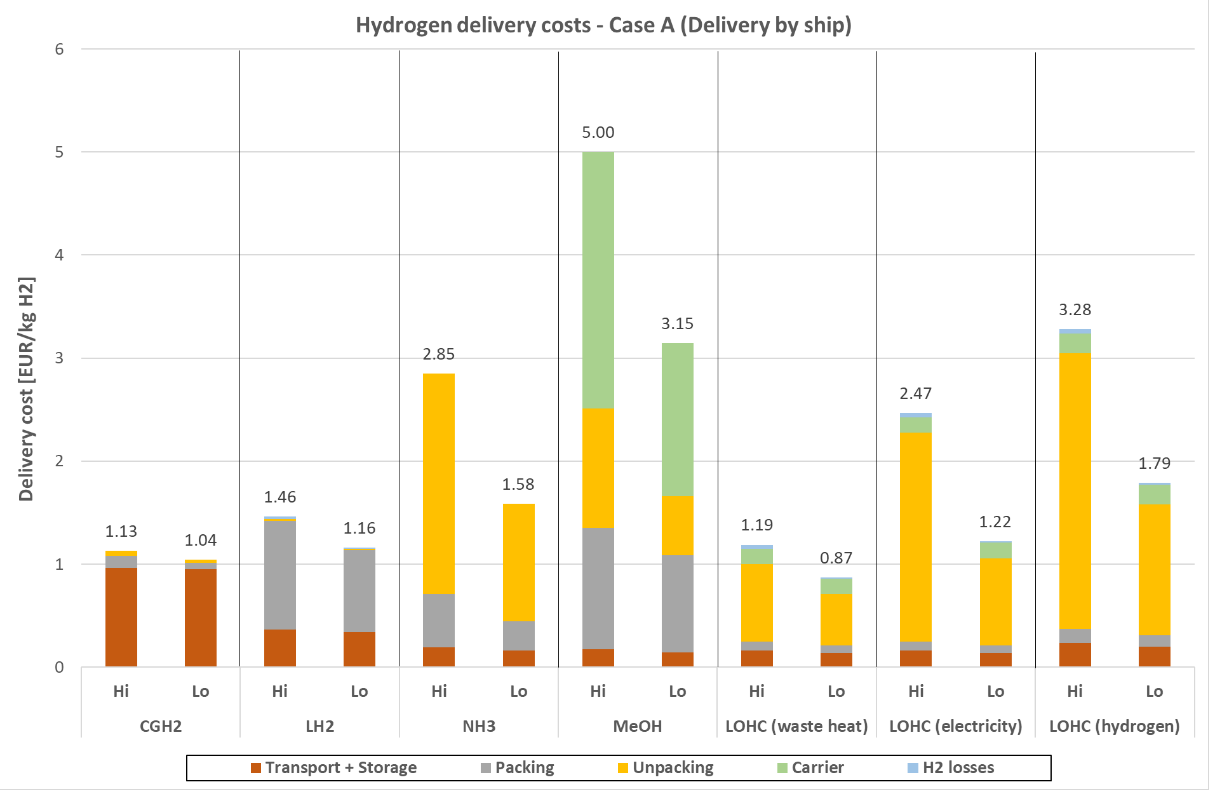
Similarly, for transport costs, a bigger fleet will be required to transport the additional amount of hydrogen necessary to compensate the boil-off. The requirements to over-dimension the equipment of the supply chain (and the extra energy consumption) due to boil-off reduces along the supply chain. For the case presented here, boil-off increases the packing costs by 10-12%. For transport, boil-off implies an increase of 3-5%, while unpacking costs are barely affected by boil-off.

NH_3 has a high energy demand for unpacking, as well as high capital costs for the unpacking plants. For transport and packing, the costs are in between those for the CGH_2 and LOHC options.

The carrier cost is a major share of the delivery costs for MeOH (shown as “carrier” in **Figure 21** and **Figure 22**). This is due to the high energy demand for DAC. For MeOH, the packing and unpacking costs are quite balanced, which is due to the relatively higher energy demand for packing than for the other chemical carriers. This is compensated by a lower energy demand for unpacking (see **Figure 12**).

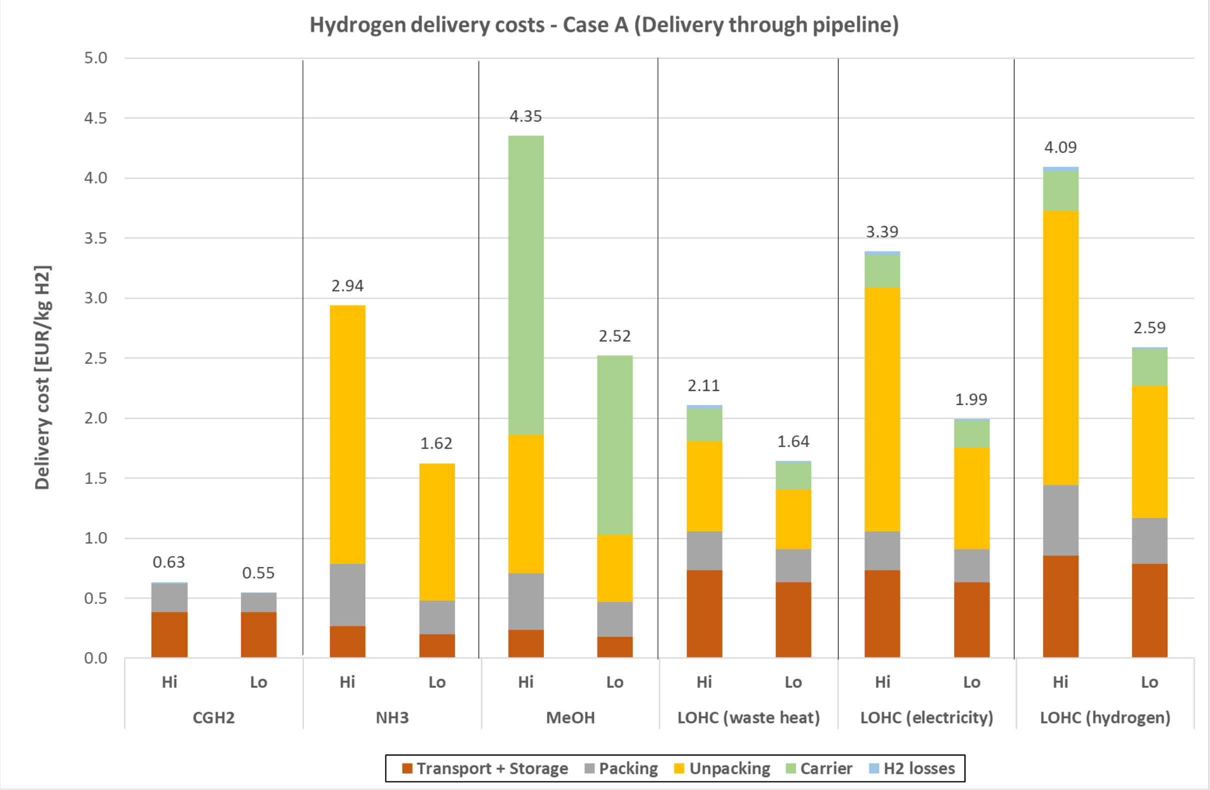
For LOHC, different scenarios are shown in **Figure 7** and **Figure 8** based on the source of energy for dehydrogenation. The options compared are waste heat, electricity and hydrogen. LOHC unpacking costs have the highest share of total costs (see also **Figure 26**) and even for the waste heat case. Transport costs, as mentioned above, are low, which makes this option more attractive for longer transport distances than considered in Case A (see section 6.4). The waste heat option is very competitive, but of course contingent on the availability of cheap, high grade (250˚C) waste heat. This may be the case for specific applications, such as steel manufacturing. The use of hydrogen to provide the energy for dehydrogenation is not found to be a convincing alternative, even in the case of low electricity prices. Using electricity to provide heat for dehydrogenation is the cheaper option, for both electricity price scenarios.

Figure 7 Hydrogen delivery costs for Case A (delivery by ship). High and Low electricity prices for each carrier.



Source: JRC analysis

Figure 8 Hydrogen delivery costs for Case A (delivery through pipeline). High and Low electricity prices for each carrier.



Source: JRC analysis

Transport and storage costs of the whole infrastructure include storage tanks, pipelines, pumping stations, and their maintenance and operation.

Figure 8 shows that transport and storage costs are barely affected by the electricity price scenario; on the other hand, packing costs are reduced by 1/3 with lower energy prices. Hydrogen losses represent between 1-2% of total delivery cost, depending on the electricity price scenario.

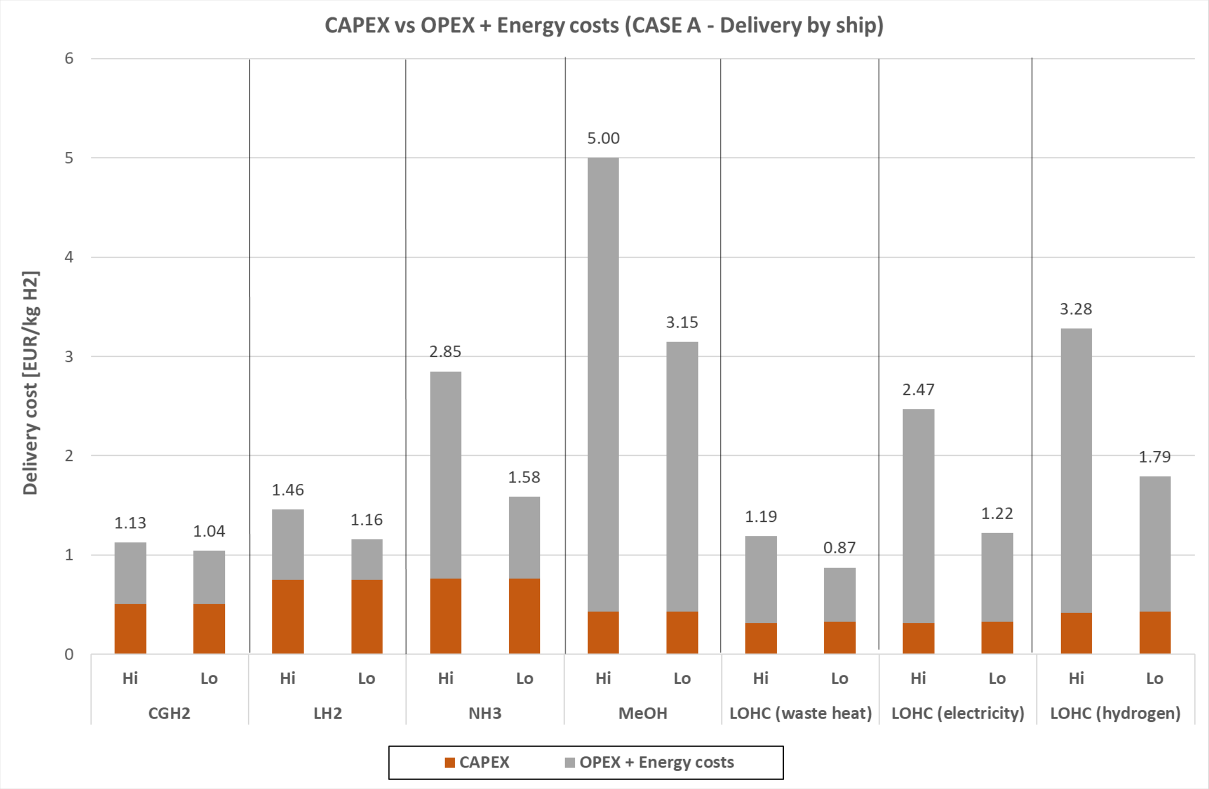
Transport and storage costs represent the higher share of costs for transporting compressed hydrogen through pipelines (see **Figure 8**). For compressed hydrogen, packing costs include investment in all compressor stations along the pipeline and their operational and maintenance costs.

The costs of transporting chemical carriers through pipelines are significantly higher than those for compressed hydrogen. The lower costs in pipeline infrastructure for chemical carriers, due to their higher density (and the fact that they are transported in liquid state) do not compensate the costs for the packing/unpacking that chemical carriers have in comparison to compressed hydrogen. Moreover, unlike compressed hydrogen, hydrogen delivery with chemical carriers show lower costs when transported by ship, unless for the high electricity price scenario. It has to be recalled that electricity price scenarios only modify electricity prices and not fuel prices. Therefore, delivery through pipelines is more influenced by these scenarios (e.g. for the low energy cost scenario, pipeline transport for NH_3 and MeOH has comparable costs to delivery by ship). Another factor in favour of the transport by ship of these carriers is their higher density, in comparison to compressed hydrogen. The combination of higher density, ship size and ship speed, results in that for the same amount, or more correctly, the same flowrate of carrier, delivery by ship requires less energy and material costs than pipelines do.

It can be observed in that transport and storage costs in any of the LOHC pathways are significantly higher than in any other pathway. This is logical, considering that the LOHC pathway requires a double pipeline, one to send the hydrogenated LOHC to its destination and one to return the dehydrogenated LOHC. For the LOHC-hydrogen pathway, a greater amount of LOHC has to be transported (around 40% more, to provide energy for dehydrogenation), it has the highest transport and storage costs among all the LOHC pathways.

An analysis on cost distribution between costs related to investments (i.e. CAPEX) and costs related to the operation (OPEX plus energy costs) is shown in **Figure 9** and **Figure 10.** All options except for LH_2 are dominated by operational costs, and are therefore more sensitive to energy price variations. As can be seen from **Figure 9**. CAPEX[50] for LOHC is the lowest for all the options considered[51], making this a competitive route especially for the low energy cost scenario. It should be noted that this assumption is based on industry estimates, rather than data from existing plants, and is therefore subject to considerable uncertainty. Both LH_2 and NH_3 have the highest CAPEX costs, but as LH_2 needs less energy for packing/unpacking than NH_3 (see also **Figure 12**), operational costs are considerably lower.

Figure 9 CAPEX vs OPEX + energy cost for hydrogen delivery by ship



Source: JRC analysis

In the case of compressed hydrogen delivered by pipeline, costs are mostly related to infrastructure, i.e. pipelines and compressors (see **Figure 10**). This suggests that repurposing existing natural gas pipelines for hydrogen transport would significantly decrease the associated delivery cost, making this option even more competitive. The natural gas industry estimates that cost savings could be more than 50% compared to a newly built pipeline [43].

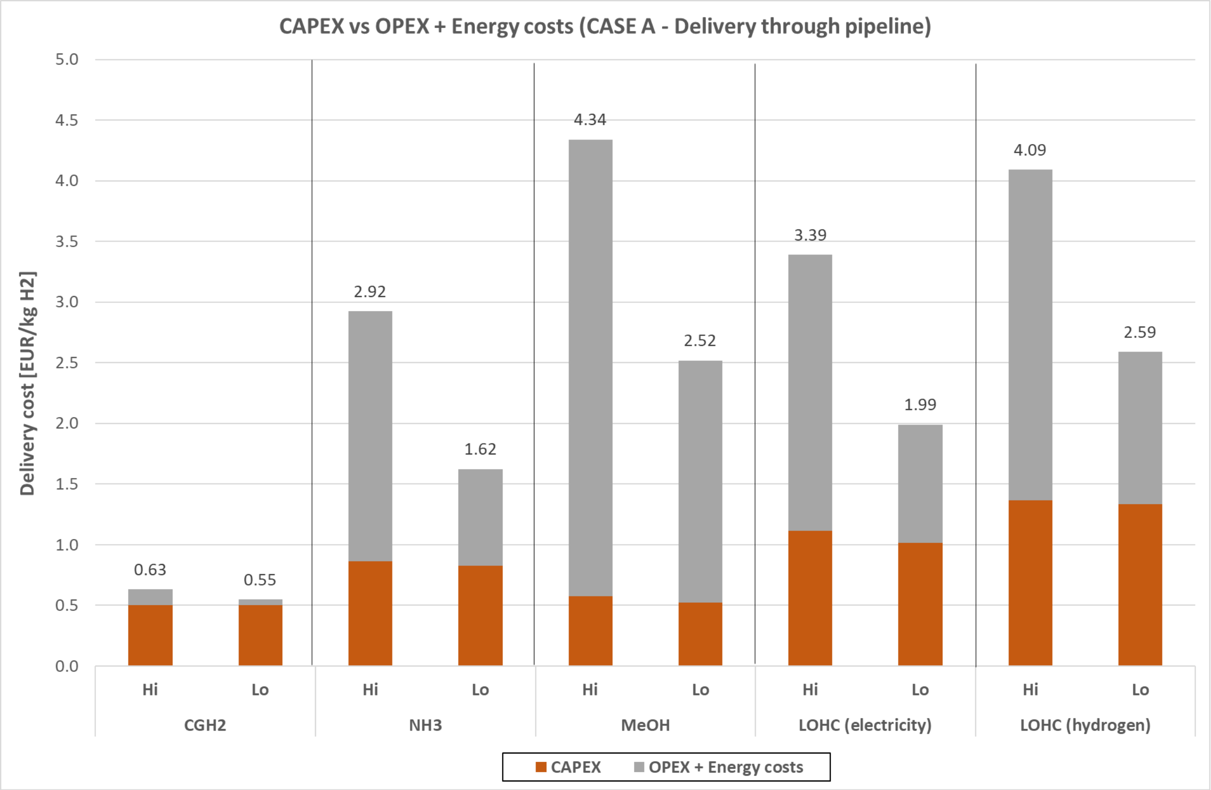
A previous study by the JRC had different outcomes of the delivery cost assessment, due to changes in some of the assumptions. This is discussed further in Section 6.6.

---

[50] See Section 3 for more detail on CAPEX assumptions.

[51] This is based on the assumption that the costs of the packing and unpacking processes are lower than for the other options due to the lower technical complexity.

Figure 10 CAPEX vs OPEX + energy cost for hydrogen delivery through pipelines



Source: JRC analysis

6.2 Case B

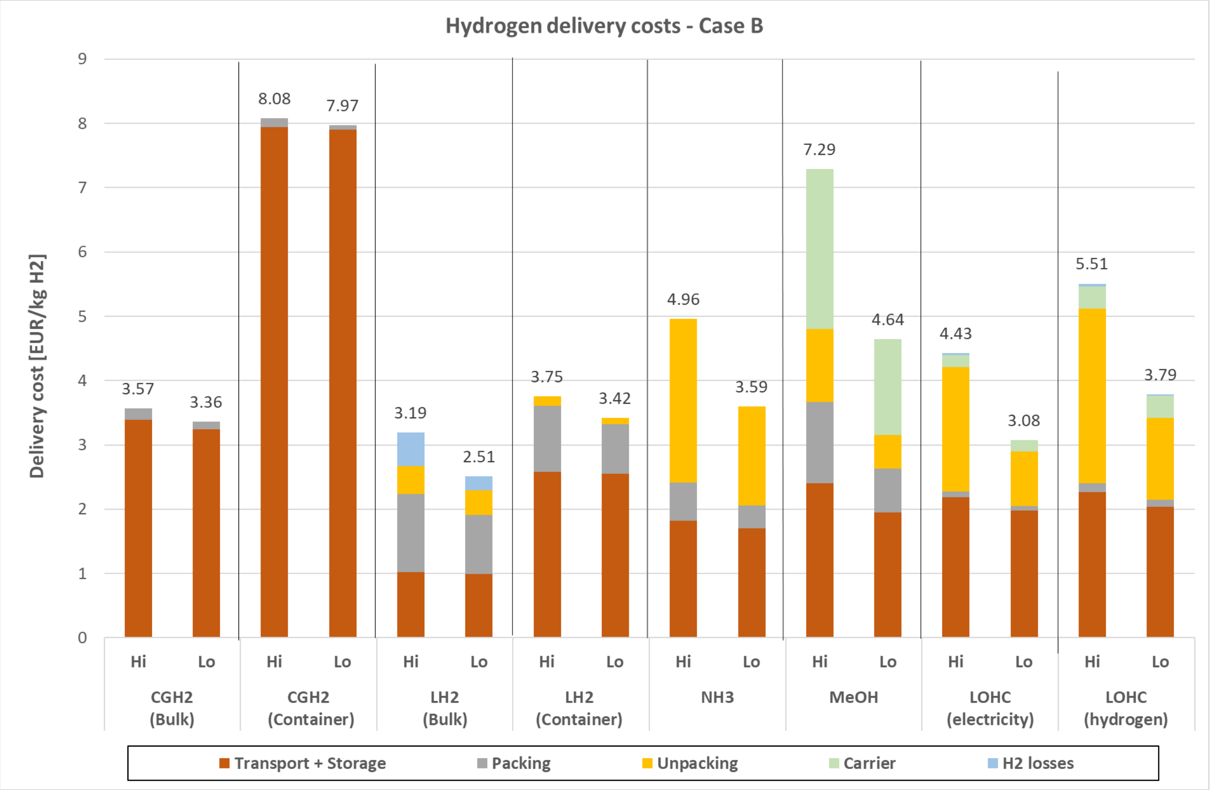
A more distributed delivery scenario involving smaller quantities of hydrogen (Case B) leads to different conclusions. Transport and storage costs increase significantly in this scenario, in particular penalising the packaging solutions with lower gravimetric density (i.e. compressed hydrogen). Liquefied hydrogen appears as the cheapest option for the scenario considered here (Case B, see **Figure 11**), also because achieving the purity level required by HRS is more demanding for chemical carriers. LH_2 delivery costs could be as low as EUR 2.51 for the low electricity cost scenario, to EUR 3.19 in case of high electricity costs. Regarding chemical carriers, it has to be recalled that for the case of NH_3 and MeOH, it is assumed that carrier unpacking takes place at the railport (see 5.2.5), as the last leg of the delivery route is in the form compressed hydrogen. This brings an additional cost in terms of CGH_2 containers and transport (due to lower density of compressed hydrogen), explaining the high costs related to transport and storage for these carriers. This also serves to explain the similar costs that CGH_2 and NH_3 (ranging from EUR 3.36 – 3.75).

Two possible scenarios are considered for hydrogen delivered by LOHC (see 5.2.5), either the LOHC is dehydrogenated at the railport (and transported in gaseous form to the HRS) or LOHC dehydrogenation takes place at the HRS. Results of this analysis showed that when dehydrogenation takes place at the railport, the delivery costs are lower than in the HRS scenario. Therefore, values reported in **Figure 11** correspond to dehydrogenation at the railport. For the low electricity cost scenario, LOHC is the second cheapest option, if electricity is used to provide heat for dehydrogenation. It was assumed that waste heat would not be readily available at a railport or HRS, so this option was not considered.

A containerised delivery option has been assessed against the delivery in bulk as well for Case B (only for compressed and liquefied hydrogen). This implies that the containers are delivered from the hydrogen production site (i.e. exporting terminal) to the HRS, with no emptying/refilling steps in between, contrary to bulk delivery. Although this is interesting in terms of simplifying logistics, costs are higher than the bulk delivery options, particularly in the case of CGH_2. This can be attributed to the high number of containers needed, combined with the cost of the containers themselves. LH_2 delivery by containers shows better performance than CGH_2 when compared to their respective bulk delivery options. This is due, on the one hand, to a higher transport density than in the case of CGH_2 (so less containers are needed for the same amount of hydrogen transported) and, on the other hand, to the lack of hydrogen losses, unlike for LH_2 bulk transport

As evidenced by **Figure 11**, unpacking costs are dominant for most chemical carrier options for Case B.

Figure 11 Hydrogen delivery costs for Case B (distributed delivery). High and Low electricity prices for each carrier.



Source: JRC analysis

While comparing hydrogen costs between Case A and Case B (see **Figure 7** vs **Figure 11**) it should also be noted that a smaller amount of hydrogen is distributed in the latter case. Economies of scale also influence the final cost of hydrogen, particularly the cost shares related to the packing and unpacking processes.

6.3 Energy demand

The energy demand of the various hydrogen delivery options have been assessed for both Case A (**Figure 12**) and Case B (**Figure 13**). As indicated in section 5, thermal energy demand can be covered with waste heat (only for LOHC), electric heaters or burning fuel (either hydrogen, ammonia or methanol). In case of hydrogen losses, or hydrogen used as fuel, the energy considered is the energy necessary for the fuel production (i.e. 180 MJ/kg H_2, considering a 50 kWh/ kg H_2 electrolyser efficiency) and not the heating value of the fuel (i.e. 120 MJ/kg H_2), as in this study hydrogen is produced via water electrolysis. A similar approach is used for other fuels. This approach increases the total amount of energy consumed by the pathway, but it offers a more realistic estimate than the one given simply considering the energy requirements for each step in the delivery chain as outlined in section 5.5.

Compressed and liquefied hydrogen are the least energy demanding distribution options in both Case A and Case B, while methanol is the most energy demanding pathway due to the Direct Air Capture of CO_2. This has been added under the cost category "Carrier", as the CO_2 is needed to produce methanol.

Analysis of energy demand for Case A shows that, for liquefied hydrogen, more than 80% of its energy demand is related to the liquefaction process (i.e. packing). For NH_3 and LOHC, energy demand concentrates in the unpacking process (around 75% in the case of NH_3 and LOHC). The packing process for NH_3 is also energy demanding, unlike for LOHC.

On the contrary, energy demand in the case of CGH_2 is dominated by transport energy requirements, particularly for CGH_2 delivered by ship (more than 70% of energy demand related to transport). For CGH_2 delivered through pipeline, transport energy represents around 45% of the energy requirements, however, the energy demand of the compressor at the beginning of the pipeline has been considered as packing. If this compressor was also considered as part of the transport, then energy related to transport will represent almost the 80% of the energy demand for this pathway.

Energy demand for chemical carriers delivered through pipelines is not represented in **Figure 12**. Analysis showed that energy requirements are quite similar to the ones of their respective chemical carrier delivered by ship. This can be explained as energy demand for these pathways is also dominated by the packing/unpacking step, therefore the energy demand related to transport (the only step in which pipeline and ship may differ) is only a small fraction of the total.

CGH_2 pipeline energy demand, on the other hand, is significantly lower (5.6 MJ/kg H_2) than CGH_2 by ship (24.4 MJ/ kg H_2), due to lower compression requirements and the higher transport efficiency of pipeline compared to CGH_2 ship.

Another advantage of pipelines (except LOHC) when compared to ship transport is that pipelines do not need to perform a return trip (as ships do) from the delivery location to the hydrogen production site, as these sites are permanently connected through the pipeline. Other energy advantage of transport through pipeline is that energy is only used to move the fluid (either hydrogen or chemical carrier), while in the case of delivery by ship energy is necessary to move both the fluid and the ship.

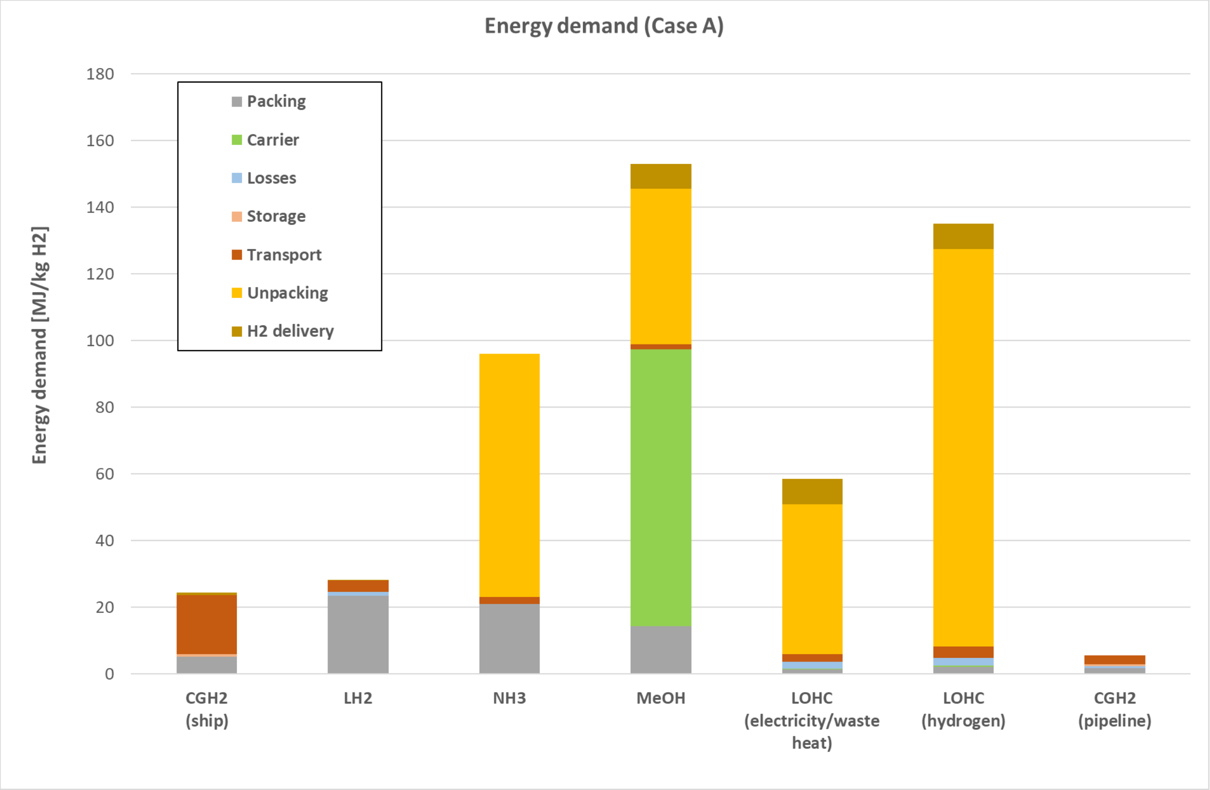
Case B brings an additional 500 km delivery distance, in addition to a more distributed network, when compared to Case A. Despite the extra amount of energy demand from the train/truck distribution leg, transport energy demand still represents a small fraction of the energy demand of hydrogen delivery except in the case of CGH_2. For the LOHC pathway, the values showed in **Figure 13** correspond to the case where unpacking takes place at the railport.

Packing and unpacking energy requirements, per kg of hydrogen, should not change between Case A and Case B, as their efficiency is not dependent on plant size, as mentioned in section 6.4.

However, this is not the case for the LH_2 pathway. The addition of several steps for delivery in Case B implies a significant increase in hydrogen losses and hydrogen boil-off, due to additional travelling distance and transfers between transport and storage. The hydrogen losses increase the energy demand for this pathway as more hydrogen has to be produced (per kg of hydrogen delivered) but also because they will imply a higher energy demand for the packing, as more hydrogen has to be liquefied. Additionally, the higher amount of boil-off will also incur more hydrogen being reliquefied, increasing also the energy demand for packing per kg of hydrogen delivered.

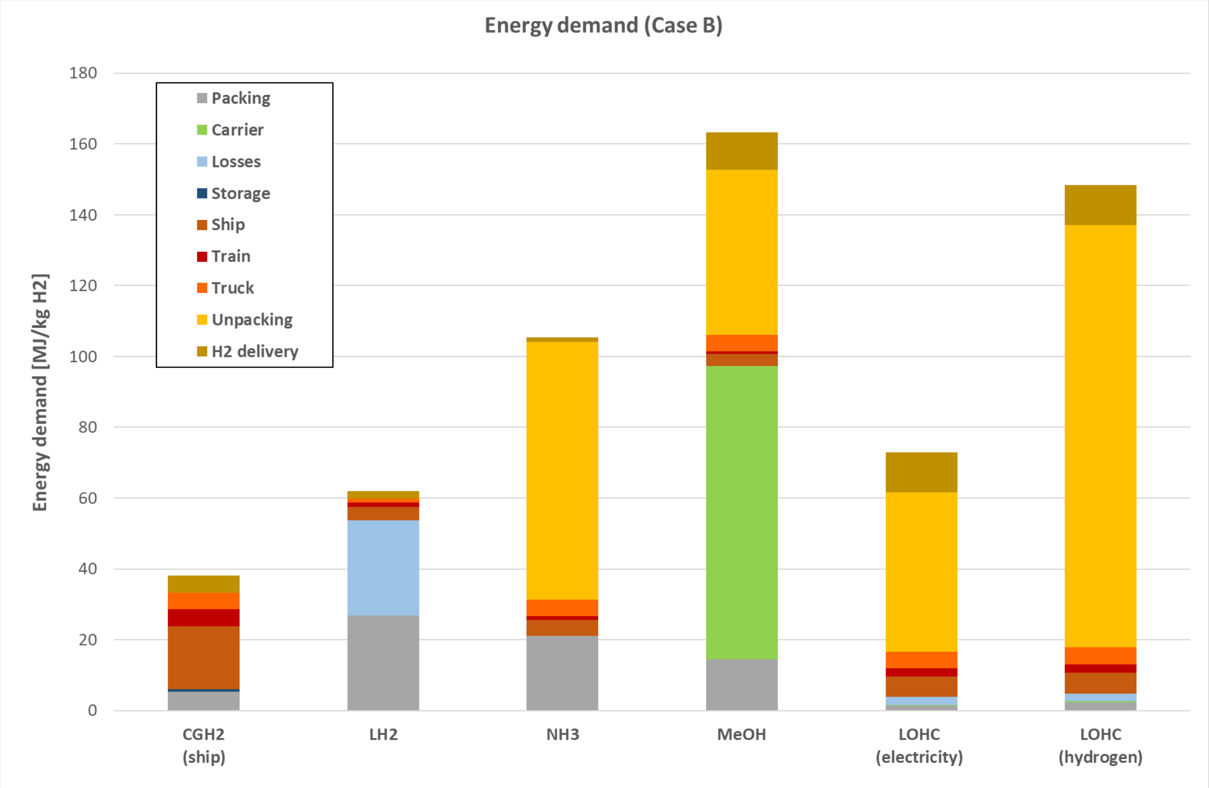
Another aspect that justifies a higher energy demand for Case B than for Case A is that the former requires that hydrogen is delivered at higher pressure and purity than in Case A. This is particularly relevant for the chemical carrier pathways, where this additional step requires around 10-11 MJ/ kg H_2. In the case of NH_3, energy demand for the final compression and purification of the hydrogen delivered is included in the unpacking energy, as the ammonia cracking plants considered already included the purification and compression system.

Figure 12 Energy demand per kg of hydrogen delivered (Case A)



Source: JRC analysis

Figure 13 Energy demand per kg of hydrogen delivered (Case B)



Source: JRC analysis

In order to put the values of energy demand for each pathway into context, they are compared in Table 14 against the energy necessary to produce 1 kg of hydrogen (180 MJ/kg H_2, considering a 50 kWh/ kg H_2 electrolyser efficiency). Whereas in Case A, delivery of 1 kg of hydrogen through CGH_2 pipelines only requires 3% more energy, delivery of 1 kg of hydrogen through the MeOH pathway needs a similar amount of energy (85%) as necessary for its production. Values for Case B show that, after hydrogen production, at least an additional 20% of energy will be necessary for its delivery. Moreover, for some pathways the energy demand for delivery is more than half the energy demand for production (e.g. NH_3) or almost equal (i.e. MeOH). In **Table 14** it can be also be observed that moving to more distributed delivery networks has a higher impact in CGH_2 and LH_2 pathways energy demand (between 50% and 100% increase compared to Case A) than for chemical carriers (5-15 % increase). However, the better performance of chemical carriers in terms of transport is still not sufficient to compensate for the high energy demand of packing and unpacking processes.

Table 14 Delivery energy demand vs Hydrogen production energy demand. Source: JRC analysis.

	Energy ratio between hydrogen delivery and hydrogen production	
Pathway	Case A	Case B
CGH_2	0.14	0.21
LH_2	0.16	0.34
NH_3	0.53	0.58
MeOH	0.85	0.91

LOHC (electricity/waste heat)	0.32	0.41
LOHC (hydrogen)	0.75	0.82
CGH_2 (pipeline)	0.03	N/A

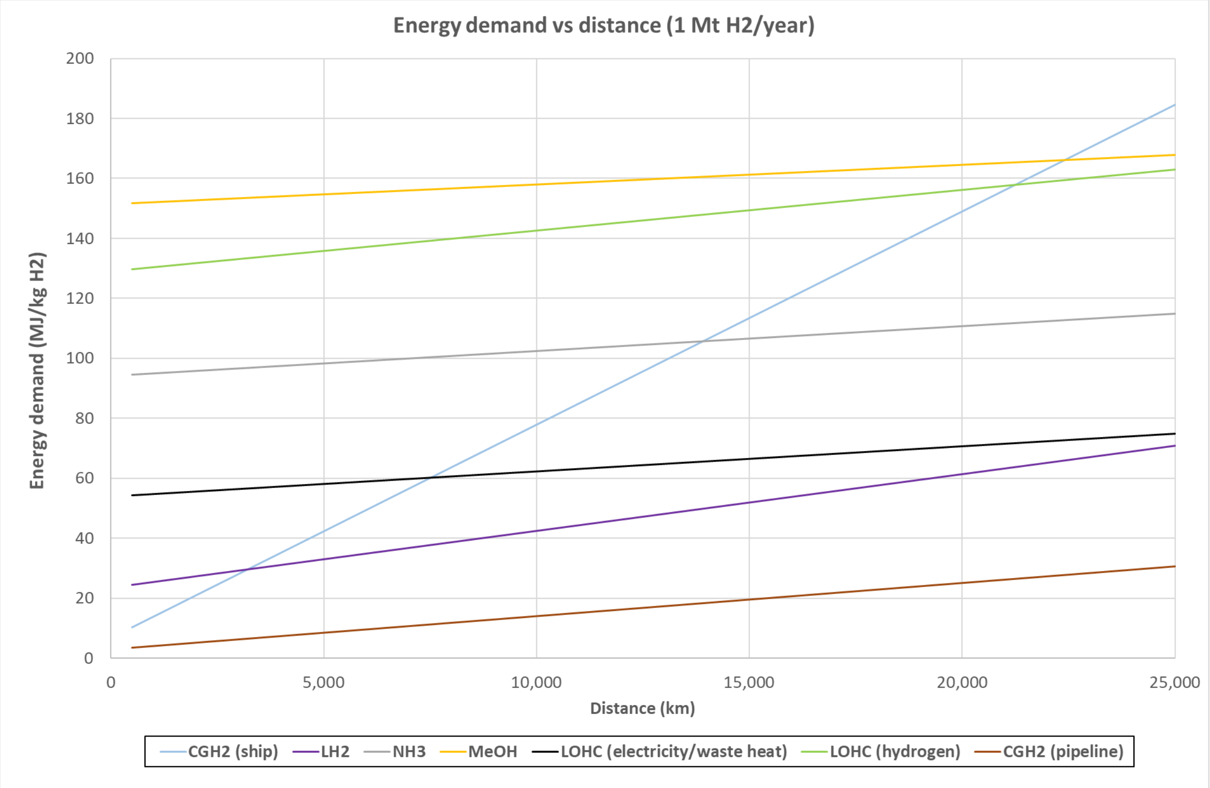
Energy requirements will increase with delivery distance, but not all the energy needs related to hydrogen delivery are distance dependent. While energy demand for transport will depend on delivery distance, energy requirements related to packing/unpacking plants or storage will remain the same, independent of the delivery distance. Nevertheless, in the case of the LH_2 pathway, liquefaction energy requirements will increase with distance, as more hydrogen will be lost due to boil-off (see Section 5.5.2.3). Average energy requirements per delivery distance (including return trip) and per kg of hydrogen delivered for transport by ship considered in this study (for Case A) can be seen in Table 15, where transport energy requirements for CGH_2 pipelines (i.e. compression work) are also included.

In **Figure 14**, energy requirements against distance are plotted. Despite lower transport energy requirements, chemical carriers perform worse, from energy point of view, than LH_2 and CGH_2 (pipeline) for any distance considered due to their very high energy needs for packing/unpacking. CGH_2 delivered by ship is the opposite case to chemical carriers, with very low packing/unpacking energy requirements but high transport energy needs, due to its low density, becoming the most energy demanding pathway for very long distances, together with LOHC pathway (unpacking with hydrogen).

Table 15 Average transport energy demand (Case A). Source: JRC analysis.

Pathway	Transport energy demand (kJ/kg $H_2 \cdot km$)
CGH_2	7.12
LH_2	1.41
NH_3	0.83
MeOH	0.66
LOHC (electricity/waste heat)	0.85
LOHC (hydrogen)	1.38
CGH_2 (pipeline)	1

Figure 14. Energy demand against delivery distance.



Source: JRC analysis

6.4 Cost vs delivery rate

The influence of the delivery rate (tonnes of H_2 per year) on the costs of hydrogen delivery can be observed when comparing both cases. However, the additional complexity of Case B does not allow for a direct comparison of this aspect.

Delivery rate influence has been analyzed in the particular case of compressed hydrogen pipelines. Considering delivery distances compatible with Case A (i.e. 2 500 km), the delivery costs per unit of hydrogen (kg) in three different annual delivery rate scenarios has been calculated. Results are shown in **Figure 15**. In the pathway analyzed, a ten-fold increase on hydrogen delivery rate (i.e. from 0.1 Mt/year to 1 Mt/year) reduces the delivery costs of a unit of hydrogen by around 2/3. However, it is expected that for delivery rates higher than the ones analyzed here, the cost of delivery per unit of hydrogen would only reduce marginally.

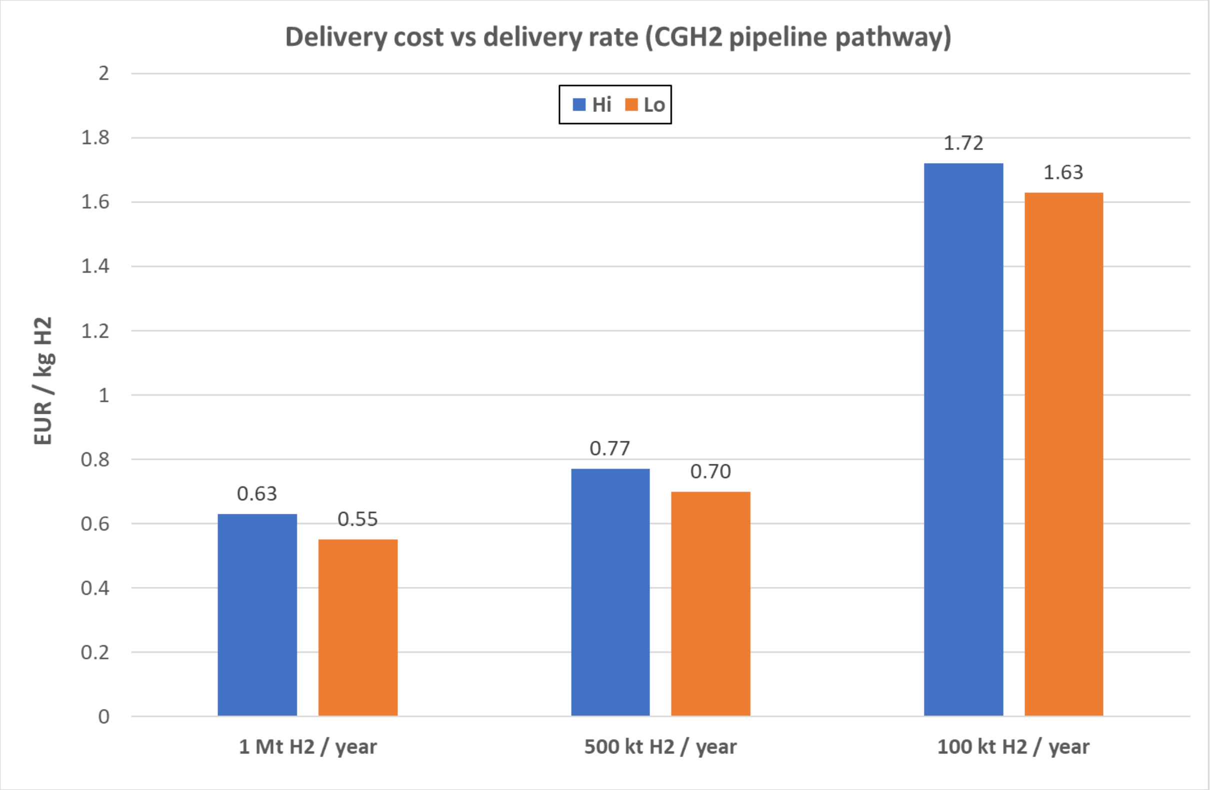
For the delivery rate range considered, pipelines are the only delivery pathway where economies of scale are applied for the whole delivery rate range considered, therefore, pipelines show a bigger variation in delivery costs as function of the delivery rate than any other pathway. For the rest of the pathways, economies of scale are applied up to certain size and from there a liner approach is taken (see Section 3). This implies that delivery costs are less dependent on delivery rate, for the range considered.

Costs were calculated based on the two electricity prices scenarios ("Hi" and "Lo"). Cost differences between two energy price scenarios observed in **Figure 15** do not show a dependence on delivery rate. This difference is around 0.08 EUR/kg H_2 in each delivery rate scenario.

This can be explained considering two aspects: 1) pathway energy demand (i.e. costs affected by electricity price) is defined by the energy demand of the equipment comprising the pathway, 2) equipment efficiency (e.g. MJ/kg H_2) considered in this pathway (i.e. compressed hydrogen pipelines) is independent of equipment size. For 2), energy demand per hydrogen unit will remain constant in any delivery rate scenario, the energy costs difference should remain constant between energy price scenarios. This applies to any other pathway where the efficiency of the equipment does not depend on equipment size.

As an additional observation, due to the lack of dependence on delivery rate, the impact of energy prices on delivery costs is proportionally higher the lower the total cost, i.e. for large delivery rates.

Figure 15 Hydrogen delivery costs (through compressed hydrogen pipelines) as a function of annual hydrogen delivered amount



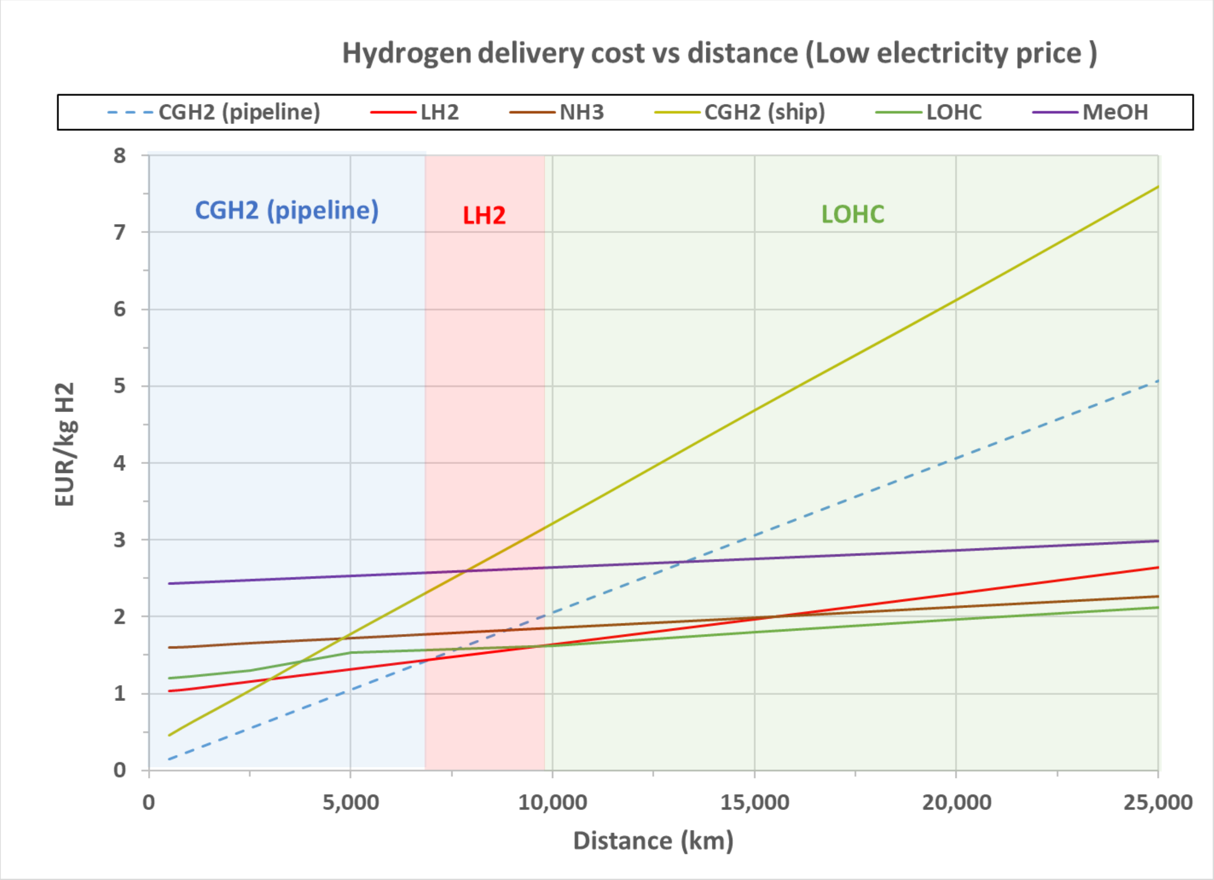
Source: JRC analysis

6.5 Cost vs distance

Figure 16 and **Figure 17** show the evolution of hydrogen delivery costs with distance, up to 25 000 km for delivery rates equivalent to those of Case A (i.e. 1 Mt H_2 per year)

For low electricity prices (see **Figure 16**), hydrogen pipelines are the cheapest option up to around 6 500 km, after which LH_2 becomes the more economic option. From around 10 000 km LOHC becomes the most cost competitive. For very long distances (above 15 000 km), chemical carriers (ammonia and LOHC) perform better than LH_2, mainly due to the issue of boil-off. Should pipelines not be available, shipping of compressed hydrogen is cheapest up to 3 000 km.

Figure 16 Hydrogen delivery costs plotted against distance for 1 Mt H_2/year and low electricity price.



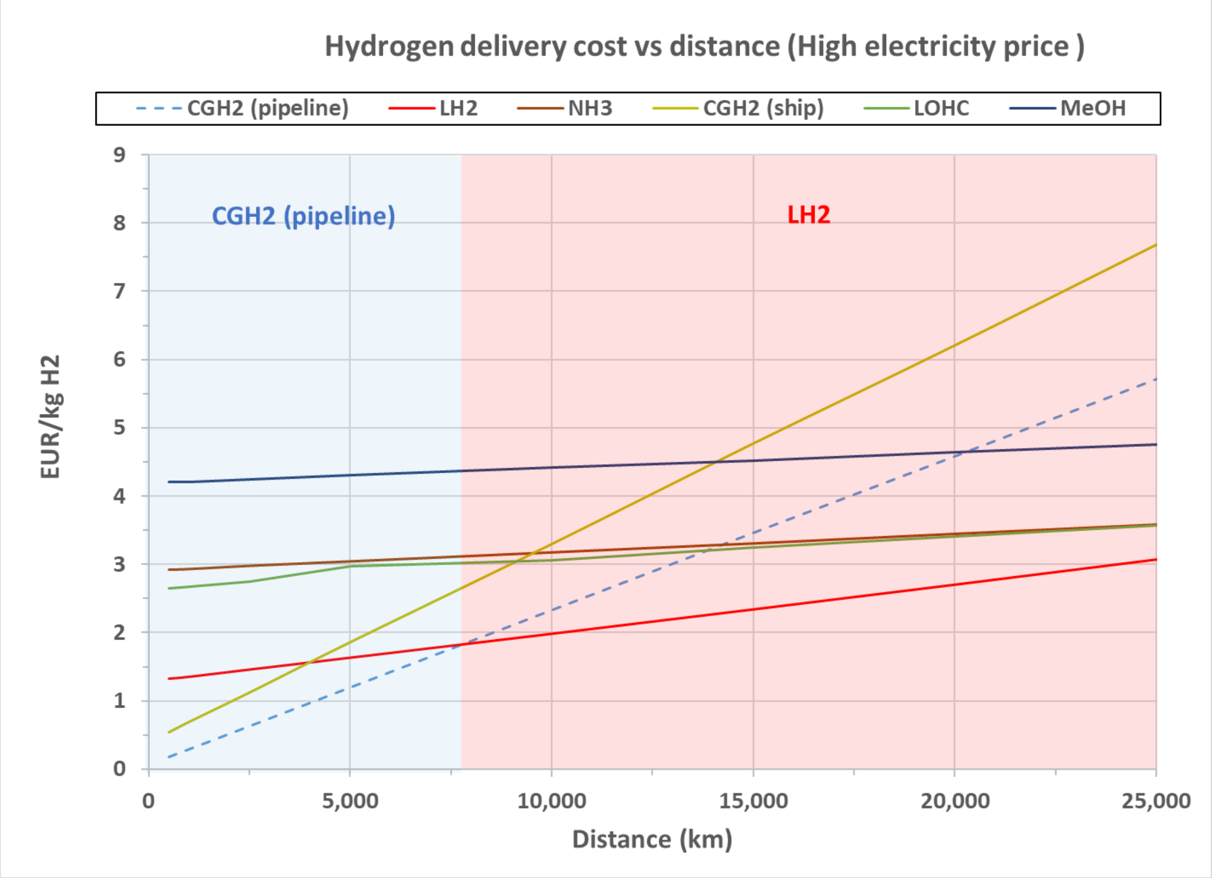
Source: JRC analysis

In the case of high electricity prices, CGH_2 pipelines also appear as the most economic option up to 7 500 km, where it is outperformed by LH_2, If CGH_2 pipelines is not a feasible option, delivery of hydrogen in CGH_2 ships is the cheapest option up to 4 000 km, and from there LH_2, as it can be seen in **Figure 17**. Chemical carriers do not show up as an interesting option in this scenario, this can be mainly explained by the fact that chemical carriers are more influenced by high electricity prices than liquid hydrogen. It has to be recalled that liquefaction of hydrogen takes place at production site with lower electricity prices than delivery site, where chemical carriers as NH_3 and LOHC are processed.

The MeOH pathway is the most expensive amongst the chemical carriers, for any electricity price scenario and distance considered. Its low transport costs are not enough to compensate the high costs related to its packing/unpacking and the CO_2 DAC necessary for the MeOH synthesis, even in the case of very long delivery distances.

In order to optimize delivery costs, the LOHC ships' capacity is modified with delivery distance, this explains the sudden changes observed in the LOHC trend (around 5 000 km). For other pathways this approach was not applied since the authors of this study considered that the use of bigger ships for those pathways would not be realistic.

Figure 17 Hydrogen delivery costs plotted against distance for for 1 Mt H_2/year and high electricity price.



Source: JRC analysis

Preliminary results of this study have been published in a policy brief [3]. Since then, the authors have refined the model and made several changes to the assumptions.

The following changes have been made to the assumptions, compared to [3]:

- CAPEX for the processing plants has increased, as the costs are assumed to scale linearly from a specific capacity onwards. This leads to higher costs for liquefactions plants. LOHC is mainly OPEX driven, and therefore less affected by this change in assumptions.
- The delivery chain has become more complex, including additional steps of compression and storage, to better reflect a probable scenario.
- The costs for compressors have been reduced, leading to lower costs for H_2 pipelines.
- The costs for CGH_2 ships have been increased.
- The amount of LOHC assumed to be needed for long distance shipping has been increased significantly. The size of the ships is increased from a Suezmax capacity to VLCC from 5 000 km onwards.

Whereas the overall outcome of the study remains largely the same, there are some important differences, the main one being that the costs of all the shipping options has increased considerably. This can be partially attributed to the fact that the scaling factor for CAPEX has been set to linear from 100 000 t/year plant capacity. The authors do not believe that in the timeframe considered (2030+), large single plants for packing/unpacking would be built. For a future hydrogen economy, this assumption could be revisited. The comparison of the outcomes reveals the role of basic assumptions on CAPEX and OPEX on the ranking of hydrogen delivery options.

6.6 Comparison to other studies

A large number of studies have been published on the topics of hydrogen delivery. These studies have attempted to identify the lowest cost transport solution for various use cases. Comparisons between the different options have also been made considering energy demand and in some cases GHG emissions. A full literature review is outside the scope of this work, however, the differences between our results and those of a few selected recent studies are briefly summarised. In literature, the "best" option (in terms of economics) was identified as either LH_2 [255], NH_3 [21], [256] or LOHC [257]. The various outcomes can partially be explained by differences in the scenarios used, for example the amount of hydrogen transported, and the distance considered. Also the assumptions for costs and energy demand of the many technologies involved diverge widely. It is therefore not possible to compare the results directly.

In recent work by Ishimoto et al., the options of LH_2, NH_3 and pipeline transport have been compared [255]. The energy demand, GHG emissions, and costs for transport of hydrogen from Norway to either Rotterdam or Tokyo have been derived. The amount of hydrogen to be transported compares to our Case B with 128 000 – 157 000 t H_2/year. The outcome of the study revealed that the LH_2 option for transport to Rotterdam was more cost effective than the NH_3 pathway, which is in line with our findings. Also, considering delivery to Tokyo, LH_2 has either similar or lower costs than the NH_3 pathway, depending on conservative or optimistic assumptions regarding LH_2 processing and handling costs. The LH_2 transport to Rotterdam costs EUR 2.27, for a transport distance of 2 539 km, which is far higher than we have found (see **Figure 7**). This difference can, at least in part, be attributed to the much higher LH_2 infrastructure costs assumed in the Ishimoto et al. study.

The IEA Future of Hydrogen report also compares various hydrogen delivery pathways [177] and [258], namely CGH_2, LOHC and NH_3. For some of the cost calculations, the IEA studies are based on today's costs, rather than on potential future costs as is the case for our study, a difference which is particularly relevant for low TRL technologies. For pipeline costs, CGH_2 and NH_3 options were compared with figures provided up to 3 000 km. The cost for hydrogen distribution by pipeline was given as USD 2 / kg H_2 for a distance of 3 000 km, which is far higher than the costs assumed in our study (< EUR 1/kg H_2, see **Figure 8**). NH_3 costs for the same distance are about USD 1.2/kg H_2 (compared to EUR 1.6 – 2.9/kg H_2). It is not possible to fully understand this discrepancy based on the assumptions given in the IEA study, but as the costs for the pipeline itself are similar, the differences would have to be attributed to the compression step. Both CAPEX and OPEX for compressors are likely to be much higher in the IEA study. In our study these have been optimised for the amount of hydrogen or ammonia to be transported. Compression needs have been calculated bottom up based on pipeline diameter and the pressure drop. There are also major differences in the costs for shipping of LH_2, where in our study the costs are considerably lower. It should be noted that in the IEA report, the costs for shipping include the costs for liquefaction, whereas for the LOHC and NH_3 pathways, the costs for dehydrogenation/cracking are not included. The costs for the transport part itself would be around USD 0.4 / kg H_2 for 3 000 km, compared to EUR 0.34-0.37 / kg H_2 for 2 500 km in this study. The overall difference is partially due to the boil-off rate considered (0.2%/d in the IEA report vs 0.1%/d in the present study). For hydrogen conversion, the costs provided in the IEA report are higher for all three options [177]. For LH_2, this is likely to be attributable to the electricity costs, as other assumptions are similar. Otherwise the IEA study is based on today's costs rather than future costs of the technologies, as already mentioned, which leads to higher costs for conversion technologies.

In "A North Africa – Europe Hydrogen Manifesto", Ad van Wijk et al. made the case for the large scale import of hydrogen to Europe [16]. In this vision, a 1 000 GW pipeline connection between Europe and North Africa would be installed by 2050, also converting existing natural gas pipelines. A report by the Hydrogen Import Coalition has found that large scale green hydrogen imports to Belgium is technically feasible and cost-effective [19]. Hydrogen is seen as playing a crucial role to enable carbon neutrality, for end-users such as shipping and aviation, and as a feedstock for industrial clusters. Several import locations were assessed, ranging from Australia to the North Sea. The study considered several cases, with the use case for importation from Morocco being most similar to our study. The findings show that, for the time horizon of 2030-2035, the lowest cost options are NH_3 and MeOH, with an overall cost of around EUR 2.25/kg H_2, with a hydrogen cost of around EUR 1.2 / kg H_2. The delivery options LH_2 and LOHC are more costly at about EUR 2.7 / kg H_2. Also hydrogen delivered by pipeline is found to be more expensive than the delivery as NH_3 or MeOH, a marked difference to the outcome of our study. This could possibly be attributed to the assumed compression costs, or for the unpacking costs for NH_3 and MeOH.

A study by Hank et al. assessed five different hydrogen delivery pathways (LH_2, LOHC, methanol, methane, ammonia) as to their energy efficiency and costs, for a case study considering the transport of 42 500 t H_2/year from Morocco to northern Europe [21]. LH_2 and NH_3 are the most economic options, with delivery costs around 1.70 EUR / kg H_2. The main difference to the results of our study is the much lower cost assumed for NH_3, which comes out as the lowest cost option for shipping, for all distances. Among the outcomes was that LOHC has the highest overall cost among those studied, which can be attributed to the high purchasing costs for DBT. A similar amount of DBT was assumed to be necessary as for our Case B, which, however, in our study is used to transport more than double the amount of hydrogen to be delivered as in the Hank study. Due to the high costs for DBT, we assume that the logistics of this pathway would be optimised as far as possible, and that the amount of DBT needed can be reduced.

Raab et al. [175] compared various liquid hydrogen carriers, LH_2 and two types of LOHC, for transport of hydrogen from Australia to Japan. The total delivery costs range are in line with the outcomes of this study, apart from the fact that the costs for the LOHC pathways in the study by Raab et al. have lower costs than the LH_2 option. They assume that the dehydrogenation costs are far lower, as LNG is used to provide the heat, whereas in our study either electricity or hydrogen is used. This choice was made to minimise the CO_2 footprint of hydrogen transport.

In 2021, IRENA published the study “Green Hydrogen Supply” [259], which compared several hydrogen transport options over distance, all with higher costs than in the JRC study. IRENA published a more detailed assessment of hydrogen delivery options in 2022 [256], in this report a cost comparison is made for ammonia, LH_2, LOHC and hydrogen pipelines. The IRENA study found that, apart from pipelines, ammonia shipping is the most cost effective option, with costs being 7-23% lower than that of the other alternatives. Ammonia cracking is said to contribute around 30-40% of the total cost. In the JRC study, the costs for ammonia cracking are much higher, at 72-75% of the cost, which helps explain the different outcomes (**Figure 24** and **Figure 25**). Since our assessment uses hydrogen and ammonia as a source of heat for cracking ammonia, this significantly increases the final costs for ammonia as a carrier. The costs for LH_2 ships are a major cost component in the IRENA study, but not in the JRC study, where the cost for this option is dominated by the liquefaction plant and energy demand, at close to 70% (see **Figure 20** and **Figure 21**). For LOHC the IRENA study found that the costs for purchasing the carrier material can be considerable, and similar to the cost of the ships. In the JRC study, the cost of the DBT is almost twice that of the ships, and constitutes 12% of the total costs (see **Figure 26** and **Figure 27**). A similar analysis of transport cost as a function of distance is shown in the IRENA study (Fig. 6.7, compare to **Figure 17** in the JRC study). New pipelines are shown to be the most economic option (except for repurposed pipeline, which are cheaper) up to a distance of 3 000 km, following which ammonia shipping becomes the most economic option. Comparing the two figures, the costs are generally much lower in the IRENA study (the assumed volumes of hydrogen to be transported were higher at 1.5 Mt H_2/year), in particular the costs of Ammonia for packing and unpacking.

The Levelised Cost of Hydrogen for hydrogen delivered to HRS was calculated as part of a study by the ASSET (Advanced System Studies for Energy Transition) project, which is providing studies to support EU policy making. This work aimed at identifying investment opportunities for the hydrogen value chain, and the report looked into the different cost components of hydrogen delivery. For the low cost case, the transmission, distribution and storage cost components amounted to around EUR 0.5/kg H_2, for pipeline distribution over 600 km, which is roughly in line with the results of this study.

Roland Berger [260] recently published a study comparing hydrogen transport options, LOHC, ammonia and LH_2. Similar to the findings of this study, the report concludes that there is not one single, best solution for all use cases. Four scenarios were assessed, referred to as archetypes. One of these was a simple harbour to harbour delivery, as in our Case A, but with a distance of 12 000 km one way and a volume of hydrogen of 73 000 t/year. Another archetype was a multimodal delivery as for our Case B, but also including inland shipping, for a volume of 7 300 t/year. The studies are therefore not directly comparable, also as the Roland Berger report does not provide any details on the assumptions. The most cost effective option for the harbour to harbour case is LOHC, with delivery costs ranging from 1.6 – 1.9 EUR/kg H_2 transported for the 2035 scenario. Considering the lower volume transported, the figures could be considered roughly in line with those found in our study, with the exception of ammonia. For LH_2, the main differences are likely to be the assumed costs for conversion and shipping.

In summary, the many assumptions (and their inherent uncertainty) that have to be made for the calculation of the cost of hydrogen delivery can help explain the differences in the outcomes of the various studies. The list above is by no means exhaustive, and only serves to illustrate this fact. Indeed even two pathways based on the same carrier will likely obtain different results depending on the assumptions made on volumes transported and distances considered and in particular regarding the technological parameters and energy sources used for the transport value chain. Reducing the uncertainty of the assumptions is therefore a key objective for further research, see also Section 8.3.

7 Conclusions

This report presents the analysis of cost and energy requirements of hydrogen delivery in EU-compatible scenarios. It considers two delivery cases, Case A and Case B, and two electricity price scenarios. Case A represents a simple point to point delivery scenario (with a delivery rate of 1 Mt H_2 per year), whereas Case B is a more complex distribution pathway (with a delivery rate of 100 kt H2 per year). This study considers several packaging options for the hydrogen delivery, comprising delivery in its pure form (i.e. CGH_2 and LH_2) or using hydrogen chemical carriers such as NH_3, MeOH or LOHC. Additionally, for Case A, two transport options (i.e. shipping and pipelines[52]) have been analysed.

From energy point of view, delivery of compressed hydrogen by pipeline is the most interesting option by far. It combines a very low energy demand for packing with relatively low energy requirements for the transport. CGH_2 delivered by ship is also identified as a delivery option with low energy demand, although it has the highest transport energy demand, its energy needs for packing are very low. LH_2 also offers good energy performance, particularly for Case A. However, in more distributed networks (i.e. Case B), hydrogen losses become a relevant source of energy demand, worsening the performance of this option.

For chemical carriers, having low energy demand related to their transport is not enough to compensate for the high energy requirements for their respective packing and/or unpacking processes. This is the case in particular for MeOH, due to the high energy consumption of the DAC necessary to supply the CO_2 for its synthesis. For this pathway (MeOH) it has been concluded that energy for hydrogen delivery is similar to the energy need for hydrogen production. This contrasts with CGH_2 by pipeline, where energy for delivery is equivalent to only 3 % of the energy necessary for hydrogen production.

Regarding delivery costs, for the cases and scenarios considered, hydrogen delivery in its pure form (i.e. CGH_2 and LH_2) are identified as the most competitive delivery options. This is mainly due to the lower complexity of the delivery chain, not involving chemical transformations. For Case A, CGH_2 delivered through pipeline is the most cost effective option, followed by CGH_2 delivered by ship and LH_2. However, under certain conditions (waste heat as energy source and low electricity prices) LOHC become a very interesting option, only outperformed by CGH_2 delivered through pipeline.

Case A also served to understand the economic advantage of importing hydrogen from places with lower renewable energy costs/prices, with a particular focus on the internal EU hydrogen market. From the results of the analysis it can be concluded that, for distances of 2 500 km between hydrogen production and hydrogen demand locations (compatible with a potential internal EU hydrogen market), imports of hydrogen can economically be competitive if the renewable electricity generation cost differences are above EUR 20/MWh, considering the boundary conditions for this scenario (low electricity price).

When referring to Case B, LH_2 is the most competitive pathway, as a more distributed delivery network has higher impact on transport cost for the CGH_2 than for the LH_2 pathway. Cost differences between the most cost competitive options (LH_2 and CGH_2) and chemical carriers are smaller in Case B than in Case A, as more transport is necessary (which benefits higher density carriers), however, the requirements in terms of purity and pressure defined for Case B plays against their cost competitiveness.

Electricity prices influence the final delivery costs, particularly in the case of chemical carrier pathways, which are highly influenced by electricity price variability. Unpacking chemical carriers accounts for a significant share of their total cost, mostly due to the processes' high thermal energy demand and the fact that unpacking plants are likely to be placed in locations with a relatively high electricity price. The fact that for these options the highest energy demand is during the dehydrogenation process, i.e. at the customer site, is a disadvantage compared to the CGH_2 or LH_2 delivery options. In our assumptions, electricity in unpacking sites will have higher costs as well as a higher GHG footprint than the electricity at the hydrogen production site. Optimization of unpacking processes has a key role to play in increasing the competitiveness of the chemical carrier pathways. It should be noted that, in this study, thermal energy required for the unpacking process was not considered to derive from fossil fuels and this significantly impacts the overall unpacking costs for chemical carriers.

---

[52] Pipeline transport was not considered for LH_2.

From the outcome of this study, chemical carriers do not seem to be an attractive option for hydrogen delivery, except in the case of LOHC using waste heat as energy source. However, it could be argued that for longer delivery distances they could perform better than CGH_2 and LH_2, as their transport requirements in terms of cost and energy are smaller. For that reason, analysis of the influence of distance delivery on cost and energy requirements have been also assessed. The analysis showed that chemical carriers could be the most competitive option for distances above 10 000 km, and in a low electricity price scenario. For high electricity price scenario, however, no chemical carrier seems to be able to compete against LH_2, no matter the distance considered.

Influence of delivery rate on final delivery costs (i.e. economies of scale) was also analysed in this study, but only for CGH_2 pipeline delivery. For this pathway, a ten-fold increase on hydrogen delivery rate (i.e. from 0.1 Mt/year to 1 Mt/year) reduces the delivery costs of a unit of hydrogen by around 2/3. However, it is expected that for delivery rates higher than the ones analysed here, the cost of delivery per unit of hydrogen would only reduce marginally, in particular for other pathways where economies of scale are applied up to a feasible or realistic size and from there on, a linear approach is used.

It has to be remarked that the conclusions from this study should not be extrapolated to other scenarios. In general it seems that there is no single optimal hydrogen delivery solution across every transport scenario. The most cost effective way to deliver renewable hydrogen depends on distance, amount, final use, and whether there is infrastructure already available. Final user requirements in terms of hydrogen purity and pressure can have a significant cost contribution. Therefore, a combination of these aspects could result on a different outcome to the one obtained in this study. Nevertheless, results from this study suggest that CGH_2 pipeline, if available, will the most competitive hydrogen delivery option for any scenario considered, particularly if repurposing of pipelines is possible.

The authors would like to remark that the values obtained during the analysis have a level of uncertainty, as the scale of deployment considered is beyond any existing infrastructure. Moreover, some of the technologies considered in this study are still in early stage of development. Unfortunately, this is a common issue for any study analysing the delivery of hydrogen at big scale.

8 Policy considerations and recommendations

8.1 Policy considerations

With renewable hydrogen production costs of EUR 1.5-EUR 3.5 /kgH_2, the contribution of hydrogen delivery costs to the final hydrogen price is not negligible. However, delivery costs may be low enough to facilitate the competitiveness of large imports of renewable hydrogen from cheaper production locations, particularly for a single point-to-point delivery route. As outlined in **Figure 11**, for a network of distributed hydrogen consumers, the cost of hydrogen delivery can possibly represent the highest share of the total hydrogen cost at the demand site. For this use case, even with limited renewable energy resources and consequently higher electricity prices, on-site hydrogen production may be more competitive than imported hydrogen. However, it has to be recalled that the analysis presented here did not consider the delivery of hydrogen by a capillary network of pipelines for this scenario (Case B). This option could become the most suitable option in a highly distributed scenario[53]. One of the main challenges for the delivery of large amounts of renewable hydrogen is the current lack of infrastructure (e.g. liquefaction plants, ammonia cracking or LOHC dehydrogenation solutions), both in terms of number of facilities and the lack of technically proven large-scale size designs. This challenge becomes more relevant when considering the amounts of renewable hydrogen the EU will demand in the coming years, as outlined in the European Hydrogen Strategy [2] and the RePowerEU plan [1].

Aggressive and cost-effective implementation of the EU Hydrogen Strategy and the RePowerEU plan warrants improved understanding of the costs of renewable hydrogen. In addition to the delivery aspects covered in this report, more studies are needed to accurately compare actual hydrogen production costs in the EU against the costs in places with better renewable resources (e.g. Chile, Australia or Western Africa). More clarity is also essential on the actual future demand for renewable hydrogen and renewable hydrogen-derived chemicals in the EU, and how much of that demand could be covered with hydrogen produced in the EU at a competitive price. The large scale import of green chemicals could have a significant impact on the European chemical and fertilisers industry.

An established large-scale hydrogen delivery chain would emit much greenhouse gases if fossil fuels are used to fulfil its energy needs. Therefore the definition, certification and labelling of renewable hydrogen should not only consider its production, but also the full delivery chain.

8.2 Future work

A study on the environmental impact assessment of hydrogen delivery options is underway. This work is performed under the Framework Contact the JRC has with the FCH 2 JU, and the report will be published by the end of 2022.

8.3 Recommendations

There are several technological challenges to be overcome to enable competitive delivery of large amounts of hydrogen over long distances.

- Significant technical improvements over the current state of the art are necessary for the technologies involved in the hydrogen delivery chain. Lowering as much as possible the energy demand for packaging/unpacking technologies is a key issue. Support will be needed from the public sector, as there is still a lack of clear business cases for green hydrogen, and industry is probably not able to bear the full cost of the considerable R&D and infrastructure effort.

---

[53] This option was not considered in this study, as such a network would not be purpose built for such low volumes, and moreover challenging to implement. Additionally, a distributed network would likely be based on repurposing of pipelines in our opinion.

- Further research and development should be supported on key issues such as improving the energy demand for liquefaction, enabling transport of bulk LH_2, lowering the dehydrogenation temperature for LOHC and reducing cost and energy demand for ammonia cracking. This work should be complemented by techno-economic studies, to reduce the uncertainties in the assumptions for costs and energy demand of packing/unpacking plants.

- Upscaling of several orders of magnitude also present a challenge for the industries involved, as the technologies still need to be validated at the scale required by the RePower EU Plan. De-risking this investment through EIB loans, or additional co-funding on-top of schemes such as IPCEI or EU structural funds may be needed to reach the required scale.

- As a first step, studies are needed to investigating the technical limits for scaling up, as it is not clear yet what the maximum upper limit for capacities of conversion plants, compressors or ships is. This work could be carried out by consortia composed of research centres and industry partners, and possibly supported by the Clean Hydrogen Partnership or national funding schemes. A technical assessment of optimisation margins for the technologies involved in hydrogen delivery would be useful, which could be addressed in a similar manner as the up-scaling studies.

- The possibility of flexible operation of conversion/packaging plants in order to profit from favourable low electricity prices should be investigated, in order to bring down costs. This can also help to lower the environmental impact, as renewable electricity is likely to have the lowest environmental impact. In parallel viable large-scale electricity and/or hydrogen storage solutions will have to be pursued in order to guarantee the smooth operation of conversion plants.

- Since a major cost component for hydrogen transport through pipelines is the construction cost of new infrastructure, actions aimed at clearly understanding the techno-economic potential for repurposing natural gas pipelines should be supported. There are efforts underway at industry level, often funded through national schemes. The Clean Hydrogen Partnership has issued a call topic in the AWP 2022 [261] which will help address challenges at materials/component level, if a project is funded. More work is needed though on grid operation and other relevant aspects in order to guarantee a safe conversion of existing infrastructure for the transport of hydrogen. The JRC is planning to conduct experiments on the compatibility of pipeline materials with hydrogen in its high pressure gas testing facility [262].

- Research on the potential hazard for the society and the environment (e.g. toxicity, flammability) of hydrogen packaging solutions is needed due to their presence in new settings. This research should lead to the development of adequate technological solutions and the elaboration of safety regulations.

- Modelling of the cost and availability of renewable energy in different geographical locations (within and outside Europe) is of paramount importance for understanding the economic feasibility of hydrogen transport over long distances. JRC has published a report on the assessment of the extent the currently carbon-intensive hydrogen production in Europe could be replaced by water electrolysis using electricity from RES [263], this work should be expanded to a global level. A study on storage needs for various scenarios, linked to the variability of RES, would also be useful. This action will have also clear implications in terms of energy diplomacy.

- A well-developed tool such as the Carbon Border Adjustment Mechanism is necessary in order to assess the actual carbon footprint of imported hydrogen carriers. The full transport value chain should be included, if accurate conclusions are to be drawn.

References

[1] European Commission, “REPowerEU: Joint European Action for more affordable, secure and sustainable energy,” 2022. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A108%3AFIN

[2] “Communication COM/2020/301: A hydrogen strategy for a climate-neutral Europe,” 2020.

[3] R. Ortiz Cebolla, F. Dolci, and E. Weidner, *Assessment of Hydrogen Delivery Options. EU, JRC124206*. 2021.

[4] European Environment Agency, “Energy and non-energy related greenhouse gas emissions by sector, EU-27,” pp. 1–10, 2008, [Online]. Available: https://www.eea.europa.eu/data-and-maps/indicators/en01-energy-related-greenhouse-gas-emissions/en01

[5] German Federal Government—Federal Ministry for Economic Affairs and Energy, “The National Hydrogen Strategy 2020”, [Online]. Available: https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.pdf?__blob=publicationFile&v=4

[6] “Minister Altmaier signs Memorandum of Understanding on German-Saudi hydrogen cooperation.”

[7] F. Simon, “Hydrogen trade hopes boosted by Australia-Germany deal,” *Euractiv*, 2020, [Online]. Available: https://www.euractiv.com/section/energy-environment/news/hydrogen-trade-hopes-boosted-by-australia-germany-deal/

[8] Rijksoverheid, *Netherlands Government Strategy on Hydrogen*. 2020.

[9] “The Spanish Government approves the ‘Hydrogen Roadmap: a Commitment to Renewable Hydrogen,’” *FuelCellsWorks*, [Online]. Available: https://fuelcellsworks.com/news/the-spanish-government-approves-the-hydrogen-roadmap-a-commitment-to-renewable-hydrogen/

[10] C. Chance, “FOCUS ON HYDROGEN : A ROLE FOR HYDROGEN IN ITALY ’ S CLEAN ENERGY STRATEGY A national hydrogen strategy is now expected in Italy as early Decarbonisation targets,” no. December 2020, pp. 1–7, 2021, [Online]. Available: https://www.cliffordchance.com/content/dam/cliffordchance/briefings/2020/12/focus-on-hydrogen-italy-final.pdf

[11] *Hydrogen Strategy for Canada. Seizing the Opportunities for Hydrogen*. 2020. [Online]. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

[12] *National Green Hydrogen Strategy*. Ministry of Energy, Government of Chile, 2020. [Online]. Available: https://energia.gob.cl/sites/default/files/national_green_hydrogen_strategy_-_chile.pdf

[13] “Australia’s National Hydrogen Strategy.” https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy

[14] D. Saadi and K. McQue, “Saudi Arabia, UAE vying for hydrogen exports as oil output capacity expands,” *Electr. Power | Nat. Gas | Petrochemicals*, 2021, [Online]. Available: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/062921-feature-saudi-arabia-uae-vying-for-hydrogen-exports-as-oil-output-capacity-expands

[15] “A vision for hydrogen in New Zealand : green paper,” New Zealand Government, 2019.

[16] P. A. Van Wijk and F. Wouters, *A North Africa - Europe Hydrogen Manifesto*. 2019. [Online]. Available: https://www.middleeast-energy.com/content/dam/Informa/Middle-East-Electricity/middle-east-energy-2021/reports---external/Dii hydrogen study (November 2019)_print.pdf

[17] “The Norwegian Government’s Hydrogen Strategy. Norwegian Ministry of Foreign Affairs,” 2012.

[18] “A Flemish Hydrogen Strategy 2025 – 2030,” no. December, pp. 0–52, 2020.

[19] “Shipping sun and wind to Belgium is key in climate neutral economy Hydrogen Import Coalition,” 2021. [Online]. Available: https://beslissingenvlaamseregering.vlaanderen.be/document-view/5FAD539C20B6670008000274

[20] “Communication From The Commission To The European Parliament, The European Council, The

Council, The European Economic And Social Committee, The Committee Of The Regions And The European Investment Bank. A Clean Planet for all. A European strategic long-t," *COM(2018) 773 final*.

[21] C. Hank *et al.*, "Energy efficiency and economic assessment of imported energy carriers based on renewable electricity," *Sustain. Energy Fuels*, 2020, doi: 10.1039/d0se00067a.

[22] HyET, "HyET HCS100 H2 Compression and Purification systems", [Online]. Available: https://hyethydrogen.com/upload_directory/files/HyetHydrogen-2flyers-A4.pdf

[23] HYSTORSYS, "Thermal Hydrogen Compressors." [Online]. Available: http://www.hystorsys.no/download/Hystorsys_KP_2014_April.pdf

[24] US DOE Fuel Cell Technologies Office, "DOE Technical Targets for Hydrogen Delivery." https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery

[25] Howden, "Compressor solution for fuelling stations", [Online]. Available: https://www.howden.com/en-us/applications/compressors-for-hydrogen-fuel-cell

[26] Burckhardt Compression, "OIL-FREE HIGH-PRESSURE DIAPHRAGM COMPRESSORS." www.burckhardtcompression.com

[27] Burckhardt Compression, "Compressor solutions for oil-free high-pressure piston compressors", [Online]. Available: www.burckhardtcompression.com

[28] The Linde Group, "Linde Ionic Compressor-50 MPa," *Linde Ionic Compressor*. https://www.linde-engineering.com/en/images/DS_IC 50_tcm19-523715.pdf

[29] The Linde Group, "IC90 / 30 Ionic Compressor Compressor module for gaseous hydrogen refueling station." p. 2021, 2021. [Online]. Available: https://www.linde-engineering.com/en/images/LE_LHRT_datasheet_IC90_30_Ionic_Compressor_tcm19-634422.pdf

[30] O. Kruck and F. Crotogino, "Benchmarking of Selected Storage Options," *HyUnder project, deliverable 3.3*. 2013.

[31] S. S. Christoph Noack, Dr. Fabian Burggraf, D. S. Hosseiny, Philipp Lettenmeier, Svenja Kolb, P.-L. H. Belz, Dr. Josef Kallo, Prof. K. Andreas Friedrich, Dr. Thomas Pregger, Karl Kiên Cao, Dr. Dominik Heide, Dr. Tobias Naegler, Frieder Borggrefe, Dr. Ulrich Bünger, Jan Michalski, Tetyana Raksha, Christopher Voglstätter, Dr. Tom Smolinka, Fritz Crotogino, S, and D. G.-S. Schneider, "PlanDelyKad study on large scale water electrolysis and hydrogen storage," *BMWi*. p. 298, 2015. [Online]. Available: https://elib.dlr.de/94979/1/2014_DLR_ISE_KBB_LBST_PlanDelyKaD.pdf

[32] R. K. Ahluwalia, D. D. Papadias, J.-K. Peng, and H. S. Roh, "System Level Analysis of Hydrogen Storage Options," 2019.

[33] D. G. Caglayan *et al.*, "Technical potential of salt caverns for hydrogen storage in Europe," *Int. J. Hydrogen Energy*, vol. 45, no. 11, pp. 6793–6805, 2020, doi: 10.1016/j.ijhydene.2019.12.161.

[34] O. Kruck, F. Crotogino, R. Prelicz, and T. Rudolph, "Overview on all Known Underground Storage Technologies for Hydrogen," *HyUnder Proj. Deliv. 3.1*, 2013.

[35] C. Wulf *et al.*, "Life Cycle Assessment of hydrogen transport and distribution options," *J. Clean. Prod.*, vol. 199, pp. 431–443, Oct. 2018, doi: 10.1016/j.jclepro.2018.07.180.

[36] ISO, "ISO 668:2013 Series 1 freight containers—Classification, dimensions and ratings." 2013.

[37] ISO, "ISO 1496-1:2013 Series 1 freight containers—Specification and testing—Part 1: General cargo containers for general purposes."

[38] "HYDROGEN MEGC - 8 TUBES 190 bar." City Machine & Welding, Inc, pp. 2–3, 2020. [Online]. Available: https://cmwelding.com/configuration/hydrogen-h2-multiple-element-gas-container-megc-8-tubes-un-iso-11120-2755psi-36-ft

[39] HEXAGON, "X-STORE ® GAS CONTAINER MODULES , VERSION ADR V2." https://www.californiahydrogen.org/wp-content/uploads/2021/06/Hexagon-Purus-X-STORE-Gas_Container-Modules-Version-ADR-V2-Full-Carbon-Design-500Bar-H2-1.pdf

[40] K. Reddi, A. Elgowainy, N. Rustagi, and E. Gupta, "Techno-economic analysis of conventional and advanced high-pressure tube trailer configurations for compressed hydrogen gas transportation and refueling," *Int. J. Hydrogen Energy*, vol. 43, no. 9, pp. 4428–4438, 2018, doi:

10.1016/j.ijhydene.2018.01.049.

[41] Global Energy Ventures, “Compressed Hydrogen Shipping Solution,” vol. 470. p. 809, 2021. [Online]. Available: https://gev.com/wp-content/uploads/2021/04/gev_corporate-flyer_c-h2_april-2021-1.pdf

[42] H2Tools, “Hydrogen pipelines september 2016.” https://h2tools.org/file/184/download?token=ZLadZCaM

[43] A. Wang, K. van der Leun, D. Peters, and M. Buseman, “European Hydrogen Backbone - How a dedicated hydrgen infrstructure can be created,” 2020. [Online]. Available: https://transparency.entsog.eu/

[44] J. Jens, A. Wang, K. van der Leun, D. Peters, and M. Busema, “Extending the European Hydrogen Backbone - A European hydrogen infrastructure vision covering 21 countries.,” 2021.

[45] Air Liquide, “Questions and Issues on Hydrogen Pipelines. DOE Hydrogen Pipeline Working Group Meeting,” 2005.

[46] ASME, “B31.12-2014 Hydrogen Piping and Pipe Lines, ASME Boiler & Pressure Vessel Code,” *The American Society of Mechanical Engineers*. 2014. doi: 10.1115/1.859872.ch38.

[47] NIST, “Saturation Properties for Hydrogen.” https://webbook.nist.gov/cgi/fluid.cgi?Action=Load&ID=C1333740&Type=SatT&Digits=5&PLow=.5&PHigh=1.5&PInc=.1&RefState=DEF&TUnit=K&PUnit=atm&DUnit=kg/m3&HUnit=kJ/mol&WUnit=m/s&VisUnit=uPa*s&STUnit=N/m

[48] S. Krasae-in, J. H. Stang, and P. Neksa, “Development of large-scale hydrogen liquefaction processes from 1898 to 2009,” *Int. J. Hydrogen Energy*, vol. 35, no. 10, pp. 4524–4533, 2010, doi: 10.1016/j.ijhydene.2010.02.109.

[49] H. Matsuda and M. Nagami, “Study of Large Hydrogen Liquefaction Process,” 1998. [Online]. Available: http://www.enaa.or.jp/WE-NET/ronbun/1997/e5/sanso1997.html

[50] K. Ohlig and L. Decker, “The latest developments and outlook for hydrogen liquefaction technology,” *AIP Conf. Proc.*, vol. 1573, no. February, pp. 1311–1317, 2014, doi: 10.1063/1.4860858.

[51] T. Flynn, *Cryogenic Engineering, Revised and Expanded*. CRC Press, 2004.

[52] C. R. Baker, “Efficiency and economics of large scale hydrogen liquefaction,” *SAE Technical Papers*. 1975. doi: 10.4271/751094.

[53] Monika Hartl, Robert Chad Gillis, Luke Daemen, Daniel P. Olds, Katherine Page, Stefan Carlson, Yongqiang Cheng, Thomas Hügle, Erik B. Iverson, A. J. Ramirez-Cuesta, Yongjoong Lee and Günter Muhrer, “Hydrogen adsorption on two catalysts for the ortho- to parahydrogen conversion: Cr-doped silica and ferric oxide gel,” *Phys. Chem. Chem. Phys.*, vol. 2016, no. 26.

[54] Kawasaki, “Technologies of hydrogen liquefaction, transport and storage — Paving the way to a hydrogen fueled future,” 2020. [Online]. Available: https://global.kawasaki.com/en/corp/rd/magazine/176/pdf/n176en10.pdf

[55] L. Decker, “Latest Global Trend in Liquid Hydrogen Production,” HYPER closing seminar 2019.

[56] S. Krasae-in, J. H. Stang, and P. Neksa, “Development of large-scale hydrogen liquefaction processes from 1898 to 2009,” *Int. J. Hydrogen Energy*, vol. 35, no. 10, pp. 4524–4533, 2010, doi: https://doi.org/10.1016/j.ijhydene.2010.02.109.

[57] DOE Hydrogen and Fuel Cells Program Record, “Current Status of Hydrogen Liquefaction Costs.” 2019.

[58] J. Holladay *et al.*, “MagnetoCaloric Hydrogen Liquefaction,” in *DOE Annual Merit Review, PD131*, 2021, no. June, p. 35.

[59] L. Decker, “Liquid Hydrogen Distribution Technology,” HYPER closing seminar 2019.

[60] A. Krenn and D. Desenberg, “Return to service of a liquid hydrogen storage sphere.” [Online]. Available: https://ntrs.nasa.gov/api/citations/20190028305/downloads/20190028305.pdf

[61] J. E. Fesmire and A. Swanger, “DOE / NASA Advances in Liquid Hydrogen Storage Workshop,” 2021.

[62] T. Watanabe, K. Murata, S. Kamiya, and K.-I. Ota, “Cost estimation of transported hydrogen, produced by overseas wind power generations,” *18th World Hydrog. Energy Conf. 2010 - WHEC 2010 Parallel*

Sess. B. 3 Hydrog. Prod. Technol. - Part 2, vol. 78, pp. 547–557, 2010, [Online]. Available: https://juser.fz-juelich.de/record/136442/files/HP6_pp_Wat_Watanabe.pdf

[63] H. Derking, L. Van Der Togt, and M. Keezer, “Liquid Hydrogen Storage : Status and Future Perspectives,” Cryogenic Heat and Mass Transfer 2019.

[64] G. Petitpas, “Boil-off losses along LH2 pathway. Lawrence Livermore National Laboratory,” 2018. doi: LLNL-TR-750685.

[65] A. Swanger, “Large scale cryogenic storage with active refrigeration,” 2018. [Online]. Available: https://www.researchgate.net/publication/329071191

[66] Wärtsilä, “LNG reliquefaction system.” https://www.wartsila.com/encyclopedia/term/lng-reliquefaction-system

[67] LINDE, “HELICS-Liquid helium portable tank.” https://www.linde-engineering.com/en/plant-components/helium-storage-un-portable-tanks/index.html

[68] УРАЛКРИОМАШ, “LH2 storage container -КЦВ20.” http://www.cryont.ru/production/ (accessed Feb. 28, 2022).

[69] УРАЛКРИОМАШ, “LH2 rail car - ЖВЦ100М2.” http://www.cryont.ru/company/ (accessed Feb. 28, 2022).

[70] U.S. DOT, “Regulation 173.319 - Cryogenic liquids in tank cars.”

[71] C. Cancelli, M. Demichela, and N. Piccinini, “Accidental release of hydrogen from a cryogenic tank,” *Cryogenics (Guildf).*, vol. 45, no. 7, pp. 481–488, 2005, doi: 10.1016/j.cryogenics.2004.07.009.

[72] VTG, “Technical data for a cryogenic rail tank car.” [Online]. Available: https://www.vtg.com/fileadmin/vtg/dokumente/waggon-datenblaetter/Fluessiggas-Kesselwagen-tiefkalte-Gase-LNG-G91.111D.pdf

[73] NASA, “LH2 Usage at NASA Stennis Space Center.” p. 400.

[74] Samsung Heavy Industries, “Samsung Heavy Industries builds the world’s largest LNG carrier,” 2008. https://www.samsungshi.com/eng/Pr/news_view.aspx?Seq=696&mac=4aa78642ffa19a91d68a2054c817c1e4

[75] “LNG ships. LNG Information Paper #3. GIIGNL- THE INTERNATIONAL GROUP OF LIQUEFIED NATURAL GAS IMPORTERS.” pp. 263–263, 2019.

[76] M. Al-Breiki and Y. Bicer, “Comparative cost assessment of sustainable energy carriers produced from natural gas accounting for boil-off gas and social cost of carbon,” *Energy Reports*, vol. 6, pp. 1897–1909, 2020, doi: 10.1016/j.egyr.2020.07.013.

[77] “World’s First Liquefied Hydrogen Carrier SUISO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society.” https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487

[78] “Fertilizer outlook. Market Intelligence and Agriculture Services. IFS Secretariat.,” *J. Agric. Food Chem.*, 2020, doi: 10.1021/jf60017a002.

[79] F. Dolci, “Green Hydrogen Opportunities in Selected Industrial Processes,” *JRC Technical Report*. 2018.

[80] L. Wang *et al.*, “Greening Ammonia toward the Solar Ammonia Refinery,” *Joule*, vol. 2, no. 6, pp. 1055–1074, 2018, doi: 10.1016/j.joule.2018.04.017.

[81] C. Smith, A. K. Hill, and L. Torrente-Murciano, “Current and future role of Haber–Bosch ammonia in a carbon-free energy landscape,” *Energy Environ. Sci.*, 2020, doi: 10.1039/c9ee02873k.

[82] M. Yoshida, T. Ogawa, Y. Imamura, and K. N. Ishihara, “Economies of scale in ammonia synthesis loops embedded with iron- and ruthenium-based catalysts,” *Int. J. Hydrogen Energy*, 2021, doi: 10.1016/j.ijhydene.2020.12.081.

[83] K. E. Lamb, M. D. Dolan, and D. F. Kennedy, “Ammonia for hydrogen storage; A review of catalytic ammonia decomposition and hydrogen separation and purification,” *Int. J. Hydrogen Energy*, vol. 44, no. 7, pp. 3580–3593, 2019, doi: 10.1016/j.ijhydene.2018.12.024.

[84] O. A. Ojelade and S. F. Zaman, “Ammonia decomposition for hydrogen production: a thermodynamic study,” *Chem. Pap.*, vol. 75, no. 1, pp. 57–65, 2021, doi: 10.1007/s11696-020-01278-z.

[85] A. Boisen, S. Dahl, J. K. Nørskov, and C. H. Christensen, “Why the optimal ammonia synthesis catalyst is not the optimal ammonia decomposition catalyst,” *J. Catal.*, vol. 230, no. 2, pp. 309–312, 2005, doi: 10.1016/j.jcat.2004.12.013.

[86] P. Shrestha, “Carbon footprint comparison between tranditional diesel and synthetic diesel,” Lappeenranta-Lahti University of Technology, 2020.

[87] S. Mukherjee, S. V. Devaguptapu, A. Sviripa, C. R. F. Lund, and G. Wu, “Low-temperature ammonia decomposition catalysts for hydrogen generation,” *Appl. Catal. B Environ.*, vol. 226, no. August 2017, pp. 162–181, 2018, doi: 10.1016/j.apcatb.2017.12.039.

[88] J. W. Makepeace, T. J. Wood, H. M. A. Hunter, M. O. Jones, and W. I. F. David, “Ammonia decomposition catalysis using non-stoichiometric lithium imide,” *Chem. Sci.*, vol. 6, no. 7, pp. 3805–3815, 2015, doi: 10.1039/c5sc00205b.

[89] K. Fothergill, S. Greenwood, J. Makepeace, and I. Wilkinson, “Ammonia to Green Hydrogen Project,” vol. 33, no. 0, pp. 1–70, 2015, [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/880826/HS420_-_Ecuity_-_Ammonia_to_Green_Hydrogen.pdf

[90] N. Morlanés *et al.*, “A technological roadmap to the ammonia energy economy: Current state and missing technologies,” *Chem. Eng. J.*, vol. 408, no. August 2020, 2021, doi: 10.1016/j.cej.2020.127310.

[91] M. Matzen, M. Alhajji, and Y. Demirel, “Chemical storage of wind energy by renewable methanol production: Feasibility analysis using a multi-criteria decision matrix,” *Energy*, vol. 93, pp. 343–353, 2015, doi: 10.1016/j.energy.2015.09.043.

[92] X. Liu, A. Elgowainy, and M. Wang, “Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products,” *Green Chem.*, vol. 22, no. 17, pp. 5751–5761, 2020, doi: 10.1039/d0gc02301a.

[93] O. Osman, S. Sgouridis, and A. Sleptchenko, “Scaling the production of renewable ammonia: A techno-economic optimization applied in regions with high insolation,” *J. Clean. Prod.*, vol. 271, p. 121627, 2020, doi: 10.1016/j.jclepro.2020.121627.

[94] E. R. Morgan, “Techno-Economic Feasibility Study of Ammonia Plants Powered by Offshore Wind,” *Univ. Massachusetts - Amherst, PhD Diss.*, p. 432, 2013, doi: https://doi.org/10.7275/11kt-3f59.

[95] E. Morgan, J. Manwell, and J. McGowan, “Wind-powered ammonia fuel production for remote islands: A case study,” *Renew. Energy*, vol. 72, pp. 51–61, 2014, doi: http://dx.doi.org/10.1016/j.renene.2014.06.034.

[96] D. Frattini, G. Cinti, G. Bidini, U. Desideri, R. Cioffi, and E. Jannelli, “A system approach in energy evaluation of different renewable energies sources integration in ammonia production plants,” *Renew. Energy*, vol. 99, pp. 472–482, 2016, doi: http://dx.doi.org/10.1016/j.renene.2016.07.040.

[97] J. R. Bartels and M. B. Pate, “A feasibility study of implementing an Ammonia Economy,” 2008. [Online]. Available: https://lib.dr.iastate.edu/etd

[98] K. H. R. Rouwenhorst, A. G. J. Van der Ham, G. Mul, and S. R. A. Kersten, “Islanded ammonia power systems: Technology review & conceptual process design,” *Renew. Sustain. Energy Rev.*, vol. 114, no. July 2019, 2019, doi: 10.1016/j.rser.2019.109339.

[99] A. M. Bazzanella, F. Ausfelder, and DECHEMA, “Low carbon energy and feedstock for the European chemical industry,” DECHEMA, 2017. [Online]. Available: https://dechema.de/Low_carbon_chemical_industry.html

[100] Z. Cesaro, M. Ives, R. Nayak-Luke, M. Mason, and R. Bañares-Alcántara, “Ammonia to power: Forecasting the levelized cost of electricity from green ammonia in large-scale power plants,” *Appl. Energy*, vol. 282, no. November 2020, 2021, doi: 10.1016/j.apenergy.2020.116009.

[101] O. Elishav, B. M. Lis, and G. S. Grader, *Storage and Distribution of Ammonia*. Elsevier Inc., 2021. doi: 10.1016/B978-0-12-820560-0.00005-9.

[102] I. H. Turi, “Commissioning of two 50,000 MT ammonia storage tanks,” *Ammon. Plant Saf. Relat. Facil.*, vol. 56, pp. 61–70, 2015.

[103] R. M. Nayak-Luke, C. Forbes, Z. Cesaro, R. Bañares-Alcántara, and K. H. R. Rouwenhorst, *Techno-Economic Aspects of Production, Storage and Distribution of Ammonia*. Elsevier Inc., 2020. doi: 10.1016/B978-0-12-820560-0.00008-4.

[104] O. Elishav *et al.*, "Progress and Prospective of Nitrogen-Based Alternative Fuels," *Chem. Rev.*, 2020, doi: 10.1021/acs.chemrev.9b00538.

[105] "CLIPPER SIRIUS, Solvang ASA." https://solvangship.no/wp-content/uploads/2019/08/CForm-Clipper-Sirius.pdf

[106] J. Tijdgat, "Shipping renewable hydrogen carriers," TU Delft, 2020.

[107] "Once a Niche Segment, LPG Carrier Market is Now A Boon for Ship Owners," *2019*. https://www.hellenicshippingnews.com/once-a-niche-segment-lpg-carrier-market-is-now-a-boon-for-ship-owners/

[108] M. Al-Breiki and Y. Bicer, "Technical assessment of liquefied natural gas, ammonia and methanol for overseas energy transport based on energy and exergy analyses," *Int. J. Hydrogen Energy*, vol. 45, no. 60, pp. 34927–34937, 2020, doi: 10.1016/j.ijhydene.2020.04.181.

[109] M. Al-Breiki and Y. Bicer, "Investigating the technical feasibility of various energy carriers for alternative and sustainable overseas energy transport scenarios," *Energy Convers. Manag.*, vol. 209, no. October 2019, p. 112652, 2020, doi: 10.1016/j.enconman.2020.112652.

[110] EFMA, "GUIDANCE FOR TRANSPORTING AMMONIA BY RAIL," 2014.

[111] Association of American Railroads, "Field giude to tank cars," Nov. 2012.

[112] VTG Aktiengesellschaft, "GAS RAIL TANK CARS FOR AMMONIA." https://www.vtg.com/hiring/our-fleet/g80106d

[113] R. Hattenbach, "Transportation & Delivery of Anhydrous Ammonia By Ray Hattenbach Chemical Marketing Services, Inc.," 2005.

[114] Q. I. Roode-Gutzmer, D. Kaiser, and M. Bertau, "Renewable Methanol Synthesis," *ChemBioEng Rev.*, vol. 6, no. 6, pp. 209–236, 2019, doi: 10.1002/cben.201900012.

[115] A. Boulamanti and J. A. Moya, "Production costs of the chemical industry in the EU and other countries: Ammonia, methanol and light olefins," *Renew. Sustain. Energy Rev.*, vol. 68, pp. 1205–1212, 2017, doi: http://dx.doi.org/10.1016/j.rser.2016.02.021.

[116] J. Klankermayer, S. Wesselbaum, K. Beydoun, and W. Leitner, "Selective Catalytic Synthesis Using the Combination of Carbon Dioxide and Hydrogen: Catalytic Chess at the Interface of Energy and Chemistry," *Angew. Chemie Int. Ed.*, vol. 55, no. 26, pp. 7296–7343, 2016, doi: 10.1002/anie.201507458.

[117] J. Davies, F. Dolci, D. Klassek-Bajorek, R. Cebolla Ortiz, and E. Weidner, *Current status of Chemical Energy Storage Technologies*. 2020. doi: 10.2760/280873.

[118] V. Dieterich, A. Buttler, A. Hanel, H. Spliethoff, and S. Fendt, "Power-to-liquid via synthesis of methanol, DME or Fischer–Tropsch-fuels: a review," *Energy Environ. Sci.*, vol. 13, no. 10, pp. 3207–3252, 2020, doi: 10.1039/d0ee01187h.

[119] B. Anicic, P. Trop, and D. Goricanec, "Comparison between two methods of methanol production from carbon dioxide," *Energy*, vol. 77, pp. 279–289, 2014, doi: 10.1016/j.energy.2014.09.069.

[120] G. Leonzio, E. Zondervan, and P. U. Foscolo, "Methanol production by CO 2 hydrogenation: Analysis and simulation of reactor performance," *Int. J. Hydrogen Energy*, vol. 44, no. 16, pp. 7915–7933, 2019, doi: 10.1016/j.ijhydene.2019.02.056.

[121] J. Artz *et al.*, "Sustainable Conversion of Carbon Dioxide: An Integrated Review of Catalysis and Life Cycle Assessment," *Chem. Rev.*, vol. 118, no. 2, pp. 434–504, 2018, doi: 10.1021/acs.chemrev.7b00435.

[122] G. Zang, P. Sun, A. Elgowainy, A. Bafana, and M. Wang, "Techno-Economic and Life Cycle Analysis of Synthetic Methanol Production from Hydrogen and Industry By-product CO2" (under review)," 2021, doi: 10.1021/acs.est.0c08237.

[123] A. Goeppert, M. Czaun, J. P. Jones, G. K. Surya Prakash, and G. A. Olah, "Recycling of carbon dioxide to

methanol and derived products-closing the loop," *Chem. Soc. Rev.*, vol. 43, no. 23, pp. 7995–8048, 2014, doi: 10.1039/c4cs00122b.

[124] C. Hank *et al.*, "Economics & carbon dioxide avoidance cost of methanol production based on renewable hydrogen and recycled carbon dioxide-power-to-methanol," *Sustain. Energy Fuels*, vol. 2, no. 6, pp. 1244–1261, 2018, doi: 10.1039/c8se00032h.

[125] M. Pérez-Fortes and E. Tzimas, "Techno-economic and environmental evaluation of CO2 utilisation for fuel production. Synthesis of methanol and formic acid," *EUR 27629 EN*, p. 85, 2016, doi: 10.2790/89238.

[126] A. A. Kiss, J. J. Pragt, H. J. Vos, G. Bargeman, and M. T. de Groot, "Novel efficient process for methanol synthesis by CO2 hydrogenation," *Chem. Eng. J.*, vol. 284, pp. 260–269, 2016, doi: 10.1016/j.cej.2015.08.101.

[127] M. L. De Jong, "Small Scale Methanol Production Process modelling and design of an autonomous, renewable container sized methanol plant.," TU Delft, 2018.

[128] A. Sternberg, C. M. Jens, and A. Bardow, "Life cycle assessment of CO2-based C1-chemicals," *Green Chem.*, vol. 19, no. 9, pp. 2244–2259, 2017, doi: 10.1039/c6gc02852g.

[129] J. A. Herron, J. Kim, A. A. Upadhye, G. W. Huber, and C. T. Maravelias, "A general framework for the assessment of solar fuel technologies," *Energy Environ. Sci.*, vol. 8, no. 1, pp. 126–157, 2015, doi: 10.1039/c4ee01958j.

[130] M. Pérez-Fortes, J. C. Schöneberger, A. Boulamanti, and E. Tzimas, "Methanol synthesis using captured CO2 as raw material: Techno-economic and environmental assessment," *Appl. Energy*, vol. 161, pp. 718–732, 2016, doi: http://dx.doi.org/10.1016/j.apenergy.2015.07.067.

[131] M. Pérez-Forte and E. Tzimas, "Techno-economic and environmental evaluation of carbon dioxide utilisation for fuel production. Synthesis of methanol and formic acid," Luxemburg, 2016. doi: 10.2790/981669.

[132] É. S. Van-Dal and C. Bouallou, "Design and simulation of a methanol production plant from CO2 hydrogenation," *J. Clean. Prod.*, vol. 57, pp. 38–45, 2013, doi: 10.1016/j.jclepro.2013.06.008.

[133] H. Nieminen, A. Laari, and T. Koiranen, "CO2 hydrogenation to methanol by a liquid-phase process with alcoholic solvents: A techno-economic analysis," *Processes*, vol. 7, no. 7, pp. 1–24, 2019, doi: 10.3390/pr7070405.

[134] P. Biernacki, T. Röther, W. Paul, P. Werner, and S. Steinigeweg, "Environmental impact of the excess electricity conversion into methanol," *J. Clean. Prod.*, vol. 191, pp. 87–98, 2018, doi: 10.1016/j.jclepro.2018.04.232.

[135] I. L. Wiesberg, J. L. de Medeiros, R. M. B. Alves, P. L. A. Coutinho, and O. Q. F. Araújo, "Carbon dioxide management by chemical conversion to methanol: HYDROGENATION and BI-REFORMING," *Energy Convers. Manag.*, vol. 125, pp. 320–335, 2016, doi: 10.1016/j.enconman.2016.04.041.

[136] "ATMOSPHERIC ABOVE GROUND TANK STORAGE OF METHANOL ATMOSPHERIC ABOVE GROUND TANK STORAGE OF METHANOL 1.1 INTRODUCTION METHANOL SAFE HANDLING TECHNICAL BULLETIN."

[137] "Waterfront Shipping Limited. Fleet List." https://www.waterfront-shipping.com/fleet/fleet-list

[138] DNV-GL, "USE OF METHANOL AS FUEL Methanol as marine fuel: Environmental benefits, technology readiness, and economic feasibility International Maritime Organization (IMO)," 2016. [Online]. Available: www.dnvgl.com

[139] VTG Aktiengesellschaft, "Chemical rail tank car." https://www.vtg.com/products-and-services/fleet/fleet-overview/tank-wagons

[140] M. S. Herdem, M. Y. Sinaki, S. Farhad, and F. Hamdullahpur, "An overview of the methanol reforming process: Comparison of fuels, catalysts, reformers, and systems," *International Journal of Energy Research*, vol. 43, no. 10. John Wiley and Sons Ltd, pp. 5076–5105, Aug. 01, 2019. doi: 10.1002/er.4440.

[141] D. R. Palo, R. A. Dagle, and J. D. Holladay, "Methanol steam reforming for hydrogen production," *Chemical Reviews*, vol. 107, no. 10. pp. 3992–4021, Oct. 2007. doi: 10.1021/cr050198b.

[142] A. Iulianelli, P. Ribeirinha, A. Mendes, and A. Basile, “Methanol steam reforming for hydrogen generation via conventional and membrane reactors: A review,” *Renew. Sustain. Energy Rev.*, vol. 29, no. February 2015, pp. 355–368, 2014, doi: 10.1016/j.rser.2013.08.032.

[143] “Mahler AGS. Hydrogen generation plant based on methanol reforming.” https://www.mahler-ags.com/hydrogen/hydroform-m/

[144] “CSG, La production de carburant.” http://www.capcomespace.net/dossiers/espace_europeen/CSG/usine_carburant.htm

[145] K. Faungnawakij, R. Kikuchi, and K. Eguchi, “Thermodynamic evaluation of methanol steam reforming for hydrogen production,” *J. Power Sources*, vol. 161, no. 1, pp. 87–94, 2006, doi: 10.1016/j.jpowsour.2006.04.091.

[146] K. Ghasemzadeh, S. M. Sadati Tilebon, and A. Basile, *Reforming and Partial Oxidation Reactions of Methanol for Hydrogen Production*. Elsevier B.V., 2018. doi: 10.1016/B978-0-444-63903-5.00009-1.

[147] G. Garcia, E. Arriola, W. H. Chen, and M. D. De Luna, “A comprehensive review of hydrogen production from methanol thermochemical conversion for sustainability,” *Energy*, vol. 217, p. 119384, 2021, doi: 10.1016/j.energy.2020.119384.

[148] G. Garcia-Garcia, M. C. Fernandez, K. Armstrong, S. Woolass, and P. Styring, “Analytical Review of Life-Cycle Environmental Impacts of Carbon Capture and Utilization Technologies,” *ChemSusChem*, vol. n/a, no. n/a, doi: https://doi.org/10.1002/cssc.202002126.

[149] F. R. García-García, M. León, S. Ordóñez, and K. Li, “Studies on water–gas-shift enhanced by adsorption and membrane permeation,” *Catal. Today*, vol. 236, pp. 57–63, 2014, doi: https://doi.org/10.1016/j.cattod.2014.02.050.

[150] R. B. Gupta, A. Basile, and T. N. Veziroglu, *Compendium of hydrogen energy. Volume 2: Hydrogen Storage, Distribution and Infrastructure*. Woodhead Pub., 2008.

[151] D. R. Palo, R. A. Dagle, and J. D. Holladay, “Methanol steam reforming for hydrogen production,” *Chem. Rev.*, vol. 107, no. 10, pp. 3992–4021, Oct. 2007, doi: 10.1021/cr050198b.

[152] L. F. Brown, “A comparative study of fuels for on-board hydrogen production for fuel-cell-powered automobiles,” *Int. J. Hydrogen Energy*, vol. 26, no. 4, pp. 381–397, 2001, doi: 10.1016/S0360-3199(00)00092-6.

[153] R. Terwel and I. J. Kerkhoven, “Hydrohub HyChain 2: Cost implications of importing renewable electricity, hydrogen and hydrogen carriers into the Netherlands from a 2050 perspective,” no. November, pp. 1–79, 2019.

[154] D. D. Papadias, J.-K. Peng, and R. K. Ahluwalia, “Chemical Carrier Concepts for Hydrogen Delivery,” *Int. Hydrog. Infrastruct. Work. Bost. Conv. Exhib. Cent.*, 2018.

[155] A. V. Bøe, D. O. Gullbrå, and T. A. Reinertsen, “An efficiency comparison of liquid hydrogen, ammonia, and liquid organic hydrogen carriers for maritime use,” Western Norway University of Applied Sciences, Bergen, Norway, 2021.

[156] P. T. Aakko-Saksa, C. Cook, J. Kiviaho, and T. Repo, “Liquid organic hydrogen carriers for transportation and storing of renewable energy – Review and discussion,” *J. Power Sources*, vol. 396, no. February, pp. 803–823, 2018, doi: 10.1016/j.jpowsour.2018.04.011.

[157] J. Zheng *et al.*, “Current research progress and perspectives on liquid hydrogen rich molecules in sustainable hydrogen storage,” *Energy Storage Mater.*, vol. 35, no. December 2020, pp. 695–722, 2021, doi: 10.1016/j.ensm.2020.12.007.

[158] F. Sotoodeh, B. J. M. Huber, and K. J. Smith, “Dehydrogenation kinetics and catalysis of organic heteroaromatics for hydrogen storage,” *Int. J. Hydrogen Energy*, vol. 37, no. 3, pp. 2715–2722, 2012, doi: 10.1016/j.ijhydene.2011.03.055.

[159] R. K. Ahluwalia, T. Q. Hua, J.-K. Peng, and H. S. Roh, “System Level Analysis of Hydrogen Storage Options. Project ID: ST001,” *US DOE Hydrog. Fuel Cells Program. Annu. Merit Rev.*, 2013.

[160] HYSTOC, “Deliverable 8.4 Business development and sustainability LOHC production cost estimation study,” 2019.

[161] V. Meille and I. Pitault, “Liquid Organic Hydrogen Carriers or Organic Liquid Hydrides: 40 Years of History,” *Reactions*, vol. 2, no. 2, pp. 94–101, 2021, doi: 10.3390/reactions2020008.

[162] D. Teichmann, *Konzeption und Bewertung einer nachhaltigen Energieversorgung auf Basis fluessiger Wasserstofftraeger*. PhD Thesis, Friedrich Alexander Universitaet Erlangen-Nuernberg, 2014.

[163] “Marlotherm SHSafety Data Sheet.” https://eurol.com/product_img/SDS/IE_E124838_SDS.pdf

[164] M. Niermann, A. Beckendorff, M. Kaltschmitt, and K. Bonhoff, “Liquid Organic Hydrogen Carrier (LOHC) – Assessment based on chemical and economic properties,” *International Journal of Hydrogen Energy*, vol. 44, no. 13. Elsevier Ltd, pp. 6631–6654, Mar. 08, 2019. doi: 10.1016/j.ijhydene.2019.01.199.

[165] “H2 @ Scale : Outlook of Hydrogen Carriers at Different Scales D . D . Papadias , J-K Peng , and R . K . Ahluwalia Department of Energy Hydrogen Carriers Workshop : Novel Pathways for Optimized Hydrogen Transport & Stationary Storage Denver Marriott West T,” 2019.

[166] HYSTOC, “Deliverable 5.4 – HRS-specific LOHC Hydrogen Release System Potential DBT Mixtures Identified,” 2018.

[167] “Surveyor: A Quarterly Magazine from American Bureau of Shipping.”

[168] ODFJELL, “The Chemical Tankers Market.” 2012. [Online]. Available: https://www.fonasba.com/wp-content/uploads/2012/10/Chemical-Market-Report.pdft-Report.pdf.

[169] United Nations, “Review of Maritime transport 2012”

[170] VTG Aktiengesellschaft, “MINERAL OIL RAIL TANK CAR”, [Online]. Available: https://www.vtg.com/hiring/our-fleet/m16086c

[171] “Alberta plans to buy 7,000 rail cars to ease ‘crisis’ in oil price differentials,” *Financial Post*. https://financialpost.com/pmn/business-pmn/alberta-plans-to-buy-7000-railcars-to-ease-crisis-in-oil-price-differentials (accessed May 20, 2021).

[172] DANTECO, “20ft ISO tank UN portable T11.” https://www.danteco.com/index.php/products/item/2-20ft-iso-tank-un-portable-t11-25cbm

[173] R. Aslam, M. H. Khan, M. Ishaq, and K. Müller, “Thermophysical Studies of Dibenzyltoluene and Its Partially and Fully Hydrogenated Derivatives,” *J. Chem. Eng. Data*, vol. 63, no. 12, pp. 4580–4587, 2018, doi: 10.1021/acs.jced.8b00652.

[174] P. T. Aakko-Saksa, C. Cook, J. Kiviaho, and T. Repo, “Liquid organic hydrogen carriers for transportation and storing of renewable energy – Review and discussion,” *Journal of Power Sources*, vol. 396. Elsevier B.V., pp. 803–823, Aug. 31, 2018. doi: 10.1016/j.jpowsour.2018.04.011.

[175] M. Raab, S. Maier, and R. U. Dietrich, “Comparative techno-economic assessment of a large-scale hydrogen transport via liquid transport media,” *Int. J. Hydrogen Energy*, vol. 46, no. 21, pp. 11956–11968, 2021, doi: 10.1016/j.ijhydene.2020.12.213.

[176] HYSTOC, “Deliverable 8.3 Business Development and sustainability – Concept Studies , Economic Analysis , Life Cycle Assessment,” 2019.

[177] “The Future of Hydrogen - Seizing today’s opportunities - Report prepared for the G20, Japan,” *Int. Energy Agency*, no. June, 2019.

[178] Y. Ishimoto, M. Voldsund, P. Nekså, S. Roussanaly, D. Berstad, and S. O. Gardarsdottir, “Large-scale production and transport of hydrogen from Norway to Europe and Japan: Value chain analysis and comparison of liquid hydrogen and ammonia as energy carriers,” *Int. J. Hydrogen Energy*, vol. 45, no. 58, pp. 32865–32883, 2020, doi: 10.1016/j.ijhydene.2020.09.017.

[179] “Inflation calculator - Euro.” https://www.inflationtool.com/euro

[180] “US Inflation Calculator.” https://www.usinflationcalculator.com/

[181] “Historical converter.” https://fxtop.com/en/historical-currency-converter.php

[182] G. Towler and R. Sinnott, *CHEMICAL ENGINEERING DESIGN*. Elsevier Science Publishers, 2013. doi: 10.1016/b978-0-08-096659-5.00022-5.

[183] “Hydrogen for Climate Action: Hydrogen IPCEI.” https://www.hydrogen4climateaction.eu/projects

[184] NESTE, “Biodiesel prices (SME & FAME).” https://www.neste.com/investors/market-data/biodiesel-prices-sme-fame#403435b2

[185] Neste corporation, “Neste Renewable Diesel Handbook,” 2020. [Online]. Available: https://www.neste.com/sites/default/files/attachments/neste_renewable_diesel_handbook.pdf

[186] Quorum corporation, “Railway Capacity Background & Overview,” 2005. [Online]. Available: http://www.quorumcorp.net/Downloads/Papers/RailwayCapacityOverview.pdf

[187] J. P. Baumgartner, “Prices and costs in the railway sector,” no. January, pp. 1–17, 2001, [Online]. Available: http://litep.epfl.ch/webdav/site/litep/shared/Baumgartner_Couts_chf_2001_e.pdf

[188] M. Otten, M. ’t Hoen, and E. den Boer, “STREAM Freight transport 2016 Emissions of freight transport modes,” 2017. [Online]. Available: www.cedelft.eu

[189] European Court of Auditors, *Rail freight transport in the EU: still not on the right track*, no. 08. 2016. doi: 10.2865/53961.

[190] Argonne National Laboratory, “HYDROGEN DELIVERY SCENARIO ANALYSIS MODEL (HDSAM).” [Online]. Available: https://hdsam.es.anl.gov/index.php?content=hdsam

[191] A. Hooper and D. Murray, “An Analysis of the Operational Costs of Trucking,” 2017. [Online]. Available: https://truckingresearch.org/wp-content/uploads/2017/10/ATRI-Operational-Costs-of-Trucking-2017-10-2017.pdf

[192] Deloitte Consulting, “Strommarktstudie 2030. Ein neuer Ausblick für die Energiewirtschaft,” 2018, [Online]. Available: https://www2.deloitte.com/content/dam/Deloitte/de/Documents/energy-resources/Deloitte-Strommarktstudie-2030-DE.pdf

[193] “Portugal reaches record-low price in solar tender awarding 670 MW,” *Renewables Now*, 2020. https://renewablesnow.com/news/portugal-reaches-record-low-price-in-solar-tender-awarding-670-mw-711343/

[194] “Renewable Power Generation Costs in 2019,” *International Renewable Energy Agency*, 2020. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf

[195] K. Grave *et al.*, “Stromkosten der energieintensiven Industrie - Ein internationaler Vergleich,” pp. 1–88, 2015, [Online]. Available: http://www.isi.fraunhofer.de/isi-wAssets/docs/x/de/projekte/Strompreiswirkung_330639/Industriestrompreise_Abschlussbericht.pdf

[196] D. G. Stenning, “COSELLE CNG: Economics and Opportunities,” *Gastech 2000*, pp. 1–13, 2000, [Online]. Available: available: http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG Conferences/2000/Data/Papers/Stenning

[197] MAN, “Propulsion Trends in Bulk Carriers, Two Stroke Engines,” *MAN Diesel Turbo*, p. 26, 2014, [Online]. Available: http://marine.man.eu/docs/librariesprovider6/technical-papers/propulsion-trends-in-bulk-carriers.pdf?sfvrsn=16

[198] Damen, “Container Feeder 2500.” [Online]. Available: https://products.damen.com/-/media/products/images/clusters-groups/shipping/container-feeder/cfe-2500/downloads/product_sheet_damen_container_feeder_2500.pdf?rev=bc3e900b3bfc46ce80223b88c5d49369

[199] Wärtsilä, “WSD80-4000 TEU CONTAINER FEEDER.” [Online]. Available: https://cdn.wartsila.com/docs/default-source/product-files/sd/merchant/feeder/data-sheet-ship-design-container-wsd80-4000.pdf?sfvrsn=6

[200] R. Grainer, “Ship operating costs : Current and future trends,” *Moore Stephens LLP*, no. December. 2011.

[201] G. Dixon, “Newbuilding orders double as prices hit highest level since 2009,” 2021. https://www.tradewindsnews.com/tankers/newbuilding-orders-double-as-prices-hit-highest-level-since-2009/2-1-1085982 (accessed Mar. 28, 2022).

[202] VTG, “Rail car for 40ft ISO container.” pp. 40–41. [Online]. Available: https://www.vtg.com/hiring/our-fleet/g92062d0-I41.040D.pdf

[203] T. P. Sheahen, *Introduction to High-Temperature Superconductivity*. New York: Plenum Press, 1994.

[204] M. Kaku, *Visions: How Science Will Revolutionize the 21st Century*. New York: First Anchor Books, 1998.

[205] M. Huss, “LH2 / CGH2 applications & solutions (Cryostar). Private communication.”

[206] N. Savvides, “Evergreen orders two dozen ships as newbuilding market sizzles,” 2021. https://theloadstar.com/evergreen-orders-two-dozen-ships-as-newbuilding-market-sizzles/ (accessed Mar. 28, 2022).

[207] DAMEN, “CONTAINER FEEDER 800.” [Online]. Available: https://products.damen.com/-/media/products/images/clusters-groups/shipping/container-feeder/cfe-800/documents/product_sheet_damen_container_feeder_800_06_2017.pdf?rev=c6365d8831c84b4d976821da4bc835c3

[208] MAN, “Propulsion Trends in LNG Carriers. Two-stroke Engines (MAN).” 2014. [Online]. Available: https://www.mandieselturbo.com/docs/default-source/shopwaredocuments/propulsion-trends-in-lngb395958927f2417aa98957b04cbb684a.pdf?sfvrsn=4

[209] M. Ragnar, “Rail transportation of liquid methane in Sweden and Finland,” 2014.

[210] K. Noelker and C. Meissner, “4,700 Mtpd Single-Train Ammonia Plant Based on Proven Technology,” *Ammon. Plant Saf. Relat. Facil.*, vol. 2016-Janua, pp. 193–202, 2016.

[211] M. Pérez-Fortes and E. Tzimas, “Techno-economic and environmental evaluation of CO2 utilisation for fuel production. Synthesis of methanol and formic acid,” *EUR 27629 EN*, p. 85, 2016, doi: 10.2790/89238.

[212] Ferrostaal, “M5000 METHANOL PLANT.” https://www.ferrostaal.com/en/top-references-ferrostaal/m5000-methanol-plant/

[213] D. W. Keith, G. Holmes, D. St. Angelo, and K. Heidel, “A Process for Capturing CO2 from the Atmosphere,” *Joule*, vol. 2, no. 8, pp. 1573–1594, 2018, doi: https://doi.org/10.1016/j.joule.2018.05.006.

[214] Waterfront Shipping Limited, “Taranaki Sun.” https://www.waterfront-shipping.com/fleet/vessel/taranaki-sun

[215] “Marine traffic: Taranaki Sun.” https://www.marinetraffic.com/en/ais/details/ships/shipid:3787775/mmsi:319091800/imo:9751406/vessel:TARANAKI_SUN

[216] “EMSA THETIS-MRV.” https://mrv.emsa.europa.eu/#public/eumrv

[217] HYSTOC, “WP8 - Business Development and LCA LCA of LOHC and alternative transport hydrogen technologies,” 2021.

[218] M. Niermann, S. Drünert, M. Kaltschmitt, and K. Bonhoff, “Liquid organic hydrogen carriers (LOHCs) – techno-economic analysis of LOHCs in a defined process chain,” *Energy Environ. Sci.*, vol. 12, p. 290, 2019.

[219] HYSTOC, “Deliverable 4.1 – LOHC logistics infrastructures Decision on LOHC storage and logistics concept,” 2018.

[220] K. J. Ptasinski, *Efficiency of Biomass Energy: An Exergy Approach to Biofuels, Power, and Biorefineries.* Wiley, 2016.

[221] Eurochlor, “The European Chlor-Alkali industry: an electricity intensive sector exposed to carbon leakage,” 2010.

[222] M. Reuß, T. Grube, M. Robinius, P. Preuster, P. Wasserscheid, and D. Stolten, “Seasonal storage and alternative carriers: A flexible hydrogen supply chain model,” *Appl. Energy*, vol. 200, pp. 290–302, 2017, doi: 10.1016/j.apenergy.2017.05.050.

[223] C. Wulf and P. Zapp, “Assessment of system variations for hydrogen transport by liquid organic hydrogen carriers,” *Int. J. Hydrogen Energy*, vol. 43, no. 26, pp. 11884–11895, Jun. 2018, doi: 10.1016/j.ijhydene.2018.01.198.

[224] “Australia’s Emergency Liquid Fuel Stockholding Update 2013: Oil Storage Options & Costs.”

https://www.energy.gov.au/sites/default/files/aust-emergency-liquid-fuel-stockholding-update-2013-oil-storage-aux-report.pdf

[225] "TANK FARM AND STORAGE TERMINAL COST ESTIMATE," *International Construction Consulting, LLC*. http://nebula.wsimg.com/1068da11025693c5e7c8d792a437b249?AccessKeyId=727DB069F40969F8DA39&disposition=0&alloworigin=1

[226] Y. Kobayashi and V. Anbumoswhi, Eds., "Cooperation Framework for Oil Stockpiling and Emergency Response System," no. September, ERIA Research Project Report 2015-7, Jakarta: ERIA, 2016, pp. 29–58. [Online]. Available: https://www.eria.org/RPR_FY2015_No.7_Chapter_2.pdf

[227] "Suezmax Oil Tanker," *Croat. Shipbuild.*, vol. 14, p. 2, 2007, [Online]. Available: http://www.brodosplit.hr/Portals/17/SUEZMAX.pdf

[228] T. Plessas, A. Papanikolaou, M. Pytharoulis, E. Boulougouris, and N. Adamopoulos, "Simulation of loading/discharging procedure of tankers," *Dev. Marit. Transp. Exploit. Sea Resour.*, no. October, pp. 501–510, 2013, doi: 10.1201/b15813-60.

[229] H. Lindstad and G. S. Eskeland, "Low carbon maritime transport: How speed, size and slenderness amounts to substantial capital energy substitution," *Transp. Res. Part D Transp. Environ.*, vol. 41, pp. 244–256, 2015, doi: 10.1016/j.trd.2015.10.006.

[230] H. N. Psaraftis and C. A. Kontovas, "Speed models for energy-efficient maritime transportation: A taxonomy and survey," *Transp. Res. Part C Emerg. Technol.*, vol. 26, pp. 331–351, 2013, doi: 10.1016/j.trc.2012.09.012.

[231] "UN T11 Portable 25000L Large Volume SUS 316L 20ft ISO Tank Container," *Alibaba*. https://www.alibaba.com/product-detail/UN-T11-Portable-25000L-Large-Volume_60424406806.html?spm=a2700.details.deiletai6.1.39314274M1r7R6

[232] M. Eypasch *et al.*, "Model-based techno-economic evaluation of an electricity storage system based on Liquid Organic Hydrogen Carriers," *Appl. Energy*, vol. 185, pp. 320–330, Jan. 2017, doi: 10.1016/j.apenergy.2016.10.068.

[233] "HySTOC project D8.1 Potential environmental implications of LOHC concepts," 2018.

[234] Ø. Ulleberg and R. Hancke, "Techno-economic calculations of small-scale hydrogen supply systems for zero emission transport in Norway," *Int. J. Hydrogen Energy*, vol. 45, no. 2, pp. 1201–1211, 2020, doi: 10.1016/j.ijhydene.2019.05.170.

[235] HYSTOC, "WP2 - Requirement Specifications for LOHC infrastructure Interim report of initial fuel cell stability measurements," 2018.

[236] D. Papadias and R. K. Ahluwalia, "Total Cost of Ownership (TCO) Analysis for Hydrogen Fuel Cells in Maritime Applications –Preliminary Results," 2019.

[237] Y. Ligen, H. Vrubel, and H. Girault, "Energy efficient hydrogen drying and purification for fuel cell vehicles," *Int. J. Hydrogen Energy*, vol. 45, no. 18, pp. 10639–10647, 2020, doi: 10.1016/j.ijhydene.2020.02.035.

[238] O. E. Turgut, M. Asker, and M. T. Çoban, "A review of non iterative friction factor correlations for the calculation of pressure drop in pipes," *Bitlis Eren Univ. J. Sci. Technol.*, vol. 4, no. 1, 2014, doi: 10.17678/beujst.90203.

[239] "Darcy-Weisbach Equation - Major Pressure and Head Loss due to Friction." https://www.engineeringtoolbox.com/darcy-weisbach-equation-d_646.html

[240] "Magellan Pipeline System Map." https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB0702.pdf

[241] "Carbon Steel Pipe Price List." https://www.tridentsteel.co.in/carbon-steel-pipe-price-list.html

[242] "National Transportation Safety Board Pipeline Accident Brief-Magellan Pipeline Anhydrous Ammonia Release," pp. 1–6, 2020.

[243] M. M. J. Knoope, A. Ramírez, and A. P. C. Faaij, "A state-of-the-art review of techno-economic models predicting the costs of CO2 pipeline transport," *Int. J. Greenh. Gas Control*, vol. 16, pp. 241–270, 2013, doi: 10.1016/j.ijggc.2013.01.005.

[244] F. H. Saadi, N. S. Lewis, and E. W. McFarland, “Relative costs of transporting electrical and chemical energy,” *Energy Environ. Sci.*, vol. 11, no. 3, pp. 469–475, 2018, doi: 10.1039/c7ee01987d.

[245] N. Parker, “Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs,” p. 86, 2004, doi: DOI.

[246] Z. Rui, P. A. Metz, D. B. Reynolds, G. Chen, and X. Zhou, “Historical pipeline construction cost analysis,” *Int. J. Oil, Gas Coal Technol.*, vol. 4, no. 3, pp. 244–263, 2011, doi: 10.1504/IJOGCT.2011.040838.

[247] B. Leighty and T. L. Foundation, “Ammonia: Key to US Energy Independence 9-10 Oct 06, Denver”.

[248] “Process Equipment Cost Estimation, Final Report.” https://www.osti.gov/biblio/797810/

[249] “High Pressure Triplex Plunger Pump KD827.” https://www.uraca.com/en/systems-products/pumps/high-pressure-triplex-plunger-pump-kd827/

[250] “Hydrogen storage and transport using liquid organic hydrogen carriers,” 2017. [Online]. Available: https://www.vtt.fi/sites/maranda/Documents/Aakko-Saksa_public.pdf

[251] K. Müller *et al.*, “Liquid Organic Hydrogen Carriers: Thermophysical and Thermochemical Studies of Benzyl- and Dibenzyl-toluene Derivatives,” *Ind. Eng. Chem. Res.*, vol. 54, no. 32, pp. 7967–7976, 2015, doi: 10.1021/acs.iecr.5b01840.

[252] Mike Moore, “Rotary PD Screw Pumps in Crude Oil Transport,” 2010. https://www.pumpsandsystems.com/rotary-pd-screw-pumps-crude-oil-transport

[253] C. Park and D. Lee, “A Study on the Oil Pipeline Construction in Northeast Asia,” 2004.

[254] CIRCOR, “CIRCOR PUMPS CUT ENERGY USE ON MAJOR CANADIAN OIL COMPANY ’ S CRUDE OIL PIPELINE.” https://www.circorpt.com/admin/modules/article_manager/uploads/CIRCOR_Pumps_in_the_West_Case_Study.pdf

[255] Y. Ishimoto, M. Voldsund, P. Nekså, S. Roussanaly, D. Berstad, and S. Osk Gardarsdottir, “Value chain analysis of liquefied hydrogen, ammonia and pipeline for long distance hydrogen transport,” 2019.

[256] IRENA, *Global hydrogen trade to meet the 1.5 °C climate goal: Part II – TECHNOLOGY REVIEW OF HYDROGEN CARRIERS*. 2022.

[257] “Development of Business Cases for Fuel Cells and Hydrogen Applications for Regions and Cities - Hydrogen injection into the natural gas grid, Roland Berger for FCH JU, Brussels, Fall 2017 .” [Online]. Available: https://www.fch.europa.eu/sites/default/files/FCH Docs/171121_FCH2JU_Application-Package_WG5_P2H_Hydrogen into gas grid %28ID 2910558%29 %28ID 2911642%29.pdf

[258] “IEA G20 Hydrogen report: Assumptions.”

[259] IRENA, *Green hydrogen supply: A guide to policy. International Renewable Energy Agency, Abu Dhabi*. 2021.

[260] Uwe Weichenhain, “Hydrogen transportation. The key to unlocking the clean hydrogen economy. Roland Berger.,” 2021.

[261] “Annual Work Plan 2022, Clean Hydrogen Joint Undertaking.” https://www.clean-hydrogen.europa.eu/about-us/key-documents/annual-work-programmes_en

[262] “JRC High Pressure Gas Testing Facility.” https://joint-research-centre.ec.europa.eu/laboratories-and-facilities/high-pressure-gas-testing-facility_en

[263] G. Kakoulaki, I. Kougias, N. Taylor, F. Dolci, J. Moya, and A. Jäger-Waldau, “Green hydrogen in Europe – A regional assessment: Substituting existing production with electrolysis powered by renewables,” *Energy Convers. Manag.*, vol. 228, no. July 2020, 2021, doi: 10.1016/j.enconman.2020.113649.

[264] “Addendum to the Multi-Annual Work Plan 2014-2020 of the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU).” 2018. [Online]. Available: https://www.fch.europa.eu/sites/default/files/MAWP final version_endorsed GB 15062018 %28ID 3712421%29.pdf

[265] IRENA, *Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5 C Climate Goal*. 2020. [Online]. Available: /publications/2020/Dec/Green-hydrogen-cost-reduction%0Ahttps://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

[266] Sea NG corp., “Floating CNG: A less expensive way to monetize offshore gas,” 2012.

[267] WÄRTSILÄ, “WÄRTSILÄ Encyclopedia of Marine and Energy Technology.” https://www.wartsila.com/encyclopedia/term/bulk-carrier-bulker (accessed Aug. 04, 2022).

[268] “The development of container ships.” https://mccontainers.com/blog/development-of-containerships/ (accessed Aug. 04, 2022).

[269] D. Smyth, “How Much Does a Train Driver Make a Year?,” *Chron*, 2021. https://work.chron.com/much-train-driver-make-year-30958.html

[270] C. Hank *et al.*, “Electronic Supplementary Material (ESI) for Sustainable Energy & Fuels . This journal is © The Royal Society of Chemistry 2020 Supplementary Information : Energy efficiency and economic assessment of imported energy carriers based on renewable electrici,” 2020.

[271] M. M. J. Knoope, W. Guijt, A. Ramírez, and A. P. C. Faaij, “Improved cost models for optimizing CO2 pipeline configuration for point-to-point pipelines and simple networks,” *Int. J. Greenh. Gas Control*, vol. 22, pp. 25–46, 2014, doi: 10.1016/j.ijggc.2013.12.016.

[272] B. C. C. van der Zwaan, K. Schoots, R. Rivera-Tinoco, and G. P. J. Verbong, “The cost of pipelining climate change mitigation: An overview of the economics of CH4, CO2 and H2 transportation,” *Appl. Energy*, vol. 88, no. 11, pp. 3821–3831, 2011, doi: 10.1016/j.apenergy.2011.05.019.

[273] L. J. F. Comidy, M. D. Staples, and S. R. H. Barrett, “Technical, economic, and environmental assessment of liquid fuel production on aircraft carriers,” *Appl. Energy*, vol. 256, no. September, p. 113810, 2019, doi: 10.1016/j.apenergy.2019.113810.

[274] Martin Schmied, Wolfram Knörr, and L. Hepburn, “Calculating GHG emissions for freight forwarding and logistics services in accordance with EN 16258 Calculating GHG emissions for freight forward-ing and logistics services (April 2012).”

[275] The Centre for Low Carbon Futures, *Liquid Air in the energy and transport systems*. 2013. [Online]. Available: www.liquidair.org.uk

[276] “Crude Oil Tanks: A Look Into Oil Prices and Storage.” https://www.bbh.com/en-us/insights/crude-oil-tanks--a-look-into-oil-prices-and-storage--44050

[277] “TANK FARM AND STORAGE TERMINAL COST ESTIMATE,” *International Construction Consulting, LLC*, 2013. http://nebula.wsimg.com/1068da11025693c5e7c8d792a437b249?AccessKeyId=727DB069F40969F8DA39&disposition=0&alloworigin=1

[278] HYSTOC, “Deliverable 8.1 - Business Development and LCA Potential environmental implications of LOHC concepts,” 2018.

[279] Schmied, M. and Knörr, W., “Calculating GHG emissions for freight forwarding and logistics services in accordance with EN 16258 – Terms , Methods , Examples –,” 2012. [Online]. Available: https://www.clecat.org/media/CLECAT_Guide_on_Calculating_GHG_emissions_for_freight_forwarding_and_logistics_services.pdf (Accessed 22.10.2019)

[280] U. Bossel and B. Eliasson, “Energy and Hydrogen Economy,” *Eur. Fuel Cell Forum, Lucerne*, p. 36, 2002, [Online]. Available: https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf

[281] G. Wernet, C. Bauer, B. Steubing, J. Reinhard, E. Moreno-Ruiz, and B. Weidema, “The ecoinvent database version 3 (part I): overview and methodology,” *Int. J. Life Cycle Assess.*, vol. 21, no. 9, pp. 1218–1230, Sep. 2016, doi: 10.1007/s11367-016-1087-8.

List of abbreviations and definitions

AE	Alkaline electrolyser
ASU	Air Separation Unit
AWP	Annual Work Plan
BoP	Balance of plant
CAPEX	Capital up-front expenditure (investment)
CGH_2	Compressed gas hydrogen
CNG	Compressed Natural Gas
CO2	Carbon dioxide
DAC	Direct Air Capture
DBT	Dibenzyl Toluene
DoE	United States Department of Energy
DWT	Dead Weight Tonnage
EC	European Commission
ECU	Electrochemical Unit
EU	European Union
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gas
H_2	Hydrogen
HFO	Heavy Fuel Oil
HHV	Higher heating value
HRS	Hydrogen refuelling station
HT	High temperature
ICE	Internal Combustion Engine
ICT	Information Communication Technology
IEA	International Energy Agency
IMO	International Maritime Organisation
IRAS	Integrated Refrigeration And Storage
ISBL	Inside Battery Limits
ISO	International Organisation for Standardization
JRC	Joint Research Centre of the European Commission
KPI	Key performance indicator
kW	Kilowatt
LCA	Life-cycle assessment
LCC	Life-cycle cost
LCOE	Levelized Cost of Electricity
LFL	Low Flashpoint Liquid
LH_2	Liquid hydrogen

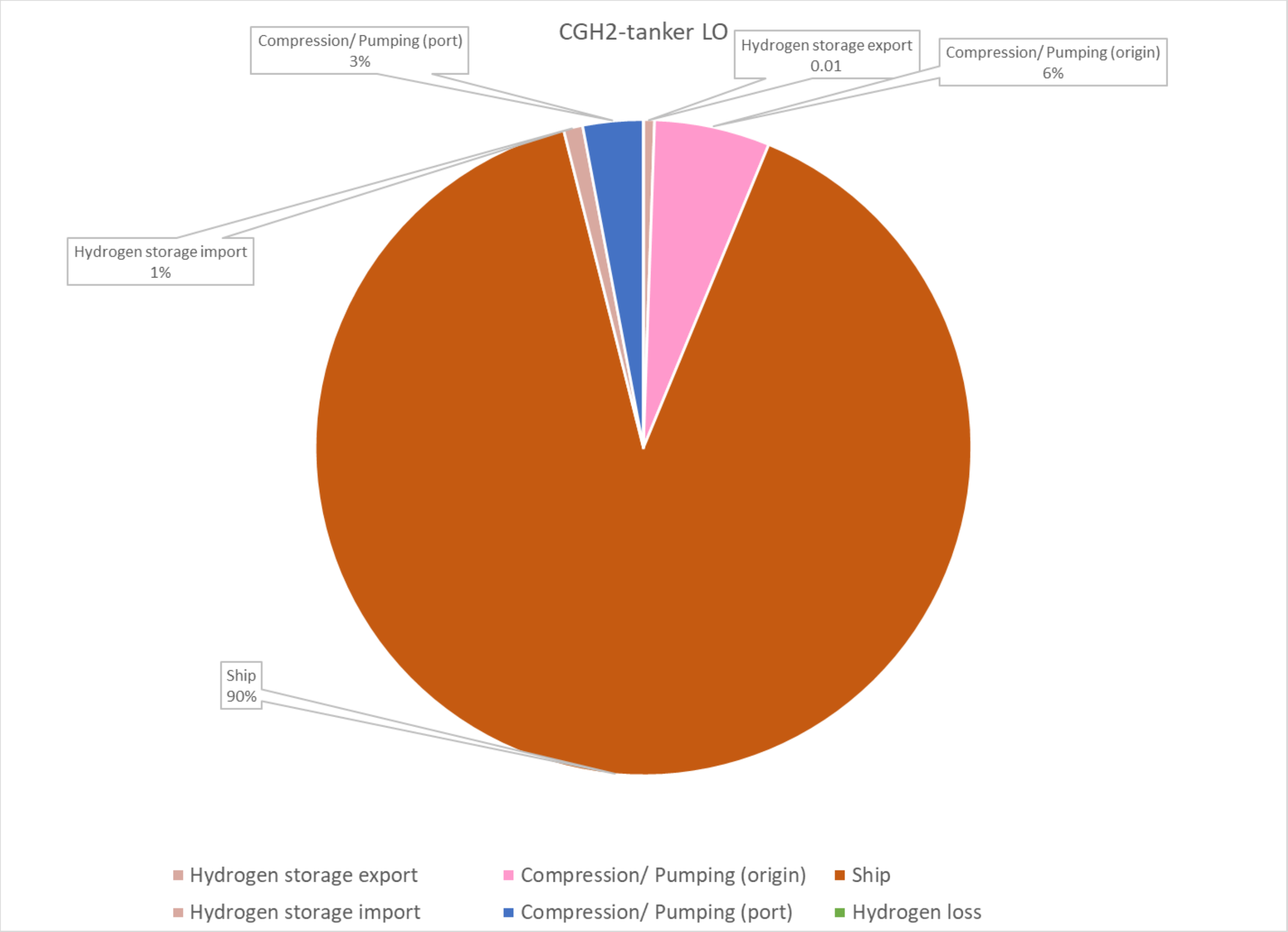
LHV	Lower heating value
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
MEGC	Multiple Element Gas Containers
MeOH	Methanol
MCH	Methylcyclohexane
MJ	Megajoule
MW	Megawatt
NH_3	Ammonia
NOx	Nitrogen oxides
O&M	Operation and Maintenance
OEM	Original equipment manufacturer
OPEX	Operational expenditure
OSBL	Outside Battery Limits
PEM	Proton exchange membrane
PEME	Proton exchange membrane electrolyser
PGM	Platinum group metals
PSA	Pressure Swing Adsorption
R&I	Research and Innovation
R&D	Research and development
RCS	Regulations, codes and standards
RES	Renewable energy sources
SME	Small and medium-sized enterprise
SMR	Steam methane reforming
SoA	State-of-the-art
SOx	Sulphur oxides
TCO	Total Cost of Ownership
TEU	Twenty-foot equivalent unit
TFCC	Total fixed capital cost
TSO	Transmission System Operator
UIC	International Union of Railways
UN-ECE	United Nations Economic Commission for Europe
USD	United States of America Dollars

List of Tables

List of Figures

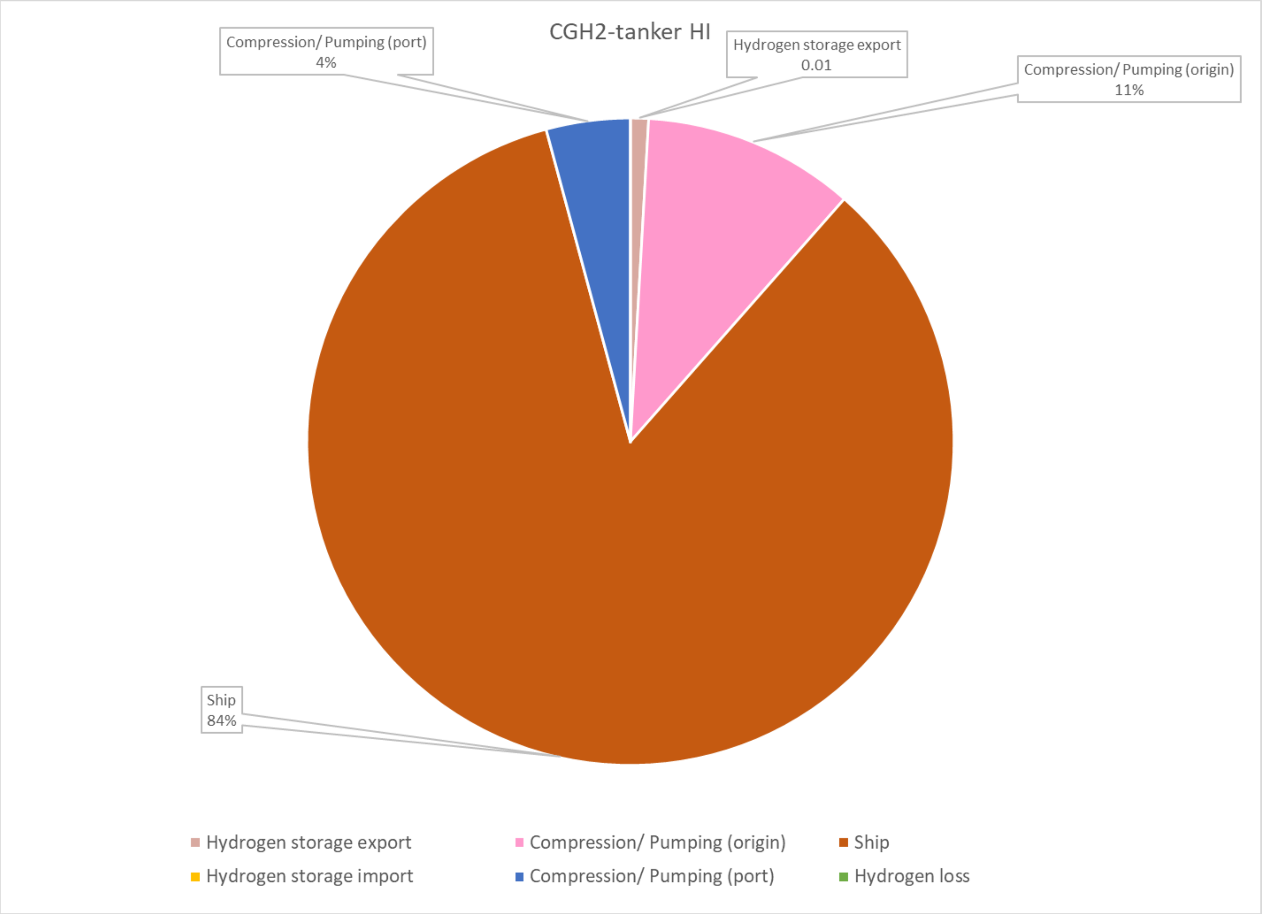
Annex 1 – additional graphs

Figure 18 Detailed cost breakdown for compressed hydrogen delivery, low electricity cost scenario.



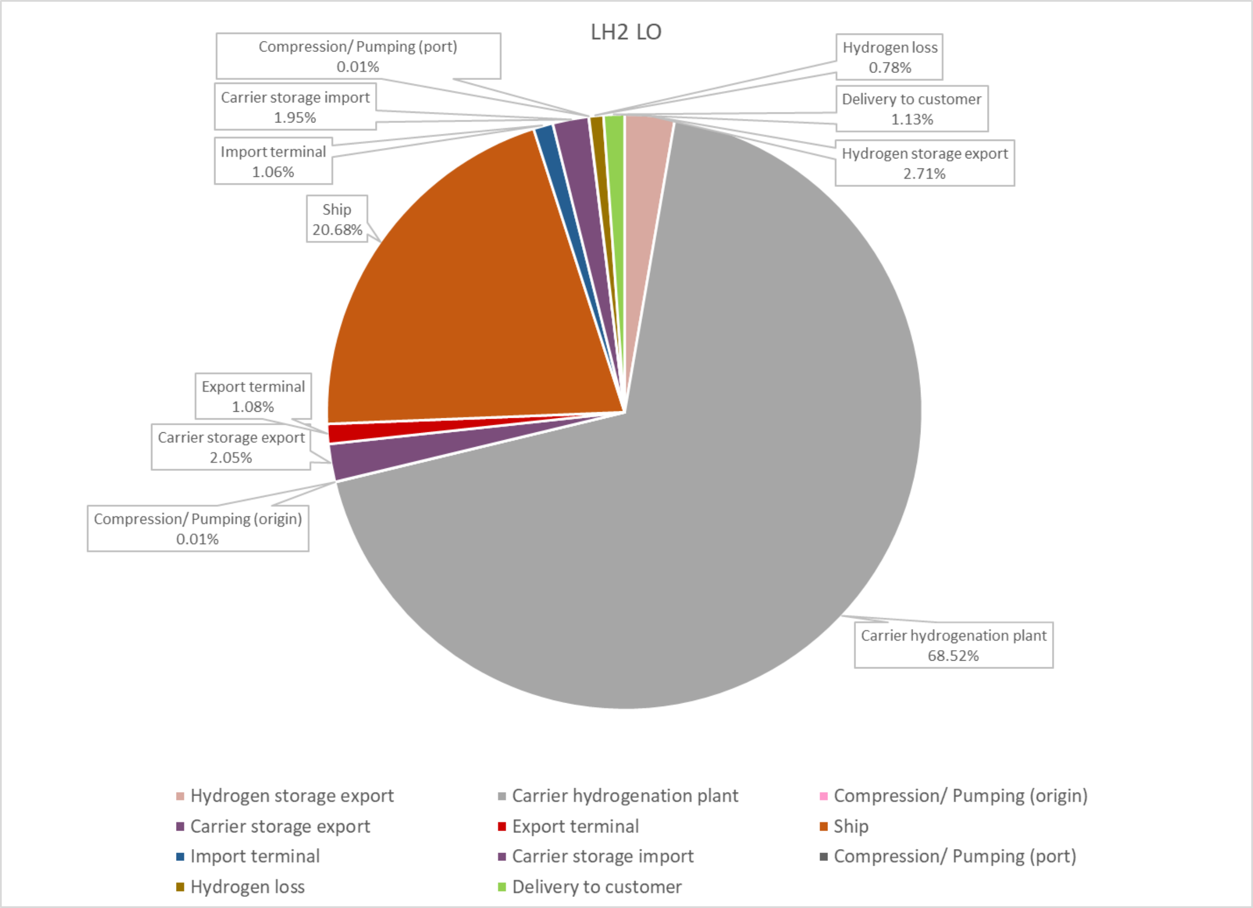
Source: JRC analysis

Figure 19 Detailed cost breakdown for compressed hydrogen delivery, high electricity cost scenario.



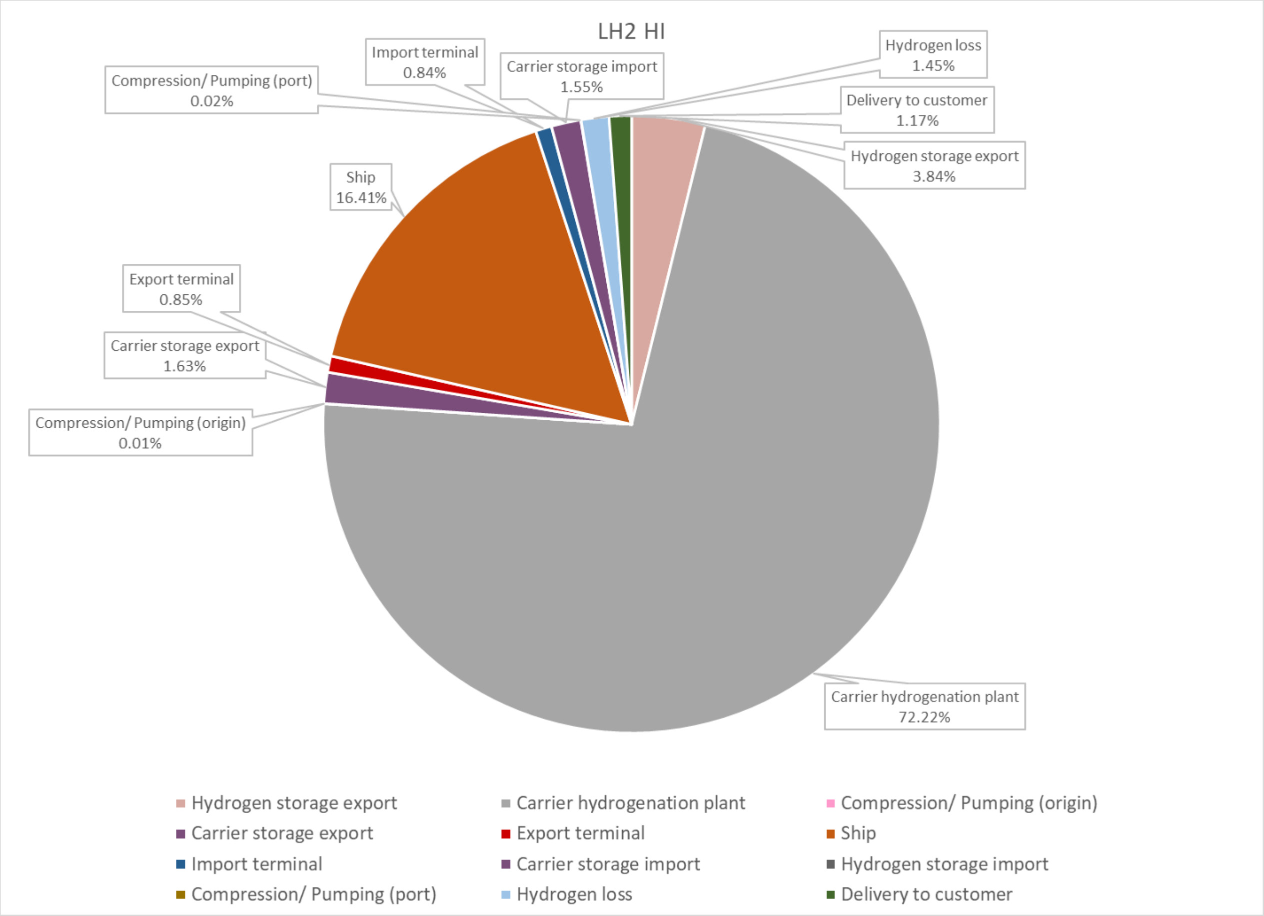
Source: JRC analysis

Figure 20 Detailed cost breakdown for liquid hydrogen delivery, low electricity cost scenario.



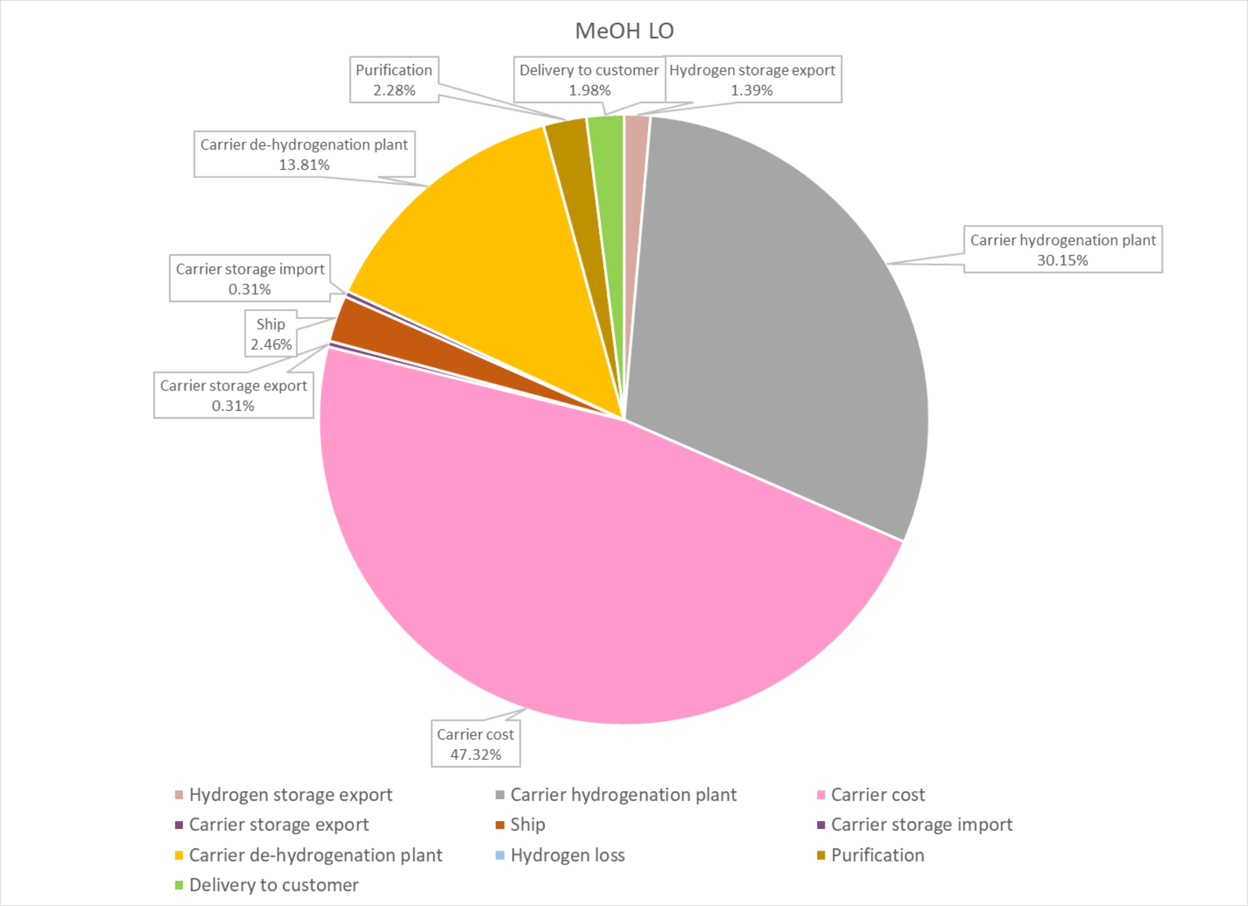
Source: JRC analysis

Figure 21 Detailed cost breakdown for liquid hydrogen delivery, high electricity cost scenario.



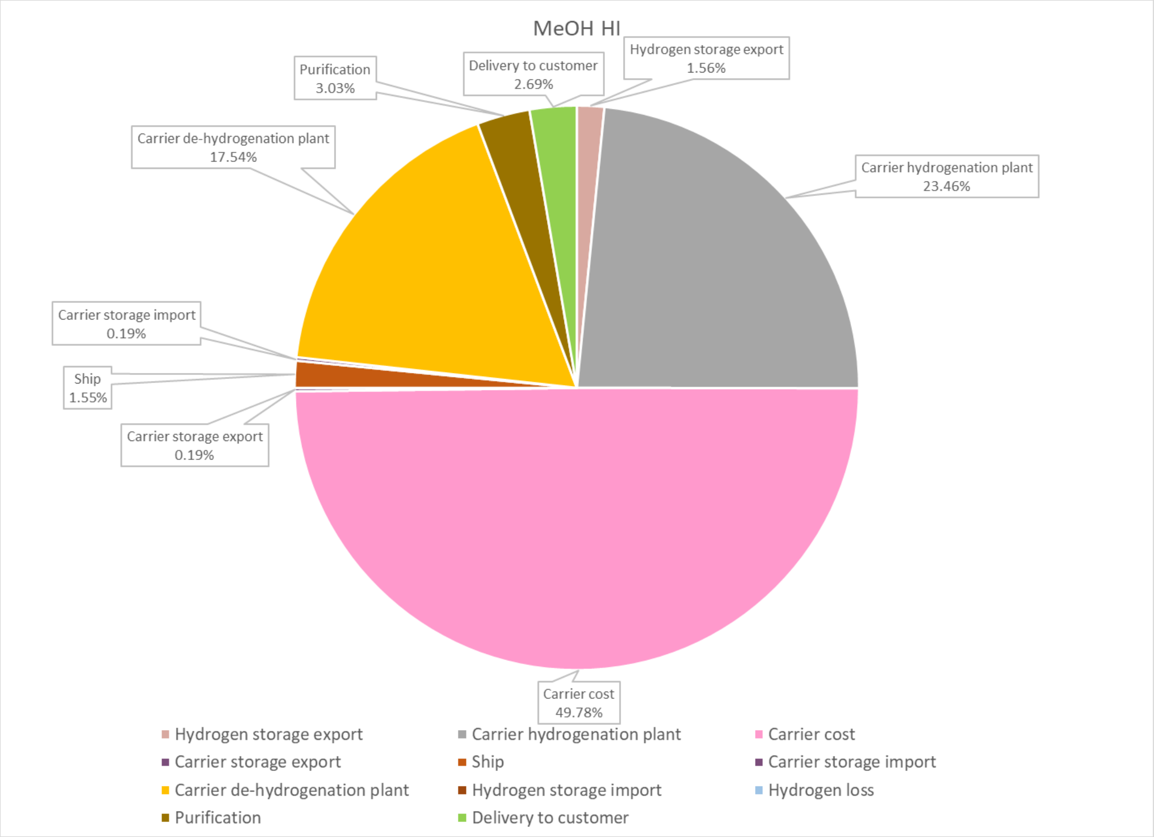
Source: JRC analysis

Figure 22 Detailed cost breakdown for chemical carrier: methanol delivery, low electricity cost scenario.



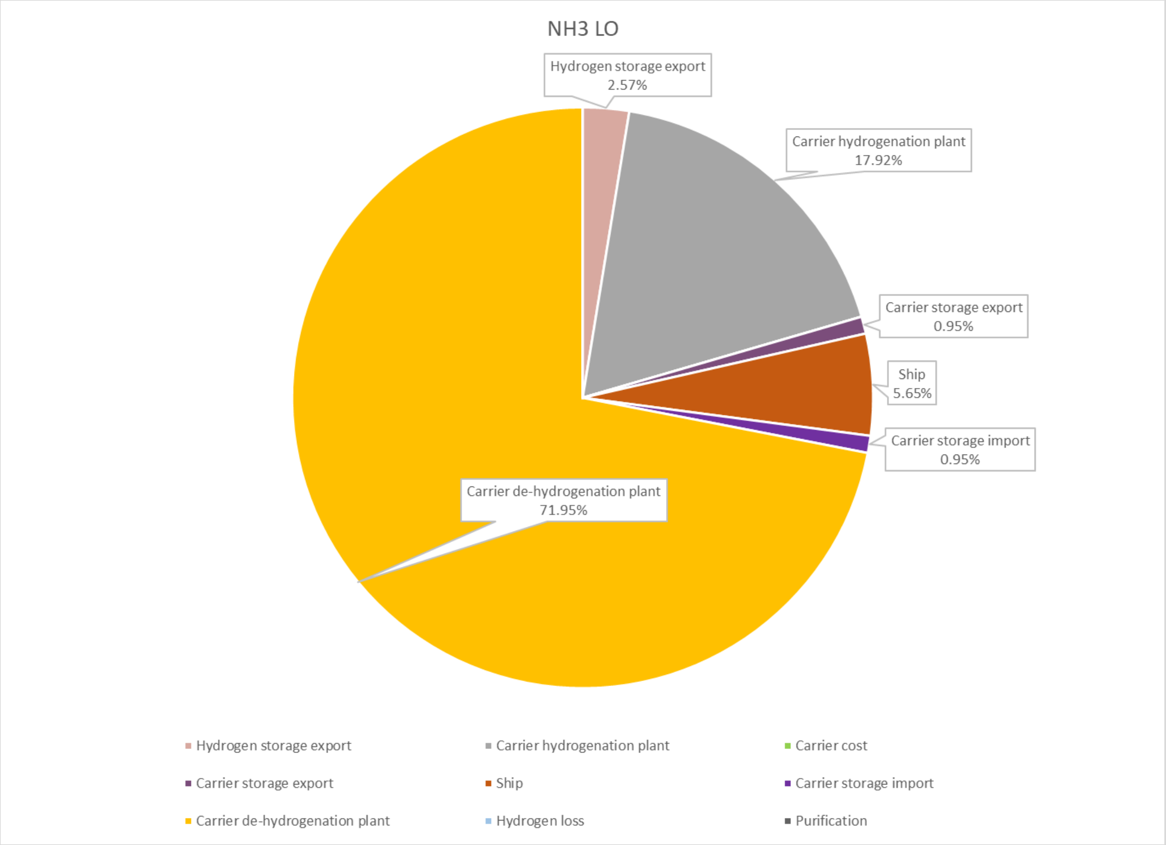
Source: JRC analysis

Figure 23 Detailed cost breakdown for chemical carrier: methanol delivery, high electricity cost scenario.



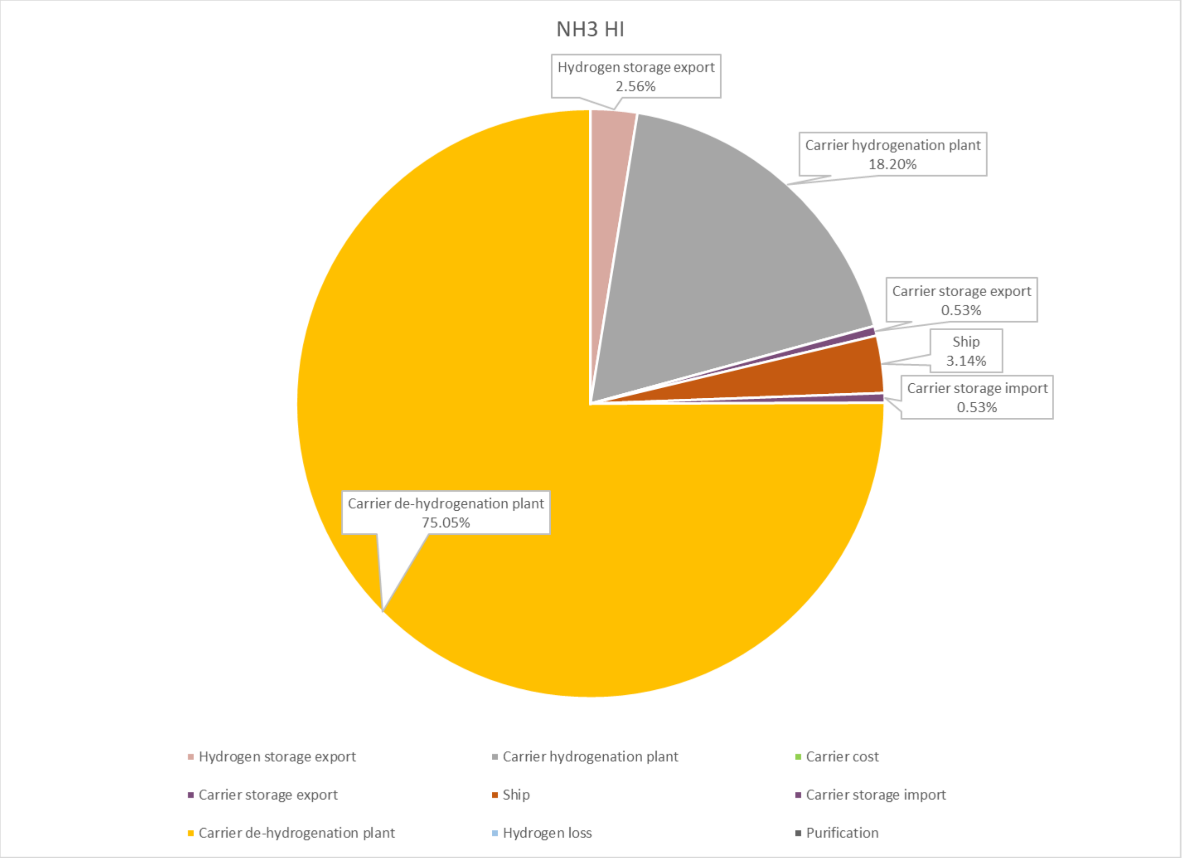
Source: JRC analysis

Figure 24 Detailed cost breakdown for chemical carrier: ammonia delivery, low electricity cost scenario.



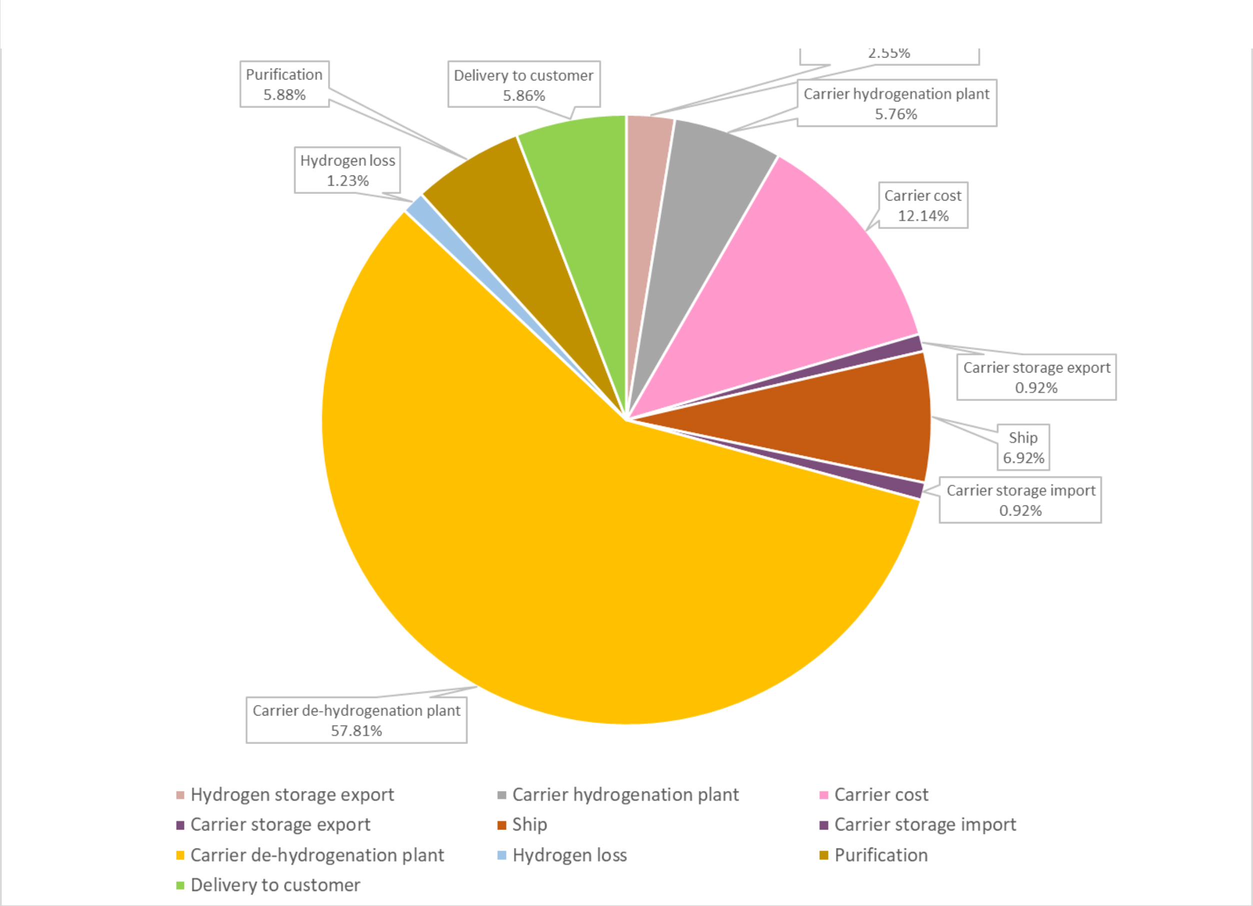
Source: JRC analysis

Figure 25 Detailed cost breakdown for chemical carrier: ammonia delivery, high electricity cost scenario.



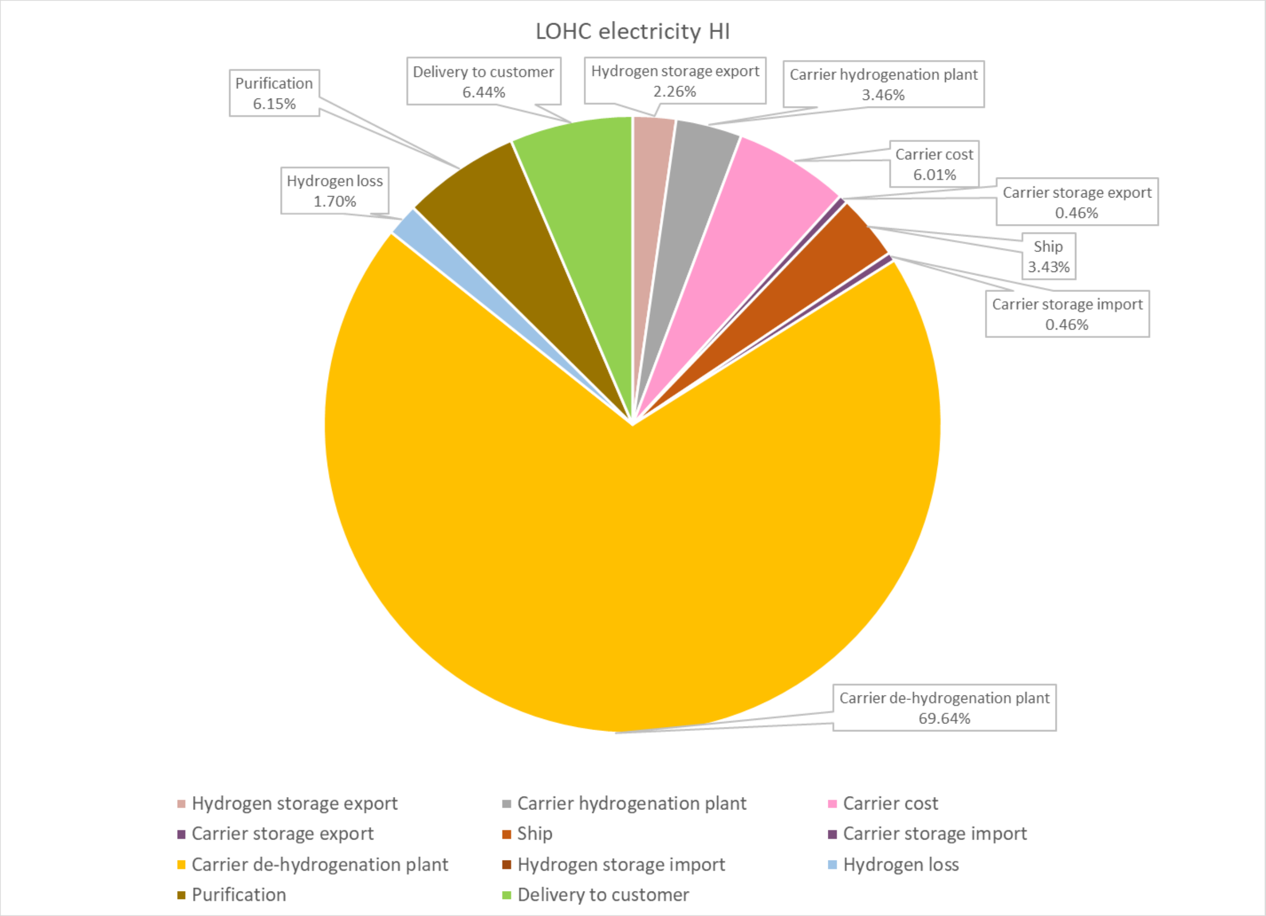
Source: JRC analysis

Figure 26 Detailed cost breakdown for chemical carrier: LOHC delivery, low electricity cost scenario



Source: JRC analysis

Figure 27 Detailed cost breakdown for chemical carrier: LOHC delivery, high electricity cost scenario. Dehydrogenation with electrical heating.



Source: JRC analysis

Annex 2 – Tables with assumptions

Table 16 Hydrogen production assumptions

Hydrogen Production						
Technology	KPI	Unit	Case A	Case B	Method/Notes	Reference
PEM Electrolyser	Total CAPEX	EUR/kW	500	500		[264]
	Annual OPEX (O&M cost plus 1 stack replacement)	%	4	4	Own calculation based on various sources	[264], [265]
	Efficiency	kWh/kg H_2	52	52		[264]
	Lifetime	years	20	20	Own assumption	
Alkaline Electrolyser	Total CAPEX	EUR/kW	400	400		[264]
	Annual OPEX	%	6.3%	6.3%	Own calculation based on various sources	[264], [265]
	Efficiency	kWh/kg H_2	49	49		[264]
	Lifetime	years	20	20	Own assumption	

Hydrogen Production						
Technology	KPI	Unit	Case A	Case B	Method/Notes	Reference
Underground H_2 storage	Lifetime	years	40	40	Own assumption	
	Storage capacity	t H_2	8 200 - 12 000[54]	8 20-1 200	Own assumption	
	Operating pressure	MPa	7	7	Own assumption	
	CAPEX[55]	MEUR	170 - 250	–17 - 25	Calculated from	[32]
	Annual OPEX	kEUR	180 - 200	100 - 110	Calculated from	[190]
H_2 Compressor	Total installed capacity	t H_2/h	115 - 160	12 - 16	Own assumption	
	Total CAPEX	MEUR	170 - 250	17 - 25	Calculated based on industry information	
	Annual OPEX	kEUR	1 900 – 2 700	200 - 280	Calculated based on industry information and	[190]
	Lifetime	years	20	20	Own assumption	

---

[54] The higher capacity is needed for Ammonia and Methanol pathways, and LOHC in case hydrogen is used to provide heat for hydrogenation.

[55] Does not include compressors.

Hydrogen Production						
Technology	KPI	Unit	Case A	Case B	Method/Notes	Reference
	Pressure input / output	MPa	3 / 9	3 / 9	Own assumption	

Table 17 Compressed Hydrogen Assumptions

Compressed Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
H_2 Compressor	Installed capacity	tH_2/h	425	130 / 25		
	Total CAPEX	MEUR	720	220 / 50	Calculated based on industry information	
	Annual OPEX	kEUR	7 500	2 300 / 540	Calculated based on industry information and	[190]
	Lifetime	years	20	20	Own assumption	
CGH_2 ship	Capacity ship	t H_2	1 370	1 370 / 3 000		
	Storage pressure	MPa	25	25 / 50	Based on	[196]
	CAPEX ship	MEUR	217	217 / 48	Based on	[196], [206], [266], [267]
	Speed ship	km/h	26	26 / 30	From	[197], [199]
	Annual OPEX	MEUR	2.8	2.8 / 3.5	Calculated from	[200]

Compressed Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	Energy consumption	MJ/km	5 000	5 000 / 7 200	Calculated from	[197], [198], [199], [207]
	Lifetime	years	30	30 / 20	Based on	[268]
CGH_2 container	Capacity	t H_2		1.1		[39]
	CAPEX	MEUR		0.9	Based on	[40]
Truck	CAPEX trailer	kEUR		60		[40]
	CAPEX truck	kEUR		115		[190]
	Speed truck	km/h		50		[189]
	Annual OPEX truck	EUR/km		0.6	Calculated from	[191]
	Fuel cost	EUR/km		1	Calculated from	[188]
Train	CAPEX diesel locomotive	MEUR		2.8	Calculated from	[187]

Compressed Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	CAPEX electric locomotive	MEUR		2.2	Calculated from	[187]
	Speed train	km/h		50		[189]
	Annual OPEX diesel train	kEUR/train		990	Calculated from	[187], [269]
	Annual OPEX electric train	kEUR/train		430	Combination of	[187] [269]
	Energy use (diesel train)	MJ/tkm		0.19	Calculated from	[188]
	Energy use (electric train)	MJ/tkm		0.07	Calculated from	[188]

Compressed Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
Underground H_2 storage	Lifetime	years	40	40	Own assumption	
	Total storage capacity	t H_2	7 100	7 100 / 8 800	Own assumption	
	Operating pressure	MPa	10	10	Based on	[24]
	CAPEX	MEUR	130	130 / 160	Calculated from	[32]
	Annual OPEX	kEUR	455	455	Calculated from	[190]

Table 18 Hydrogen pipeline assumptions

Hydrogen Pipelines						
Technology	KPI	Unit	Scenario A	Scenario B	Method/Notes	Reference
H_2 Pipelines	Lifetime	years	50	50	Own assumption	
	Pipeline diameter	inches	34	14	Own calculation	

Hydrogen Pipelines						
Technology	KPI	Unit	Scenario A	Scenario B	Method/Notes	Reference
	Pipeline operating pressure	MPa	7	7	Defined by compressor	
	Pipeline material		X42	X42	Own assumption. Compatible with hydrogen	
	CAPEX	MEUR/km	2.5	1	Calculated from	[190]
	OPEX	kEUR/year	600	340	Calculated from	[190]
H_2 compressor	Lifetime	years	20	20	Own assumption	
	Flow-rate compressor station	Nm^3/h	1 250 000	125 000	Based on industry information	
	Pressure Input/Output	MPa	3-7	3-7	Based on industry information	
	CAPEX compressor station	MEUR	150	15	Based on industry information	

Hydrogen Pipelines

Technology	KPI	Unit	Scenario A	Scenario B	Method/Notes	Reference
	OPEX	kEUR/year	1 800	200	Calculated from both	[190] Industry information
	Compressor utilisation	%	50	50	Own assumption	
Underground H_2 storage	Lifetime	years	40	40	Own assumption	
	Storage capacity	t H_2	27 000	2 700	Own assumption	
	Operating pressure	MPa	7	7	Defined by compressor	
	CAPEX	MEUR	553	55	Calculated from	[32]
	OPEX	kEUR/year	240	135	Calculated from	[32]

Table 19 Liquid Hydrogen Assumptions

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
Liquefaction	Installed capacity	ktH_2/y	1 125	130/110		
	Total CAPEX	MEUR	6 600	755/640	Calculated from	[190]
	Annual OPEX	% CAPEX	3	3	Own assumption	
	Lifetime	years	20	20	Own assumption	
	Electricity use[56]	MJ/kg H_2	21.6 (14.4)	21.6 (14.4)	Calculated from	[54]
LH_2 storage tank	Total storage capacity	t H_2	34 000	17 300/7 800		
	Total storage CAPEX	MEUR	565	290/2 100	Calculated based on industry information and	[24]
	Annual OPEX	kEUR	1 200	960/42	Calculated from	[190]

---

[56] Energy consumptions for liquefaction and re-liquefaction are presented.

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	Lifetime	years	20	20/20	Based on industry information	
	Boil-off rate	%/day	0.08	0.08-1/0.2[57]	From	[59] [60]
	Boil-off at transfer	%	2.25	2.25 / 2.5	Calculated from	[64]
LH_2 ship	Capacity ship	t H_2	8 700	4 200/3 300		
	CAPEX ship	MEUR	380	263/25	Calculated from	[62], [206], [270]
	Speed ship	km/h	35	31/30	From	[199][208]
	Annual OPEX	MEUR	10	4.5/2.1	Calculated from	[200]
	Lifetime	years	20	20/20	Assumption	
	Boil-off rate	%/day	0.2	0.2/0.2	Based on	[60], [67]

---

[57] Range of boil-off rates of the different storage systems used in this pathway.

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	Flash rate	%	2.5	2.5	Calculated from	[64]
LH_2 container	CAPEX container	kEUR		-/800	Based on industry information	
	OPEX container	kEUR		-/20	Based on industry information	
Truck	Truck capacity	t H_2		3.3/3	Based on industry information and	[67]
	CAPEX trailer	kEUR		-/60	From	[40]
	CAPEX truck	kEUR		750/115	From	[24], [190]
	Speed truck	km/h		50		[189]
	Annual OPEX truck	EUR/km		0.8/0.62	Calculated from	[191]
	Fuel cost	EUR/km		0.72/0.59	Calculated from	[188]
	Lifetime	years	-	20/20	Assumption	

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
LH_2 train	Capacity train wagon	t		7.4/3	Calculated from	[67], [69]
	CAPEX train wagon	kEUR		-/90[58]	Calculated from	[187]
	CAPEX diesel locomotive	MEUR		2.5/2.3	Calculated from	[187]
	CAPEX electric locomotive	MEUR		2.1/2	Calculated from	[187]
	Speed train	km/h		50		[189]
	Annual OPEX diesel train	kEUR/train		4200/1000	Combination of	[187],[209], [269]

---

[58] LH_2 bulk transport assumes leasing of wagons at 210 EUR/day. These costs are included in OPEX costs.

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	Annual OPEX electric train	kEUR/train		3700/420	Combination of	[187],[209], [269]
	Energy use (diesel train)	MJ/tkm		0.19		[188]
	Energy use (electric train)	MJ/tkm		0.07		[188]
Transformation at HRS	Pressure output	MPa		52		
	Energy for pumping	MJ/kg H_2		2.2	Estimated from	[24]
	Flow-rate	kg/h		46		
	Power pump	kW		25		

Liquid Hydrogen						
Technology	KPI	Unit	Case A	Case B (Bulk / Container)	Method/Notes	Reference
	CAPEX pump	kEUR		130	Based on industry information	
	Lifetime pump	years		10		[24]
	CAPEX Evaporator	kEUR		90	Calculated from	[190]
	OPEX	% total CAPEX		5		[24]

Table 20 Methanol assumptions

Methanol						
			Case A	Case B		
MeOH Pipelines	Design throughput	ktMeOH/y	6 893	689		
	Velocity	m/s	1.8	0.6	Calculated from	[239]
MeOH Pipelines General parameters	Lifetime	years	40	40		
	External diameter	inches	18	10		
	Thickness	mm	8.3	4.6		[243]
	Injection pressure	MPa	7	7		
	Material cost (X42)	EUR/t-steel	1 350	1 350		[271]
	Material cost percentage of CAPEX	%	20.0	15.0		[272], [245]
	CAPEX	(MEUR/km)	0.7	0.3	See 5.5.6.2	

	OPEX	% CAPEX	2.8	1.2	See 5.5.6.2	
	Compressor utilisation	%	50.0	50.0		
MeOH Packing	CAPEX	M EUR	654	349.2		[211]
	Capacity	tMeOH/d	5 400	2 117		
	Annual OPEX	% CAPEX	3.0	3.0		
	Electricity use	GJ/tMeOH	2.3	2.3		[211], [273]
MeOH tank	Capacity tank	tMeOH	58 000	9 656		
	Total CAPEX tank	EUR million	14.6	4.4	Calculated from	[94]
	CAPEX	kEUR/tMeOH	0.2	0.46	Calculated from	[94]
	Annual OPEX	% of CAPEX	23.6	13		[94]
MeOH ship	Capacity ship	tMeOH	41 500	9 656	Calculated from	[137], [106]
	Total CAPEX ship	EUR million	42.0	15.1	Calculated from	[106]

	CAPEX	kEUR/tMeOH	1.0	1.6		
	Speed ship	km/h	29.6	29.6		[106]
	Annual OPEX	% of CAPEX	8	13.6	Calculated from	[106]
	Fuel use	MJ/(tonMeOH*km)	0.03	0.03	Calculated from	[137], EEDI from [216]
MeOH Unpacking	Capacity	tMeOH/d	2 467	353		
	Total CAPEX	EUR million	126.7	34.4		
	Annual OPEX	% of CAPEX	3.0	3.0		
	Electricity required	MWh/tH$_2$	0.501	0.501		[143]
	Fuel Required[59]	MWh/tH$_2$	8.6	8.6		[143]
	Water consumption for steam reforming	kgH$_2$O/kgH$_2$	3.8	3.8		[143]
	Ratio	kgH$_2$/kgMeOH	0.142	0.142	Calculated from	

---

[59] Assuming a boiler efficiency of 90%.

MeOH train	Lifetime locomotive/train	years	-	20.0		
	CAPEX locomotive	MEUR	-	4.9-2.8	Calculated from	[187]
	OPEX locomotive	% CAPEX	-	14-34	Calculated from	[187]
	Driven hours / yr	h/y	-	2 500	Calculated from	
	Locomotive distance km / yr	km/y		87 600	Calculated from	
	Diesel train consumption	MJ/tkm	-	0.3		[274]
	Electric train consumption	MJ/tkm				
	Total CAPEX	kEUR	-	109		[171]
	Trailer length	m	-	15.1		[139]
	Trailer weight	kg	-	21 600		[139]
	Net capacity	kg MeOH	-	67 200		[139]

Table 21 Ammonia Assumptions

Ammonia						
			Case A	Case B		
NH_3 Pipelines	Design throughput	$ktNH_3/y$	8 200	820		
	Velocity	m/s	2.7	0.9	Calculated from	[239]
	Lifetime	years	40.0	40.0		
	External diameter	inches	18	10		
NH_3 Pipelines general parameters	Thickness	mm	8.3	4.6		[243]
	Injection pressure	MPa	7	7		
	Material cost (X42)	EUR/t-steel	1 350	1 350		[271]
	Material cost percentage of CAPEX	%	20.0	15.0		[272], [245]
	CAPEX	(MEUR/km)	0.7	0.3	See 5.5.6.2	

Ammonia						
			Case A	Case B		
	OPEX	% CAPEX	2.8	1.2	See 5.5.6.2	
	Compressor utilisation	%	50	50		
NH_3 Packing	CAPEX	M EUR	2 373.3	309	Calculated from	[97]
	Installed Capacity	tNH_3/d	24 627	2 463	Own assumption	
	Annual OPEX	% CAPEX	3.0	3.0		[94]
	Electricity use	GJ/tNH_3	2.9	2.9		[94], [81],[275]
NH_3 tank	Capacity tank	tNH_3	50 000	11 000		
	Total CAPEX tank	EUR million	32.5	8.3		
	CAPEX	$kEUR/tNH_3$	0.65	0.76		[94]
	Annual OPEX	% of CAPEX	13.6	11.6	Calculated from	[94]

Ammonia						
			Case A	Case B		
NH_3 ship	Capacity ship	tNH_3	50 000	11 234	Calculated from	[105]
	Total CAPEX ship	EUR million	70	24.7	Calculated from	[106]
	CAPEX	$kEUR/tNH_3$	1.4	2.2		
	Speed ship	km/h	29.6	29.6		[105]
	Annual OPEX	% of CAPEX	4.7	9.0	Calculated from	[236]
	Fuel use	$MJ/(tonNH_3*km)$	0.05	0.05	Calculated from	[105]
NH_3 Unpacking	Installed capacity	tNH_3/d	24 627	2 463		
	Total CAPEX	EUR million	1 100	249		[89]
	CAPEX	$EUR/(t NH_3/d)$	44.7	101.1		

Ammonia						
			Case A	Case B		
	Annual OPEX	% of CAPEX	3.0	3.0		
	Heat required	MWh/tH_2	-	-		
	Electricity required	MWh/tH_2	4.9	4.9		[89]
	Fuel Required	MWh/tH_2	14.4	14.4		[89]
	Ratio	$kgH_2/kgNH_3$	0.122	0.122	Calculated from	
NH_3 train	Lifetime locomotive/train	years	-	20.0		

Ammonia						
			Case A	Case B		
	CAPEX locomotive	MEUR	-	4.9-2.8	Calculated from	[187]
	OPEX locomotive	% CAPEX	-	14-34	Calculated from	[187]
	Driven hours / yr	h/y	-	2 500	Calculated from	
	Locomotive distance km / yr	km/y		87 600	Calculated from	
	Diesel train consumption	MJ/tkm	-	0.3	Calculated from	[274]
	Total CAPEX	kEUR	-	163.0		[113]
	Trailer length	m	-	17.2		[112]
	Trailer weight	kg	-	35 000		[112]
	Net capacity	kg NH_3	-	55 120		[112]

Table 22 LOHC Assumptions

LOHC[60]						
			Case A	Case B		
	CAPEX	EUR/kg DBT	1.5	1.5		[160]
	Cyclability	nr	750	750		[219]
LOHC Pipelines	Lifetime	years	50	50		
	Design throughput	ktH_2/y	1 000	100		
	CAPEX	(MEUR/km)	0.32	0.09	See 5.5.6.3	
	Compressor utilisation	%	50	50		
LOHC tank	Capacity tank	t DBT	284 000	30 000 /5 000	Corresponding to two shiploads	
	CAPEX tank	EUR/t DBT	264	322/368	Calculated from	[176], [276],[224], [277]
	Annual OPEX	%	1	1		

---

[60] The assumptions provided here relate to the case where electricity is used to provide the energy for dehydrogenation.

LOHC[60]						
			Case A	Case B		
	Electricity use	MJ/kg H_2	0	0		
LOHC ship	Capacity ship	t DBT	142 000	31 500 14 400		
	Total CAPEX ship	MEUR	65	26 23		[106]
	Speed ship	km/h	26	27		[227], [230]
	Annual OPEX	% CAPEX	5	10		[106]
	Fuel use	t/d	55	28 22		[227]
LOHC Packing	Installed capacity	ktH_2/y	1 000[61]	100		
	CAPEX	MEUR	280	60	Based on	[270]

---

[61] Only the base Case A and B figures are given here (not considering the use of hydrogen for heat).

LOHC[60]						
			Case A	Case B		
	Annual OPEX	%	1.5	1.5		[176]
	Electricity required	MJ/kg H_2	1.332	1.332		[222]
	Depreciation period	years	20	20	Own assumption	
LOHC Unpacking	Installed capacity	ktH_2/y	1 000	Railport 27 250 HRS 1 135		
	CAPEX	MEUR	669	Railport 27.7 HRS 4	Based on	[270]
	Annual OPEX	%	1.5	1.5	Based on	[176]
	Electricity required	MJ/kg H_2	45	45	Based on	[223], [222], [278]
	H_2 purification CAPEX	EUR/kg H_2	76	Railport 120 HRS 439	Calculated from	[165]

LOHC[60]						
			Case A	Case B		
	H_2 recovery rate	%	99.9	99.9		[278]
	PSA H_2 recovery rate	%	99	99		[278]
LOHC train	Capacity train wagon	t DBT		23.6		[170]
	CAPEX train wagon	kEUR		128		[171]
	CAPEX diesel locomotive	MEUR		4.2	Calculated from	[187]
	CAPEX electric locomotive	MEUR		2.5	Calculated from	[187]
	Speed train	km/h		50		[189]
	Annual OPEX diesel train	kEUR/train		1 000	Calculated from	[187] [269]

LOHC[60]						
			Case A	Case B		
	Annual OPEX electric train	kEUR/train		475	Calculated from	[187] [269]
	Energy use (diesel train)	MJ/tkm		0.19		[279]
	Energy use (electric train)	MJ/tkm		0.07		[279]
LOHC truck	Tank capacity	l		25 000		[231]
	CAPEX tank	kEUR		20		[231]
	CAPEX trailer	kEUR		60		[40]

LOHC[60]						
			Case A	Case B		
	CAPEX truck	MEUR		115		[190]
	Speed truck	km/h		50		[189]
	Annual OPEX truck	EUR/km		0.62	Calculated from	[191]
	Fuel cost	EUR/km		1.35	Calculated from	[191]
HRS transformation	Pressure inlet	MPa		3		
	Pressure out	MPa		52		
	Energy for compression	MJ/kg H_2		7.7	Calculated from	[280]
	Flow-rate	kg/h		41.7		
	Power	kW		90		
	CAPEX	kEUR		400		[190]
	OPEX	%CAPEX		4	Calculated from	[24]

GETTING IN TOUCH WITH THE EU

In person

All over the European Union there are hundreds of Europe Direct centres. You can find the address of the centre nearest you online (european-union.europa.eu/contact-eu/meet-us_en).

On the phone or in writing

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

— by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls),

— at the following standard number: +32 22999696,

— via the following form: european-union.europa.eu/contact-eu/write-us_en.

FINDING INFORMATION ABOUT THE EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website (european-union.europa.eu).

EU publications

You can view or order EU publications at op.europa.eu/en/publications. Multiple copies of free publications can be obtained by contacting Europe Direct or your local documentation centre (european-union.europa.eu/contact-eu/meet-us_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1951 in all the official language versions, go to EUR-Lex (eur-lex.europa.eu).

Open data from the EU

The portal data.europa.eu provides access to open datasets from the EU institutions, bodies and agencies. These can be downloaded and reused for free, for both commercial and non-commercial purposes. The portal also provides access to a wealth of datasets from European countries.

The European Commission's science and knowledge service

Joint Research Centre

JRC Mission

As the science and knowledge service of the European Commission, the Joint Research Centre's mission is to support EU policies with independent evidence throughout the whole policy cycle.

EU Science Hub
joint-research-centre.ec.europa.eu

@EU_ScienceHub

EU Science Hub - Joint Research Centre

EU Science, Research and Innovation

EU Science Hub

EU Science

Publications Office
of the European Union