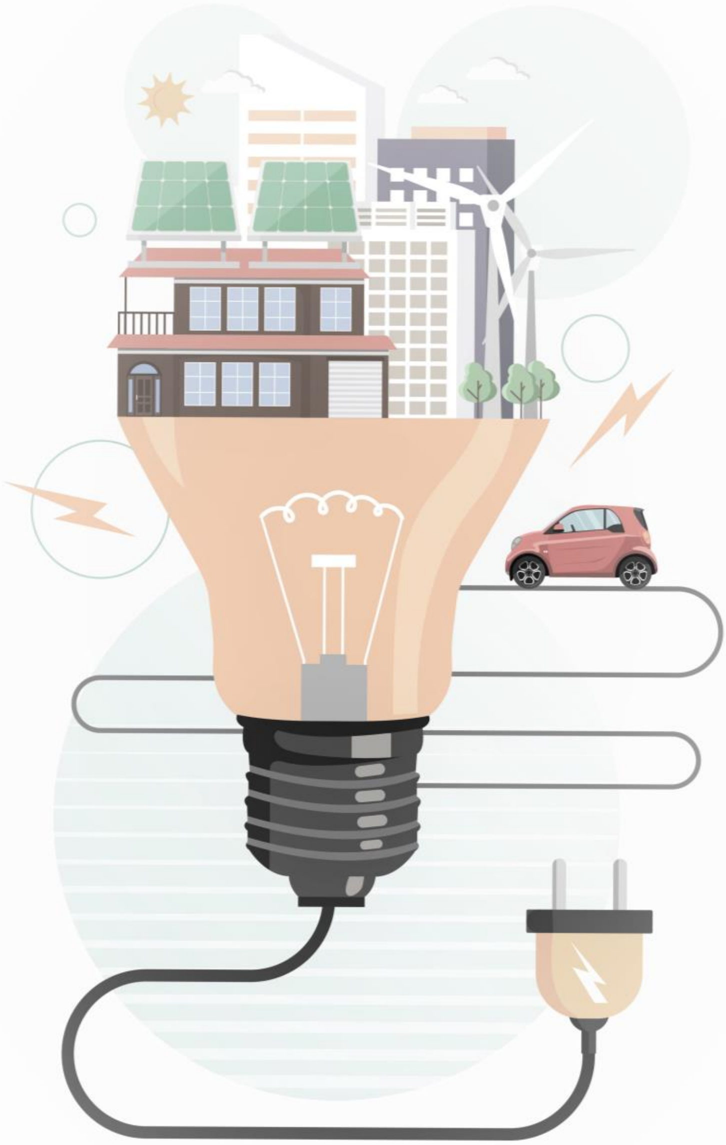
ASSET Study on

Hydrogen generation in Europe: Overview of costs and key benefits



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About the ASSET project

The ASSET Project (Advanced System Studies for Energy Transition) aims at providing studies in support to EU policy making, research and innovation in the field of energy. Studies are in general focussed on the large-scale integration of renewable energy sources in the EU electricity system and consider, in particular, aspects related to consumer choices, demand-response, energy efficiency, smart meters and grids, storage, RES technologies, etc. Furthermore, connections between the electricity grid and other networks (gas, heating and cooling) as well as synergies between these networks are assessed.

The ASSET studies not only summarize the state-of-the-art in these domains, but also comprise detailed qualitative and quantitative analyses on the basis of recognized techniques in view of offering insights from a technology, policy (regulation, market design) and business point of view.

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Authors

Lead Author: Jan Cihlar (Guidehouse)
Authoring Team: Ainhoa Villar Lejarreta (Guidehouse), Anthony Wang (Guidehouse), Fatima Melgar (Tractebel Impact), Jaro Jens (Guidehouse), Philippe Rio (Tractebel Impact)
Reviewer: Kees van der Leun (Guidehouse)

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Foreword

The European Commission published its hydrogen strategy for a climate-neutral Europe[1] on the 8th July 2020. This strategy brings different strands of policy action together, covering the entire value chain, as well as the industrial, market and infrastructure angles together with the research and innovation perspective and the international dimension, in order to create an enabling environment to scale up hydrogen supply and demand for a climate-neutral economy.

The strategy also highlights clean hydrogen and its value chain as one of the essential areas to unlock investment to foster sustainable growth and jobs, which will be critical in the context of recovery from the COVID-19 crisis. It sets strategic objectives to install at least 6 GW of renewable hydrogen electrolysers by 2024 and at least 40 GW of renewable hydrogen electrolysers by 2030 and foresees industrial applications and mobility as the two main lead markets.

This report provides the evidence base established on the latest publicly available data for identifying investment opportunities in the hydrogen value chain over the period from 2020 to 2050, and the associated benefits in terms of jobs. Considering the dynamics and significant scale-up expected over a very short period of time, multiple sources have been used to estimate the different values consistently and transparently. The report covers the full value chain, from the production of renewable electricity as the energy source for renewable hydrogen production to the investment needs in industrial applications and hydrogen trucks and buses.

Although the values range significantly across the different sources, the overall trend is clear. Driving hydrogen development past the tipping point needs critical mass in investment, an enabling regulatory framework, new lead markets, sustained research and innovation into breakthrough technologies and for bringing new solutions to the market, a large-scale infrastructure network that only the EU and the single market can offer, and cooperation with our third country partners. All actors, public and private, at European national and regional level, must work together, across the entire value chain, to build a dynamic hydrogen ecosystem in Europe.

[1] (European Commission, 2020)

1 Introduction

The role of hydrogen in the EU's energy and greenhouse gas (GHG) emission abatement efforts will rapidly increase. Europe currently uses 339 TWh (LHV; 2019) of hydrogen per year (FCH JU, 2019). Research on the future EU energy systems, such as the study published by the Joint Research Centre (Blanco, Nijs, Ruf, & Andre, 2018) expects a significant increase in the use of hydrogen – between 667 – 4000 TWh (LHV) in 2050.[2] Hydrogen is an integral part of the recently announced recovery instrument of the EU *Next Generation EU*. Several Member States (MS) have already developed a hydrogen strategy on the national level, such as France, the Netherlands, Germany, Portugal, and Spain.[3] Many other MS are likely to follow the suit soon. Besides, hydrogen is anticipated to be a key topic for EU's Innovation Fund that opened its first call in July 2020.

For hydrogen to deliver a positive role in the energy transition, it must be produced and delivered to end uses in a sustainable manner (cost, energy system, environmental, and job impact). There is no shortage of cost and technical data across the hydrogen value chain, yet their transparency and comparability due to varying assumptions are often poor. This report builds on data collected from public sources and aims to normalize them to comparable units to establish a more reliable basis for decision-making (e.g. the scale of investment necessary). Where possible, guidance on how data should be reported is provided. Besides the investment cost data across selected items in the hydrogen value chain, effects on employment in the green hydrogen value chain, as well as import options and costs, were explored to provide a more comprehensive picture. In sum, this report does not aim to provide an exhaustive list of all the possibilities in the hydrogen ecosystem, but rather looks at the currently most discussed technologies and options.

On the production side, various technology options exist. Note that most of the EU hydrogen is produced on-site (captive hydrogen; 64% of total production capacity) typically in large industrial settings, and the remaining hydrogen is generated as a by-product of industrial processes (by-product hydrogen; 21% of total production capacity), or produced centrally and delivered to points of demand (merchant hydrogen; 15% of total production capacity).[4] As of now, 95% of EU hydrogen production is done via steam methane reforming (SMR) and to a lower extent autothermal reforming (ATR), both highly carbon-intensive processes. Such unabated production from fossil fuels is commonly called *grey* hydrogen and is defined as 'fossil-based hydrogen' in the Commission's strategy. Both SMR and ATR could, however, be coupled with carbon capture, usage, and storage (CCUS) systems with various CO_2 capture rates and post-capture utilisation of the CO_2. Such production is commonly referred to as *blue* hydrogen or defined as fossil-based hydrogen with carbon capture in the hydrogen strategy.

[2] Another EU-level study, Gas for Climate, estimated the hydrogen demand potential in 2050 at 1,710 TWh (LHV) (Guidehouse, 2020).
[3] Please note that national hydrogen strategies are at various stages development regarding their implementation in the aforementioned Member States.
[4] Shares of total production capacity are Guidehouse calculations based on data from FCH JU.

Most of the remaining 5% is produced as a by-product in the chlor-alkali processes in the chemical industry. Such production uses alkaline electrolysers (ALK) to electrolyse brine. Similar alkaline electrolysers can be used in dedicated hydrogen production, while other electrolytic hydrogen production methods exist using polymer electrolyte membrane (PEM) and solid oxide (SOEC) electrolysers. In cases where the electricity used in the process is renewable, the produced hydrogen is referred to as *green*, or defined as renewable hydrogen in the hydrogen strategy.[5] This is an important distinction as using current electricity grid mixes of most EU countries results in hydrogen with much higher carbon intensity than via unabated fossil-based routes (Figure 1-1).[6] Various in-between cases exist as well (e.g. sourcing of both grid and renewable electricity, ATR coupling with electrolysis, etc), but these are not explored in this report. Many additional production routes exist,[7] yet these are relatively less developed than the main production routes mentioned above.[8]

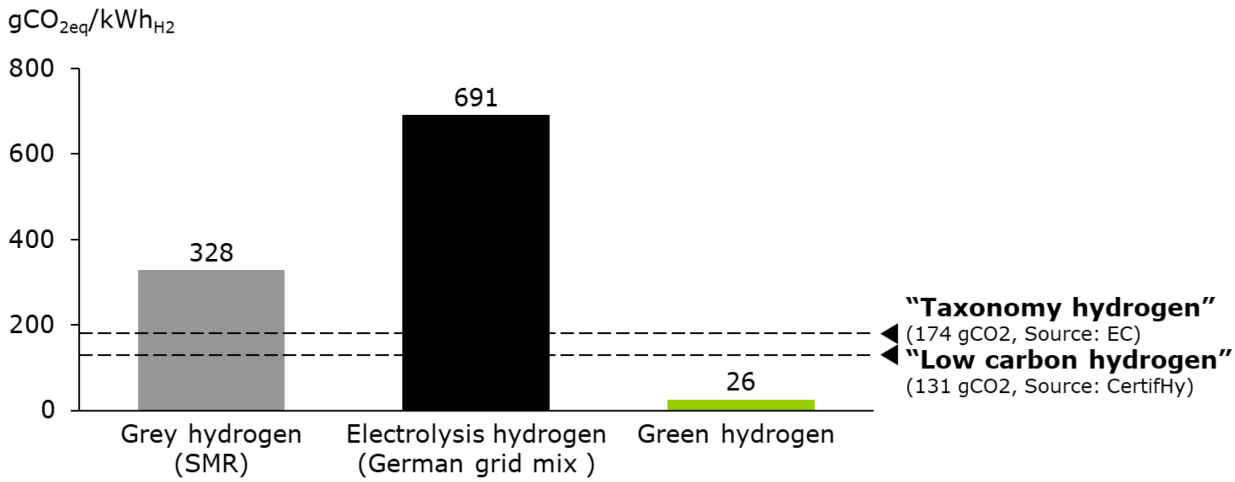

Figure 1-1: GHG footprint of different hydrogen production routes

To obtain a more comprehensive picture of the scale of investments necessary in the hydrogen sector, the report collected investment cost data on renewable electricity sources (for electrolytic production) and estimates of cost for expansion of electrolyser manufacturing capacities.

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[5] Other production processes are also being refer to as green, for instance biological production of hydrogen. Electrolytical production is commonly referred to as Power-to-Gas (P2G).
[6] Grey hydrogen emission intensity is based on state-of-the-art steam reforming or natural gas in large installation (benchmark process of CertifHy). Electrolysis hydrogen emission intensity is based on average emission intensity of the German electricity grid in 2018 (474 gCO_{2eq}/kWh). Assumed electrolysis conversion efficiency is 69% (LHV). Based on Guidehouse analysis, (CertifHy, 2019) and (Greenpeace Energy, 2020).
[7] For instance, anaerobic digestion with reformation, thermochemical conversion, thermal methane cracking, direct photoelectrochemical water splitting or supercritical gasification of wet biomass, to name a few.
[8] An argument can be made for the low Technology Readiness Level (TRL) of SOEC which should also exclude it from this overview. We decided to include the technology as it is commonly used (albeit often qualitatively) in hydrogen reports.

Importantly, hydrogen must be delivered to its intended end uses, unless production and consumption are co-located. In literature, *levelized cost of hydrogen* (LCOH) is often reported. A difference must be made between production cost[9] and delivered cost of hydrogen. Figure 1-2 provides an insight into the relative cost importance of the individual steps in hydrogen supply chain (two exemplary cases are presented). The report looks at the different components of the hydrogen delivery system (transmission, storage, distribution, in transport applications also refuelling stations). Investment cost data were also collected for hydrogen end-uses in the iron & steel industry and the transport sector. While many other potential applications exist, these remain out of the scope of this study. Finally, the employment effects of investments in the green hydrogen value chain as well as hydrogen import options are explored.

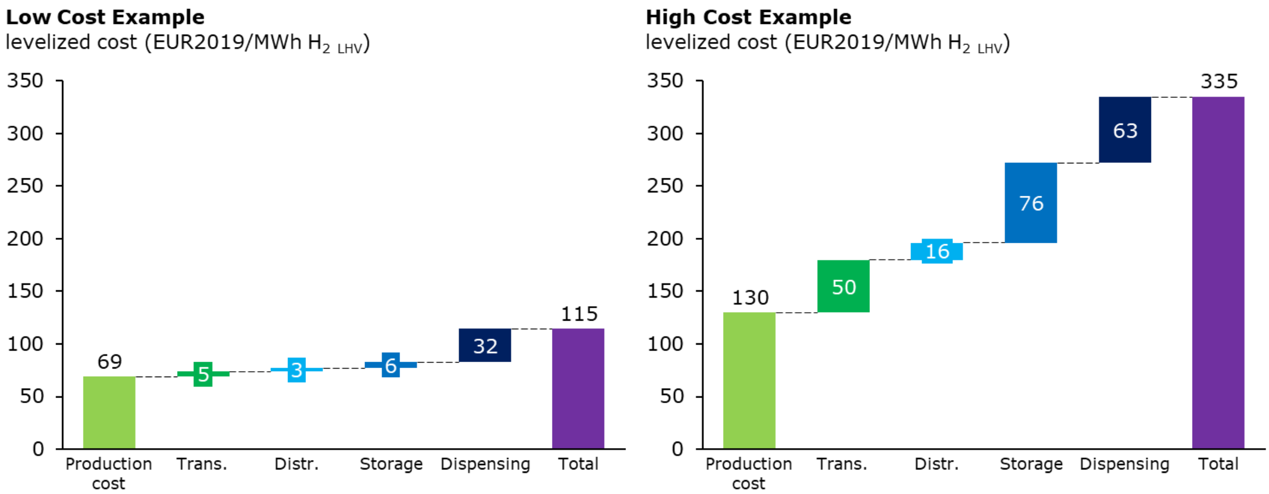


Figure 1-2: Breakdown of costs for delivered hydrogen in 2020 - example cases[10]

[9] Further, production cost is often elaborated based on unclear CAPEX assumptions – whether the total installed CAPEX has been reported, or whether CAPEX on *electricity in* or *hydrogen out* basis is being utilized. This is further explained in section 2.1.

[10] Both cases assume transmission over 600 km, distribution over 30 km, storage and dispensing. Note that distribution (industrial users might be connected directly to transmission grid), storage (not all hydrogen in the system will go via storage unit) and dispensing (only relevant for mobility applications) costs are optional. Production costs are based on Guidehouse estimations – Low Case: Alkaline, 4500 FLH, CAPEX 550 EUR/kW_{h2out}, electricity cost 40 EUR/MWh, system efficiency 70%; High Case: PEM, 3000 FLH, 800 EUR/kW_{h2out}, electricity cost 60 EUR/MWh, system efficiency 62%. Transmission costs (pipeline distribution in both cases) are based on (Guidehouse, 2019) for Low Cost and on (BNEF, 2019) for High Cost. Distribution costs based on (ENA & Navigant, 2019) for Low Cost (pipeline) and (BNEF, 2019) for High Cost (compressed trucking). Storage costs are derived from (BNEF, 2019) in both cases, where Low Cost assumes lower end of range for salt caverns and High Cost assumes higher end of range for depleted gas fields. Dispensing costs are based on (IEA, 2019).

2 Hydrogen in Europe – investment costs

2.1 Investment costs for hydrogen production technologies

Hydrogen is currently most commonly produced via steam methane reforming or by coal gasification (not common in Europe), both being carbon-intensive methods. Many alternative hydrogen production methods are at various stages of development across the scale of technology readiness levels (TRL). Below, we focus firstly on the most mature electrolytic ways of generating hydrogen: alkaline (ALK), polymer electrolyte membrane (PEM) and solid oxide (SOEC) electrolysis. Secondly, we look at the most commonly discussed fossil-based hydrogen production methods coupled with carbon capture, storage and use (CCUS) technologies. The two technologies are steam methane reforming (SMR + CCUS) and autothermal reforming (ATR + CCUS).

There are several important considerations when collecting investment cost data on hydrogen production. Figures found in public sources diverge in their scope and units reported, thus often lack the rigour necessary for direct comparison. Below, we specify the methodology and units used in this section. Where possible, we normalise the data to the standard units below.

- **CAPEX.** Sources often state CAPEX of the production unit (electrolyser, reformer), however, it is unclear whether this refers only to the investment cost of the unit itself, or also includes the balance of plant (BoP), and possibly system integration cost and the cost of capital. For current electrolyser setups, BoP and system integration can together exceed the cost of the electrolyser unit, thus their inclusion or omittance matters greatly.
    - We aim to report the total installed cost that includes the production unit CAPEX, BoP and system integration cost (cost of capital is excluded as studies do not report on it).
- **Production capacity.** Various investment figures are also being reported in terms of production capacity. This can be either defined as input capacity in terms of electricity or methane feedstock or output capacity in terms of hydrogen produced. Sometimes, this leads to confusion as production capacities are often reported in kW / MW (or Nm^3/h) without specifying whether the units refer to input or output capacities.
    - We aim to report the output production capacities in kW_{H2out} or kg_{H2out}.

Where possible, investment cost data below (Figure 2-1, Figure 2-2) were collected for 2020, 2030 and 2050 (2040 data are typically not reported). Data reported for other years were assigned to the closest decade by rounding up (e.g. 2025 datapoint would become 2030 datapoint). Summary of the data can be found in the Annex.

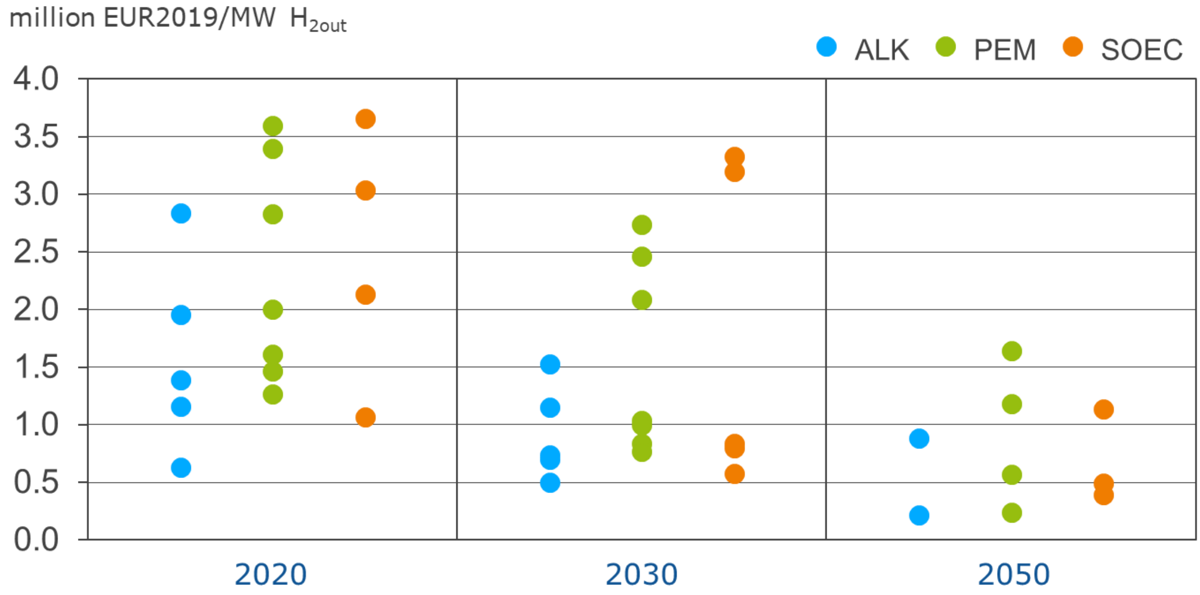


Figure 2-1: Investment cost for green hydrogen production technologies

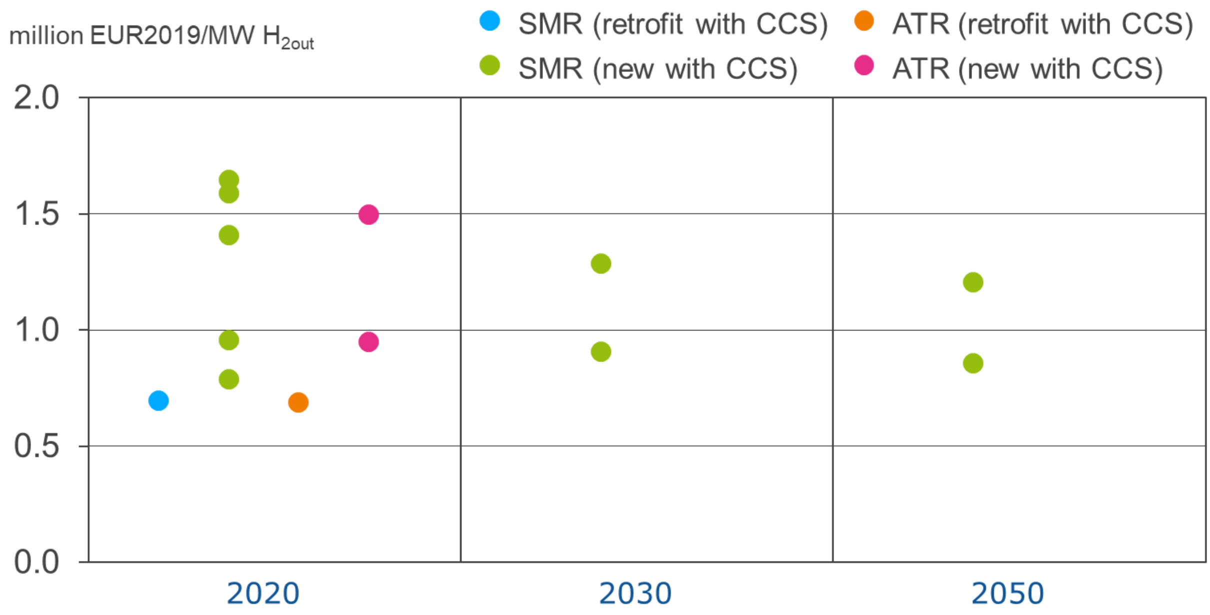


Figure 2-2: Investment cost for blue hydrogen production technologies

- **Energy efficiency.** Closely linked to cost and production capacity is energy efficiency. For electrolysis, stack[11] and system[12] energy efficiencies are often

[11] Stack energy efficiency is defined as the energy in the hydrogen produced by the stack divided by the electricity entering the stack.

reported interchangeably. Similarly, efficiencies are being reported both on lower (LHV) and higher (HHV) heating values, leading to further comparison mismatches.
  - For electrolysis, we aim to report system energy efficiency on lower heating value.[13]
  - For methane reforming, we aim to report SMR process energy efficiency on lower heating value.[14]
- **OPEX and REPEX.** Non-feedstock (e.g. electricity, natural gas, etc.) operating expense (OPEX) and replacement expenditure (REPEX) are other important components in the comparison between different hydrogen production methods.
  - For electrolysers, the main difference lies in the stack longevity (i.e. optimum operating hours before replacement). Table 2-A below illustrates the comparison.
  - For steam methane reformers with CCS, illustrative breakdown of feedstock (natural gas), electricity (mainly for CCS processes) and plant OPEX is presented in Table 2-B. The data are for 2020. Note that these mature production plants have long lifetimes (25+ years).

Table 2-A: Electrolyser efficiency and stack lifetime

	Alkaline (ALK)		Polymer Electrolyte Membrane (PEM)		Solid Oxide (SOEC)	
Year	**Efficiency (LHV)**	**Stack lifetime (hours)**	**Efficiency (LHV)**	**Stack lifetime (hours)**	**Efficiency (LHV)[15]**	**Stack lifetime (hours)**
2020	63%-70%	50,000-90,000	56%-63%	30,000-90,000	74%-81%	10,000-30,000[16]
2030	63%-72%	72,500-100,000	61%-69%	60,000-90,000	74%-84%	40,000-60,000
2050	70%-80%	100,000-150,000	67%-74%	100,000-150,000	77%-84%	75,000-100,000

[12] System energy efficiency is defined as the energy in the hydrogen produced by the system divided by the sum of the feedstock energy plus all other energy used in the process.
[13] We choose to report LHV as it is customarily in energy system analyses and it enables for quick comparison between various fuels. Please note that some experts recommend using HHV for electrolysis as it is a closed system and LHV for fuel cells.
[14] The SMR process efficiency can be understood as conversion of the energy stored in the methane feedstock and combustion fuel into hydrogen and export steam. We do not account for auxiliary energy consumption of the SMR plant here.
[15] For SOEC, electrical efficiency does not include the energy for steam generation.
[16] Schmidt et al (2017) already report significantly higher stack lifetimes for SOEC, with upper bound values of 85,000 hours in 2020, and 105,000 hours in 2030 in their 2x RD&D scenario. However, as these figures are significantly above the other current estimates, we have decided to exclude them from the overview above.

Table 2-B: SMR coupled with CCS plant efficiency and illustrative OPEX breakdown[17]

Variable	Value	Unit
Plant efficiency	69%	% (including energy demand for CCS)
Natural gas	70%	% share of total OPEX costs
System OPEX	15%	% share of total OPEX costs
Electricity	13%	% share of total OPEX costs
CCS system OPEX	Less than 0.1%	% share of total OPEX costs

2.2 Investment costs to scale up additional renewable electricity generation for electrolytic hydrogen production

The remaining component relevant in calculating the levelized production cost of hydrogen ($LCOH_{prod}$) is the cost of feedstock (electricity, heat, natural gas, etc.). In general, the feedstock costs will have the largest impact on the $LCOH_{prod}$ from all the variables (this is of course closely linked also to conversion efficiencies). It is important to distinguish between hydrogen production cost ($LCOH_{prod}$) and delivered hydrogen cost ($LCOH_{dlvd}$), the latter also including costs associated with hydrogen transmission, storage, distribution and possibly, dispensing. This difference is often not appreciated in literature where these two variables are used interchangeably, however, hydrogen delivery costs can often easily exceed production costs.

As renewable electricity is the key component in the production of green electrolytic hydrogen, data on development investment costs (in million EUR2019/MW) for utility-scale solar, onshore wind, bottom-fixed and floating offshore wind are collected (Figure 2-3). Besides, full load hour (FLH) ranges for European locations are also included (Figure 2-4). Summary of the presented data can be found in the Annex.

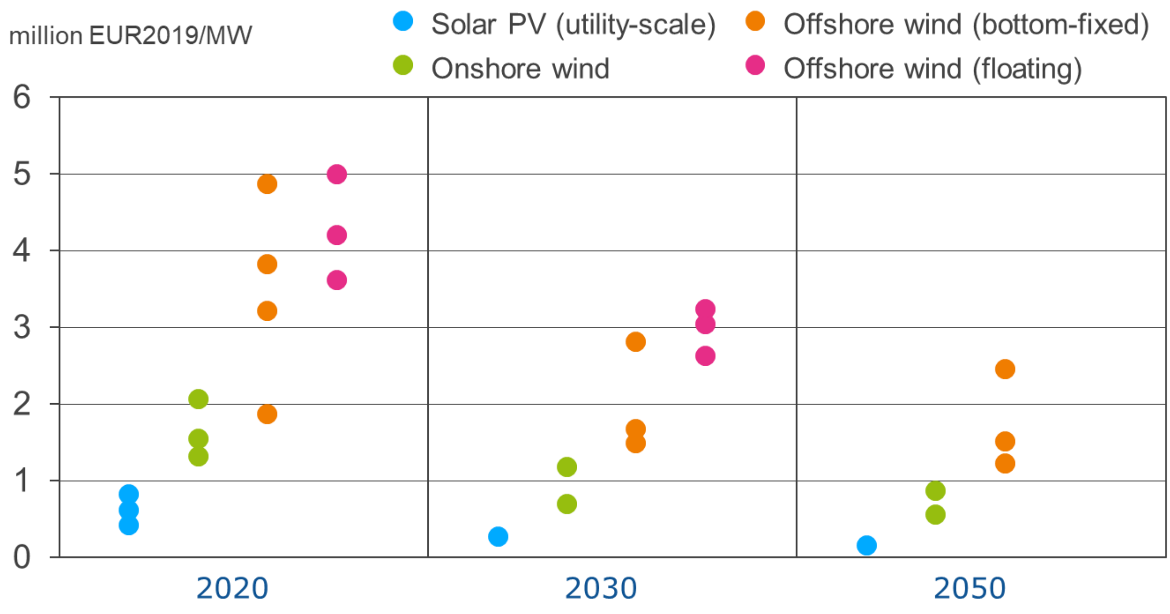


Figure 2-3: Investment costs for renewable electricity generation technologies

[17] (Jakobsen & Åtland, 2016). Please note that the figures exclude costs associated with CO_2 taxes. In the example above, captured emissions are 72% of the total emissions and unabated emissions 28% of the total emissions. Depending on the assumed CO_2 price, the total CO_2 tax costs can be a significant adder.

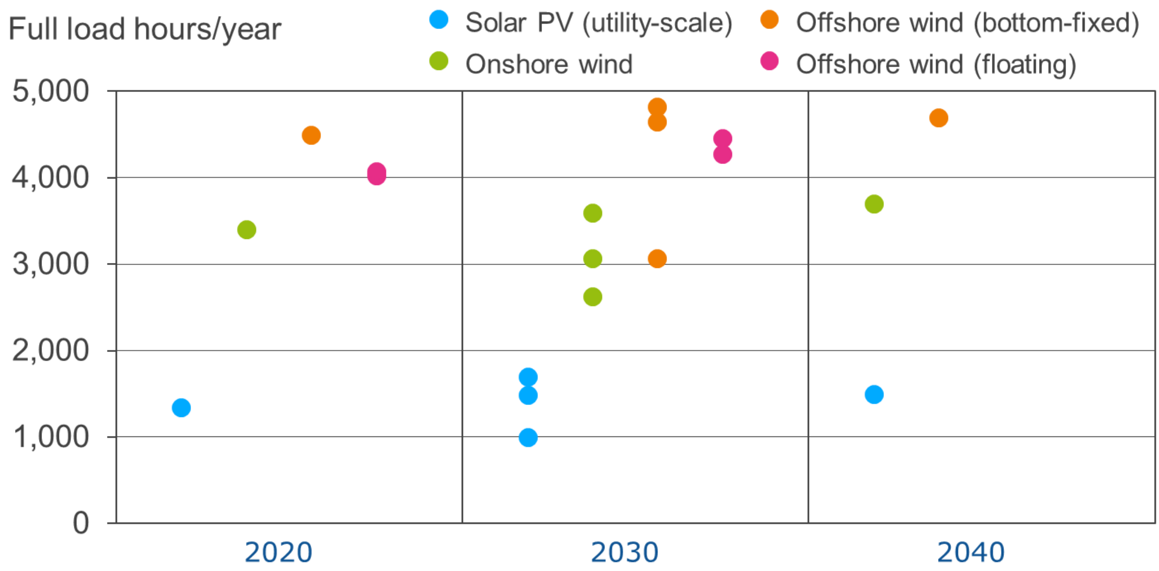


Figure 2-4: Full-load hours for renewable electricity generation technologies

2.3 Investment in electrolyser manufacturing capacity

Future energy system scenarios now routinely calculate with large volumes of hydrogen in the system. While blue hydrogen can start by retrofitting existing SMR and ATR capacities with CCS systems, the electrolytic hydrogen industry has to start from a very small base. Europe currently uses 339 TWh (2019) of hydrogen per year and 95% of that is produced via SMR without CCS.[18] Most of the remaining 5% is produced as a by-product in the chlor-alkali process in the chemical industry.

Thus, a rapid expansion of electrolysis would have to be preceded by a substantial expansion of electrolyser manufacturing capacities. Below we estimate these costs based on press releases from European manufacturers (Table 2-C). These investment costs are expressed in million EUR per MW of annual electrolyser manufacturing capacity. The two sources include NEL's 360 MW/year electrolyser production facility at Notodden, Norway and ITM Power's 1 GW/year manufacturing facility at Bessemer Park, UK.

Table 2-C: Investment cost in electrolyser manufacturing capacity

Hydrogen Production Technology	Cost in EUR/MW_{el} of production capacity/year[19]	Source
Alkaline electrolysers (ALK)	45,000	(NEL, 2018)
Polymer Electrolyte Membrane electrolysers (PEM)	69,000	(ITM Power, 2019)

[18] (FCH JU, 2019).
[19] This corresponds with 57,300 EUR/MW H_{2out} for ALK Electrolysers and 106,000 EUR/MW H_{2out} for PEM electrolysers (LHV). ALK calculated using stack efficiency (LHV) of NEL A-series upper range 78.6% (LHV) (NEL Hydrogen, 2020) and PEM using stack efficiency (LHV) of 65% (Guidehouse, 2020).

2.4 Hydrogen transmission, storage, distribution and dispensing

Hydrogen can be produced either centrally (i.e. close to the point of electricity/natural gas source) or de-centrally (i.e. close to the point of consumption). In current setups, hydrogen produced centrally (merchant hydrogen) is typically delivered to end consumers via a dedicated hydrogen pipeline infrastructure or trucks. Hydrogen produced de-centrally (on-site), typically at large consumer clusters, requires only relatively minimal infrastructure for local storage and distribution.

Existing hydrogen infrastructure in Europe is, however, insufficient to deal with the volumes of hydrogen forecasted in carbon-neutral scenarios in Europe. Some existing natural gas infrastructure will have to be retrofitted for hydrogen carrying capability; alternatively, or additionally, new dedicated hydrogen infrastructure will have to be deployed.

A typical hydrogen delivery system (besides the production component) consists of a conversion component (e.g. compression, liquefaction, etc.), transmission and distribution components (e.g. long-distance high-pressure transport pipeline infrastructure, local low-pressure distribution network), inter-seasonal and intraday storage capacities. The range of conversion, transmission, storage and distribution solutions is wide, and the best option is business case-specific, depending on a combination of factors such as distance to the customer and technology availability.

The following sections reflect our findings in terms of the investment and levelized costs associated with hydrogen transmission, storage, distribution and dispensing (hydrogen refuelling stations for vehicles). One sub-section is dedicated to each one of these elements.

2.4.1 Hydrogen transmission

For hydrogen to be available as a widely used fuel, significant volumes will need to be transported across varying distances. This section focuses on transmission via pipelines, which can move large volumes of hydrogen at a relatively low cost. Transport by ship, on the other hand, is covered in Section 3. In addition to pipelines, compressors are the second main cost component of the gas transmission network. Both components (pipelines and compressors) can be reported as costs for new infrastructure or costs of refurbishment of existing infrastructure (typically for pipelines).

Whenever possible, we normalise the data to the standard units below:

- **Cost of pipelines (new or refurbished).** Sources often refer to the CAPEX of the pipeline in CAPEX/km. Different costs are associated with different diameters and operating pressures. Note that the works associated with the construction and refurbishment of pipeline infrastructure can vary greatly between different geographies and that the reported data typically exclude installation costs (e.g. EPC costs).
    - For refurbished pipelines, the total cost of refurbishment of the pipeline network is typically divided by the total number of kilometres of the network. We aim to report the costs of refurbishment in million EUR2019/km.
    - For new dedicated pipelines, the reported costs are CAPEX. We aim to report investment costs in million EUR2019/km.

- **Investment costs for new dedicated compressors.** Sources state the global CAPEX of compressors per unit of installed compressor power. The units are normalised to CAPEX/throughput per day of the compressor whenever possible. The hydrogen throughput capacity is expressed as the amount of hydrogen passing through the compressor per unit of time. Note that significant differences in compressor size and therefore in investment cost might arise, given expected capacity utilisation of the associated pipeline. In general, pipelines with lower capacity utilisation and therefore lower pressure drop over distance can be fitted with much smaller compressors compared to when capacity utilisation is near its maximum. This is especially important for retrofitting of large transmission level pipelines with new compressors.

    - We aim to report the investment costs of new dedicated compressors in EUR2019/MW of installed compression power or million EUR2019/MWh of hydrogen daily throughput capacity.

- **Levelized cost of transmission LCOT (new or refurbished infrastructure).** It is defined as the discounted cost per MWh_{H2} transported by the pipeline. The main cost components are the CAPEX of the new or refurbished pipeline, the CAPEX of the compressor, and the cost of compression (related to the cost of energy used as fuel). A standard journey of 600 km is considered for normalisation of units.[20]
    - We aim to report the levelized cost of transmission in EUR2019/MWh_{H2} /600 km.

Figures found in public sources diverge in the units reported and in other parameters such as pipeline diameter, materials used, operating pressure, among others. They are summarized and commented in the Table 2-D below.

Table 2-D: Costs of hydrogen transmission

Investment cost – refurbishment of natural gas pipelines			
Units	**Value**	**Comments**	**Source**
million EUR2019/km	0.37	Based on estimation for the German gas network with refurbishment cost being 15% of the new build.	(FNBGas, 2019)
Investment costs - new dedicated hydrogen pipelines			
Units	**Value**	**Comments**	**Source**
million EUR2019/km	0.93	16-inch average diameter. Costs for a transmission network of 6,300 km in the UK.	(Element Energy & E4Tech, 2018)
	1.22		(Cadent, 2017)
	1.40		(Institute, 2016)
	1.55	Costs in the UK.	(H21 NoE, 2018)
	1.57		(Frontier Economics,

[20] This reflects the assumed average distance a gas molecule would travel in the EU transmission system (i.e. from point of entry to the transmission system to the point of entry to the distribution system or direct consumption). Recompression is assumed each 200 km. The figure is based on expert opinion developed in the study Gas for Climate (Guidehouse, 2019). Please note that for various use cases this figure might differ substantially.

				2016)
	2.01		48-inch pipeline, operating between 30-80 bar with a length of 300 km in the UK.	(ENA & Navigant, 2019)
	2.48		Average cost in Germany, calculated from total investments in a new and refurbished network.	(FNBGas, 2019)
	3.28		48-inch pipeline.	(Jacobs, Element Energy)
Investment costs for new dedicated compression				
Unit	**Value**		**Comments**	**Source**
million EUR2019/MW of installed compression power	1.07		Costs for a 5.8 MW[21] compressor, with a 240 t/day throughput.	(Baufumé et al., 2012)
EUR2019/MWh per day of throughput capacity	777			
million EUR2019/MW of installed compression power	0.65		5.8 MW capacity for compressor, calculated according to cost curve in source.	(Jacobs, Element Energy)
LCOT for H_2 transmission - refurbished natural gas infrastructure				
Units	**Value**		**Comments**	**Source**
EUR2019/MWh$_{H2}$ /600 km	3.7		Retrofitting existing gas infrastructure for 100% hydrogen.	(Guidehouse, 2019)
LCOT for H_2 transmission for new dedicated infrastructure				
Units	**Minimum**	**Maximum**	**Comments**	**Source**
EUR2019/MWh$_{H2}$ /600 km	4.6	4.6	48-inch pipeline. Includes pipeline and compressor CAPEX and OPEX and compression fuel-related costs.	(Guidehouse, 2019)
	9.6	9.6	34-inch pipeline with utilization of 75%. The source assumes the cost of transporting H_2 over 50 km. Normalised to 600 km.	(BNEF, 2019)
	11.4	11.4	Transportation over 1500 km is assumed by source, considering all capital and operating costs. Normalised to 600 km.	(IEA, 2019)
	16.1	49.8	Pipeline with a capacity of >100 t/day. The source assumes a 100 km pipeline. Normalised to 600 km.	(BNEF, 2019)
	45.0	45.0	Estimated including compression costs for pipes of diameters between 7-10 inch over 100 km as assumed by source.	(DNV GL, 2019)

[21] In practice, larger compressors could be needed according to the demand.

			Normalised to 600 km.	

2.4.2 Hydrogen storage

For hydrogen to play a meaningful role in the energy system, considerable hydrogen storage capacities are required to balance demand and supply. While many technologies exist (e.g. pressurised vessels, liquid hydrogen tanks, etc.) the focus in this study is on the large-scale underground storage technologies: salt caverns, depleted gas fields, and rock caverns. Salt caverns are already used today, while the latter two are being actively explored for potential use.

Only costs for new installations were collected. Where possible, we normalise the data to the standard units below.

- **Investment costs.** CAPEX is often expressed in EUR2019/MWh$_{H2}$ stored.
  - We aim to report the investment costs in EUR2019/MWh$_{H2}$ stored.
- **Levelized costs of storage LCOS.** The LCOS is defined as the discounted cost per MWh$_{H2}$ discharged. The sources we explored often include the number of cycles per year as a parameter in their calculations of LCOS.
  - We aim to report the LCOS in EUR2019/MWh$_{H2}$ discharged.

The data we collected are summarized and commented in the Table 2-E below.

Table 2-E. Costs of hydrogen storage

Investment costs					
Technology	**Minimum**	**Maximum**	**Units**	**Comments**	**Source**
Depleted gas field	280	424	EUR2019/ MWh$_{H2}$ stored	CAPEX including compressors and pipes, 4% OPEX.	(BNEF, 2019)
Salt caverns	334	334	EUR2019/ MWh$_{H2}$ stored	CAPEX for 1,160 t of working capacity (+1/3 additional for cushion gas), but highly dependent of geography. 4% OPEX, includes compressors and pumps.	(BNEF, 2019)
Rock caverns	1232	1232	EUR2019/ MWh$_{H2}$ stored	4% OPEX.	(BNEF, 2019)
Levelized cost of storage (LCOS)					
Technology	**Minimum**	**Maximum**	**Units**	**Comments**	**Source**
Salt caverns	6	26	EUR2019/ MWh$_{H2}$	300-10,000 t per cavern, lower bound: monthly cycling, upper value: bi-annual cycling.	(BNEF, 2019)
	17	17	EUR2019/ MWh$_{H2}$		(IEA, 2019)
Rock caverns	19	104	EUR2019/ MWh$_{H2}$	300-2,500 t per cavern, lower bound: monthly cycling, upper bound: bi-annual cycling.	(BNEF, 2019)
Depleted gas field[22]	51	76	EUR2019/ MWh$_{H2}$	Cost for working gas capacity, 1 cycle/year. Including the cost of	(BNEF, 2019)

[22] A higher LCOS is a consequence of a lower technological maturity for hydrogen storage, which is likely to make borrowing more expensive.

	compression and pipelines needed for the facility to function.

2.4.3 Hydrogen distribution

While large industrial users can potentially connect directly to the transmission network, depending on the location and potential need for high-pressure delivery, other end users (e.g. residential customers, hydrogen refuelling stations, smaller industrials) will have to be supplied via a distribution network.

Two common methods of hydrogen distribution exist - pipelines and trucks. Pipelines transport gaseous hydrogen and are the cheapest method of distribution where demand is large enough. The cost of a new hydrogen distribution pipeline network can present a substantial investment. However, existing natural gas distribution networks can potentially be refurbished to carry hydrogen. On the other hand, trucks are more advantageous in case demand is low, with the additional possibility to transport hydrogen in a liquid and gaseous state.

This section compares the cost of distribution of hydrogen, with a larger focus on distribution by pipelines given their potentially lower costs when the level of demand is high enough.

Where possible, we normalize the data to the standard units below.

- **Investment costs for refurbished natural gas pipelines and ancillary components.** The data show the cost of reinforcements or refurbishments of the distribution network per unit of length of the pipeline. Note that these costs may not be representative of all geographies and regions. Assumptions for each data point can be found in the comments in the tables below when available.
    - We aim to report the investment costs of refurbished natural gas infrastructure in million EUR2019/km.
- **Levelized cost for hydrogen distribution by pipelines (new or refurbished).** The LCOD by pipeline is defined as the discounted cost per MWh_{H2} transported by pipeline while performing a journey across a given unit of length. In the case of new infrastructure, the CAPEX of the pipeline is the main cost component. For refurbished pipelines, costs of reinforcement and other costs are considered as reflected in the comments in the tables below.
    - We aim to report the levelized cost of distribution in EUR2019/MWh_{H2} /km.
- **Levelized cost of distribution by truck:** Defined as the discounted cost per MWh_{H2} discharged by the truck while performing a journey across a unit of length. Trips become costlier across longer distances, and therefore different trip lengths are accounted for.
    - We aim to report the levelized cost of distribution in EUR2019/MWh_{H2} /km.

Figures found in public sources diverge in the units reported and in other parameters such as pipeline diameter, materials used, operating pressure, among others. The data we collected are summarized and commented in the Table 2-F below.

Table 2-F. Costs of hydrogen distribution

Investment costs - refurbished existing natural gas pipeline			
Units	**Value**	**Comments**	**Source**
Million EUR2019/km	0.23	Cost of reinforcing low-pressure 5-inch pipeline with a flow of 0.3 million standard cubic metres a day. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
	0.41	Cost of reinforcing low-pressure 9-inch pipeline. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
	0.47	Cost of reinforcing low-pressure 10.5-inch pipeline in the UK. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
LCOD for H_2 distribution - new infrastructure			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.05	Levelized cost of distribution by pipe over 1000 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	0.06	Levelized cost of distribution by pipe over 100 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	0.16	Levelized cost of distribution by pipe over 10 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	1.61	Levelized cost of distribution by pipe over a 1 km journey. Includes compression and storage.	(BNEF, 2019)
LCOD for H_2 distribution - refurbishment			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.11	DSO operation and integration cost. CAPEX adapted from (H21 NoE, 2018) and scaled to UK-level investments. Based on current natural gas distribution costs in the UK uplifted by 20% due to an assumed drop in energy-carrying capacity for hydrogen.	(ENA & Navigant, 2019)
LCOD for distribution by truck			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.54	Levelized cost of a 50 km trip by pressurized H2 truck today, including compression and storage.	(BNEF, 2019)
EUR2019/ MWh_{H2} /km	2.46	Levelized cost of a 50 km trip using a liquid hydrogen truck.	(BNEF, 2019)

2.4.4 Hydrogen dispensing

For mobility applications, hydrogen dispensing is typically done via Hydrogen Refuelling Stations (HRS) which include multiple components (e.g. compression, dispensers, the balance of station, etc.). In the retrieved data, installation costs are not reported (e.g. labour, construction, etc.).

The data points have been categorized into two sizes, determined by the output capacity per day:

- **Small refuelling stations:** Output of <20 MWh_{H2} /day (approximately <600 kg_{H2}/day)
- **Large refuelling stations:** Output of >20 MWh_{H2}/day (approximately >600 kg_{h2}/day)

Note that the station sizes can respond to different use cases, for example cars for personal use, fleets of trucks or buses, among others. Larger demands will require larger stations to be installed.

The units for the datapoints are normalized as follows:

- **Investment costs per station.** Note that the output capacity of the stations is different for each datapoint, therefore differences in investment costs can arise. The output capacity is reported in Table 2-G.
    - We aim to report the investment costs in EUR2019/HRS.
- **Levelized cost for hydrogen dispensing (LCOHD).** Defined as the discounted cost of the refuelling stations over the MWh_{H2} delivered over the lifetime of the station. The LCOHD has been calculated considering the average reported station size for each category: 10 MWh_{H2} /day for small stations of capacity below 20 MWh_{H2}/day, and 35 MWh_{H2}/day for large stations of capacity above 20 MWh_{H2}/day. Other parameters introduced in the calculations are a real WACC of 5%, a utilisation rate of 60%, and a lifetime of 20 years.
    - We aim to report the levelized cost of the HRS in EUR2019/MWh_{H2}.

Where possible, data for investment costs in Table 2-G were reported for projects starting in years 2020, 2024 and 2030, and according to the size of the station.

Table 2-G. Costs of hydrogen refuelling stations

H$_2$ refuelling stations (Small; <20 MWh$_{H2}$/day)				
Units	**Year**	**Value**	**Comments**	**Source**
million EUR2019/HRS	2020	0.85	HRS for cars, 200 kg$_{H2}$/day, 10% utilisation.	(IEA, 2019)
		0.89	212 kg$_{H2}$/day capacity.	(Forschungszentrum Jülich, 2018)
		2.44	Cost for stations installed after 2016 with a capacity of 600 kg$_{H2}$/day, 76% utilisation, average output 456 kg$_{H2}$/day.	(NREL, 2013)
H$_2$ refuelling stations (Large >20 MWh$_{H2}$/day)				
Units	**Year**	**Value**	**Comments**	**Source**
million EUR2019/HRS	2020	1.71	HRS for trucks 1000 kg$_{H2}$/day, 40% utilisation.	(IEA, 2019)
		2.00	1,000 kg$_{H2}$/day capacity.	(Forschungszentrum Jülich, 2018)
		3.99	Cost for stations installed after 2016 with a capacity of 1500 kg$_{H2}$/day, 80% utilization, average output 1200 kg$_{H2}$/day.	(NREL, 2013)

The following table shows the averaged levelized costs for the hydrogen refuelling stations[23].

Table 2-H Average levelized costs of hydrogen refuelling stations

LCOHD refuelling stations (Small; <20 MWh$_{H2}$/day)			
Unit	**Year**	**Value**	**Comments**
EUR2019/ MWh$_{H2}$	2020	63	Based on a 10 MWh/day average size for a station, WACC 5%, utilization rate 60%, 20-year lifetime.
LCOHD refuelling stations (Large; >20 MWh$_{H2}$/day)			
Unit	**Year**	**Value**	**Comments**
EUR2019/ MWh$_{H2}$	2020	32	Based on a 35 MWh$_{H2}$/day average size for a station, WACC 5%, utilization rate 60%, 20-year lifetime.

2.5 Hydrogen end-use sectors

Today, nearly all hydrogen produced is used as a feedstock in the chemical and refining industries. Over 90% of hydrogen in Europe is used in refining, ammonia and methanol production. In future, however, hydrogen is anticipated to become one of the key decarbonisation levers across all key energy-demanding segments of the economy (power system, industries, transport and buildings).

The following section focuses on the investment costs associated with hydrogen in the iron & steel industry and the transport sectors (across various modes).

[23] These were calculated based on the information in Table 2-G, representing LCOH for the average size of the stations as reflected in the comments of Table 2-H.

2.5.1 Iron & steel industry

We assess two hydrogen-involving production technologies for the steel industry. These include:

(1) Blast furnace-basic oxygen furnace (BF-BOF) with hydrogen fuel injection, and

(2) Hydrogen-based direct reduced iron (DRI) – electric arc furnace (EAF).

The general consensus is that BF-BOF route with H_2 injection provides a short- to medium-term decarbonisation solution – with CO_2 emission reductions of up to 20%. Large-scale DRI-EAF deployment will be needed to fully decarbonise the steel sector with a view on 2050 targets. For both of these technologies, three types of data are collected (where available), as shown in Table 2-I.

- The investment cost for new hydrogen-based steel manufacturing capacity. This entails all necessary adaptation cost from current BF-BOF set-ups into DRI-EAF route (brownfield) or greenfield construction of DRI-EAF.
- The production cost of steel using hydrogen-based technology. The significant variation in DRI-EAF production stems from the wide variability in the cost of hydrogen itself, which in turn is driven by the cost of electricity (green hydrogen is assumed). Excluding electricity costs, production costs are around EUR 260 per tonne of crude steel.
- Hydrogen demand per tonne of crude steel production.

Table 2-I: Hydrogen cost data for steel end-use sector

Cost parameter	Value (range)	Unit	Source
Investment cost of new hydrogen DRI-EAF based manufacturing capacity	400-752	million EUR/tonne annual DRI steel production capacity	(Guidehouse, 2020), (IEA, 2019)
Steel production costs, DRI-EAF technology	386-685	EUR/tonne crude steel	(Material Economics, 2019), (Vogl, Ahman, & Nilsson, 2018)
Hydrogen demand per tonne of crude steel production – BF-BOF injection	20-40	kg H_2/tonne crude steel production	(Guidehouse, 2020), (Yilmaz, Wendelstorf, & Turek, 2017)
Hydrogen demand per tonne crude steel – DRI-EAF	47-68	kg H_2/tonne crude steel production	(Material Economics, 2019), (IEA, 2019)

2.5.2 Transport sector

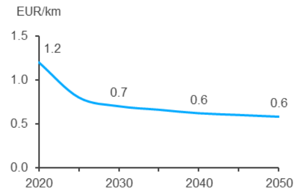
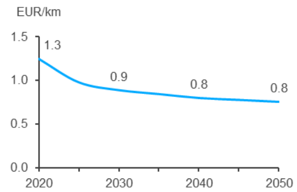
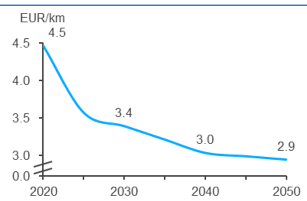
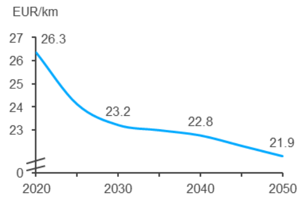
Hydrogen cost data for the transportation end-use sector covers fuel-cell based heavy-duty vehicles (HDV), buses, trains, and ocean-going ships. For each of these vehicle types, we examine the following costs, as summarised in Table 2-J.

- **Production (or in some cases retail) costs.** Note that production costs for ocean-going ships vary significantly, from 1.99 million EUR for a tugboat (28.8x13x6m) to 3.7 million EUR for a ferry ship (100x24x5m) up to 17 million EUR for container ships (233x32x10m).
- **Annual H_2 demand.** Calculated by multiplying the efficiency (kg_{h2}/km) by typical annual distances covered for each vehicle type as reported in national

and global transportation statistics. As with production costs, H_2 consumption efficiencies can vary widely between models as a result of the significant diversity in designs for each of the vehicle types.

- **The total cost of ownership (TCO).** Reported per vehicle on a per km basis along with anticipated cost reductions over time.

Table 2-J: Hydrogen cost data for transportation end-use sector

Transportation segment	Production (or retail) costs (million EUR/unit)	Hydrogen consumption (kg_{h2}/vehicle/year)	Total Cost of Ownership (EUR/km)
Heavy-Duty Vehicles	0.12 – 0.19	4,600 - 9,200	
Buses	0.37 – 0.67	2,078 - 9,800	
Trains	5.47- 5.88	8,010 - 27,000	
Ocean-going ships	1.99 – 17.1	494,000	

2.6 Employment in the green hydrogen value chain

We estimate the EU employment impacts of hydrogen deployment using a spreadsheet-based economic model, initially developed for Guidehouse Gas for Climate study. The model is based on an industry-standard input-output methodology and derives estimates of employment as a result of investment in different parts of the hydrogen supply chain on a per billion EUR invested basis. Investment amounts are broken down into capital investment, operation and maintenance costs, feedstock supply costs, as well as the corresponding economic sectors that represent these investment buckets. Employment results represent the annual average number of jobs related to the deployment (investment in) hydrogen and are broken down into direct and indirect jobs:

- **Direct jobs** are calculated in each sector based on the level of expenditures allocated to each sector multiplied by the employment factor (jobs/EUR invested). The employment factor is defined using the share of expenditures

allocated to employee compensation (salaries) and the average annual EU-wide wage for the sector.
- **Indirect jobs** are derived in the same way using the input-output interactions between each sector of the economy. Indirect jobs can be understood as jobs created in the value chains of the sectors listed in Figure 2-5 below made possible by investments in green hydrogen projects, but not as a direct output of the projects themselves.

Required input parameters for this analysis include:
- Distribution of investment costs across the various components of the hydrogen supply chain based on expert insights and validated in interviews.
- Average shares of expenditures allocated to employee compensation using the symmetric input-output table from Eurostat for 2017[24].
- Average wages per sector are obtained from labour cost statistics from Eurostat for 2018[25].

Given that the symmetric input-output table is based on historical data, it should be noted that economic inputs are backwards-looking and not a predictor of how money might flow between economic sectors in the future. Nonetheless, this methodology is widely recognised in literature sources[26] and by the European Commission[27].

The employment results are shown in the below figures. For a given year (e.g. 2030 or 2050), these results should be interpreted as the number of jobs that will be created for each billion EUR invested into the hydrogen value chain in that year.

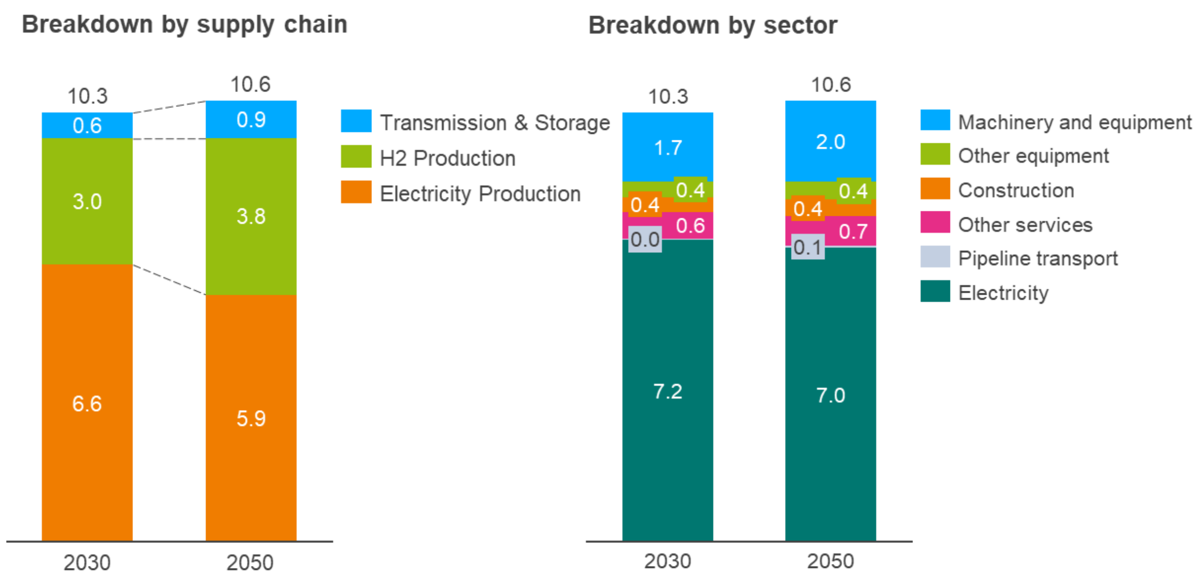


Figure 2-5: Number of jobs (000's) created per billion EUR invested, breakdown by supply chain and by sector

[24] (Eurostat, 2019).
[25] (Eurostat, 2019).
[26] Examples include: (Federal Planning Bureau, 2017) or (Climate Action Tracker, 2018).
[27] (European Commission, 2019).

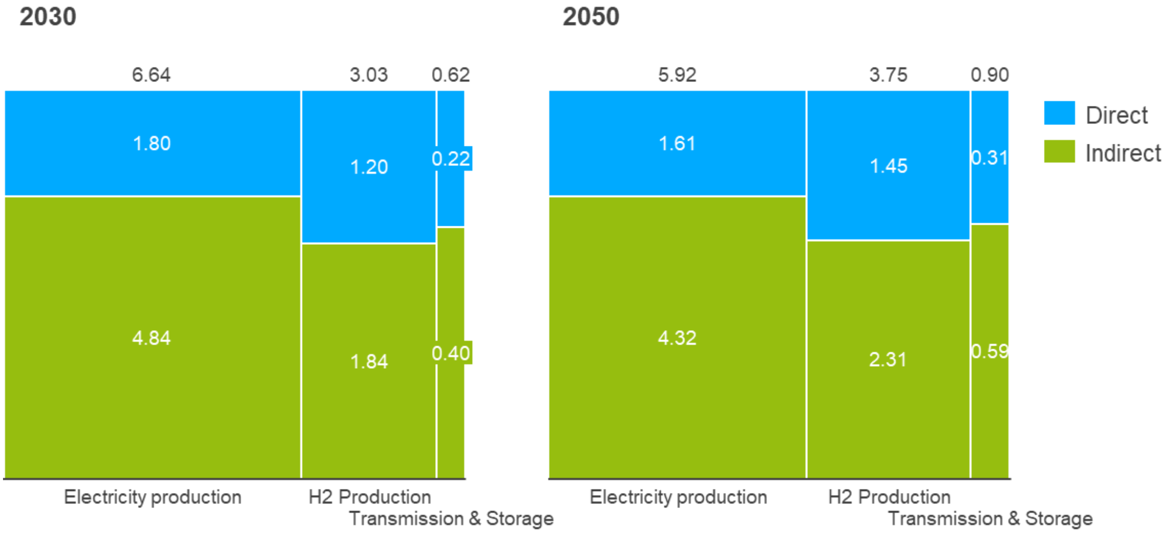


Figure 2-6: Number of jobs created per billion EUR invested, breakdown by direct vs indirect jobs

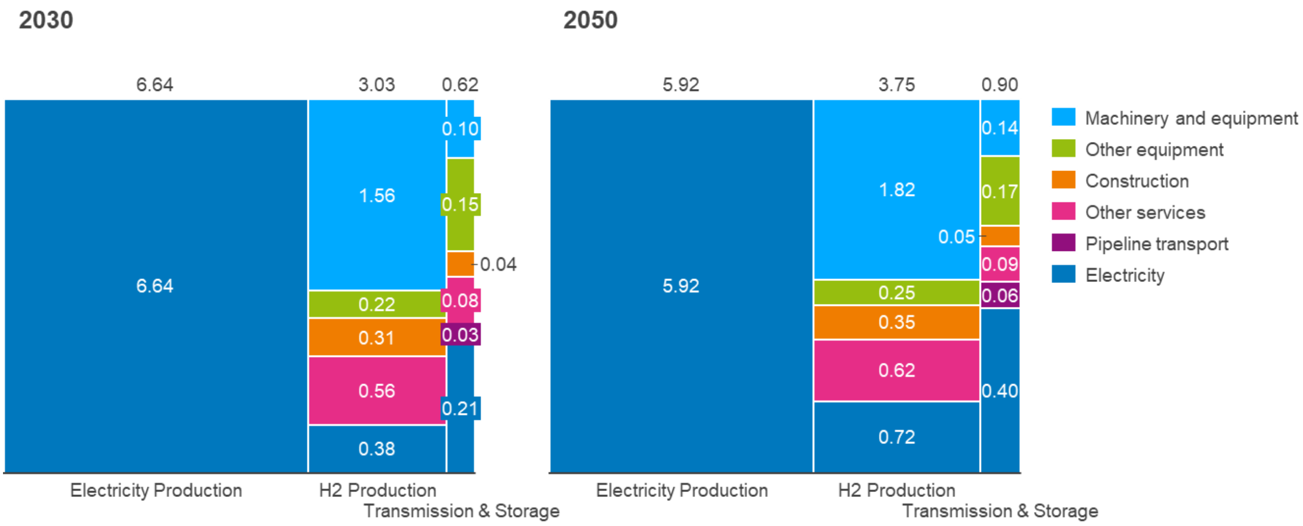


Figure 2-7: Number of jobs created per billion EUR invested, breakdown by supply chain and by sector

3 Hydrogen import

In this section, the costs associated with importing low-carbon hydrogen to the European border are collected. The potential for import of hydrogen to Europe depends on the production location, the selected transport technology, the transport distance and the infrastructure available at the reception point. The transport technologies considered include ships (transporting liquid hydrogen or ammonia) and pipelines (gaseous hydrogen). In terms of the shipping routes, imports from Australia, Chile, Saudi Arabia, North Africa (for renewable hydrogen) and Russia (for fossil-based hydrogen with carbon capture) are considered as the most relevant for a cost analysis. Three countries of entry have been considered: The Netherlands (Port of Rotterdam by pipeline and ship), Spain (Cordoba by pipeline, Algeciras by ship) and Germany (Frankfurt by pipeline). Countries of export were collected from the literature.

The following sub-sections illustrate the costs associated with the conversion of hydrogen into liquid hydrogen and ammonia, the costs of the journey by ship or pipeline and associated distances, the cost of reconversion to hydrogen (for the case of ammonia). To facilitate the comparison between different supply chains, we also sum up costs at the most representative export sites and import sites.

Figure 3-1, Figure 3-2 and Figure 3-3 provide insights into the total costs calculated for imports to Europe.[28]

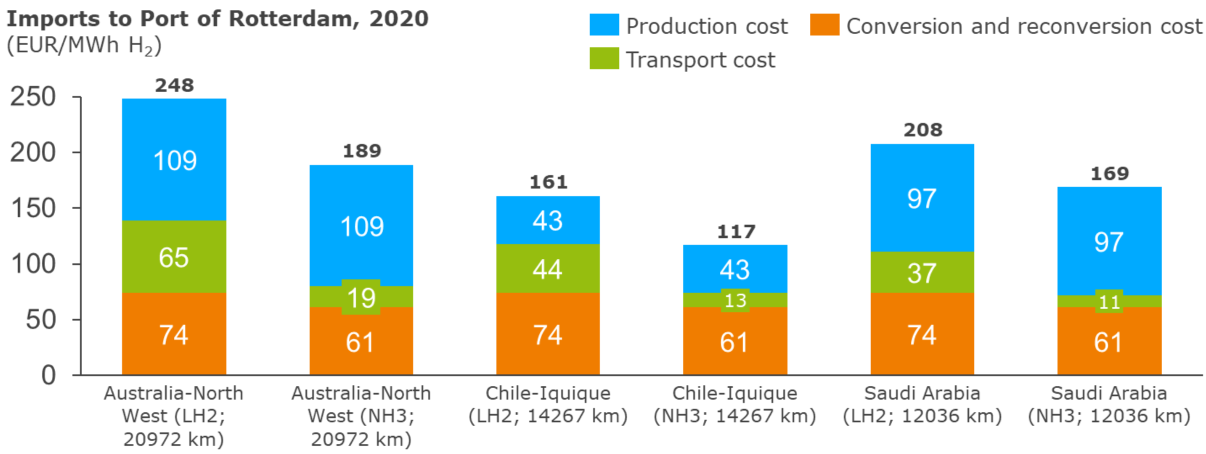


Figure 3-1: Levelized costs of import of hydrogen and hydrogen carriers to Port of Rotterdam via ship in the year 2020

[28] 1. LH2: Liquid Hydrogen, NH_3: Ammonia.
2. Own elaboration, based on normalised data in Table 3-A for conversion, Table 3-C for the average levelized cost of journey per km using liquid hydrogen and ammonia ships, and Table 3-D for the cost of hydrogen production in year 2020.
3. The costs for H_2 production in Chile for 2020 are based on year 2025 costs. Source: Own elaboration, based on normalised data in the following Sections.
4. The cost of H_2 production in Morocco is assumed to be the same as in Algeria (2050)
5. Production cost in Russia is based on blue hydrogen (2050).

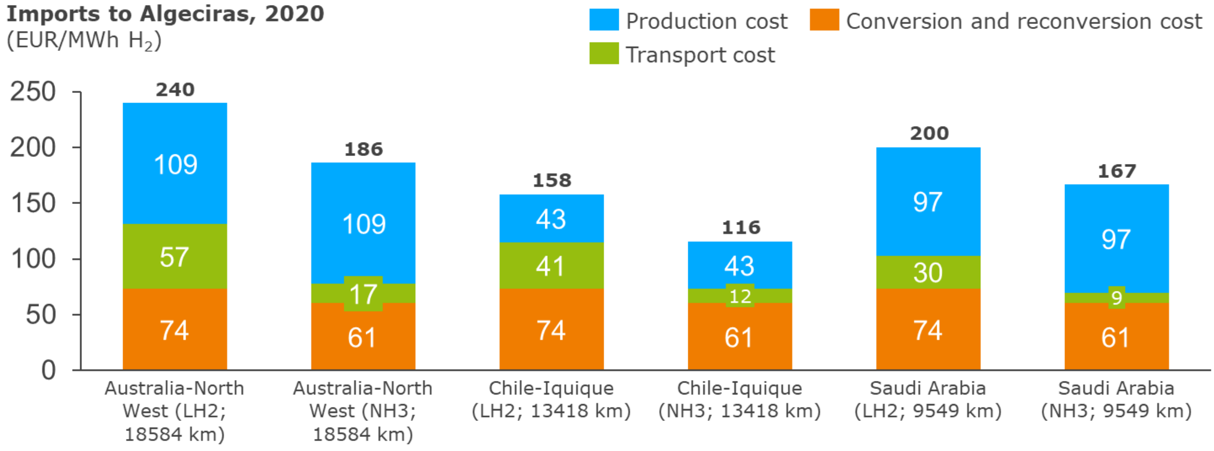


Figure 3-2: : Levelized costs of import of hydrogen and hydrogen carriers to Algeciras via ship in the year 2020

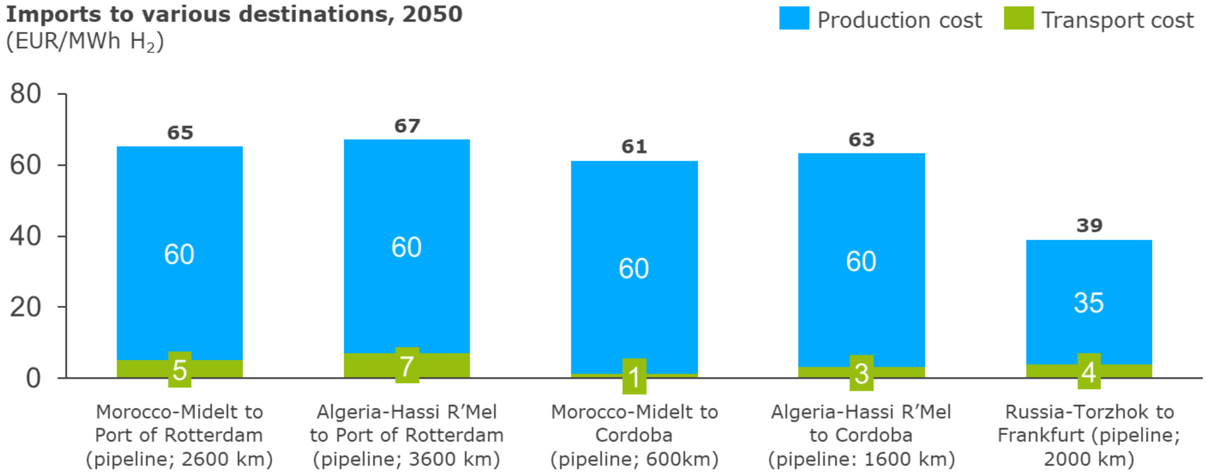


Figure 3-3: Levelized cost of hydrogen import to various destinations via pipelines in the year 2050

3.1 Cost of conversion and reconversion

Gaseous hydrogen has a low energy density which makes it costly to transport large volumes across long distances. Hydrogen can, therefore, be liquefied or converted into another energy carrier such as ammonia. While these alternatives offer potential benefits in the increase of energy density, the cost of conversion into these products as well as the energy intensity of the process must be considered.
The following parameter was used to normalise the units:

- **Levelized cost of hydrogen conversion.** This reflects the discounted costs of conversion of the MWh_{H2} delivered over the lifetime of the system.
    - We aim to report the levelized cost of conversion in EUR2019/MWh_{H2}.

These costs are reported for the year 2020 in Table 3-A below.

Table 3-A Levelized costs of hydrogen conversion

Conversion process	Unit	Minimum	Maximum	Comment	Source
H_2 to ammonia	EUR2019 /MWh_{H2}	27	27	Approximate number, small variations can arise due to the cost of electricity in different countries.	(IRENA, 2019)
H_2 to liquid hydrogen	EUR2019 /MWh_{H2}	38	74	Cost contribution to the LCOH with liquid delivery. Costs for a liquefier with a capacity of 27,000 kg_{H2}/day. Lower bound: Capital costs only, upper bound including additional recurring costs (e.g. electricity).	(DOE, 2019)
Ammonia to H_2	EUR2019 /MWh_{H2}	34	34	Based on a decentralized configuration for reconversion to hydrogen.	(IEA, 2019)

3.2 Cost of journey

The cost of the journey via pipelines or ships is reported in this section. For the normalisation of units, the following parameters are considered:

- **Investment costs for the export journey**. The CAPEX to transport hydrogen via ships is reflected here. Investment costs include new liquid hydrogen carrier ships currently still at a demonstration phase, refurbishment of LNG ships to transport liquid hydrogen and new ammonia carrier ships.
  - We aim to report the CAPEX of ships transporting liquid hydrogen or ammonia in million EUR2019/ship.
- **Levelized cost of the journey.** This parameter represents, for each of the selected transport technologies, the discounted cost of a journey across a fixed distance of 1,000 km for one MWh_{H2} delivered.
  - We aim to report the levelized cost of the journey in EUR2019/MWh_{H2}/1,000 km.

Table 3-B and Table 3-C summarise the figures found in the literature.

Table 3-B Investment costs for hydrogen the export journey

Cost	Year	Value	Unit	Comments	Source
Refurbishment of a ship to transport LH_2	2020	0.83	million EUR2019 /ISO container	CAPEX of LH_2 ISO container of 4.4t-H_2 capacity mounted on a tanker, 4% OPEX.	(BNEF, 2019)
New LH_2 ships	2030	390.80	million EUR2019 /ship	CAPEX of LH_2 ship with an 11,000 t-H_2 carrying capacity, still at the trial stage. No time horizon specified; year assumed to be 2030.	(IEA, 2019)
New ammonia ship	2020	80.62	million EUR2019 /ship	CAPEX of a 53,000 t-NH_3 ammonia tanker (9,328t-H_2), OPEX 4%.	(IEA, 2019)

Table 3-C Levelized cost of journey by technology

Technology for the export journey	Year	Minimum (EUR2019 /MWh$_{H2}$ /1,000 km)	Maximum (EUR2019 /MWh$_{H2}$ /1,000 km)	Comment	Source
LH_2 refurbished ship	2030	2.16	2.16	Based on a 10,000 km journey. Cost is foreseen to remain stable, as the technology is well developed	(IEA, 2019)
LH_2 ship	2020	3.00	3.00	Based on a 10,000 km journey	(BNEF, 2020)
	2020	3.18	3.18	Journey from Australia to Japan over 9,000 km. Based on data from the Hystra demonstration project led by Kawasaki, Shell and Iwatani.	(BNEF, 2020)
	2030	2.05	2.05	Journey from Australia to Japan over 9,000 km. Based on data from the Hystra demonstration project led by Kawasaki, Shell and Iwatani.	(BNEF, 2020)
NH_3 Ship	2020	0.91	0.91	Based on a 10,000 km journey.	(IEA, 2019)
H_2 Pipe	2050	2.01	2.01	1,600 km pipeline from Algeria to Spain, assuming a 6,600 t/day pipeline. Compression costs included.	(BNEF, 2020)

3.3 Costs at export sites

This sub-section reflects the datapoints collected for the levelized cost of hydrogen at the export site. Selected export geographies include North Africa, the Middle East, Australia, Russia and Chile. The units are normalised as follows:

- **Levelized cost of hydrogen at the export site**. The levelized cost of hydrogen at the export site is defined as the discounted costs of hydrogen production over the hydrogen produced over the lifetime of the system. The exact location of renewable production, LCOE of renewables, and electrolysis costs applicable to the datapoints are reported in the comments.
    - We aim to report the levelized costs of hydrogen at the export site in EUR2019/MWh$_{H2}$.

The following Table 3-D illustrates the costs found in the literature.

Table 3-D Levelized hydrogen costs at export sites

Export country	Year	Minimum (EUR2019 /MWh_{H2})	Maximum (EUR2019 /MWh_{H2})	Comment	Source
Australia	2020	101.0	116.3	Production in South Australia with an LCOE for PV of 29.8-41.2 USD/MWh and 2600 full load hours.	(IRENA, 2019)
	2030	65.9	65.9	Production in South Australia with an LCOE for PV of 21 USD/MWh and 2600 full load hours. Considers cost reductions + efficiency improvements of electrolysers.	(IRENA, 2019)
	2050	20.4	20.4	Production in North West Australia, with an LCOE of 12 USD/MWh, and additional savings from the integrated design of the electrolyzer and generator, and additional learning from increased renewable deployment for hydrogen.	(BNEF, 2020)
Chile	2025	42.9	72.3	Lower bound with a grid-connected system, upper bound with an LCOE of 40-50 USD/MWh for a combined PV/CSP plant.	(IRENA, 2019)
Saudi Arabia	2020	88.7	105.8	Lower bound produced by PV panels (LCOE: 23.4 USD/MWh, 2100 full load hours), upper bound with wind farms (LCOE: 21.3 USD/MWh, 2620 full load hours).	(IRENA, 2019)
Qatar	2050	34.0	34.0	Cost of blue hydrogen (natural gas production with CCS).	(BNEF, 2020)
North Africa	2050	34.0	44.0		(Guidehouse, 2020)
Algeria	2050	20.4	20.4	Renewable production in Algeria.	(BNEF, 2020)
Russia	2050	35.4	35.4	Cost of blue hydrogen (natural gas production with CCS).	(BNEF, 2020)

3.4 Costs at import sites

This sub-section reflects the datapoints collected concerning the total costs for hydrogen import at the import site. The sources report the total costs including multiple criteria, which may not be directly comparable. While some sources only consider the steps of production, conversion and transport, others also include elements such as storage, transmission and distribution up to the end-user.
The units are normalised as follows:

- **Levelized cost of hydrogen at import site.** Defined as discounted all the steps in the supply chain up to the import site over the MWh_{H2} delivered over the lifetime of the system. For each datapoint, the export and import locations are specified.
    - We aim to report the levelized costs at the import site in $EUR2019/MWh_{H2}$.

The following Table 3-E reflects the datapoints for the years 2030 and 2050, as extracted from the literature.

Table 3-E Levelized cost of hydrogen at the import site

Route	Year	Minimum	Maximum	Comment	Source
North Africa to HRS pump in Europe (Pipeline)	2030	200.9	241.1	Transport by pipeline. Cost of electrolytic hydrogen imports from Africa supplied to a refuelling station in Europe including costs for production, conversion, import/export terminals, transmission, distribution, reconversion, refuelling station	(IRENA, 2019)
North Africa to buildings in Europe (Pipeline)	2030	128.1	170.7	Levelized cost of hydrogen with the refurbishment of transmission and distribution in existing infrastructure. Lower bound: Hydrogen produced from natural gas with CCUS, upper bound: electrolytic hydrogen.	(IEA, 2019)
Qatar to port in the UK (ship)	2050	105.3	105.3	Transport for an 11,190 km journey in an LH_2 ship, with production costs for natural gas with CCUS. Production, conversion, storage, transport and reconversion costs included	(BNEF, 2020)
Russia to Germany (Pipeline)	2050	41.3	41.3	Transport over 4.000 km pipeline with natural gas with CCUS production, including compression and storage costs	(BNEF, 2020)
Algeria to Spain (Pipeline)	2050	23.6	23.6	Transport costs over 1,600 km with renewable production, including compression and storage costs	(BNEF, 2020)

Annex

Table A - 1 Investment costs and efficiency levels for blue and green hydrogen production technologies per year

Technology	Year	Investment cost min (million EUR2019/MWH2out)	Investment cost min (million EUR2019/MWH2out)	Efficiency min (system; LHV)	Efficiency max (system; LHV)	Source
Green - Alkaline electrolysers (ALK)	2020	0.628	1.955	63%	70%	(IEA, 2019)
	2020	0.444	0.947	63%	68%	(H21 NoE, 2018)
	2020	1.395	1.395	51%	51%	(IRENA, 2018)
	2020	1.158	2.837	49%	69%	(Schmidt, 2017)
	2030	0.496	1.151	65%	71%	(IEA, 2019)
	2030	0.361	0.740	68%	69%	(Hydrogen Europe, 2020)
	2030	0.700	0.700	65%	65%	(IRENA, 2018)
	2030	0.736	1.531	52%	73%	(Schmidt, 2017)
	2050	0.220	0.880	70%	80%	(IEA, 2019)
	2050	0.289	0.289	69%	69%	(Hydrogen Europe, 2020)
Green - Polymer Electrolyte Membrane electrolysers (PEM)	2020	1.613	2.828	56%	60%	(IEA, 2019)
	2020	1.997	1.997	57%	57%	(IRENA, 2018)
	2020	1.474	3.402	55%	63%	(JRC, 2019)
	2020	1.266	3.596	52%	63%	(Schmidt, 2017)
	2030	0.841	2.095	63%	68%	(IEA, 2019)
	2030	1.037	1.037	64%	64%	(IRENA, 2018)
	2030	0.998	2.457	59%	68%	(JRC, 2019)
	2030	0.772	2.739	52%	69%	(Schmidt, 2017)
Green - Solid Oxide Electrolysers (SOEC)	2020	3.041	6.658	74%	81%	(IEA, 2019)
	2020	1.066	1.066	76%	76%	(JRC, 2019)
	2020	2.132	3.664	80%	80%	(Schmidt, 2017)
	2030	0.838	3.199	77%	84%	(IEA, 2019)
	2030	0.582	0.582	80%	80%	(JRC, 2019)
	2030	0.799	3.331	80%	80%	(Schmidt, 2017)
	2050	0.489	1.143	77%	90%	(IEA, 2019)
	2050	0.388	0.388	80%	80%	(JRC, 2019)
Blue - CCS for existing Steam Methane Reforming (SMR) plant	2020	0.701	0.701	N/A	N/A	(Jakobsen & Åtland, 2016)
Blue - New Steam Methane Reforming (SMR) plant & CCS	2020	1.650	1.650	N/A	N/A	(Jakobsen & Åtland, 2016)
	2020	0.963	0.963	N/A	N/A	(ASSET, 2018)
	2020	1.594	1.594	69%	69%	(IEA, 2019)
	2020	0.792	1.408	N/A	N/A	(IEA, 2019)
	2030	0.909	0.909	N/A	N/A	(ASSET, 2018)
	2030	1.290	1.290	69%	69%	(IEA, 2019)
	2050	0.856	0.856	N/A	N/A	(ASSET, 2018)
	2050	1.214	1.214	69%	69%	(IEA, 2019)
Blue - CCS for existing Autothermal Reforming (ATR) plant	2020	0.688	0.688	N/A	N/A	(Jakobsen & Åtland, 2016)
Blue - New Autothermal Reforming (ATR) plant & CCS	2020	1.498	1.498	N/A	N/A	(Jakobsen & Åtland, 2016)
	2020	0.952	0.952	N/A	N/A	(H21 NoE, 2018)

Table A - 2 Investment costs for renewable energy technologies per year

Technology	Datapoint year	Investment cost min (million EUR2019/MW)	Investment cost max (million EUR2019/MW)	Source
Utility-scale solar energy	2020	0.431	0.431	(Vartiainen, Masson, Breyer, Moser, & Roman Medina, 2019)
	2020	0.623	0.830	(Fraunhofer ISE, 2018)
	2030	0.275	0.275	(Vartiainen, Masson, Breyer, Moser, & Roman Medina, 2019)
	2040	0.204	0.204	(Vartiainen, Masson, Breyer, Moser, & Roman Medina, 2019)
	2040	0.363	0.415	(Fraunhofer ISE, 2018)
	2050	0.164	0.164	(Vartiainen, Masson, Breyer, Moser, & Roman Medina, 2019)
Onshore wind energy	2020	1.317	1.317	(IRENA, 2019)
	2020	1.557	2.076	(Fraunhofer ISE, 2018)
	2030	0.704	1.188	(IRENA, 2019)
	2050	0.572	0.880	(IRENA, 2019)
Bottom-fixed offshore wind energy	2020	1.880	1.880	(Energinet, 2019)
	2020	3.830	3.830	(IRENA, 2019)
	2020	3.218	4.879	(Fraunhofer ISE, 2018)
	2030	1.680	1.680	(Energinet, 2019)
	2030	1.496	2.815	(IRENA, 2019)
	2050	1.520	1.520	(Energinet, 2019)
	2050	1.232	2.464	(IRENA, 2019)
Floating offshore wind energy	2020	5.000	5.000	(PNEC, 2019)
	2020	3.633	4.214	(NREL, 2020)
	2030	3.051	3.051	(PNEC, 2019)
	2030	2.638	3.243	(NREL, 2020)
	2040	2.695	2.695	(PNEC, 2019)

Table A - 3 Full-load hours for renewable energy technologies per year

Technology	Datapoint year	Full-load hours min (hours)	Full-load hours max (hours)	Source
Utility-scale solar energy	2020	1,343	1,343	(Energinet, 2019)
	2030	1,484	1,484	(Energinet, 2019)
	2030	1,000	1,700	(Neo Carbon Energy, 2018)
	2040	1,499	1,499	(Energinet, 2019)
Onshore wind energy	2020	3,400	3,400	(Energinet, 2019)
	2030	3,600	3,600	(Energinet, 2019)
	2030	2,628	3,066	(Wind Europe, 2019)
	2040	3,700	3,700	(Energinet, 2019)
Bottom-fixed offshore wind energy	2020	4,500	4,500	(Energinet, 2019)
	2030	4,650	4,650	(Energinet, 2019)
	2030	3,066	4,818	(Wind Europe, 2019)
	2040	4,700	4,700	(Energinet, 2019)
Floating offshore wind energy	2020	4,030	4,079	(NREL, 2020)
	2030	4,272	4,455	(NREL, 2020)

Table A - 4 Investment in electrolyser manufacturing capacities

Hydrogen Production Technology	Cost in EUR/MW_{el} of production capacity/year	Source
Alkaline electrolysers (ALK)	45,000	(NEL, 2018)
Polymer Electrolyte Membrane electrolysers (PEM)	69,000	(ITM Power, 2019)

Table A - 5 Hydrogen transmission cost data

Investment cost – refurbishment of natural gas pipelines

Units	Value	Comments	Source
million EUR2019/km	0.37	Based on estimation for the German gas network with refurbishment cost being 15% of the new build.	(FNBGas, 2019)
Investment costs - new dedicated hydrogen pipelines			
Units	**Value**	**Comments**	**Source**
million EUR2019/km	0.93	16-inch average diameter. Costs for a transmission network of 6,300 km in the UK.	(Element Energy & E4Tech, 2018)
	1.22		(Cadent, 2017)
	1.40		(Institute, 2016)
	1.55	Costs in the UK.	(H21 NoE, 2018)
	1.57		(Frontier Economics, 2016)
	2.01	48-inch pipeline, operating between 30-80 bar with a length of 300 km in the UK.	(ENA & Navigant, 2019)
	2.48	Average cost in Germany, calculated from total investments in a new and refurbished network.	(FNBGas, 2019)
	3.28	48-inch pipeline.	(Jacobs, Element Energy)
Investment costs for new dedicated compression			
Unit	**Value**	**Comments**	**Source**
million EUR2019/MW of installed compression power	1.07	Costs for a 5.8 MW compressor, with a 240 t/day throughput.	(Baufumé et al., 2012)
EUR2019/MWh per day of throughput capacity	777		
million EUR2019/MW of installed compression power	0.65	5.8 MW capacity for compressor, calculated according to cost curve in source.	(Jacobs, Element Energy)
LCOT for H_2 transmission - refurbished natural gas infrastructure			
Units	**Value**	**Comments**	**Source**
EUR2019/MWh$_{H2}$ /600 km	3.7	Retrofitting existing gas infrastructure for 100% hydrogen.	(Guidehouse, 2019)

LCOT for H_2 transmission for new dedicated infrastructure				
Units	**Minimum**	**Maximum**	**Comments**	**Source**
EUR2019/MWh$_{H2}$ /600 km	4.6	4.6	48-inch pipeline. Includes pipeline and compressor CAPEX and OPEX and compression fuel-related costs.	(Guidehouse, 2019)
	9.6	9.6	34-inch pipeline with utilization of 75%. The source assumes the cost of transporting H_2 over 50 km. Normalised to 600 km.	(BNEF, 2019)
	11.4	11.4	Transportation over 1500 km is assumed by source, considering all capital and operating costs. Normalised to 600 km.	(IEA, 2019)
	16.1	49.8	Pipeline with a capacity of >100 t/day. The source assumes a 100 km pipeline. Normalised to 600 km.	(BNEF, 2019)
	45.0	45.0	Estimated including compression costs for pipes of diameters between 7-10 inch over 100 km as assumed by source.	(DNV GL, 2019)

			Normalised to 600 km.	

Table A - 6 Hydrogen storage cost data

Investment costs					
Technology	**Minimum**	**Maximum**	**Units**	**Comments**	**Source**
Depleted gas field	280	424	EUR2019/ MWh_{H2} stored	CAPEX including compressors and pipes, 4% OPEX.	(BNEF, 2019)
Salt caverns	334	334	EUR2019/ MWh_{H2} stored	CAPEX for 1,160 t of working capacity (+1/3 additional for cushion gas), but highly dependent of geography. 4% OPEX, includes compressors and pumps.	(BNEF, 2019)
Rock caverns	1232	1232	EUR2019/ MWh_{H2} stored	4% OPEX.	(BNEF, 2019)
Levelized cost of storage (LCOS)					
Technology	**Minimum**	**Maximum**	**Units**	**Comments**	**Source**
Salt caverns	6	26	EUR2019/ MWh_{H2}	300-10,000 t per cavern, lower bound: monthly cycling, upper value: bi-annual cycling.	(BNEF, 2019)
	17	17	EUR2019/ MWh_{H2}		(IEA, 2019)
Rock caverns	19	104	EUR2019/ MWh_{H2}	300-2,500 t per cavern, lower bound: monthly cycling, upper bound: bi-annual cycling.	(BNEF, 2019)
Depleted gas field	51	76	EUR2019/ MWh_{H2}	Cost for working gas capacity, 1 cycle/year. Including the cost of compression and pipelines needed for the facility to function.	(BNEF, 2019)

Table A - 7 Hydrogen distribution cost data

Investment costs - refurbished existing natural gas pipeline			
Units	**Value**	**Comments**	**Source**
Million EUR2019/km	0.23	Cost of reinforcing low-pressure 5-inch pipeline with a flow of 0.3 million standard cubic metres a day. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
	0.41	Cost of reinforcing low-pressure 9-inch pipeline. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
	0.47	Cost of reinforcing low-pressure 10.5-inch pipeline in the UK. Cost of other network replacement or reinforcements not included.	(Jacobs, Element Energy)
LCOD for H_2 distribution - new infrastructure			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.05	Levelized cost of distribution by pipe over 1000 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	0.06	Levelized cost of distribution by pipe over 100 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	0.16	Levelized cost of distribution by pipe over 10 km journey, normalized to a per km basis. Includes compression and storage.	(BNEF, 2019)
	1.61	Levelized cost of distribution by pipe over a 1 km	(BNEF,

		journey. Includes compression and storage.	2019)
LCOD for H_2 distribution - refurbishment			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.11	DSO operation and integration cost. CAPEX adapted from (H21 NoE, 2018) and scaled to UK-level investments. Based on current natural gas distribution costs in the UK uplifted by 20% due to an assumed drop in energy-carrying capacity for hydrogen.	(ENA & Navigant, 2019)
LCOD for distribution by truck			
Units	**Value**	**Comments**	**Source**
EUR2019/ MWh_{H2} /km	0.54	Levelized cost of a 50 km trip by pressurized H2 truck today, including compression and storage.	(BNEF, 2019)
EUR2019/ MWh_{H2} /km	2.46	Levelized cost of a 50 km trip using a liquid hydrogen truck.	(BNEF, 2019)

Table A - 8 Hydrogen dispensing cost data

H_2 refuelling stations (Small; <20 MWh_{H2}/day)				
Units	**Year**	**Value**	**Comments**	**Source**
million EUR2019/HRS	2020	0.85	HRS for cars, 200 kg_{H2}/day, 10% utilisation.	(IEA, 2019)
		0.89	212 kg_{H2}/day capacity.	(Forschungszentrum Jülich, 2018)
		2.44	Cost for stations installed after 2016 with a capacity of 600 kg_{H2}/day, 76% utilisation, average output 456 kg_{H2}/day.	(NREL, 2013)
H_2 refuelling stations (Large >20 MWh_{H2}/day)				
Units	**Year**	**Value**	**Comments**	**Source**
million EUR2019/HRS	2020	1.71	HRS for trucks 1000 kg_{H2}/day, 40% utilisation.	(IEA, 2019)
		2.00	1,000 kg_{H2}/day capacity.	(Forschungszentrum Jülich, 2018)
		3.99	Cost for stations installed after 2016 with a capacity of 1500 kg_{H2}/day, 80% utilization, average output 1200 kg_{H2}/day.	(NREL, 2013)

LCOHD refuelling stations (Small; <20 MWh_{H2}/day)			
Unit	**Year**	**Value**	**Comments**
EUR2019/ MWh_{H2}	2020	63	Based on a 10 MWh/day average size for a station, WACC 5%, utilization rate 60%, 20-year lifetime.
LCOHD refuelling stations (Large; >20 MWh_{H2}/day)			
Unit	**Year**	**Value**	**Comments**
EUR2019/ MWh_{H2}	2020	32	Based on a 35 MWh_{H2}/day average size for a station, WACC 5%, utilization rate 60%, 20-year lifetime.

Table A - 9 Hydrogen cost data for steel end-use sector

Cost parameter	Value (range)	Unit	Source
Investment cost of new hydrogen DRI-EAF based manufacturing capacity	400-752	million EUR/tonne annual DRI steel production capacity	(Guidehouse, 2020), (IEA, 2019)
Steel production costs, DRI-EAF technology	386-685	EUR/tonne crude steel	(Material Economics, 2019), (Vogl, Ahman, & Nilsson, 2018)
Hydrogen demand per tonne of crude steel production – BF-BOF	20-40	kg H_2/tonne crude steel production	(Guidehouse, 2020), (Yilmaz, Wendelstorf, &

injection			Turek, 2017)
Hydrogen demand per tonne crude steel – DRI-EAF	47-68	kg H_2/tonne crude steel production	(Material Economics, 2019), (IEA, 2019)

Table A - 10 Hydrogen cost data for transportation end-use sector

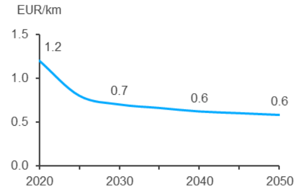
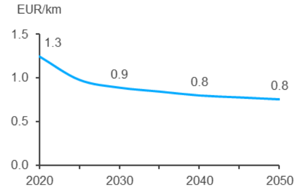
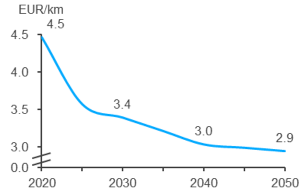
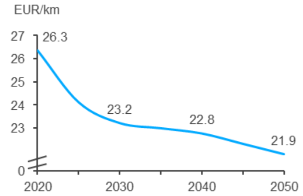
Transportation segment	Production (or retail) costs (million EUR/unit)	Hydrogen consumption (kg_{h2}/vehicle/year)	Total Cost of Ownership (EUR/km)
Heavy-Duty Vehicles	0.12 – 0.19	4,600 - 9,200	
Buses	0.37 – 0.67	2,078 - 9,800	
Trains	5.47- 5.88	8,010 - 27,000	
Ocean-going ships	1.99 – 17.1	494,000	

Table A - 11 Levelized cost of hydrogen conversion

Conversion process	Unit	Minimum	Maximum	Comment	Source
H_2 to ammonia	EUR2019 /MWh_{H2}	27	27	Approximate number, small variations can arise due to the cost of electricity in different countries.	(IRENA, 2019)
H_2 to liquid hydrogen	EUR2019 /MWh_{H2}	38	74	Cost contribution to the LCOH with liquid delivery. Costs for a liquefier with a capacity of 27,000 kg_{H2}/day. Lower bound: Capital costs only, upper bound including additional recurring costs (e.g. electricity).	(DOE, 2019)
Ammonia to H_2	EUR2019 /MWh_{H2}	34	34	Based on a decentralized configuration for reconversion to hydrogen.	(IEA, 2019)

Table A - 12 Investment costs for hydrogen the export journey

Cost	Year	Value	Unit	Comments	Source
Refurbishment of a ship to transport LH_2	2020	0.83	million EUR2019/IS	CAPEX of LH_2 ISO container of 4.4t-H_2 capacity mounted on a	(BNEF, 2019)

			O container	tanker, 4% OPEX.	
New LH_2 ships	2030	390.80	million EUR2019/ship	CAPEX of LH_2 ship with an 11,000 t-H_2 carrying capacity, still at the trial stage. No time horizon specified; year assumed to be 2030.	(IEA, 2019)
New ammonia ship	2020	80.62	million EUR2019/ship	CAPEX of a 53,000 t-NH_3 ammonia tanker (9,328t-H_2), OPEX 4%.	(IEA, 2019)

Table A - 13 Levelized hydrogen costs at export sites

Export country	Year	Minimum (EUR2019/ MWh_{H2})	Maximum (EUR2019/ MWh_{H2})	Comment	Source
Australia	2020	101.0	116.3	Production in South Australia with an LCOE for PV of 29.8-41.2 USD/MWh and 2600 full load hours.	(IRENA, 2019)
	2030	65.9	65.9	Production in South Australia with an LCOE for PV of 21 USD/MWh and 2600 full load hours. Considers cost reductions + efficiency improvements of electrolysers.	(IRENA, 2019)
	2050	20.4	20.4	Production in North West Australia, with an LCOE of 12 USD/MWh, and additional savings from the integrated design of the electrolyzer and generator, and additional learning from increased renewable deployment for hydrogen.	(BNEF, 2020)
Chile	2025	42.9	72.3	Lower bound with a grid-connected system, upper bound with an LCOE of 40-50 USD/MWh for a combined PV/CSP plant.	(IRENA, 2019)
Saudi Arabia	2020	88.7	105.8	Lower bound produced by PV panels (LCOE: 23.4 USD/MWh, 2100 full load hours), upper bound with wind farms (LCOE: 21.3 USD/MWh, 2620 full load hours).	(IRENA, 2019)
Qatar	2050	34.0	34.0	Cost of blue hydrogen (natural gas production with CCS).	(BNEF, 2020)
North Africa	2050	34.0	44.0		(Guidehouse, 2020)
Algeria	2050	20.4	20.4	Renewable production in Algeria.	(BNEF, 2020)
Russia	2050	35.4	35.4	Cost of blue hydrogen (natural gas production with CCS).	(BNEF, 2020)

Table A - 14 Levelized hydrogen costs at export sites

Route	Year	Minimum	Maximum	Comment	Source
North Africa to HRS pump in Europe (Pipeline)	2030	200.9	241.1	Transport by pipeline. Cost of electrolytic hydrogen imports from Africa supplied to a refuelling station in Europe including costs for production, conversion, import/export terminals, transmission, distribution, reconversion, refuelling station	(IRENA, 2019)
North Africa to buildings in Europe (Pipeline)	2030	128.1	170.7	Levelized cost of hydrogen with the refurbishment of transmission and distribution in existing infrastructure. Lower bound: Hydrogen produced from natural gas with CCUS, upper bound: electrolytic hydrogen.	(IEA, 2019)
Qatar to port in the	2050	105.3	105.3	Transport for an 11,190 km journey in an LH_2 ship, with production costs for	(BNEF, 2020)

UK (ship)				natural gas with CCUS. Production, conversion, storage, transport and reconversion costs included	
Russia to Germany (Pipeline)	2050	41.3	41.3	Transport over 4.000 km pipeline with natural gas with CCUS production, including compression and storage costs	(BNEF, 2020)
Algeria to Spain (Pipeline)	2050	23.6	23.6	Transport costs over 1,600 km with renewable production, including compression and storage costs	(BNEF, 2020)

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