ISSN 1831-9424

Environmental life cycle assessment (LCA) comparison of hydrogen delivery options within Europe

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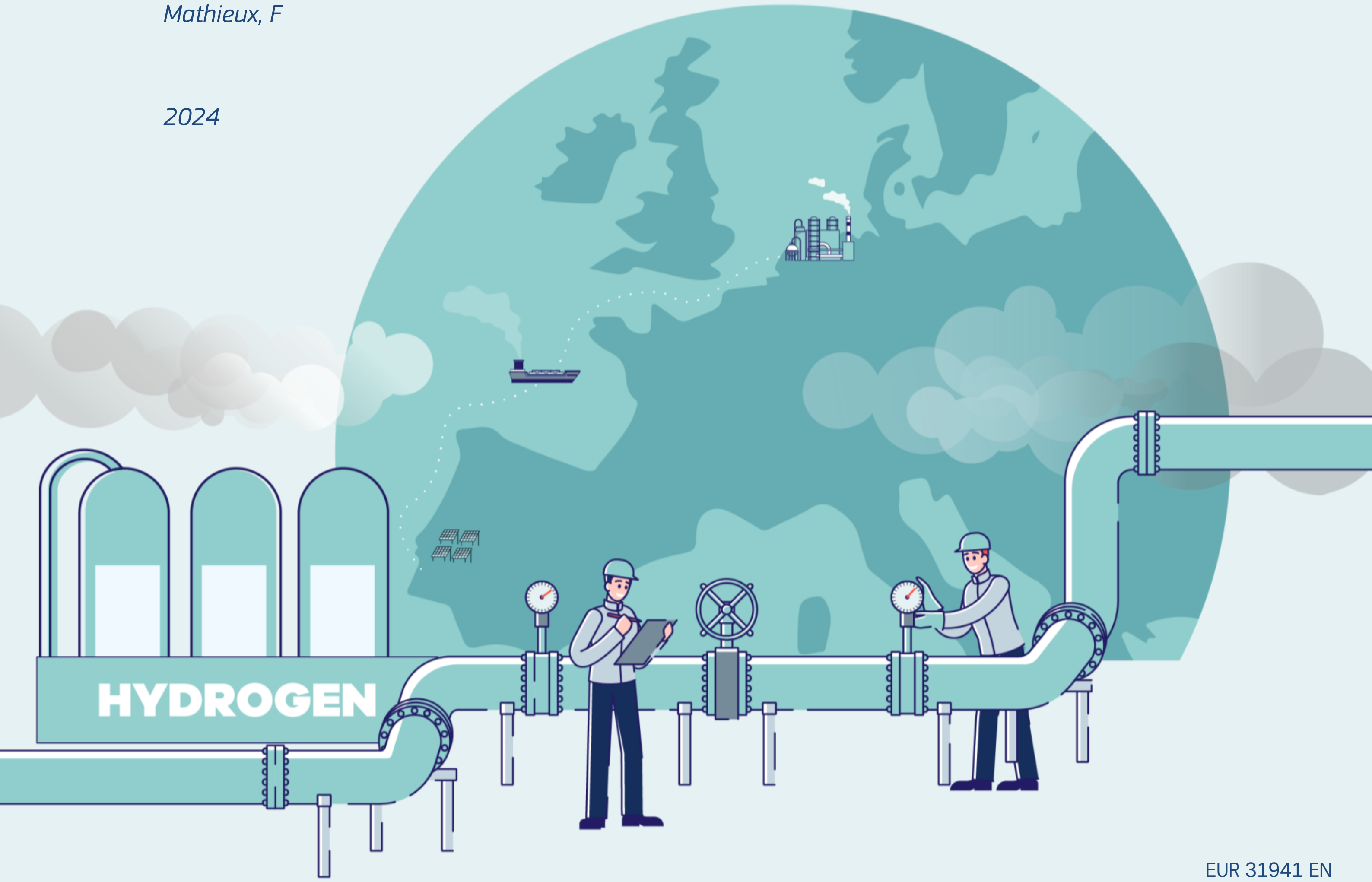
2024



EUR 31941 EN

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JRC137953

EUR 31941 EN

PDF ISBN 978-92-68-16356-6 ISSN 1831-9424 doi:10.2760/5459 KJ-NA-31-941-EN-N

Luxembourg: Publications Office of the European Union, 2024

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How to cite this report: European Commission, Joint Research Centre, Arrigoni, A., Dolci, F., Ortiz Cebolla, R., Weidner, E., D'Agostini, T., Eynard, U., Santucci, V. and Mathieux, F., Environmental life cycle assessment (LCA) comparison of hydrogen delivery options within Europe, Publications Office of the European Union, Luxembourg, 2024, https://data.europa.eu/doi/10.2760/5459, JRC137953.

Contents

Abstract

Renewable hydrogen is expected to play an important role in European decarbonisation efforts. A previous JRC study showed that importing hydrogen from a location where renewable energy is cheaper can be more cost effective than producing it locally. However, the environmental impact of transporting large amounts of hydrogen over long distances has not been fully understood yet. Our work aims at advancing this field by comparing the life cycle environmental impacts of three options for delivering hydrogen from a distant location (i.e., hydrogen compression, liquefaction, and chemical bonding to other molecules) to on-site production via steam methane reforming (SMR) or electrolysis. Ammonia, liquid organic compounds, methanol, and synthetic natural gas were considered as potential hydrogen chemical carriers. The goal is to understand whether importing hydrogen could make sense from an environmental perspective, and if so, which is the option with the lowest impact among the environmental categories considered in this study. Impacts are assessed covering the delivery chain from hydrogen production, through its conversion into a suitable carrier for transportation (ships and pipelines are considered), to the supply of pure hydrogen to an industrial user. A distance (2 500 km) compatible with European territory, corresponding to a large delivery of hydrogen produced in Portugal and used in the Netherlands, and a timeframe extending beyond 2030 were considered. The Environmental Footprint (EF) impact assessment method of the European Commission (impact on 16 environmental categories summarized in a single score) was used for the assessment.

Contrasting results are obtained for the different environmental impact categories considered: while all the delivery options would guarantee a supply of hydrogen with a lower global warming potential than on-site production via fossil fuels, producing hydrogen locally via SMR would generate lower impacts in 12 of the 16 environmental impact categories considered, including the use of natural resources such as water, land, and minerals and metals. When the overall environmental impact is expressed as a single score using the normalization and weighting factors of the EF impact assessment method, all the delivery options would guarantee an environmental advantage compared to on-site fossil-based productions (without carbon capture). Renewable liquid hydrogen transported by ship and compressed hydrogen transported by pipeline prove to be the most environmentally friendly options to deliver hydrogen for the 2 500-km distance considered in the assessment. The transportation efficiency advantage of packing hydrogen into more manageable carriers does not seem to translate in an environmental impact advantage. On the contrary, the energy required to pack the carrier at the hydrogen production site and unpack it at the delivery site significantly increase the impact with respect to the compressed and liquid hydrogen options.

These results should be considered as preliminary. Much of the infrastructure for large scale hydrogen delivery does not yet exist, and therefore assumptions on technologies and emissions are subject to a high degree of uncertainty. More primary data on hydrogen technologies and emissions along the supply chain are necessary to increase the accuracy of our results. Finally, more research is needed on the methodological side, to develop the robust tools to investigate the environmental impact of uncertain future activities (i.e., prospective LCA).

Acknowledgements

This report was prepared under the framework contract between the Directorate-General JRC of the European Commission and the Clean Hydrogen Joint Undertaking (Clean H_2 JU). The authors would like to express their gratitute to the Clean Clean H_2 JU for its financial support and Alberto Garcia Hombrados for his encouragement. Additionally, the authors extend their thanks to Marc Steen for his meticulous review of the draft, and to Bagdagul Tan for the cover page illustration.

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1 Introduction

Hydrogen has emerged as a key player in the global effort to reduce the climate impact of energy use across various sectors, particularly those that are challenging to decarbonize, such as heavy industry and transport. Recognising its potential, the European Union has set ambitious targets and enacted legislation under the European Green Deal to increase the production and use of renewable hydrogen as an integral part of its strategy to achieve climate neutrality by 2050. Initiatives such as the European hydrogen strategy (European Commission, 2020) have been pivotal in integrating hydrogen into the EU's energy transition and fostering innovation and investment in the hydrogen economy. The Hydrogen Strategy already anticipated the possibility that renewable hydrogen might need to be transported across Europe or even imported from EU's neighboring regions in order to meet the demand of the European market. In the wake of Russian invasion of Ukraine, the RePowerEU Plan has further reinforced these ambitions by setting significant milestones for the import of renewable hydrogen, aiming for a target of 10 million tonnes imported by the year 2030 (European Commission, 2022).

In a previous study, JRC investigated different delivery chains for the supply of renewable hydrogen in Europe (Ortiz Cebolla, Dolci, and Weidner, 2022). The goal of this study was to answer the question whether it is more convenient to produce renewable hydrogen close to the demand location or to import it from a location where renewable hydrogen production is cheaper. A second objective was to look into how long the transport route can be for the cost of hydrogen to still be competitive. JRC assessed 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. The study examined the transportation of compressed and liquid hydrogen, as well as the utilization of liquid hydrogen carriers such as ammonia, methanol, and liquid organic hydrogen carriers (LOHC). Two delivery cases were assessed, 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 H_2 per year). The outcome of this analysis highlighted the fact that the most cost effective way to deliver renewable hydrogen depends on distance, amounts of hydrogen moved, and the final target application. In the case of distances compatible with European territory, for the cases and scenarios considered, hydrogen delivery in its pure form (i.e., compressed or liquid hydrogen) was identified as the most competitive delivery option. This is mainly due to the lower complexity of the delivery chain, not involving chemical transformations. For Case A, compressed hydrogen delivered through pipeline was found to be the most cost effective option, followed by compressed hydrogen delivered by ship and liquid hydrogen. However, under certain conditions (i.e., waste heat as energy source and low electricity prices) LOHC became an interesting option, only outperformed by compressed hydrogen delivered through pipeline.

The current report aims at integrating the Case A of the previous techno-economic study with a life cycle assessment (LCA) in order to understand whether the cheapest option is also the best in terms of environmental impacts. In light of the EU’s stringent sustainability targets, it is imperative that hydrogen imports into Europe are characterised by minimal environmental impacts. To ensure a holistic evaluation of the environmental impacts associated with various hydrogen delivery methods, the Environmental Footprint (EF) impact assessment method developed by the European Commission (2021) is used for the assessment outlined in this document.

2 Goal and scope definition

2.1 Goal

The goal of the assessment is to evaluate and compare the potential environmental impact of various hydrogen supply pathways for a large industrial cluster situated in the north of Europe, projected to be operational after 2030 in the Netherlands. Two primary modes of hydrogen supply are assessed: local production (defined as "on-site" in the report), either through steam methane reforming or electrolysis, and import of renewable hydrogen from the south of Europe "packed"[1] in various suitable forms (i.e., compressed hydrogen, liquid hydrogen, ammonia, liquid organic hydrogen carrier, methanol, and synthetic natural gas). Details on the case study and the delivery options are provided in Section 2.2.3.

This study aims to provide insightful data to policymakers, stakeholders, and the public on the environmental implications of transporting hydrogen over long distances.

2.2 Scope

The system considered for the assessment ranges from cradle to gate: i.e., from the extraction of the raw materials used along the hydrogen delivery chain (e.g., to manufacture the electrolyser or to generate electricity) to the delivery of hydrogen to the end user. Emissions from the production of the infrastructure needed along the delivery chain are also included in the assessment. A simplified flow chart with the main processes included in the assessment is presented in Figure 1. The assessment is set within the geographical context of Europe, with a timeframe beyond 2030. The approach we adopted for the LCA is attributional, since the scope of the assessment is limited to the life cycle comparison of the different options and not to the overall consequences for the global emissions. In cases of multifunctionality (i.e., when an activity provides multiple co-products with different functions), impacts are attributed to the co-products according to the cut-off system model from ecoinvent (i.e., via allocation)[2]. However, for new multifunctional activities created for this study (e.g., the co-production of dibenzyltoluene and hydrochloric acid), alternative scenarios where system expansion is adopted were also considered to account for the direct consequences of hydrogen delivery (e.g., to account for the potential benefit of producing extra hydrochloric acid). Data from the previous JRC report "*Assessment of Hydrogen Delivery Options*" (Ortiz Cebolla, Dolci, and Weidner, 2022) are combined with inventories found in the literature and the version 3.9 of the ecoinvent database (cut-off system model) for the life cycle inventory (Wernet et al., 2016). The version 9.2 of the software SimaPro was used for the assessment (PRé Sustainability, 2021).

Figure 1. System considered for the assessment

Source: JRC (2024)

2.2.1 Functional unit

The functional unit considered for the assessment is the delivery of 1 Mt of hydrogen (30 bar, 99.97 % purity) in one year at an industrial site in the Netherlands (chosen as prototypical location in the north of Europe). Although the industrial user might not require hydrogen with such purity level, the value was chosen to be compliant with ISO 14687 (ISO, 2019) for a broad range of final applications.

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[1] The terms "packing" and "unpacking" were used in the previous report (Ortiz Cebolla, Dolci, and Weidner, 2022) to indicate, respectively, the processes required to transport hydrogen (e.g., compression, liquefaction, chemical bonding), and the reverse processes to have purified, gaseous hydrogen at a defined pressure and purity at the use site.

[2] The ecoinvent database (https://ecoinvent.org/) includes different system models for distributing the impacts between producers and consumers. The underlying philosophy of the cut-off system model is that wastes are responsibility of the producer, and recyclable products are available burden-free to the user (ecoinvent, 2022).

2.2.2 Life cycle impact assessment

The assessment covers the 16 life cycle impact categories recommended by the EF impact assessment method (European Commission, 2021): acidification, climate change, ecotoxicity (freshwater), particulate matter, eutrophication (marine), eutrophication (freshwater), eutrophication (terrestrial), human toxicity (cancer), human toxicity (non-cancer), ionising radiation, land use, ozone depletion, photochemical ozone formation, resource use (fossils), resource use (minerals and metals), water use. The EF is a LCA-based method to quantify the environmental impacts of products (goods or services) and organisations. The updated characterization factors of the EF method[3] were used for the impact assessment (Andreasi Bassi et al., 2023). It is important to note that the characterization models employed by the EF method to assess the impact for each category exhibit varying degrees of robustness. While, for instance, the model for climate change is highly robust, those for toxicity and resource use (including land, fossil fuels, minerals and metals, and water) exhibit a lower level of robustness (European Commission, 2021). The EF method used was adapted by PRé Sustainability[4] for better correspondence with the substances used in the SimaPro data libraries (Fazio et al., 2018). Given the growing concern about the potential role of hydrogen emissions in altering the climate (Arrigoni and Bravo Diaz, 2022), the latest characterization factor for the indirect global warming effect of hydrogen emissions published in a peer-reviewed journal was also included for the climate change category[5]: i.e., 11.6 kg CO_2e/kg H_2 over a 100-year time horizon (Sand et al., 2023). The absolute impact assessment results were then normalized and weighted to obtain a single environmental impact score for the different delivery pathways considered. Normalization and weighting are mandatory steps according to the EF methodology to support the interpretation and communication of the results. Normalization allows to calculate and compare the magnitude of the impact with respect to a reference unit. In the EF method, normalisation factors indicate the global impact on a per capita basis (European Commission, 2021). Finally, normalised results are multiplied for the set of weighting factors recommended by the EF method (Sala, Cerutti, and Pant, 2018). These factors are intended to represent the relative importance of each environmental impact category considered. The set of weighting factors are reported in Table 1, showing for instance a higher perceived importance for climate change with respect to the other impact categories.

Table 1. Weighting factors for the different environmental impact categories as recommended by the EF method.

Impact category	Weighting factor (%)
Acidification	6.20
Climate change	21.06
Ecotoxicity, freshwater	1.92
Particulate matter	8.96
Eutrophication, marine	2.96
Eutrophication, freshwater	2.80
Eutrophication, terrestrial	3.71
Human toxicity, cancer	2.13
Human toxicity, non-cancer	1.84
Ionising radiation	5.01
Land use	7.94
Ozone depletion	6.31
Photochemical ozone formation	4.78
Resource use, fossils	8.32
Resource use, minerals and metals	7.55
Water use	8.51

Source: Sala, Cerutti, and Pant (2018)

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[3] https://eplca.jrc.ec.europa.eu/EFVersioning.html

[4] https://pre-sustainability.com

[5] For climate change, the global warming potential metric over a 100 year time horizon (GWP_{100}) is considered, with the following main characterization factors based on the 6th assessment report of the IPCC (IPCC, 2021): 29.8 kg CO_2e/kg for fossil methane, 27 kg CO_2e/kg for biogenic methane, and 273 kg CO_2e/kg for nitrous oxide.

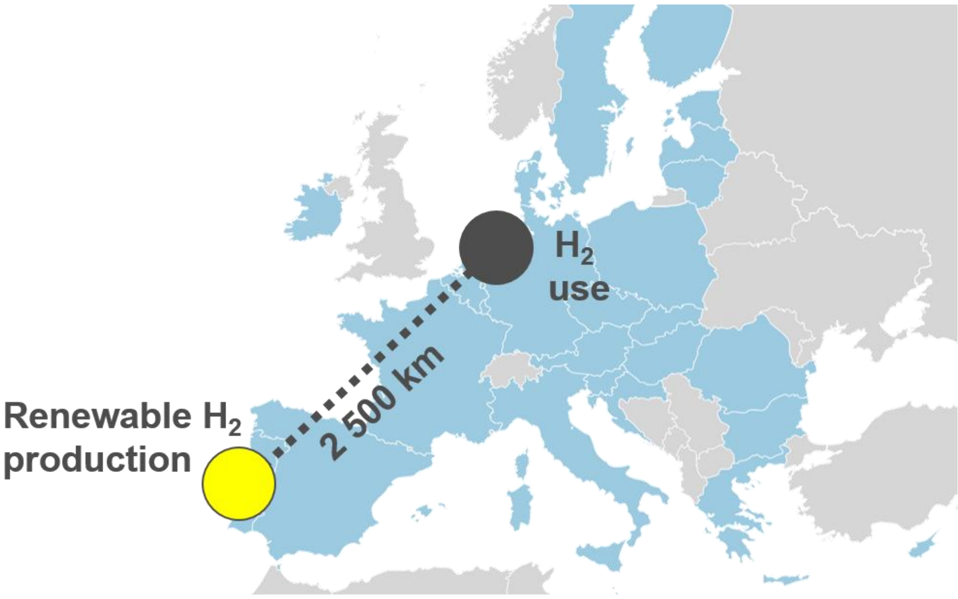
2.2.3 Case study and delivery options

The case study is based on the preceding JRC techno-economic analysis (Ortiz Cebolla, Dolci, and Weidner, 2022) aimed at investigating the most cost-competitive option to deliver hydrogen. In the analysis, JRC developed a database and an analytical procedure to assess each step of different hydrogen delivery pathways. In particular, the present report refers to the Case A investigated in the previous report: i.e., the delivery of one million tonnes (Mt) of renewable hydrogen per year to an industrial plant in the north of Europe from a single production site located in the south of Europe. Due to their potential to produce and use renewable hydrogen, the Netherlands and Portugal have been selected as prototypical locations in the north and south of Europe, respectively. A representation of the case study is shown in Figure 2. The distance considered between production and use is 2 500 km, and two transportation options are considered: ship and pipeline. Hydrogen production and end-user sites are assumed to be close to the port, and therefore no further distribution is considered. The amount of hydrogen delivered 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 delivery is expected to take place in a timeframe of 2030+.

Six modes of "packing" hydrogen are considered for the delivery pathways: compressed hydrogen (C-H_2), liquid hydrogen (L-H_2), ammonia (NH_3), a liquid organic hydrogen carrier (LOHC), methanol (MeOH), and synthetic natural gas (SNG). To understand whether shipped hydrogen could be a sustainable option in terms of environmental impacts, two pathways considering hydrogen produced on site were also included in the assessment: steam methane reforming and water electrolysis. Steam methane reforming was selected as the reference hydrogen production method at the use site, given its large predominance in today's market (International Energy Agency, 2023). Electrolysis was considered as the main alternative for future hydrogen generation based on announced European projects (Hydrogen Europe, 2023). While alternative processes such as autothermal reforming (ATR) and pyrolysis could have been considered for on-site production, a comprehensive comparison of all hydrogen production pathways falls beyond the scope of this study.

The different chains are briefly presented in this section, while all the assumptions and data used for the assessment are provided in the life cycle inventory section (section 3).

Figure 2. Representation of the case study: i.e., delivery of 1 million tonnes of renewable hydrogen per year to a single industrial customer in the north of Europe (the Netherlands) from a single production site located in the south of Europe (Portugal).



Source: JRC (2024) adapted from Ortiz Cebolla, Dolci, and Weidner (2022)

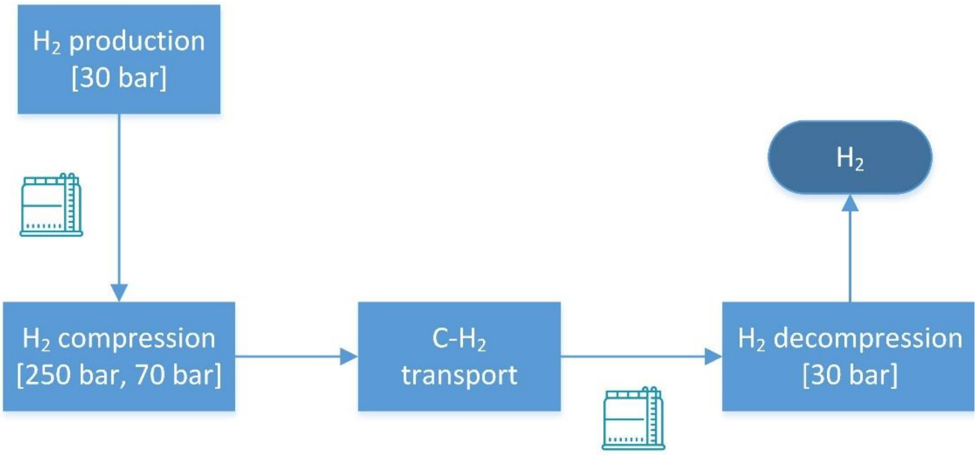
2.2.3.1 On-site production

For the local production pathways at the use site (i.e., on-site productions), hydrogen is assumed to be produced either via steam methane reforming or from electrolysis. For SMR, all the carbon dioxide produced in the process is assumed to be emitted to the atmosphere (Section 3.8.1). In the sensitivity analysis, a scenario where part of the carbon dioxide is captured and stored is also considered (Section 0). Two options were considered for the source of electricity in the electrolysis pathway: local grid (i.e., the Dutch electricity grid mix forecasted for 2030), and a dedicated on-shore wind farm (i.e., the main source of renewable electricity in the Netherlands). In the sensitivity analysis, a dedicated photovoltaic (PV) power plant is also considered as source of electricity for the electrolyser on-site (Section 5.2.1.1).

2.2.3.2 *Compressed hydrogen (C-H_2)*

The delivery chain for C-H_2 is schematized in Figure 3: hydrogen is assumed to be produced in Europe where renewables are cheapest (i.e., south-west), compressed, stored when necessary in a salt cavern, transported via ship or pipeline to the north of Europe, stored underground, and extracted by the end-user. More details for each step of the delivery chain are provided in section 3.

Figure 3. Delivery chain for the compressed hydrogen (C-H_2) option. Light blue boxes indicate processes involving hydrogen, and dark blue smooth boxes indicate products containing hydrogen. Blue arrows indicate flows containing hydrogen. Blue icons indicate a storage for hydrogen (e.g., tank or salt cavern). Compression at 250 bar refers to the ship scenario, while lower pressures (70 bar) are considered for pipelines.

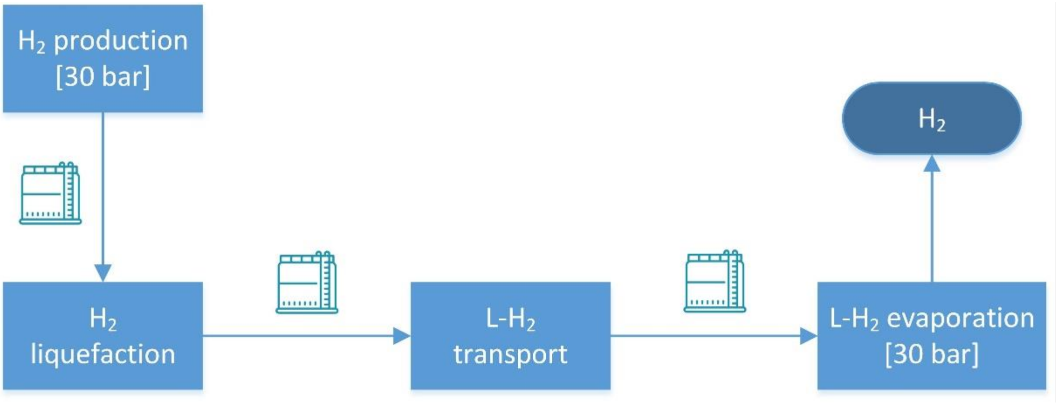


Source: JRC (2024)

2.2.3.3 *Liquid hydrogen (L-H_2)*

The delivery chain for L-H_2 comprises the production of gaseous H_2, its storage in a salt cavern, its liquefaction in a plant located near the storage site, the delivery of L-H_2 via ship, its storage in tanks, and its evaporation for the final use (Figure 4). Unlike for the other carriers, pipeline transportation was not considered to be a feasible option for L-H_2 in the timeframe studied due to the very low temperature required and the likely associated safety risks.

Figure 4. Delivery chain for the liquid hydrogen (L-H_2) option. Light blue boxes indicate processes involving hydrogen, and dark blue smooth boxes indicate products containing hydrogen. Blue arrows indicate flows containing hydrogen. Blue icons indicate a storage for hydrogen.

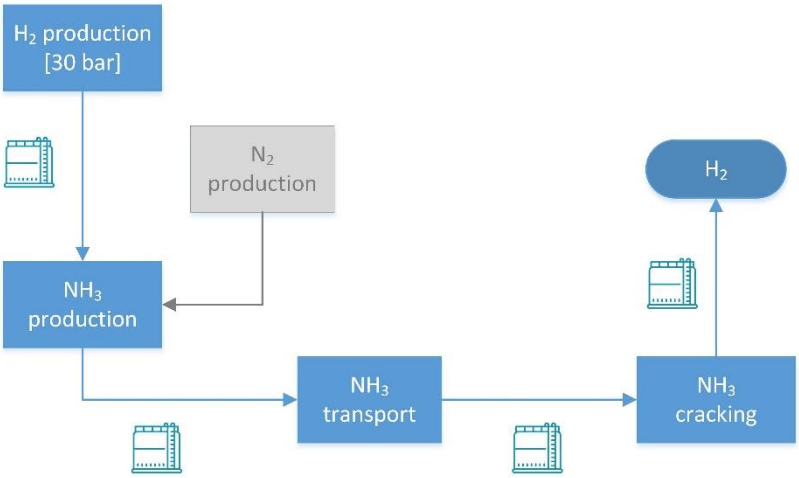


Source: JRC (2024)

2.2.3.4 Ammonia (NH_3)

The delivery pathway for hydrogen via ammonia is presented in Figure 5. Once produced, hydrogen is combined with nitrogen sourced from air to form ammonia. Liquid ammonia is stored in tanks, and is shipped by ship or pipeline to the end-use location. Ammonia is then sent to a cracking facility, where it is converted back to gaseous hydrogen and nitrogen. Then, hydrogen is either taken directly from the cracker, or is stored underground for future use.

Figure 5. Delivery chain for the ammonia (NH_3) option. Light blue boxes indicate processes involving hydrogen, grey boxes indicate processes not involving hydrogen directly (e.g., N_2 production), and dark blue smooth boxes indicate products containing hydrogen. Blue arrows indicate flows containing hydrogen, while grey arrows indicate flows without hydrogen. Blue icons indicate a storage for hydrogen or hydrogen carrier.

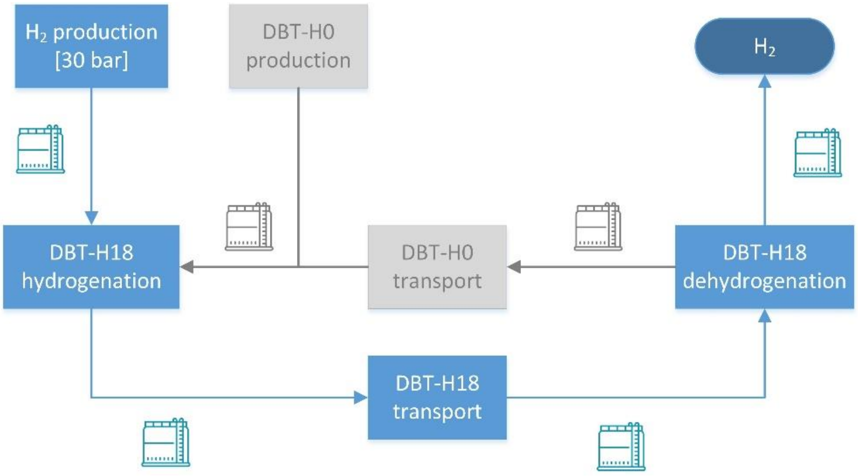


Source: JRC (2024)

2.2.3.5 Liquid organic hydrogen carrier (LOHC)

In the case of LOHC, once hydrogen is produced and stored, it is combined with a liquid organic compound purchased from the market (dibenzyltoluene in our case) to be transported (Figure 6). The carrier is then dehydrogenated to deliver the gaseous hydrogen to the end-user. The dehydrogenated carrier is shipped back to the hydrogen production site for a new delivery.

Figure 6. Delivery chain for the liquid organic hydrogen carrier (LOHC) option. Light blue boxes indicate processes involving hydrogen, grey boxes indicate processes not involving hydrogen directly, and dark blue smooth boxes indicate products containing hydrogen. Blue arrows indicate flows containing hydrogen, while grey arrows indicate flows without hydrogen. Blue icons indicate a storage for hydrogen or hydrogen carrier, while grey icons indicate storage for other materials.

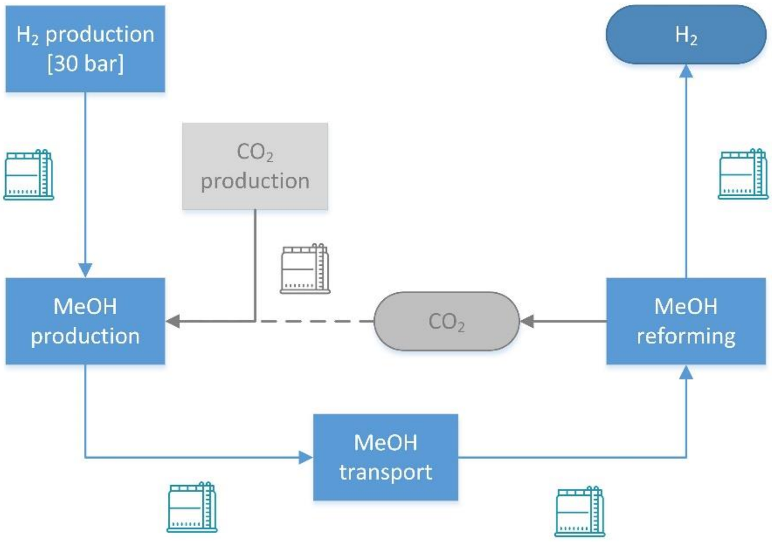


Source: JRC (2024)

2.2.3.6 Methanol (MeOH)

In the case of hydrogen delivery via methanol, the stored hydrogen is combined with carbon dioxide. To avoid additional emissions of greenhouse gases, CO_2 is assumed to be taken from the atmosphere via direct air capture (DAC). Once synthesized, methanol is stored in tanks and shipped to the end-use site by tanker or pipeline. Hydrogen is finally obtained from methanol via steam reforming. Carbon dioxide is assumed to be emitted back to the atmosphere, and hydrogen to be either used directly or stored underground for future use. The flow chart of the delivery chain is shown in Figure 7. Although not considered for this study, CO_2 could also be captured at the reforming site and shipped back to the methanol production site.

Figure 7. Delivery chain for the methanol (MeOH) option. Light blue boxes indicate processes involving hydrogen, grey boxes indicate processes not involving hydrogen directly, dark blue smooth boxes indicate products containing hydrogen, and dark grey smooth boxes indicate other products. Blue arrows indicate flows containing hydrogen, while grey arrows indicate flows without hydrogen. Blue icons indicate a storage for hydrogen or hydrogen carrier, while grey icons indicate storage for other materials. Dashed arrows indicate potential future flows (e.g., CO_2 transport to the hydrogenation plant).

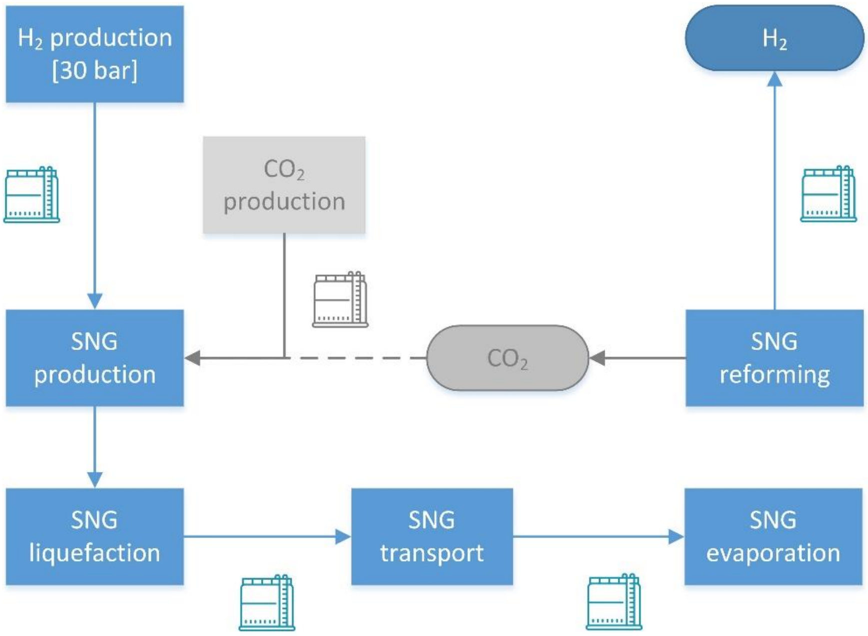


Source: JRC (2024)

2.2.3.7 Synthetic natural gas (SNG)

The delivery chain for SNG (Figure 8) is equivalent to the one of methanol: hydrogen is combined with carbon dioxide from DAC to form SNG. Afterwards, SNG is either liquid, stored in tanks, and shipped via tankers to the destination, or it is compressed for pipeline transportation. At the end-use site, hydrogen is obtained from gaseous SNG via steam reforming. Also for this case, CO_2 at the delivery site was not assumed to be captured.

Figure 8. Delivery chain for the synthetic natural gas (SNG) option. In the case SNG is transported by pipeline, the liquefaction and evaporations stages were not considered. Light blue boxes indicate processes involving hydrogen, grey boxes indicate processes not involving hydrogen directly, dark blue smooth boxes indicate products containing hydrogen, and dark grey smooth boxes indicate other products. Blue arrows indicate flows containing hydrogen, while grey arrows indicate flows without hydrogen. Blue icons indicate a storage for hydrogen or hydrogen carrier, while grey icons indicate storage for other materials. Dashed arrows indicate potential future flows.



Source: JRC (2024)

3 Life cycle inventory

The inventory for the assessment is mostly based on the previous JRC report on H_2 delivery (Ortiz Cebolla, Dolci, and Weidner, 2022). The deliveries are not expected to take place before 2030, and therefore data reflect the efficiencies and emission factors expected for that year[6]. Some of the processes considered in the study (e.g., “packing” and “unpacking” of the hydrogen carriers) are in an early development phase. Therefore, inventory data are subject to a high level of uncertainty. The background database for the assessment is the cut-off system model from ecoinvent 3.9 (Wernet et al., 2016). The cut-off model was chosen for easier traceability. The inventories for the different pathways are presented from Section 3.1 to 3.8. All values reported are approximated to three significant digits, where applicable. When available, a range of values found in the literature was provided together with the reference value used for the assessment. An uncertainty range of ± 10 % approximated to the nearest whole number[7] was considered when only one value was found in the literature.

3.1 Common activities for the transported hydrogen delivery pathways

3.1.1 Electricity generation

Four sources of electricity are considered in the study: 1) electricity from a new renewable plant available at the hydrogen production site[8]; 2) electricity from the average EU grid during transportation (i.e., for pipelines); 3) electricity from the local grid at the hydrogen use site; and 4) electricity from a new renewable plant available at the hydrogen use site.

For the imported pathways, hydrogen is assumed to be produced where renewable energy is cheapest. Based on previous bids for solar generation (Renewables Now, 2020) and the current lowest costs (5.2 EUR/kg) for renewable hydrogen production in Europe (Hydrogen Europe, 2023), hydrogen was assumed to be produced in Portugal. The inventory for solar electricity generation was based on the ecoinvent dataset of photovoltaic electricity in Portugal. The dataset was adapted to match the GHG emission factor estimated by the Hydrogen Council (2021) for hydrogen production via photovoltaic electricity in 2030 (i.e., 20 g CO_2e/kWh, resulting in a carbon footprint of hydrogen of 1 kg CO_2e/kg H_2)[9]. The capacity factor considered by the Hydrogen Council (2021) for solar power generation is assumed to be 17 % (i.e., 1 500 hours per year), higher than the ecoinvent value for Portugal in 2020 (14 %)[10]. A lifetime of 30 years was considered for the panels (Wernet et al., 2016). A scenario where wind power is used for electricity generation in Portugal is also considered in the sensitivity analysis (5.2.1.1).

As for electricity from the grid in the EU and in the Netherlands, mixes for 2030 in line with the EU Fit for 55 plan were considered. Fit for 55 refers to the EU target of reducing GHG emissions by at least 55 % by 2030 (European Commission, 2021). The mixes were produced by E3Modelling via the PRIMES (price-induced market equilibrium system) model (E3Modelling, 2021). In 2030, 65 % of the EU electricity is assumed to be sourced from renewable sources and 16 % from nuclear. As for the Netherlands, 73 % of the electricity mix is assumed to be covered by renewables (58 % by wind power) and 2 % by nuclear. The complete electricity mixes for the EU and the Netherlands assumed for 2030 and the related modelling assumptions for our LCA are reported in Annex I.

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[6] The scale of the activities assumed for this study seems ambitious for 2030. Therefore, assuming that processes will reduce their emissions with time (e.g., emissions to generate 1 kWh of electricity will be lower in 2040 compared to 2030), the emissions assessed here (2030) might be overestimated for the moment this hydrogen delivery could actually take place (e.g., 2040).

[7] It should be noted that the emission ranges take into account the ranges for the inputs generating the emissions as well, and therefore may be higher than ±10%

[8] From an attributional LCA perspective the electricity input does not need to be from a new plant to be considered renewable, but Guarantees of Origin certificates are sufficient (European Commission, 2021). However, to be aligned with the more consequential approach of the Renewable Energy Directive (European Commission, 2023), in our case study renewable electricity production is assumed to be additional, and geographically and temporally correlated to hydrogen production.

[9] The GHG emission factor for hydrogen production via photovoltaic electricity (1.0 kg CO_2e/kg H_2) was estimated by the Hydrogen Council (2021) using average global carbon intensities for the manufacturing of the photovoltaic panels in 2030. Assuming a consumption for PEM electrolysers in 2030 of 50 kWh/kg H_2 (Table 2), an associated GHG emission factor for photovoltaic electricity of 20 g CO_2e/kWh can be calculated. In our model, inputs and emissions of the original ecoinvent dataset of photovoltaic electricity from Portugal (corresponding to a life cycle GHG emissions of 62 g CO_2e//kWh) were scaled down by two thirds to align with the adjusted GHG emission factor of 20 g CO_2e//kWh. As a result of scaling down all inputs and emissions, the associated impacts in the other environmental categories were also reduced proportionally.

[10] The capacity factor considered for photovoltaic plants in Portugal appears to be conservative when compared to other sources (e.g., 21% from the EMHIRES dataset (Gonzalez Aparicio et al., 2017)).

Finally, a dedicated onshore wind farm is considered for the on-site renewable electrolysis pathway. This option was explored primarily for comparative purposes, as the study aimed to assess the impact of importing renewable hydrogen given the unavailability of inexpensive renewable electricity at the site. Wind power was selected as renewable energy source for the Netherlands due to its current prominence as the main renewable source in the country (see Annex I). In line with the approach used for photovoltaic electricity in Portugal, the ecoinvent dataset for onshore wind electricity (> 3 MW) in the Netherlands was adapted to align with the GHG emission factor estimated by the Hydrogen Council (2021) for hydrogen production via onshore wind electricity in 2030 (i.e., 10 g CO_2e/kWh, resulting in a carbon footprint of hydrogen of 0.5 kg CO_2e/kg H_2)[11]. The capacity factor for onshore wind was estimated by the Hydrogen Council (2021) to be 27 % (i.e., 2 400 hours per year), higher than the ecoinvent value for the Netherlands in 2020 (24 %). A lifetime of 20 years was considered for the wind turbines (Wernet et al., 2016). In the sensitivity analysis, a scenario where solar power was used as electricity source is also considered (5.2.1.1).

3.1.2 Hydrogen losses

Potential losses of hydrogen to the atmosphere are considered throughout the delivery chains. The losses are reported for each activity in the following sections. When no information was available regarding the losses for a specific activity, a reference loss of 0.1 % was assumed for each step of the delivery chain involving pure hydrogen handling. Given the large uncertainty surrounding this parameter, the uncertainty range considered was often higher than ± 10 %.

3.1.3 Renewable hydrogen production

Hydrogen is assumed to be produced via water electrolysis. Three main electrolyser technologies are currently available: polymer electrolyte membrane (PEM), alkaline, and solid oxide. In this study, a PEM electrolyser with an average consumption of 50 kWh/kg H_2 is assumed to be used for the reference scenario (Element Energy Ltd., 2018). The PEM electrolyser efficiency for 2030 is in line with the target value (48 kWh/kg) reported in the latest strategic research and innovation agenda (2021-2027) of the Clean Hydrogen Joint Undertaking (2021). The hydrogen output pressure from the electrolyser is assumed to be 30 bar. The inputs for hydrogen production are presented in Table 2. For the infrastructure, the inventory for the electrolyser considered for the assessment is reported in Table A2 in the Annex I[12].

Table 2. Inventory H_2 production via PEM electrolysis

Inputs	Reference	Range		Sources
Electricity	50	48 - 60	kWh	(Element Energy Ltd., 2018; FCH_2JU, 2018)
Water (ultrapure)	10	9 - 11	kg	(Lampert et al., 2015)
Water (tap)	5	4 - 6	kg	(Lampert et al., 2015)
Outputs				
Hydrogen	1.0		kg	
Emission to air				
Hydrogen	0.3	0.3 - 40	g	(Arrigoni and Bravo Diaz, 2022; Cooper et al., 2022)

Source: JRC (2024)

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[11] The same considerations made in footnote 9 are valid here: in our model, inputs and emissions of the original ecoinvent dataset of onshore wind electricity from the Netherlands (corresponding to a life cycle GHG emissions of 24 g CO_2e/kWh) were scaled down by almost 60% to align with the GHG emission factor (i.e., 10 g CO_2e/kWh) estimated by the Hydrogen Council (2021). As a result of scaling down all inputs and emissions, the associated impacts in the other environmental categories were also reduced by almost 60%.

[12] Assuming the electrolyser is connected only to its dedicated renewable plant, its dimension depends on the capacity factor of the renewable plant. The nominal power of the electrolyser connected to the photovoltaic plant in the cheap renewable energy location (i.e., Portugal) is therefore different (higher) from the one at the hydrogen use-site, connected to the wind farm or the grid. Nevertheless, we assumed the same normalized inventory (i.e., per 1 kg of hydrogen produced) for all the electrolyser options. To simplify, we assumed in fact that the material inputs were proportional to the output, and that the electrolysers had the same operational lifetime (60 000 hours) independently from the yearly working hours. In other words, the electrolyser in Portugal will have a larger material intensity, but it will also produce more hydrogen during its lifetime.

3.1.4 Hydrogen compression and storage

To guarantee a constant supply of hydrogen, a storage facility is assumed to be available at the production site. In our case, a facility able to store 3 days of hydrogen demand was deemed necessary. Salt caverns are assumed to be used for the storage[13], given their ability to store large quantities. Electricity consumption to move and compress the hydrogen from the electrolyser to the salt cavern (from 30 up to 120 bar) is assumed to be 0.65 kWh/kg H_2 (Ortiz Cebolla, Dolci, and Weidner, 2022). For the estimate, adiabatic compressors with an 80 % efficiency were assumed to be used.

For the compressed hydrogen option, it is assumed that all the hydrogen goes through the salt cavern before being loaded onto the ship. For the other options, only 1 % of the hydrogen produced is assumed to go through the salt cavern, with the rest going directly to the packing stage. The packed hydrogen will then be stored aboveground before transportation. A scenario where 10 % of the hydrogen is stored in the cavern before packing is considered in the sensitivity analysis. It is assumed that 1 % of the hydrogen stored leaks to the atmosphere (Wulf et al., 2018), with losses up to 3 % being considered in the sensitivity analysis. Once extracted from the cavern, hydrogen is assumed to be dried (0.104 kWh/t H_2) before use (Wulf et al., 2018). The inventory for hydrogen storage used for the assessment is presented in Table 3. The infrastructure has not been considered for this process due to lack of data.

Table 3. Inventory salt cavern

Inputs	Reference	Range		Sources
Hydrogen	1.01	1 – 1.03	kg	
Electricity (compression)	0.65	0.58 – 1.17	kWh	(Ortiz Cebolla, Dolci, and Weidner, 2022; Raluy and Cortés, 2023)
Electricity (drying)	0.10	0.09 – 0.11	kWh	(Wulf et al., 2018)
Outputs				
Hydrogen	1.00		kg	
Emission to air				
Hydrogen	10	0.02 – 30	g	(Wulf et al., 2018; Reuß et al., 2017; Frazer-Nash Consultancy, 2022; Thaysen et al., 2021)

Source: JRC (2024)

3.1.5 Transportation

Two options were considered for transportation: shipping and pipelines. The main assumptions for the two options are reported in this section.

3.1.5.1 Ships

Capacity and fuel consumption for the different ships are taken from the precedent JRC study (Ortiz Cebolla, Dolci, and Weidner, 2022). As large electric and hydrogen-powered ships are not anticipated be available by 2030, it is assumed that ships will operate on biodiesel in the reference scenario. Biodiesel was selected as the shipping fuel in the precedent JRC study to align with a more decarbonized hydrogen delivery chain. To further investigate the impact of shipping fuel on the environmental footprint of hydrogen delivery, a sensitivity analysis was conducted (see Section 5.5). This analysis considered two extreme scenarios in terms of fuel emissions: a worst-case scenario, using conventional heavy fuel oil, and a best-case scenario, using renewable hydrogen. Although ammonia, methanol, or SNG may emerge as viable shipping fuels in the future, their inclusion in the assessment was not deemed necessary. We anticipate the outcomes of these potential scenarios to fall within the range defined by the worst and best options.

Greenhouse gas emissions from the combustion of biodiesel are taken from the inventory of the United States Environmental Protection Agency: 2.84 kg CO_2, 42.0 mg CH_4, and 150 g N_2O per kg of biodiesel (US

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[13] Underground storage in salt cavern was assumed for the storage of hydrogen at the delivery site as well.

EPA, 2021). Emissions of SO_x and NO_x are assumed to be compliant with the global limits set in MARPOL Annex VI[14] (IMO, 2011), corresponding to a maximum sulphur content in the fuel of 0.5 % and a maximum of 7.7 g NO_x emissions per unit of energy (kWh) produced by the engine. According to the IMO regulation, stricter emission limits apply to ships operating within the designated Emission Control Areas (ECA), such as the Baltic Sea, North Sea, and Mediterranean. However, since ships in our case study primarily travel in non-ECA areas, higher emissions were conservatively assumed. Emissions of 10 g SO_2 and 40 g NO_x per kg of biodiesel are therefore considered[15]. The inventory was then integrated with the emissions of other non-greenhouse gases, assuming conservatively the same factors reported on GaBi for heavy fuel oil burned in an oil tanker (Sphera Solutions GmbH, 2021): 2.78 g CO, 7.30 g PM2.5, and 30.9 g NMVOC per kg of biodiesel. It is important to note that these emissions are also expected to reduce over time due to the more stringent global and regional environmental regulations. Finally, an emission of 0.26 g of black carbon per kg of biodiesel burned was also assumed based on the IMO emission factors for heavy fuel oil (IMO, 2020). The use of exhaust gas cleaning systems was estimated to increase only marginally (about 2 %) the fuel consumption of the ship, and therefore it was not accounted for in our calculations.

Given that the fuel consumption information available for the different ships was in tonnes of heavy fuel oil or marine diesel, the same energy was assumed to be required in the case biodiesel was used instead. To calculate the mass of biodiesel required, the lower heating values (LHVs) for the different fuels were considered: 37.5 MJ/kg of biodiesel, 39 MJ/kg of heavy fuel oil, and 42.8 MJ/kg of marine diesel oil (The Engineering ToolBox, 2021). In the text, rounded figures were used for the number of ships necessary for the delivery; however, decimals were considered in the calculations. The rationale for using decimals in the calculations is that ships would not travel half empty to the delivery site, and therefore only a share of the impact arising from the last ship is attributed to our functional unit. Inventories available on ecoinvent were used for the production and maintenance of ships. A lifetime of 30 years was assumed for the ships. Since the biodiesel dataset was not available on ecoinvent, a biodiesel mix composed of soy oil methyl ester (44 %), rapeseed oil methyl ester (26.5 %), refined canola oil from rapeseed (14.6 %), and palm oil methyl ester (0.3 %) available on the Environmental Footprint 3.1 database was used.

3.1.5.2 Pipelines

Delivery by pipeline is considered to be feasible for all hydrogen carriers but L-H_2, due to the very low temperature required and the safety risks due to boil-off. The length of the pipeline is assumed to be equal to the shipping distance (2 500 km). Most of the assumptions regarding materials and energy consumption for the transportation by pipeline are from the precedent JRC study (Ortiz Cebolla, Dolci, and Weidner, 2022) and ecoinvent (Wernet et al., 2016). A lifetime of 40 years was assumed for all pipelines, and the same low-alloyed steel (in different quantities) was considered for the pipes. Steel was modelled as it is done in ecoinvent for natural gas pipelines in Europe, assuming a combination of unalloyed (63 %) and low-alloyed (37 %) steel. More information regarding pipeline diameter, amount of steel needed, and energetic consumption is reported in the following sections dedicated to the different carriers and in Annex III. Whether new hydrogen pipelines or repurposed existing pipelines are used does not affect the results in our attributional LCA, as the assessment attributes one year of pipeline usage to the hydrogen transported in that year. Even if existing pipelines were reused, the hydrogen would still be attributed the impact of using that pipeline for one year. Impacts would vary if a consequential LCA approach was adopted, with the goal of evaluating the global emission variations associated with repurposing existing pipelines or constructing new ones.

3.1.6 Hydrogen combustion

Several activities along the delivery chain require heat. At the hydrogen production site (i.e., Portugal), heat is assumed to be provided by electricity whenever feasible. Electricity was chosen given the assumed large availability of cheap renewable electricity at the production site. However, some activities require temperatures that could not be met easily by electricity. An example is the heat required for the direct air capture plant for the regeneration of the sorbent material. For these cases, heat was assumed to be provided by a hydrogen boiler with an efficiency of 90 % (Ortiz Cebolla, Dolci, and Weidner, 2022). Heat could also be

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[14] MARPOL is the International Convention for the Prevention of Pollution from Ships, which was adopted on 2 November 1973 at the International Maritime Organization (IMO). Annex VI, which was added in 1997 and entered into force in 2005, sets emission limits from ship exhausts to prevent air pollution.

[15] In our assessment, it was assumed that all sulphur present in the fuel would convert to SO_2, and an engine efficiency of 50% was considered to estimate NO_x emissions.

required at the hydrogen use site, mainly to dehydrogenate the carrier used to deliver hydrogen. Since cheap renewable electricity is not assumed to be available at the use site, extra hydrogen is assumed to be delivered to produce the heat necessary for these processes. Unless specified differently in a specific section, hydrogen boilers are assumed to be used to produce heat also for these cases. The combustion of hydrogen in the boiler is assumed to emit 6.82 g NOx/kg H_2 based on data available on the GREET® model (Wang et al., 2022). A hydrogen loss of 0.5 % was also assumed (Cooper et al., 2022; Fayaz et al., 2012).

3.1.7 Infrastructure

The assessment incorporates emissions from the construction of infrastructure required throughout the hydrogen delivery chain. In cases where infrastructure data for specific processes was unavailable, generic data from the ecoinvent database were employed. For example, a generic chemical factory dataset was used for processes in an early development phase, such as "unpacking" processes. The infrastructure impacts are normalized over the entire operational life.

For the catalysts utilized in the different processes, such as the iron-based catalyst for ammonia synthesis, information found in the scientific literature was used. It should be noted that the lifetime of the catalyst and the additional materials required to replenish the catalyst over time are factored into the reported values. Whenever available, information about the lifetime of the catalyst is also reported.

3.2 Compressed hydrogen

As presented in Figure 3, the only extra processes required to deliver hydrogen via compressed hydrogen are compression and transportation. From the cavern, hydrogen is assumed to be compressed either into gas cylinders (250 bar) for shipping, or into the pipeline (70 bar). Once transported, hydrogen is assumed to be stored in a salt cavern available at the delivery site. The end user will then withdraw the hydrogen from the cavern, and dry it before use (Table 3).

3.2.1 Compressed hydrogen transportation

3.2.1.1 Ship

The capacity of the ships transporting compressed hydrogen (i.e., 1 370 t of hydrogen) was calculated from the dimensions of the ships transporting compressed natural gas (Ortiz Cebolla, Dolci, and Weidner, 2022). The energy demand for the compressors was calculated using the same assumptions for adiabatic compressors used for the storage, resulting in 1.05 kWh per kg of compressed hydrogen if processed directly from the electrolyser (i.e., hydrogen compressed from 30 bar to 250 bar) and 0.77 kWh per kg of compressed hydrogen if extracted from the salt cavern, where hydrogen is assumed to have an average pressure of 50 bar. As for the ship, since no inventory was available on ecoinvent for the transport of gaseous goods, data for an LNG tanker were used instead. Data were adapted to account for the different volumes transported by the ship modelled on ecoinvent and the one transporting compressed hydrogen. In total, 30 ships (rounded up from 29.1) and 534 kt of biodiesel are estimated to be necessary to deliver 1 Mt of compressed hydrogen over 2 500 km (i.e., more than 0.5 kg of fuel per kg of hydrogen delivered). Hydrogen losses of 0.1 % are assumed to take place during shipping (range for sensitivity from 0 to 2.3 % based on Esquivel-Elizondo et al. (2023)).

3.2.1.2 Pipeline

Hydrogen pipelines are modelled based on the results presented in Ortiz Cebolla, Dolci, and Weidner (2022). The pipelines are assumed to operate between 70 and 30 bar, have an outer diameter of 86.4 cm, and a thickness of 3.2 cm. To maintain the hydrogen pressure in the pipes between 70 and 30 bar, energy is required for initial compression from 30 to 70 bar and continuous recompression as the pressure drops. The energy demand for this process is 1.83 kWh per tonne of hydrogen transported per kilometre. Overall, the energy demand to deliver 1 Mt of hydrogen to the user would be 4.56 TWh. As for materials, 664 tonnes of steel were considered necessary per km of pipeline. The rest of the inventory for the CH_2 pipeline (Table 4) was adjusted from the ecoinvent dataset for long-distance low-capacity onshore natural gas pipeline (i.e., values were scaled for the different pipeline dimensions). One percent of the hydrogen delivered is assumed to be lost to the atmosphere during transportation (Arrigoni and Bravo Diaz, 2022). For the sensitivity analysis, a hydrogen loss between 0.1 and 2 % was considered (Fan et al., 2022; Esquivel-Elizondo et al., 2023).

Table 4. Compressed hydrogen pipeline inventory

Inputs	Amount		Source
Steel, unalloyed	418	t	(Ortiz Cebolla, Dolci, and Weidner, 2022; Wernet et al., 2016)
Steel, low-alloyed	246	t	(Ortiz Cebolla, Dolci, and Weidner, 2022; Wernet et al., 2016)
Drawing of pipe, steel	664	t	(Ortiz Cebolla, Dolci, and Weidner, 2022; Wernet et al., 2016)
Pitch	2.32	t	(Wernet et al., 2016)
Polyethylene	4.64	t	(Wernet et al., 2016)
Sand	1 950	t	(Wernet et al., 2016)
Electricity	836	MWh	(Ortiz Cebolla, Dolci, and Weidner, 2022; Wernet et al., 2016)
Outputs			
Pipeline	1.00	km	

Source: JRC (2024)

3.3 Liquid hydrogen

3.3.1 Hydrogen liquefaction

The inventory for hydrogen liquefaction is reported in Table 5. A hydrogen loss of 1.6 % was assumed during liquefaction in the reference scenario, based on Heuser et al. (2019). No infrastructure has been considered for this process.

Table 5. Hydrogen liquefaction inventory

Inputs	Reference	Range		Source
Hydrogen (gas)	1.02	1.001 – 1.1	kg	
Electricity	6.00	6 - 15	kWh	(Ortiz Cebolla, Dolci, and Weidner, 2022; Noh, Kang, and Seo, 2023)
Outputs				
Hydrogen (liquid)	1.00		kg	
Emission to air				
Hydrogen	0.016	0.001 – 0.10	kg	(Heuser et al., 2019; Lee et al., 2022; Arrigoni and Bravo Diaz, 2022)

Source: JRC (2024)

3.3.2 Liquid hydrogen storage, transportation, and delivery

Liquid hydrogen is stored in double-hulled cryogenic tanks. Boil-off, which can vary from a rate of 0.035 %/d for large tanks to 0.1-0.3 %/d for smaller tanks (Decker, 2019; Krenn, 2012), is assumed to be vented. In the reference scenario, 0.21 % of the stored hydrogen is considered to be vented, assuming that hydrogen will be stored in large tanks for up to six days before shipping. Alternatively, the boil-off could be re-liquefied. In this case, considered for the sensitivity analysis, a consumption of 4.07 kWh of electricity is assumed to be needed to cool one kilogram of hydrogen from 80 K to 20 K (Ortiz Cebolla, Dolci, and Weidner, 2022).

Liquid hydrogen is assumed to be transported via tankers. Since only hydrogen carrier prototypes are currently available, data for shipping were estimated from liquid natural gas (LNG) tankers (Ortiz Cebolla, Dolci, and Weidner, 2022). The tanker is assumed to carry 9 800 t of liquid hydrogen (Ortiz Cebolla, Dolci, and Weidner, 2022), and to consume 19 g of biodiesel per tonne of hydrogen transported per one kilometre. Biodiesel consumption was estimated from the fuel consumption reported in the ecoinvent dataset for LNG carriers. In total, 4 ships (rounded up from 3.7) and 47 kt of biodiesel are calculated to be required for the delivery, assuming it would take 3.5 days for the ships to reach the destination. For the L-H_2 ships, it was conservatively assumed that twice the amount of materials used for LNG ships are needed. The inventory for LNG ships was taken from ecoinvent. A boil-off rate of 0.2 % per day (i.e., 7 g of hydrogen per kg of hydrogen delivered), which is assumed to be vented, was considered for the shipping phase (Ortiz Cebolla, Dolci, and Weidner, 2022).

At the delivery site, liquid hydrogen is stored again in cryogenic tanks. However, in this case, the boil-off is used directly by the consumer. So, no losses (i.e., hydrogen emissions) are considered before use. However, energy is assumed to be used to compress the liquid hydrogen (assumed to be shipped at 5 bar) to the pressure required by the user (30 bar). Energy for the cryogenic pump is calculated from the formula provided by the hydrogen delivery scenario analysis model by the Argonne National Laboratory (Elgowainy et al., 2018), resulting in a consumption of 0.0136 kWh/kg H_2 delivered.

3.4 Ammonia

3.4.1 Ammonia synthesis

A fully electric ammonia plant was considered for the assessment (Morgan, 2013), and electricity for the synthesis process is assumed to be provided by the same solar plant feeding the electrolyser. Although part of the hydrogen (1 %) arrives to the transformation plant from the salt cavern at pressures higher than 30 bar, it was conservatively assumed that all of the hydrogen input has the same 30 bar pressure. The energy consumption for ammonia synthesis is assumed to be 0.806 kWh/kg NH_3, including nitrogen separation from air (Ortiz Cebolla, Dolci, and Weidner, 2022). An iron-based catalyst composed of magnetite (92 wt.%), zeolite (5 wt.%), and lime (3 wt.%), was assumed to be used for the synthesis (D'Angelo et al., 2021). Figures reported from D'Angelo et al. were also considered for water use and process emissions (Table 6). Regarding water for cooling, 9 % of the water is assumed to be consumed while the rest is returned to the water body (ecoinvent, 2023). Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure[16].

Table 6. Ammonia synthesis inventory. Nitrogen is not explicitly listed among the inputs because the process utilizes air directly, and the energy required to separate nitrogen is accounted for within the electricity input.

Inputs	Reference	Range	Unit	Sources
Hydrogen	0.18	0.18 – 0.20	kg	(Dolci, 2018; Liu, Elgowainy, and Wang, 2020)
Electricity	0.81	0.56 – 4	kWh	(Smith, Hill, and Torrente-Murciano, 2020; Liu, Elgowainy, and Wang, 2020; D'Angelo et al., 2021; Kim, Huh, and Seo, 2022)
Iron-based catalyst	0.055	0.055 - 200	g	(D'Angelo et al., 2021; Boero et al., 2021)
Water (deionised)	1.90	1.7 – 2.1	L	(Boero et al., 2021)
Water (cooling)	150	46 - 150	L	(D'Angelo et al., 2021; Morgan, 2013)
Outputs				
Ammonia	1		kg	
Emissions to air				
Hydrogen	0.77	0.69 – 0.85	g	(D'Angelo et al., 2021)
Ammonia	1.63	0.07 – 1.63	g	(D'Angelo et al., 2021; Boero et al., 2021)
Nitrogen oxides	1.0	0 – 1.0	g	(D'Angelo et al., 2021; Boero et al., 2021)

Source: JRC (2024)

3.4.2 Ammonia storage

Liquid ammonia is stored in refrigerated tanks. A loss of 0.02 % is considered (Boero et al., 2021), while the boil-off is assumed to be liquefied and recirculated in the tank (Ortiz Cebolla, Dolci, and Weidner, 2022). Electricity (0.068 kWh/kg NH_3) is needed to operate the compressors to keep the ammonia refrigerated and to re-liquefy the boil-off (Boero et al., 2021; Morgan, 2013).

3.4.3 Ammonia transportation

For transportation, both ships and pipeline were considered.

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[16] The ecoinvent dataset "Chemical factory, organics {RER}| chemical factory construction, organics | Cut-off, U" was considered.

3.4.3.1 Ship

The inventory for shipping is modelled from the information available for existing ammonia carriers (Ortiz Cebolla, Dolci, and Weidner, 2022). Five ships (rounded up from 4.5) and 57 kt of biodiesel are calculated to be necessary to deliver 1 Mt of hydrogen for 2 500 km via ammonia. Minimal loss (0.02 %) is assumed to happen on the ship: the boil-off is assumed to be captured, cooled down, and re-liquefied. Energy to refrigerate the ammonia is included in the fuel consumption. As for the ship life cycle, the inventory available on ecoinvent for tankers for liquid goods was used for the assessment.

3.4.3.2 Pipeline

Pipelines for ammonia are modelled from the results of Ortiz Cebolla, Dolci, and Weidner (2022): the operating pressure is assumed to be between 17 and 70 bar, with a flow rate of 0.37 m^3/s. To transport one tonne of ammonia per one km 0.034 kWh are assumed to be consumed, resulting in a total consumption of 623 GWh to deliver 1 Mt of hydrogen per 2 500 km. The outer diameter of the pipeline is assumed to be 43.2 cm, and the thickness 0.8 cm. The mass of steel needed is 81.7 tonne per km of pipeline. The same quantities reported in Table 4 for compressed hydrogen pipelines were considered for the remaining materials (i.e., pitch, plastic, and sand).

3.4.4 Ammonia dehydrogenation and hydrogen delivery

To extract hydrogen, ammonia needs to be cracked. The inventory used for the process, and the relevant sources are reported in Table 7. The same loss considered for storing ammonia (0.02 %) is assumed for the cracking process. The hydrogen exiting the cracker is assumed to be at 99.97 % purity and at 240 bar (Fothergill et al., 2015). Therefore, hydrogen does not need to be further compressed to be stored in a salt cavern and/or delivered to the user. In our study, part of the ammonia delivered is assumed to be used to provide heat for the reaction. Considering that 5.67 kg of ammonia are needed stoichiometrically per kg of hydrogen produced, 1.63 kg of extra ammonia are assumed to be needed in the process. Alternatively, a lower amount of ammonia could be theoretically shipped and a larger amount of electricity consumed. This scenario was investigated for the sensitivity analysis, assuming an ammonia input of 5.67 kg NH_3/kg H_2 and an electricity consumption of 14.4 kWh kg H_2 (Akhtar et al., 2021). It should be noted that the current scale of purely electric ammonia cracker is not compatible with the amount of hydrogen output required by our scenario. For the catalyst, a mix of magnesium oxide (94 %) and nickel oxide (6 %) was considered (Noh, Kang, and Seo, 2023). Zeolite powder was assumed to be used as adsorbent material for the hydrogen purification via pressure swing adsorption (Antonini et al., 2020). Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure.

Table 7. Ammonia cracking

Inputs	Reference	Range		Source
Ammonia	7.30	7.3 – 8.2	kg	(Fothergill et al., 2015; Ortiz Cebolla, Dolci, and Weidner, 2022)
Electricity	4.86	1.1 - 9.4	kWh	(Fothergill et al., 2015; Noh, Kang, and Seo, 2023)
Nickel-based catalyst	1.46	1.3 – 1.6	g	(Noh, Kang, and Seo, 2023)
Zeolite powder	0.88	0.8 – 1.0	g	Own assumption
Outputs				
Hydrogen	1.00		kg	
Emissions to air				
Ammonia	7.05	6.3 – 150	mg	(Boero et al., 2021; Kanchiralla et al., 2022)
Nitrous oxide (N_2O)	4.89	4.4 – 48	mg	(Boero et al., 2021; Kanchiralla et al., 2022)
Nitrogen oxide (NO)	14.2	12 - 16	mg	(Boero et al., 2021)
Nitrogen dioxide (NO_2)	2.04	1.8 – 9.6	g	(Boero et al., 2021; Kanchiralla et al., 2022)
Hydrogen	0	0 – 31	g	(Cooper et al., 2022; Lee et al., 2022)

Source: JRC (2024)

3.5 LOHC

3.5.1 LOHC hydrogenation

The LOHC considered for the study is dibenzyltoluene (DBT). The inventory for its production was sourced from Wulf et al. (2018). In the production process, 0.41 kg of hydrochloric acid are produced per kg of DBT; since no information was available on the use of hydrochloric acid (Hydrogenious, 2023), all the impacts from the production process were attributed to DBT. Nevertheless, if the co-produced hydrochloric acid was put on the market and the credit for avoiding the production of the acid via the traditional route was included, the impact attributed to DBT would reduce by less than 4 %[17]. Dibenzyltoluene is assumed to be stored in standard steel tanks, using the dataset available on ecoinvent for the life cycle inventory. The inventory for the subsequent hydrogenation phase is presented in Table 8. The ranges reported in Table 8 for the DBT-H0 needed and the DBT-H18[18] produced reflect the efficiency of the dehydrogenation process (see Section 3.5.4): i.e., from 85 % (19 kg of DBT-H18 per kg of hydrogen released) to a complete release of the hydrogen bound to DBT (HYSTOC, 2018). For the reference scenario, a 98.8 % release efficiency was considered. In any case, it is not necessary to produce 15.3 kg DBT-H0 per kg of hydrogen to be delivered, since DBT can be reused after dehydrogenation. Based on our calculations, to guarantee a continuous supply of hydrogen at the delivery site (2 740 t H_2/d), 1.62 Mt of DBT-H0 need to be produced (Ortiz Cebolla, Dolci, and Weidner, 2022). Moreover, this amount of DBT could be used for much longer than one year: according to HySTOC, DBT could be reused more than 750 times. Considering that in our scenario the same DBT molecules are reused for 24 times in one year, the DBT produced could be reused for the same application for approximately 30 years. Therefore only one thirtieth of the DBT production impact was allocated to the hydrogen delivered in the first year. The amount of heat generated from the exothermic reaction was estimated from HySTOC (HYSTOC, 2018), and was assumed to be lost in the reference scenario. Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure.

Table 8. LOHC hydrogenation

Inputs	Reference	Range		Sources
DBT-H0	15.3	15.3 - 18	kg	(HYSTOC, 2018)
Hydrogen	1		kg	
Electricity	0.37	0.2 – 1.0	kWh	(HYSTOC, 2018; Reuß et al., 2017; Wulf and Zapp, 2018)
Platinum	0.16	0.09 - 1.5	mg	(Wulf et al., 2018; Wulf and Zapp, 2018; Rüde et al., 2022)
Aluminium oxide	32	29 - 35	mg	(Wulf et al., 2018; Wulf and Zapp, 2018)
Water (cooling)	1.4	1.3 – 1.5	L	(Spatolisano et al., 2023)
Outputs				
DBT-H18	16.3	16.3 - 19	kg	(HYSTOC, 2018)
Heat	5.64	5.64 - 10.6	kWh	(HYSTOC, 2018; Eypasch et al., 2017)
Emissions to air				
Hydrogen	1	0 – 2	g	Own assumption

Source: JRC (2024)

3.5.2 LOHC storage

No energy consumption was assumed for the storage of LOHC, which can be stored in the same double walled containers used for crude oil or diesel. The same inventory used for the storage of DBT was considered for the hydrogenated compound.

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[17] The credit was calculated using the substitution approach for dealing with multifunctional activities, and the dataset representing the hydrochloric acid sold in Europe available on ecoinvent was used for the assessment.

[18] DBT-H18 indicates the hydrogen-rich form of dibenzyltoluene (perhydro-dibenzyltoluene)

3.5.3 LOHC transportation

The dehydrogenation process of DBT is endothermic, requiring extra heat at the hydrogen use site. Depending on the source of heat for dehydrogenation, the assumptions regarding transportation vary. In the reference scenario, heat is assumed to be provided by hydrogen, requiring extra hydrogen to be produced and transported via LOHC. For the sensitivity analysis, two alternative scenarios are considered: using on-site electricity from the grid, and heat available at the delivery site (see Section 0). Two transportation options were considered: ship and pipeline.

3.5.3.1 Ship

Four ships (rounded up from 3.9) with a capacity of 320 kt were calculated to be needed for the trips (assuming that the ships are filled at 90 % of their capacity) in the reference scenario, consuming approximately 77 kt of biodiesel in total. The number of ships would drop to three (rounded up from 2.4) and the amount of biodiesel consumed to 48 kt, if local sources of heat were used for the dehydrogenation process instead of transporting extra hydrogen.

3.5.3.2 Pipeline

Two pipelines are necessary in the case of LOHC: one to deliver the hydrogenated carrier to the use site, and one to transport back the dehydrogenated compound to the hydrogenation facility. The operating pressure is assumed to be between 10 and 70 bar in both cases, with an outbound flowrate of 0.91 m^3/s in the case hydrogen is used as source of heat for dehydrogenation. Approximately 0.026 kWh are assumed to be consumed from the average EU grid mix to transport one tonne of hydrogenated DBT per one km, and 0.015 kWh/km to transport one tonne of dehydrogenated DBT back (Ortiz Cebolla, Dolci, and Weidner, 2022). The total energy consumption to transport DBT back and forth to deliver 1 Mt of hydrogen results to be 2.71 TWh. Outbound pipeline is assumed to have an outer diameter of 86.4 cm and to be 3.2 cm thick, while inbound pipeline is slightly smaller (outer diameter: 81.3 cm, thickness: 3.1 cm). The mass of steel needed results to be 664 tonne per km of outbound pipeline and 592 tonne per km of the inbound one. In the case electricity were used to provide heat, dimensions of the pipelines and energetic consumption would reduce. Total energy (including return) to deliver 1 Mt of hydrogen would be approximately half (1.44 TWh) of the energy needed if extra hydrogen is used to provide heat. The total amount of steel needed would be approximately 84 % of the reference scenario (i.e., 2.64 Mt vs. 3.14 Mt). The same mix of low-alloyed and unalloyed steel considered for the natural gas pipelines in the ecoinvent dataset was assumed.

3.5.4 LOHC dehydrogenation and H_2 delivery

The hydrogenated LOHC is stored in containers at the port and sent to the dehydrogenation unit. The inventory for the reference dehydrogenation process (i.e., extra H_2 used as source of heat) is reported in Table 9. The amount of electricity needed for the process reported in Table 9 includes the purification of hydrogen via pressure swing adsorption. In the case hydrogen is used to provide heat, 0.5 % is assumed to leak to the atmosphere (see 3.1.6). The amounts of catalysts used for the process were taken from Wulf et al. (2018). Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure. The hydrogen output from the dehydrogenation unit is assumed to have a pressure of 2 bar. Further compression is therefore required to deliver the hydrogen at 30 bar (1.3 kWh/kg H_2) or to store it in a salt cavern (2.0 kWh/kg H_2). As for the other carriers, 99 % of the unpacked hydrogen is assumed to be sent to the user directly from the unpacking unit, while 1 % is temporarily stored in the salt cavern.

Table 9. LOHC dehydrogenation inventory

Inputs	Amount	Range		Sources
DBT-H18	16.3	16.2 – 19	kg	(HYSTOC, 2018)
DBT-H18 (for heat)	10	6.9 – 13.6	kg	(HYSTOC, 2018; Eypasch et al., 2017)
Electricity	2	0.003[19] – 2.2	kWh	(HYSTOC, 2018; Eypasch et al., 2017)
Platinum	0.16	0.09 - 1.5	mg	(Wulf et al., 2018; Wulf and Zapp, 2018; Rüde et al., 2022)
Aluminium oxide	32	29 - 35	mg	(Wulf et al., 2018; Wulf and Zapp, 2018)
Water (cooling)	358	322 - 394	L	(Spatolisano et al., 2023)
Outputs				
Hydrogen	1		kg	
Emissions to air				
Hydrogen	3.1	0 - 74	g	(Cooper et al., 2022; Fayaz et al., 2012)
Nitrogen oxides	4.2	3.8 – 4.6	g	(Wang et al., 2022)

Source: JRC (2024)

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[19] For the sensitivity analysis we considered two scenarios in terms of energy consumption: a best-case scenario using 6.9 kg DBT-H18 for heat and 0.36 kWh of electricity, and a worst-case scenario using 13.6 kg DBT-H18 and 0.003 kWh of electricity based on HYSTOC (2018) and Eypasch et al. (2017) data.

3.6 Methanol

3.6.1 CO_2 production

Synthesis of methanol requires carbon dioxide. In this assessment, CO_2 is assumed to be provided via direct air capture (DAC). The inventory and the sources used for the assessment are presented in Table 10. The thermal energy required for the process is assumed to be provided by a hydrogen boiler with an efficiency of 90 % (Ortiz Cebolla, Dolci, and Weidner, 2022). For the sensitivity analysis, a fully electric system with a consumption of 1.27 - 2.79 kWh/kg CO_2 was considered for DAC (Fasihi, Efimova, and Breyer, 2019; Terlouw et al., 2021). For the sorbent, a generic organic chemical was considered (Terlouw et al., 2021).

Table 10. CO_2 production

Inputs	Reference	Range		Sources
Hydrogen	0.05	0.04 – 0.15	kg	(Ortiz Cebolla, Dolci, and Weidner, 2022; Deutz and Bardow, 2021; Terlouw et al., 2021)
Electricity	0.5	0.08 – 0.7	kWh	(Keith et al., 2018; Ortiz Cebolla, Dolci, and Weidner, 2022; Terlouw et al., 2021; Deutz and Bardow, 2021)
Sorbent	7.5	3 - 8	g	(Deutz and Bardow, 2021; Terlouw et al., 2021)
Water (cooling)	4.7	4.2 – 5.2	L	(Keith et al., 2018)
Outputs				
Carbon dioxide	1.00		kg	
Emission to air				
Hydrogen	0.25	0.2 – 0.7	g	Own assumption

Source: JRC (2024)

3.6.2 Methanol synthesis

The amounts of hydrogen and CO_2 needed to produce methanol are reported in Table 11. Electricity is assumed to be used for all the energy needs of the factory: synthesis, heating, cooling, and pumping. For heating and cooling, an electric boiler with a 95 % efficiency is assumed to be used (Ortiz Cebolla, Dolci, and Weidner, 2022). A Cu-based catalyst with aluminium oxide acting as structural promoter was considered for the synthesis (Etim, Song, and Zhong, 2020). The composition of the catalyst was assumed to be 64 % CuO, 24 % ZnO, and 12 % Al_2O_3, with a lifetime of 2-5 years (Althaus et al., 2007). For the infrastructure, a methanol factory dataset from the ecoinvent database was utilized. The dataset mainly comprises materials such as concrete, steel, zinc, copper, and nickel.

Table 11. Methanol synthesis inventory

Inputs	Reference	Range		Sources
Hydrogen	0.199	0.19 - 0.23	kg	(Pérez-Fortes and Tzimas, 2016; Ravikumar, Keoleian, and Miller, 2020)
Carbon dioxide	1.46	1.37 - 1.66	kg	(Pérez-Fortes and Tzimas, 2016; Ravikumar, Keoleian, and Miller, 2020; Zang et al., 2021)
Electricity	0.639	0.035 - 0.7	kWh	(Ortiz Cebolla, Dolci, and Weidner, 2022; Ravikumar, Keoleian, and Miller, 2020)
Copper-based catalyst	133	33 - 232	mg	(Althaus et al., 2007)
Water (cooling)	92.3	83 - 102	L	(Pérez-Fortes and Tzimas, 2016)
Outputs				
Methanol	1.00		kg	
Emissions to air				
Carbon dioxide	0.085	0.04 - 0.1	kg	(Pérez-Fortes and Tzimas, 2016; Muazzam et al., 2022)
Hydrogen	0.2	0 – 0.4	g	Own assumption

Source: JRC (2024)

3.6.3 Methanol storage

Methanol is assumed to be stored in steel tanks, and no energy consumption nor methanol losses were considered (Ortiz Cebolla, Dolci, and Weidner, 2022).

3.6.4 Methanol transportation

Two options were considered to transport methanol: ship and pipeline.

3.6.4.1 Ship

Data from an actual methanol deep sea tanker were considered for shipping. The tanker has a maximum methanol capacity of 41 500 t, an average speed of 29.6 km/h, and a fuel consumption of 33.4 t HFO/d (Ortiz Cebolla, Dolci, and Weidner, 2022). Based on the speed and the capacity, 6 ships (rounded up from 5.2) and 48 kt of biodiesel were considered to be necessary to deliver all the hydrogen required (i.e., 6.8 g biodiesel per kg of methanol transported). For the ship life cycle, the inventory of a tanker carrying liquid goods available on ecoinvent was used.

3.6.4.2 Pipeline

For the pipeline scenario, methanol is assumed to be transported at 70 bar via dedicated pipelines. The pressure loss before the following pump (each 80 km) is calculated to be 45 bar (Ortiz Cebolla, Dolci, and Weidner, 2022). An outer diameter of 43 cm and a thickness of 7.8 mm are assumed, resulting in 82 tonnes of steel used per km. The same mix of low-alloyed and unalloyed steel considered for the natural gas pipelines in the ecoinvent dataset was considered. Electricity (average EU mix in 2030) was assumed to be used during the pipeline installation and operation, and a lifetime of 40 years was considered. For the transportation, a consumption of 0.022 kWh per tonne of methanol transported per one km was assumed (i.e., 390 GWh to deliver 1 Mt of hydrogen). No losses were considered.

3.6.5 Methanol dehydrogenation and hydrogen delivery

Methanol is stored in steel tanks at the delivery site and sent to the dehydrogenation unit. Dehydrogenation of methanol requires heat, which is assumed to be provided by methanol itself (Ortiz Cebolla, Dolci, and Weidner, 2022). The inventory for the process is presented in Table 12. If we consider that 5.3 kg methanol are needed per kg of hydrogen stoichiometrically, 1.7 kg of extra methanol are assumed to be needed for heat purposes. Moreover, 0.5 kWh of electricity are assumed to be needed for the process (Mahler AGS). Nickel-based, and Fe-Cr and Cu-Zn composite catalysts were considered for the reforming stage and water gas shift reaction, respectively. Compositions and quantities were based on the work of Antonini et al. (2020) on steam methane reforming of natural gas and ecoinvent (Wernet et al., 2016). The Fe-Cr and Cu-Zn composite catalyst is assumed to be composed of ferric oxide (29 %), chromium oxide (3 %), copper oxide (33 %), and zinc oxide (35 %). The CO_2 generated in the reforming process is assumed to be emitted to the atmosphere. The CO_2 could also be captured at the reforming site and shipped back to the methanol synthesis plant. This option was not included in the assessment. Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure. Hydrogen is assumed to leave the reforming plant at 10 bar, requiring additional electricity to be compressed for the delivery (0.5 kWh/kg H_2 delivered) or the storage (1.3 kWh/kg H_2 stored). As for the previous carriers, 99 % of the hydrogen is supplied directly to the user from the dehydrogenation unit, while 1 % ends up in the temporary storage. The purity of hydrogen exiting the reforming plant is assumed to be 99.97 % (Ortiz Cebolla, Dolci, and Weidner, 2022).

Table 12. Methanol reforming inventory

Inputs	Reference	Range		Sources
Methanol	7.06	7 – 7.2	kg	(Ortiz Cebolla, Dolci, and Weidner, 2022; Brown, 2001; Ahmed, Upadhyay, and Tiwari, 2023; Chen et al., 2022)
Electricity	0.50	0.4 – 4.4	kWh	(Mahler AGS, 2016; Chen et al., 2022)
Nickel-based catalyst	0.20	0.18 – 0.22	g	(Antonini et al., 2020; Wernet et al., 2016)
Fe-Cr and Cu-Zn catalyst	1.1	1.0 – 1.2	g	(Antonini et al., 2020)
Zeolite powder	0.88	0.8 – 1.0	g	(Antonini et al., 2020)
Water, cooling	380	340 - 420	L	Own assumption
Water, deionised	3.8	3.4 - 4.7	kg	(Mahler AGS, 2016; Ahmed, Upadhyay, and Tiwari, 2023; Chen et al., 2022)
Outputs				
Hydrogen	1.00		kg	
Emissions to air				
Carbon dioxide	9.7	9.6 – 9.9	kg	Stoichiometric
Hydrogen	2.5	1 - 10	g	Own assumption

Source: JRC (2024)

3.7 SNG

3.7.1 SNG synthesis

The synthesis of SNG is modelled based on the information provided by Chauvy et al. (2021; 2020) and ecoinvent. The same inventory for CO_2 production used for methanol is applied for SNG synthesis (section 3.6.1). The inventory considered for the synthesis process is reported in Table 13, ending with the compression of hydrogen (70 bar). As in Chauvy et al. (2021), electricity needed for the multistage compression is assumed to be produced with the excess heat released from the methanation process. Nickel supported on magnesium aluminate spinel (Ni 15 wt.%) was considered to be used as catalyst for the reference scenario (Chauvy et al., 2021). Due to the unavailability of datasets, aluminium oxide was used as proxy for magnesium aluminate spinel in the assessment. In the sensitivity analysis, the use of rhodium on alumina (Rh/Al_2O_3) catalyst (rhodium 0.5 wt.%) based on Bargiacchi et al. (2021) was also considered. A LHV for SNG of 45.4 MJ/kg was considered, with a molar composition of 92.9 % CH_4, 3.7 % CO_2, and 3.4 % H_2 (Chauvy et al., 2021). For the sensitivity analysis, extreme cases where SNG is composed of 100 % methane (LHV 50 MJ/kg), or by 80 mol% methane and 20 mol% hydrogen (LHV 52 MJ/kg) based on Frigo and Spazzafumo (2020), were also considered to understand the role that the composition of the SNG has on the environmental impact of this pathway. Steam and electricity are assumed to be produced from the recovered excess heat (Chauvy et al., 2021). For the reference scenario, SNG is assumed to be further treated (liquefaction) to be shipped in traditional LNG tankers. Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure.

Table 13. SNG synthesis inventory

Inputs	Reference	Range		Sources
Hydrogen	0.46	0.46 - 0.52	kg	(Chauvy et al., 2021; Frigo and Spazzafumo, 2020)
Carbon dioxide	2.53	2.53 - 2.75	kg	(Chauvy et al., 2021; Perna et al., 2020)
Nickel-based catalyst	0.41	0.25 – 0.45	g	(Chauvy et al., 2021; Bargiacchi et al., 2021)
Electricity	0	0 – 0.29	kWh	(Chauvy et al., 2021)
Outputs				
SNG (liquid)	1.00		kg	
Water	2.16	0 – 2.2	kg	(Chauvy et al., 2021)
Emission to air				
Hydrogen	0.5	0 - 1	g	Own assumption

Source: JRC (2024)

3.7.2 SNG storage and transportation

As for the other carriers, two options are considered for the transportation of SNG: ship and pipeline. Depending on the mode of transportation, SNG requires different treatment and storage.

3.7.2.1 Ship

When shipped, SNG is assumed to be liquid. Additional 1.43 kWh per kg of SNG are assumed to be necessary for liquefaction (Wernet et al., 2016). Data are based on the ecoinvent dataset for liquid natural gas, assuming that local electricity was used for the energy requirements of liquefaction. Liquid SNG is assumed to be stored in liquid storage tanks and shipped via LNG carriers. A density for SNG of 423 kg/m^3 was considered, and the same ship volumetric capacity considered for liquid hydrogen (140 000 m^3) was used for the analysis. For the delivery, 2 ships and 27 kt of biodiesel are considered to be necessary. No methane loss is assumed during storage and transportation (Wernet et al., 2016).

3.7.2.2 Pipeline

In the pipeline scenario, SNG is assumed to be transported at 70 bar via traditional natural gas pipelines. The dataset for onshore low-capacity pipeline available on ecoinvent was considered for the infrastructure. The pipeline has a diameter of 950 mm, and a thickness of 10 mm. A mix of unalloyed (63 %) and low-alloyed (37 %) steel was assumed to be used. Electricity (average EU mix in 2030) was assumed to be used during the pipeline installation, and a lifetime of 40 years was considered. For the transportation, a consumption of 0.076 kWh per tonne of SNG transported per one km was assumed, and a methane loss of 0.02 % every thousand kilometres (Wernet et al., 2016). Overall, 620 GWh are calculated to be needed to deliver 1 Mt of hydrogen.

3.7.3 SNG steam reforming and H_2 delivery

Liquid SNG delivered by ship is stored in tankers, re-gasified, and reformed to produce hydrogen. Evaporation data are from ecoinvent, assuming 0.01 % of fugitive emissions and an electricity consumption of 0.061 kWh/kg SNG (Wernet et al., 2016). The inventory for the reforming process (Table 14) is based on the SNG composition considered in the synthesis stage (Section 3.7.1) and on the work from Antonini et al. (2020). We assumed that 58.5 MJ/kg H_2 are needed for the process, and that the waste heat generated is not utilized. However, a scenario where this energy (0.14 kWh/kg H_2) is converted into electricity and injected into the grid replacing local electricity production is considered in the sensitivity analysis. The same catalysts (nickel and Fe-Cr and Cu-Zn composite catalysts) considered for the dehydrogenation of methanol (3.6.5), based on the work from Antonini et al. (2020), were considered. Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure.

The hydrogen purity at the gate of the reforming plant is assumed to be at least 99.97 %, and its pressure 200 bar. Therefore, no additional energy consumption is needed to provide the hydrogen at the required purity and pressure to the user, or to store it in a salt cavern.

Table 14. SNG steam reforming inventory

Inputs	Amount	Range		Source
SNG	2.21	1.94 – 2.21	kg	Own assumption based on Chauvy et al. (2021), Antonini et al. (2020) and Frigo and Spazzafumo (2020)
SNG (for heat)	1.29	1.17 – 1.29	kg	
Nickel-based catalyst	0.203	0.18 – 0.22	g	(Antonini et al., 2020; Wernet et al., 2016)
Fe-Cr and Cu-Zn catalyst	1.08	1.0 – 1.2	g	(Antonini et al., 2020)
Zeolite powder	0.883	0.8 – 1.0	g	(Antonini et al., 2020)
Water (pure)	7.54	6.8 – 8.3	kg	(Antonini et al., 2020)
Water (cooling)	381	340 - 420	kg	(Antonini et al., 2020)
Outputs				
Hydrogen	1.00		kg	
Electricity	0	0 – 0.14	kWh	(Antonini et al., 2020)
Emissions to air				
Carbon dioxide	8.98	8.2 – 9.0	kg	Own assumption
Methane	41.8	38 - 46	mg	(Antonini et al., 2020)

Source: JRC (2024)

3.8 On-site hydrogen production

3.8.1 Steam methane reforming

The inventory for hydrogen production via steam methane reforming is in line with the one used for the reforming of SNG (Table 14 in Section 3.7.3). The two processes differ for the source of natural gas and its composition: while in the SNG case, synthetic natural gas was entering the reformer, fossil natural gas was considered for this scenario. The ecoinvent dataset "Hydrogen, gaseous {RER}| hydrogen production, steam reforming | Cut-off" adapted for the Netherlands in terms of water sources and natural gas supply chains was used for the assessment. Generic data for a chemical factory available in the ecoinvent database were considered for the plant infrastructure. Natural gas is assumed to be sourced from Norway (61 %), the Netherlands (20 %), and Russia (19 %), based on ecoinvent data (Wernet et al., 2016). Approximately 3.36 kg of natural gas are assumed to be needed per kilogram of hydrogen produced, which generate 8.95 kilogram of carbon dioxide during the reforming process (Antonini et al., 2020). The slight variation in the amount of carbon dioxide emitted per kilogram of hydrogen produced with respect to the SNG case (8.98 kg CO_2/kg H_2) can be attributed to differences in natural gas composition[20]. Approximately 0.6 % of the natural gas delivered to the reformer is assumed to leak to the atmosphere along the supply chain[21].

As for the other pathways, a salt cavern storing 1 % of the annual production of hydrogen was deemed necessary to guarantee the hydrogen supply to the industrial user.

3.8.2 Electrolysis

On-site electrolysis was modelled as in the case for renewable hydrogen production in Portugal (Section 3.1.2), but for the source of electricity. While for Portugal a dedicated solar farm was assumed to provide the electricity for the electrolyser, electricity from either the Dutch grid mix in 2030 or a dedicated onshore wind farm was assumed to be used for this case. The use of a dedicated PV power plant was also considered in the sensitivity analysis (5.2.1.1).

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[20] The molar composition of the natural gas considered by Antonini et al. (2020) is: CH_4 (89 %), C_2H_6 (7 %), CO_2 (2 %), C_3H_8 (1 %), N_2 (0.9 %), nC_4H_{10} (0.1 %), and H_2S (5 ppmv).

[21] The loss of natural gas along the supply chain varies considerably from one source to another. For instance, the estimate for natural gas losses in the major natural gas fields in the United States is 2.6 % of the gas produced (Howarth and Jacobson, 2021). The value we considered is estimated based on the information available on the ecoinvent database for our specific scenario.

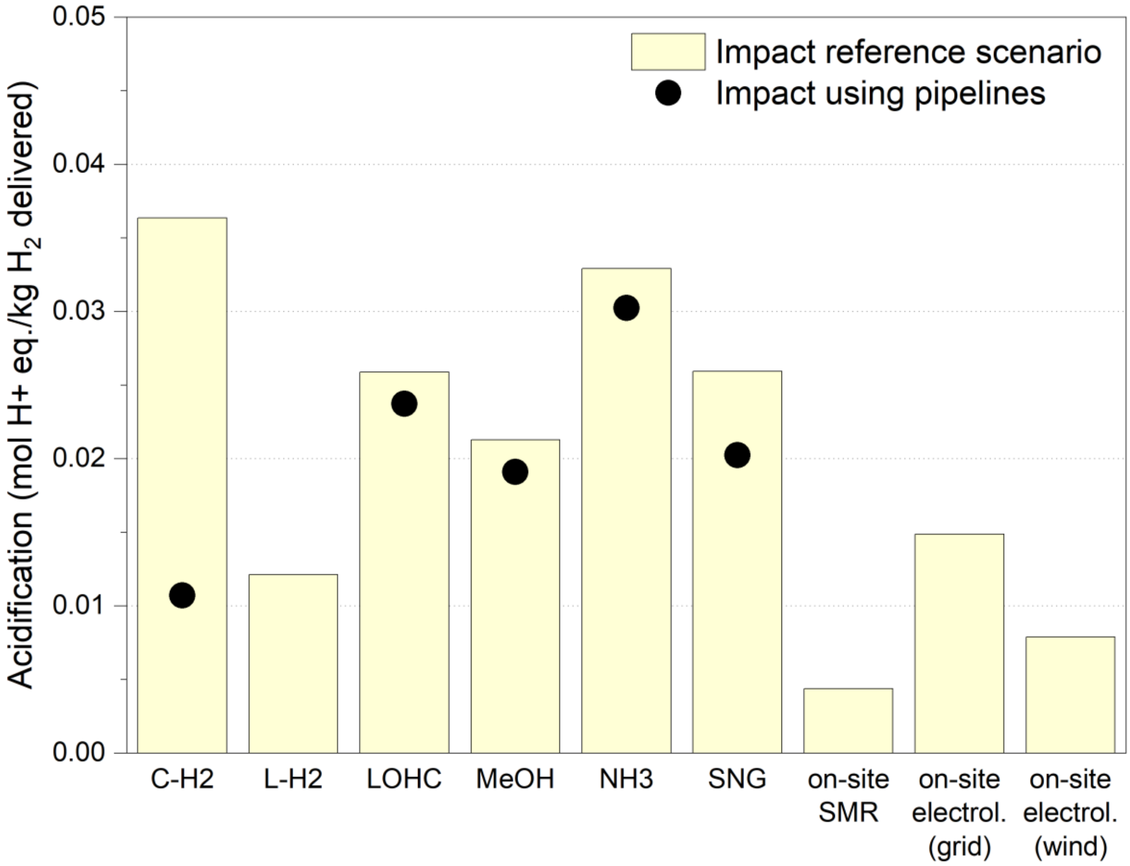
4 Impact assessment

In this section, the results from the life cycle impact assessment are reported. The assessment covers the 16 life cycle impact categories recommended by the EF method. Results are presented without error bars to improve readability, but an extensive sensitivity analysis of parameters used for the assessment is presented in Section 5. A detailed analysis for the climate change impact category is provided in Section 4.2. Single score results are presented in Section 4.17.

4.1 Acidification

In Figure 9 are presented the impact results for the acidification category in terms of moles of hydrogen ion equivalents. The unit indicates the change in critical load exceedance of the area to which acidifying substances deposit. Compressed hydrogen delivered by ship results to be the most impactful option to deliver hydrogen, while on-site SMR results to be the least impactful. The reason for the higher impact for the compressed hydrogen pathway is the large consumption of biodiesel, resulting in significant acidifying emissions of sulphur dioxide and nitrogen oxides. For this reason, transportation via pipeline results in a lower impact for this category compared to shipping. Among the imported options, compressed hydrogen via pipeline proves to be the least impactful solution, followed by liquid hydrogen. When biodiesel is not part of the hydrogen supply chain, the impact is mainly related to sulphur dioxide emissions generated when electricity and heat are produced from fossil fuels, mainly coal. Although the share of electricity produced from coal is expected to be minimal in the EU, coal is expected to still be used for heat and electricity generation for the production of imported materials (e.g., photovoltaic panels). Among the imported options, the ammonia pathway is the one leading to the highest emissions after compressed hydrogen, due to ammonia lost along the supply chain.

Figure 9. Acidification results



Source: JRC (2024)

4.2 Climate change

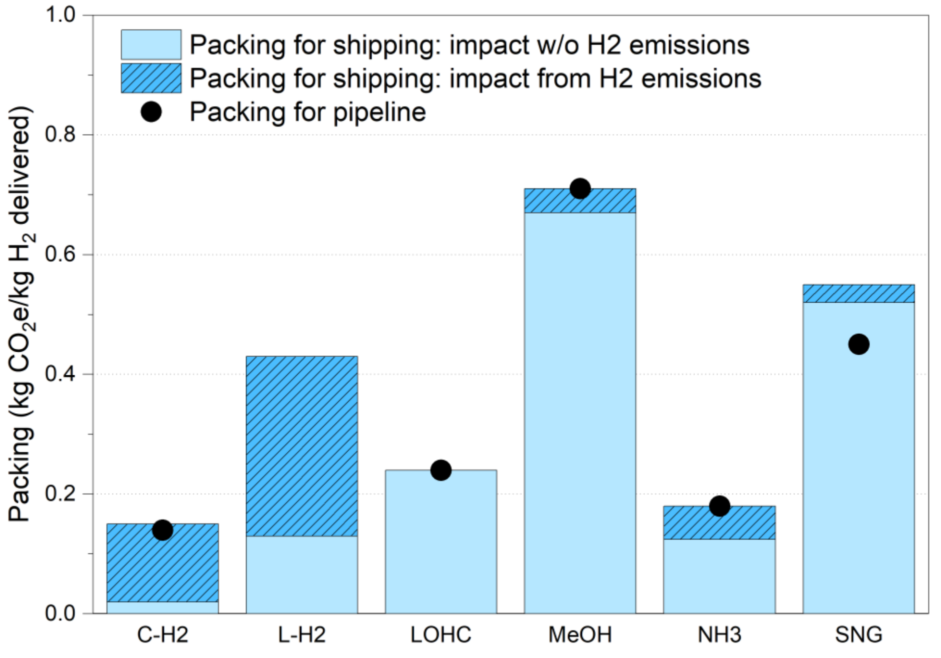
The impact assessment results for climate change are first presented in terms of kilograms of carbon dioxide equivalents divided per life cycle stages: packing (4.2.1), transportation (4.2.2), and unpacking (4.2.3), and then aggregated over the entire hydrogen delivery chain (4.2.4).

4.2.1 Packing

The climate change impact results for the packing stage are reported in Figure 10. Since the carbon dioxide captured to produce methanol and SNG is assumed to be emitted at the unpacking stage, the potential credit for storing carbon in the product is not included. The impact is divided between the global warming potential impact arising from all greenhouse gases emitted during the packing of hydrogen into a suitable carrier for transportation (light blue), and the potential impact from hydrogen emissions (dark blue with diagonal pattern). The impact for packing hydrogen in case the carrier is transported by pipeline instead of ship is also shown in Figure 10 (black dots). The impact does not include the emissions arising from the packing of the extra hydrogen needed to be transported for heating purposes at the delivery site; this impact is attributed to the unpacking stage.

Compressed hydrogen is the carrier requiring less processing to deliver hydrogen: the GHG emission impact is limited to its compression, which appears to be negligible when electricity is produced with a very low carbon footprint, and hydrogen losses. The relatively higher impact from hydrogen losses for this pathway is linked to the storage phase: in contrast to the other carriers which store hydrogen in its packed forms, which are less prone to losses, this pathway assumes all hydrogen to be stored in a salt cavern before being loaded onto a ship. Ammonia results to be the second-best option, with a packing stage emitting 0.18 kg CO_2e/kg H_2 delivered, with a small contribution from the indirect global warming caused by hydrogen leaks during ammonia synthesis. LOHC follows (0.23 kg CO_2e/kg H_2 delivered), with the slightly higher emissions linked to the production of DBT. Liquid hydrogen shows a larger global warming impact contribution mainly linked to the indirect global warming effect of hydrogen lost to the atmosphere during liquefaction. Finally, methanol and SNG are the carriers emitting more GHG during the packing stage. Most of their emissions arise from the energy consumed to capture carbon dioxide from the atmosphere. Methanol shows higher emissions than SNG since more carbon dioxide is assumed to be needed for the synthesis process. The packing impact changes in case the carrier is transported by pipeline only for the SNG option. Transportation by pipeline generates a lower impact for SNG since the additional liquefaction step is not considered for this pathway.

Figure 10. Climate change potential impact from the packing stage.



Source: JRC (2024)

4.2.2 Transportation

Climate change impact resulting from the transportation stage for the different carriers are reported in Figure 11. In the figure, transportation by ship (green bars) is compared to transportation by pipeline (black dots). As for the packing stage, the impact from hydrogen emissions (dark green bars with diagonal pattern) is shown separately from the other global warming contributors (light green bars). The impact does not include the emissions to transport the extra hydrogen for heating purposes at the delivery site, which were attributed to the unpacking stage.

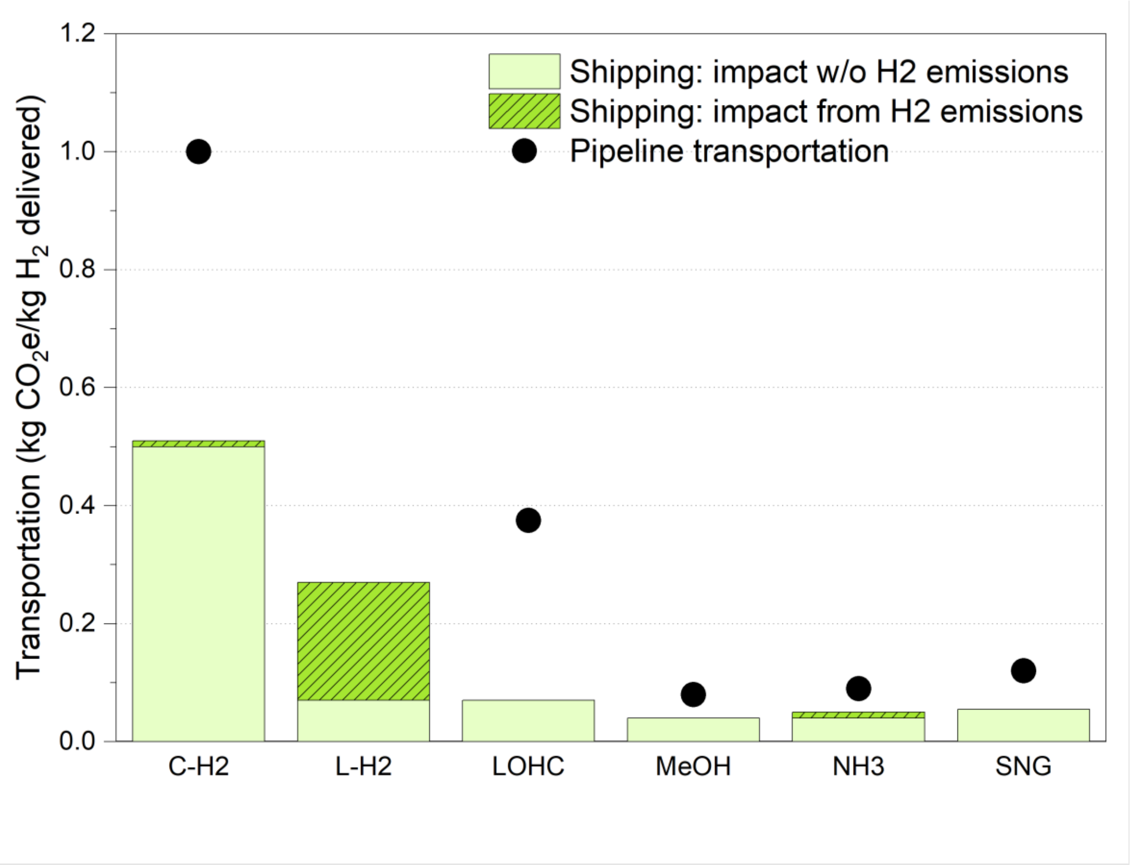
Transportation by pipeline generates a higher impact on climate than ships powered by biodiesel, mainly due to the residual fossil component of the electricity grid mix in 2030 in the EU. Even with the EU ambitious targets of the Fit for 55 plan, the consumption of 1 kWh from the EU grid was calculated to emit approximately 159 g of CO_2 equivalents. This value is in line with the emission factor for electricity in Europe in 2030 (150 g CO_2e/kWh) estimated by the European Commission for the EUCO3232.5 scenario (European Commission, 2019). On the other hand, one kWh provided by biodiesel on the ship was calculated to emit approximately 88 g of CO_2 equivalents (considering the emissions throughout its life cycle).

Compressed hydrogen is the carrier showing the highest impact in both modes of transportation, due to the large volumes that need to be moved. Impacts from transportation significantly decrease for the other carriers, with LOHC transported by pipeline being the second worst. The higher impacts for LOHC compared to the other carriers are mainly linked to the need to transport the DBT back to the hydrogenation site. While this does not represent a significant environmental hurdle compared to the other carriers in the case of shipping (ships need to return to the production site anyway), it causes a significant increase of the impact when pipelines are considered. Shipping hydrogen in a liquid form generates a larger climate impact compared to the other carriers mainly due to the indirect warming caused by the boil-off gas lost to the atmosphere. When this impact is neglected, the climate impact from shipping using biodiesel is low and comparable to the other carriers. Among the different carriers, methanol appears to be the least climate impacting solution in terms of transportation (0.04 kg CO_2e/kg H_2 delivered), followed by ammonia (0.05 kg CO_2e/kg H_2 delivered) and SNG (0.06 kg CO_2e/kg H_2 delivered). The impact for SNG shipping does not include the liquefaction and evaporation processes, which were attributed to the packing and unpacking stages, respectively.

Ship infrastructure seems to play a negligible role in the impacts for transportation: assuming a lifetime of 30 years for the ships, the impact from building, maintaining, and disposing of them would be less than 0.02 kg CO_2e/kg H_2 delivered. However, as highlighted in a previous JRC report (Istrate et al., 2022), more studies are necessary to investigate the environmental impacts from the use phase and the end of life of ships. Overall, apart from the C-H_2 case, shipping with biodiesel does not seem to pose a significant global warming threat for intra-European hydrogen deliveries. However, more studies are necessary to investigate the potential consequences for direct and indirect land use change. Infrastructure could play a larger role in the environmental impact of hydrogen delivery when transportation by pipeline is considered. In the case of LOHC, approximately one fourth of the transportation impact can be ascribed to the production of steel. The impact is lower for ammonia and methanol, where smaller pipelines requiring less steel per unit of hydrogen delivered were considered.

The transportation mode might affect the environmental performance of the delivery pathway at the use site as well. For instance, the use of pipelines could reduce the need for storage at the delivery site (i.e., linepack). On the other hand, if storage was needed, additional compression might be required to transfer the hydrogen carrier from the pipeline to a cavern or tank. These aspects were not included in the assessment.

Figure 11. Climate change potential impact from the transportation stage



Source: JRC (2024)

4.2.3 Unpacking

The potential climate change impact resulting from the unpacking stage and, if needed, from the final compression are presented in Figure 12. As in the previous figures, the indirect potential climate impact from hydrogen emissions is shown separately (dark yellow bar with diagonal pattern) from the other contributors (light yellow bar). Moreover, the impact from the final compression stage potentially needed to deliver hydrogen at 30 bar is also shown separately (orange bar). Finally, the impact for unpacking in case hydrogen is delivered by pipeline is also presented in Figure 12 (black dots).

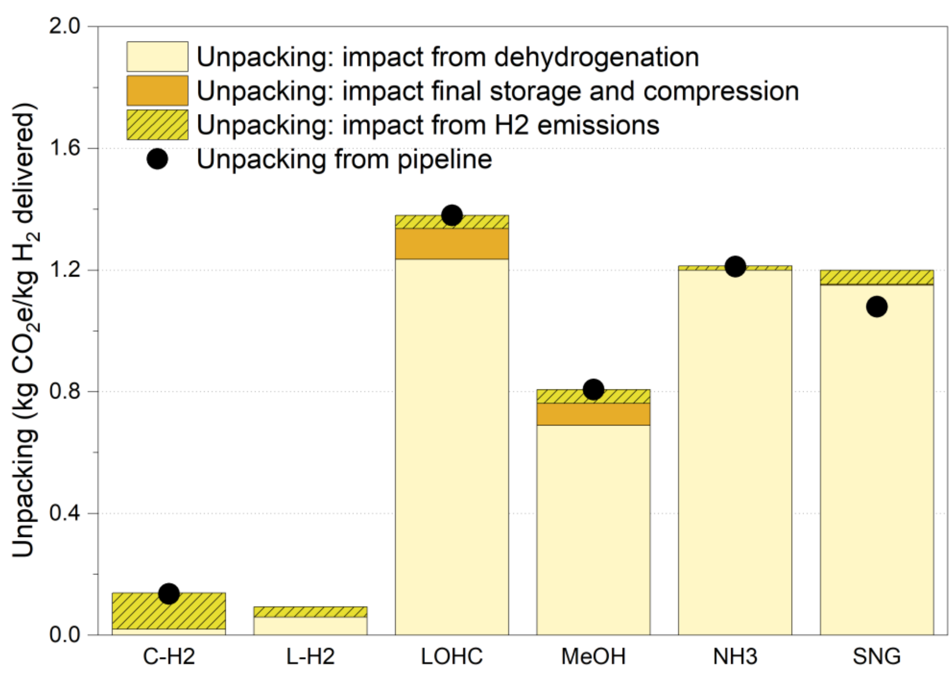
In the case of compressed and liquid hydrogen, “unpacking” includes the activities from taking the hydrogen from the ship or pipeline and delivering it to the user, such as evaporation, storage, and compression. The impact at the delivery site is significantly lower for the compressed and liquid hydrogen pathways, compared to the other options. The impact in the unpacking stage for the chemical carriers is mainly linked to the energy needs of the dehydrogenation process. For all the pathways, additional hydrogen is assumed to be delivered via the carrier for heating purposes. Moreover, electricity at the delivery site might also be needed for the processes. Electricity from the Dutch grid mix was assumed to be used. Based on the energy sources expected for 2030 in the Netherlands, the emission factor for electricity consumption was estimated to be 158 g CO_2e/kWh, slightly lower than the EU average.

Methanol appears to be the option among the carriers with the lowest climate impact, while LOHC the highest. The difference among the carriers lies mainly in the energy requirements for the dehydrogenation process at the delivery site, leading to extra hydrogen being produced and shipped via the carrier. In case alternative sources of energy were available at the delivery site, the results might change. Unlike LOHC, whose impact is mainly linked to the production and transportation of the extra hydrogen, most of the impact in the ammonia pathway is due to the electricity consumed on-site for cracking. The impact of methanol and SNG at the unpacking stage could be reduced if the CO_2 emitted in the process were captured from the flue gas and stored permanently. If captured and reused, an assessment should be carried out to investigate which solution would be better in terms of climate impact: capture the CO_2 at the use site and ship it back to the hydrogenation facility, or emit the CO_2 at the use site and capture the CO_2 at the hydrogenation facility (i.e., option considered for this assessment). Capturing the CO_2 from the flue gas would be less energy intense than capturing it from the air, but additional energy and infrastructure would be needed to compress and transport the CO_2 to the hydrogenation facility.

The transportation mode does not affect the climate impact from the unpacking stage except for the case of SNG, where evaporation is assumed to be needed in the case SNG is transported in liquid form by ship.

Greenhouse gas emissions linked to final compression and storage prove to be significantly lower than the emissions from the dehydrogenation stage. Storage emissions mainly depend on the energy required to compress the hydrogen after the dehydrogenation stage to store it in a salt cavern or to use it directly. However, the climate impact linked to hydrogen emissions results to be significant in the compressed hydrogen pathway. The reason can be ascribed to the assumption that all the hydrogen from this pathway is stored in a salt cavern at the delivery site. In the case of liquid hydrogen, GHG emissions resulting from the use of cryogenic pumps result to be almost negligible.

Figure 12. Climate change potential impact from the unpacking stage



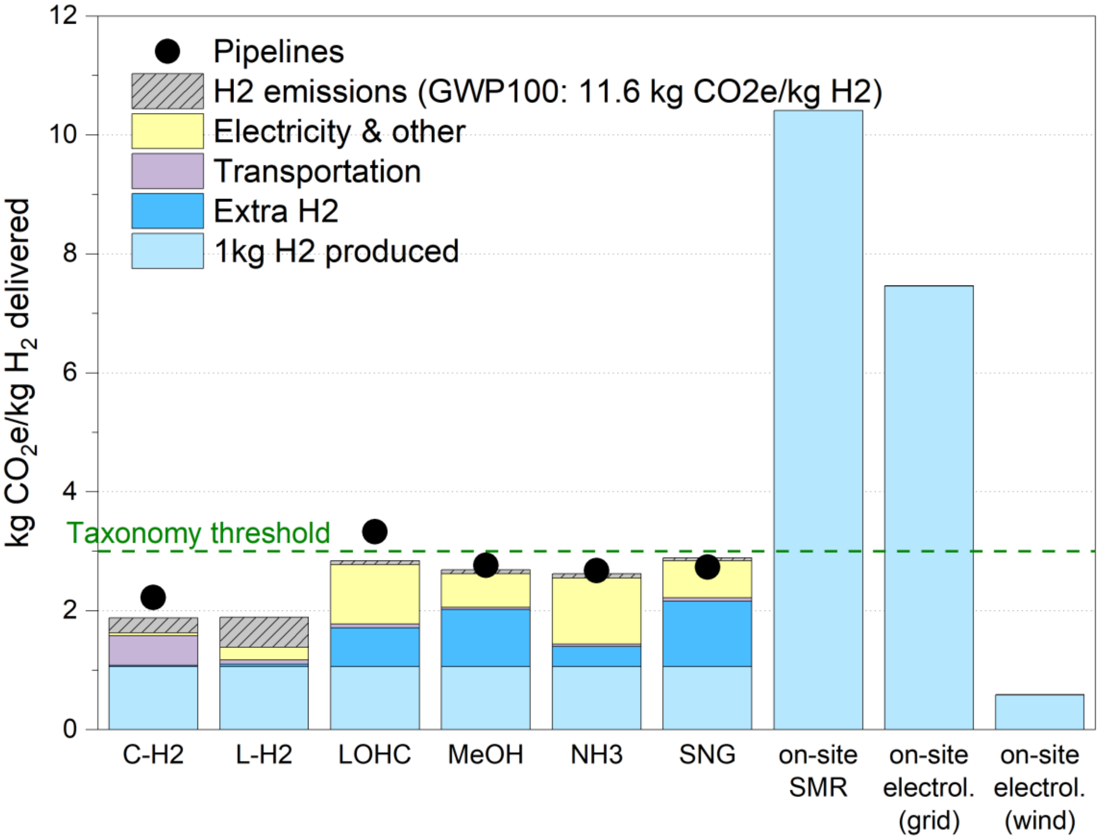
Source: JRC (2024)

4.2.4 Life cycle

The comparison of the life cycle climate change impact arising from the delivery of 1 kg of hydrogen at 30 bar is presented in Figure 13. The overall impact for the different pathways is divided into five components: i) the production of 1 kg of hydrogen (light blue part of the bar); ii) the impact arising from the extra hydrogen needed to deliver this 1 kg of hydrogen (dark blue part of the bar), due to hydrogen losses and to the use of hydrogen as heat source for process along the delivery chain (e.g., carbon capture, decomposition of the chemical carrier); iii) the impact arising from transportation stage (purple part of the bar), which also includes the impact of transporting the extra hydrogen (unlike Figure 11, where the impact of transporting the extra hydrogen was not included); iv) the impact from electricity and other material inputs along the delivery chain (yellow part of the bar); and v) the impact from hydrogen losses, which was not included in the previous four components (grey part of the bar). For instance, the impact from hydrogen lost during transportation is included in the grey part of the bar ("H_2 emissions") and not in the purple part ("Transportation"). In Figure 13, the Taxonomy threshold for sustainable investments for hydrogen production is given for reference (European Commission, 2022). Although infrastructure emissions (e.g., PV panel production) can be excluded from the life cycle assessment to comply with the Taxonomy regulation, the threshold is provided for comparative purposes.

As is to be expected based on common sense, the option generating the lowest amount of GHG emissions is to produce hydrogen on-site via renewable energy. However, when this is not feasible, our results show that the delivery of hydrogen from a location where renewable energy is cheaper would be significantly less impactful on climate than producing it on site from either SMR or electrolysis powered by the grid mix. Despite the reduction in carbon intensity expected from the electricity grid mix of European countries, the residual fossil component in the expected 2030 mix would lead to significant GHG emissions when producing electrolytic hydrogen (i.e., approximately 8 kg CO_2e). Although better than hydrogen produced via SMR, electrolytic hydrogen produced via the electricity grid mix is not expected to meet the Taxonomy criterion for climate change mitigation of 3 kg CO_2e/kg hydrogen. On the other hand, renewable hydrogen would meet the Taxonomy criterion in most cases, even when delivered from a distant location and the infrastructure emissions are included in the assessment. In our reference scenario, the life cycle GHG emissions for the different carriers varied from a minimum of 1.9 kg CO_2e/kg H_2 delivered for liquid hydrogen and shipped compressed hydrogen to a maximum of 3.4 kg CO_2e/kg H_2 delivered for LOHC transported by pipeline. The transportation advantage of packing hydrogen into a more manageable carrier does not seem to translate in a GHG advantage. On the contrary, the energy required to pack the carrier at the hydrogen production site and unpack it at the delivery site significantly increase the impact with respect to the compressed and liquid hydrogen options. Liquid hydrogen results to be the best option in terms of direct GHG emissions, but the expected higher losses of hydrogen in this pathway make its 100-year climate impact comparable to that of compressed hydrogen. Nevertheless, further research is needed to gain a better understanding of hydrogen losses throughout the liquid hydrogen supply chain, which will enable more accurate assessments of the associated climate impact. Impacts prove to be very similar, between 2.7 and 2.9 kg CO_2e/kg H_2, for the pathways involving chemical carriers. Best options among the carriers resulted to be methanol and ammonia transported by ship, followed by SNG transported by pipeline. The only outlier among the options is the transport of hydrogen via LOHC pipelines, due to the extra energy needed to transport back the dehydrogenated DBT. The delivery of renewable hydrogen from Portugal to the Netherlands via this option could deliver molecules of hydrogen with a carbon footprint slightly higher than the Taxonomy threshold.

Figure 13. Life cycle climate change impact from hydrogen delivery

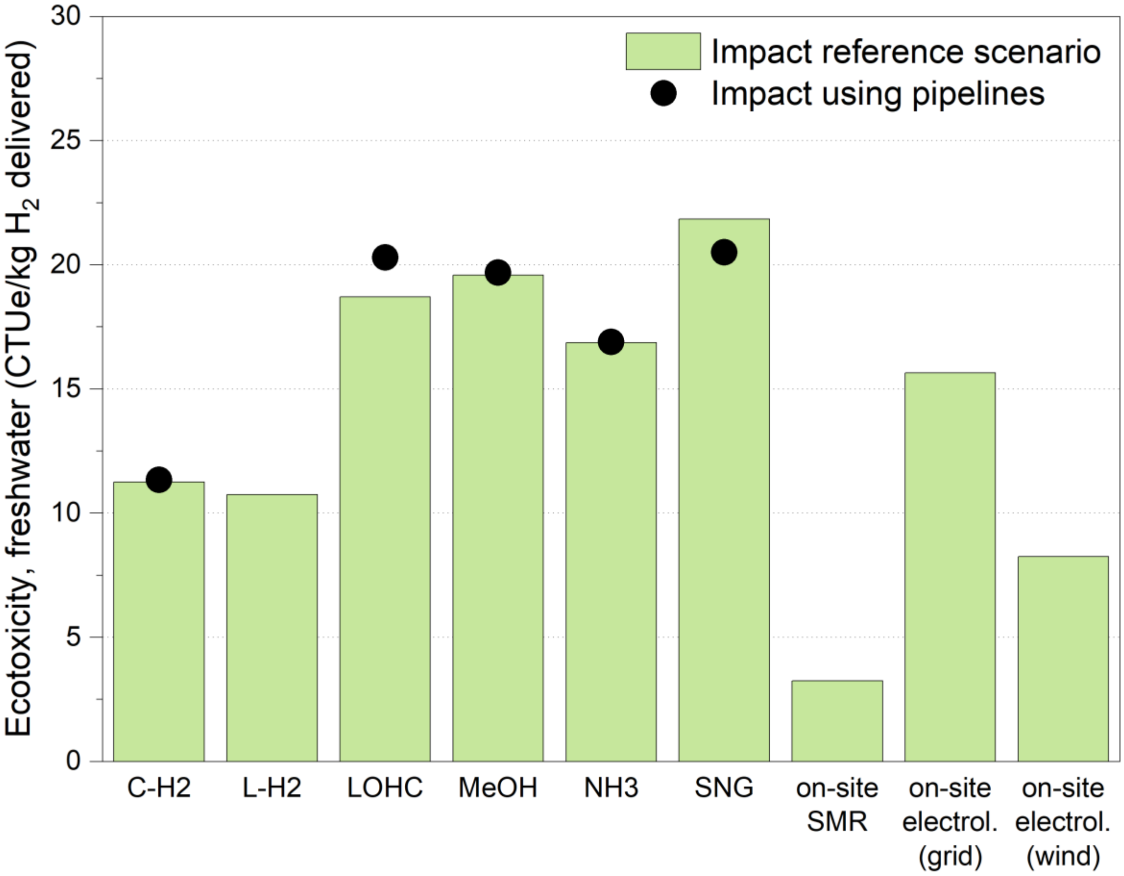


Source: JRC (2024)

4.3 Ecotoxicity, freshwater

Results for the ecotoxicity impact on freshwater bodies are shown in Figure 14 in terms of comparative toxic unit for ecosystems (CTUe). The unit indicates an estimate of the potentially affected fraction of species integrated over time and volume per unit mass of a chemical emitted, using the USEtox model. For most pathways, the impact is strictly linked to the manufacture of PV panels. In fact, the impact is mainly caused by the effluents from the sulfidic tailings[22] from the mining of minerals, by the chlorine in the wastewater from PV cell production, and by the chlorides emitted from fossil fuel processing. The SNG pathway results to be the most intense for this impact category due to the highest demand for PV panels, linked to the extra hydrogen required both for capturing the CO_2 at the SNG production site and for the heating needs at the reforming site. Approximately 80 % of the SNG impact is linked to the production of PV panels. Among the options requiring transportation, compressed and liquid hydrogen result to be the least toxic for the freshwater ecosystems thanks to the lower demand for minerals and fossil fuels. However, on-site production via SMR proves to be the most sustainable option for this impact category. The lower impact is linked to the lower needs for minerals in the delivery chain. The impact for the SMR pathway is due to the water discharge from natural gas extraction and to the tailings from the extraction of copper used as catalyst in the reforming process. Interestingly, the SMR pathway would generate a lower impact for this category than hydrogen produced on-site via wind electricity. The reason could be ascribed to the tailings generated when extracting the copper used for the wind turbines.

Figure 14. Ecotoxicity, freshwater results



Source: JRC (2024)

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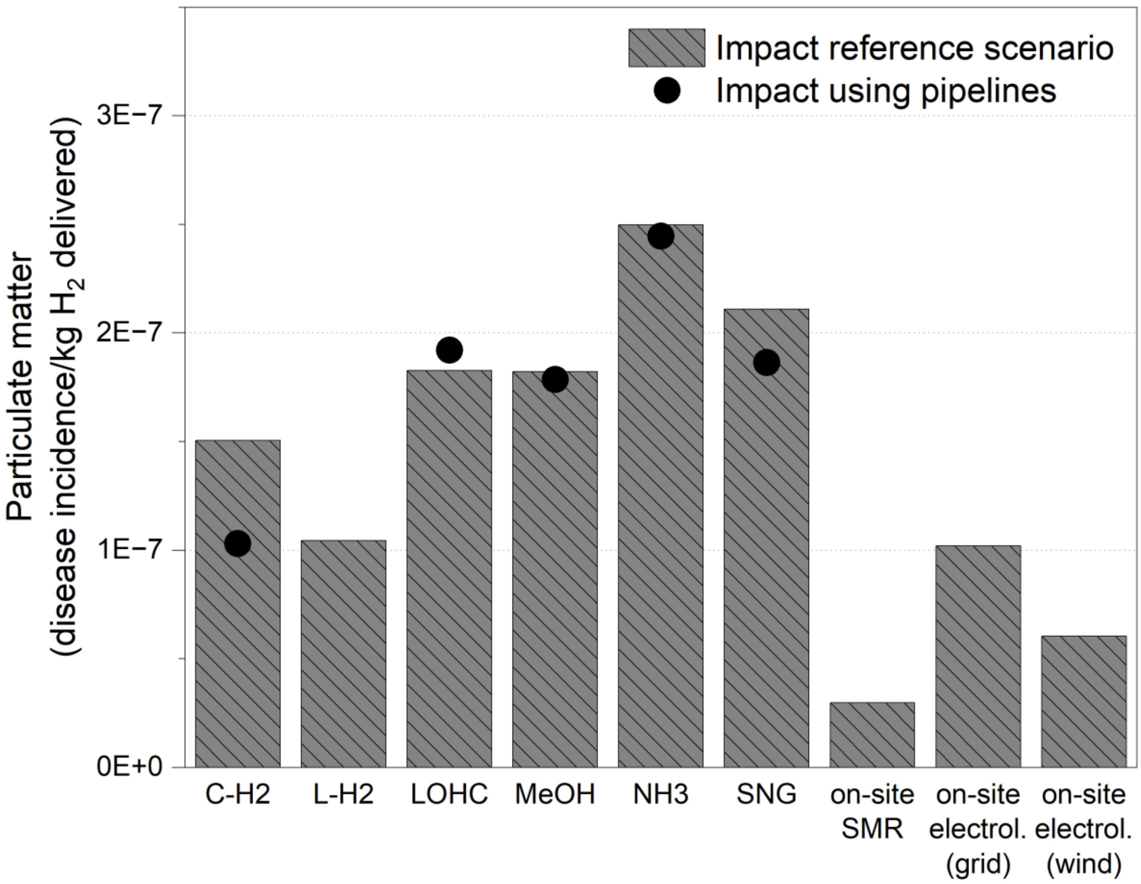
[22] Sulfidic tailings are a type of mine waste that contain sulphide minerals, such as pyrite, which can generate acid when exposed to air and water. This can lead to acid mine drainage, which is a major water quality problem as it reduces the pH of water resource, making dissolved metals readily available for uptake by aquatic life.

4.4 Particulate matter

Results for particulate matter are presented in Figure 15 in terms of disease incidence due to the emissions of particulate matter smaller than 2.5 µm (PM2.5). The main emissions contributing to the impact are particles smaller than 2.5 µm, ammonia, and sulphur dioxide.

Overall, on-site production via SMR proves to be the best solution in terms of particulate matter emissions, followed by electrolytic hydrogen produced on-site via wind electricity. Among the imported options, compressed hydrogen delivered by pipeline and liquid hydrogen delivered by ship prove to be the ones emitting less particulate matter. Transportation of ammonia shows a higher impact compared to the other carriers due to the loss of ammonia along the delivery chain. On the other hand, the higher impact of SNG via ship is linked to the larger demand for electricity from coal along the supply chain, mainly linked to the production of PV panels in China. Electricity production in China proves to be one of the key emission sources for this impact category. Emissions from the combustion of biodiesel on ships results to be significant only for the compressed hydrogen option, due to the large amount of fuel needed for this pathway. It is worth mentioning that the severity of the impact depends on the amount of people breathing these particles. In our study, we assumed that emissions happen in low populated areas. Nevertheless, particulate emissions could still affect the health of people on board (Kennedy, 2019), and the health of people working or living near the harbour or the shipping lane (Andersson, Bergström, and Johansson, 2009; Sofiev et al., 2018). A more thorough investigation of the number of people affected by the particulate matter emissions along the supply chain is necessary to assess the real impact of the different pathways. If emissions from ship reached highly populated areas, transportation by pipeline could significantly reduce the particulate matter impact.

Figure 15. Particulate matter results

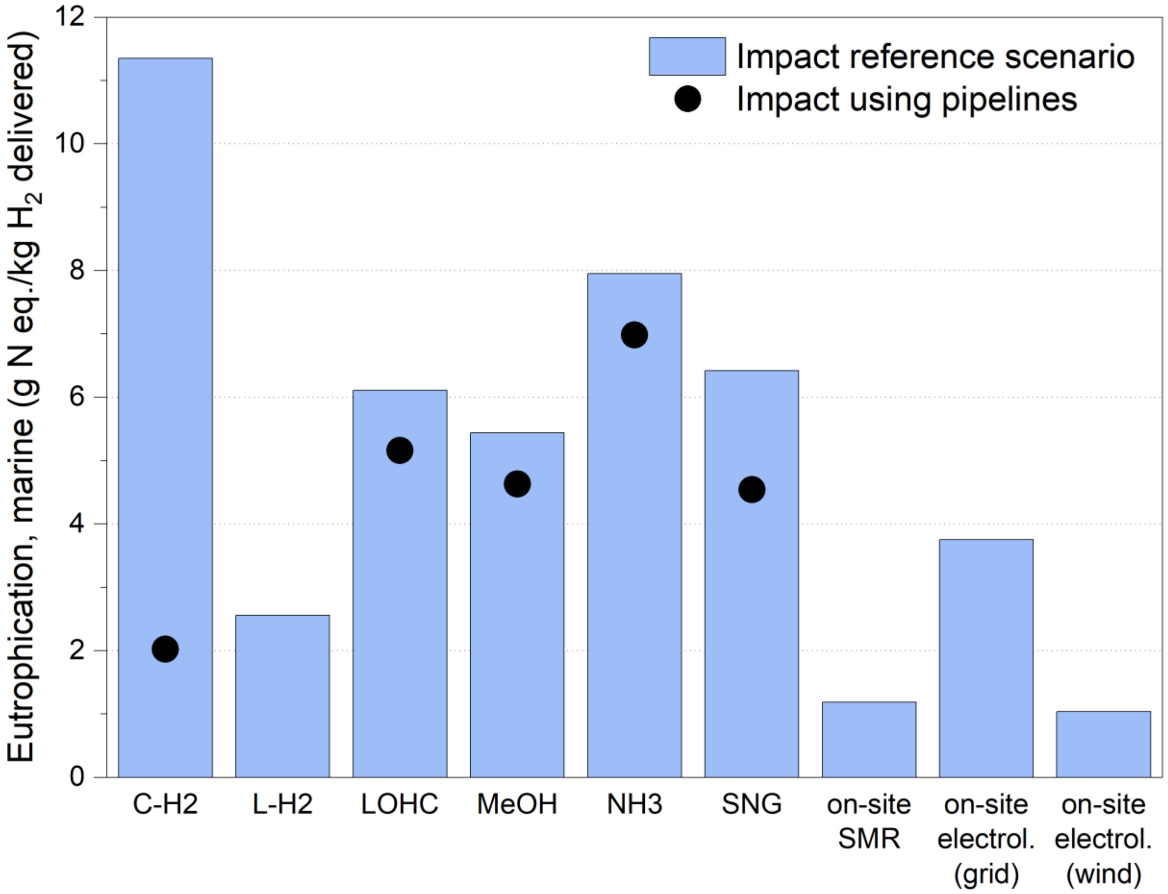


Source: JRC (2024)

4.5 Eutrophication, marine

Results for marine eutrophication are presented in Figure 16 in terms of grams of nitrogen equivalents. The unit indicates the degree to which the emitted nutrients reach the sea. On-site production via renewable electricity is the pathway generating less impact for this category, followed by on-site SMR and compressed hydrogen transported by pipeline. Results for the other pathways are comprised between 2.6 g N eq./kg H_2 delivered for liquid hydrogen and 8.0 g N eq./kg H_2 delivered for shipped ammonia. The higher impact for the ammonia pathway is mainly due to the emissions of nitrogen oxides in the ammonia synthesis process. The outlying pathway is the delivery of compressed hydrogen by ship, with an impact that is almost 10 times the one generated by on-site SMR. The reason for the high impact can be attributed to the nitrogen oxides emissions from the use of biodiesel on board. For the options not involving shipping, emissions of nitrogen oxides and nitrate linked to mining and fossil fuel use are the main contributors to the impact.

Figure 16. Eutrophication, marine results

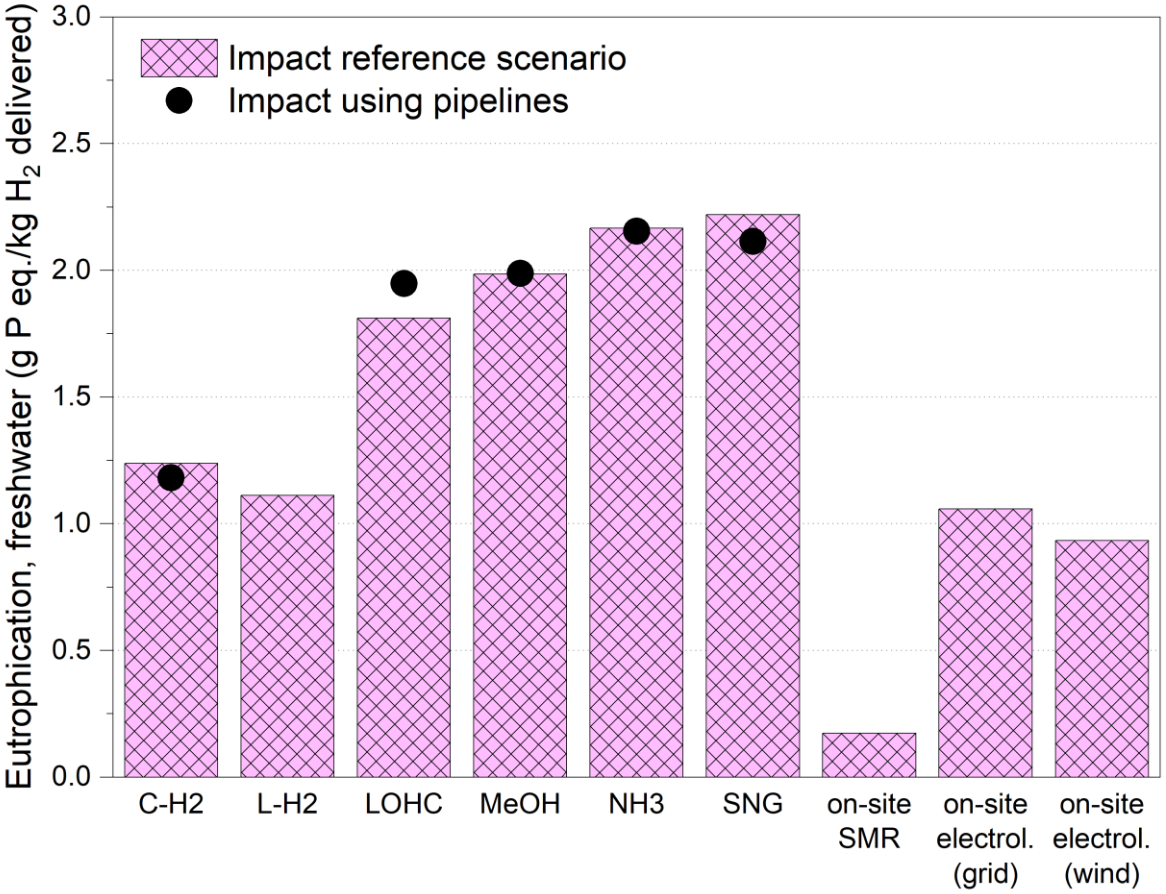


Source: JRC (2024)

4.6 Eutrophication, freshwater

Results for eutrophication of freshwater bodies are presented in Figure 17 in terms of grams of phosphorus equivalents. The unit indicates the degree to which the emitted nutrients reach freshwater bodies. On-site hydrogen production via SMR proves to be the option generating the least impact. For the other pathways, most of the impact is generated from the purification of water for hydrogen production, followed by the use of copper, silver, and coal for the electricity generation infrastructure. In particular, the impact is related to emission of phosphate in water. No significant difference was noticed regarding the type of transportation (i.e., ship or pipeline). Excluding on-site SMR, liquid hydrogen, compressed hydrogen, and on-site electrolysis pathways are the ones generating the lowest impact. The higher impact for the chemical carrier pathways is linked to the larger need of hydrogen, requiring more ultrapure water and electricity generation.

Figure 17. Eutrophication, freshwater results

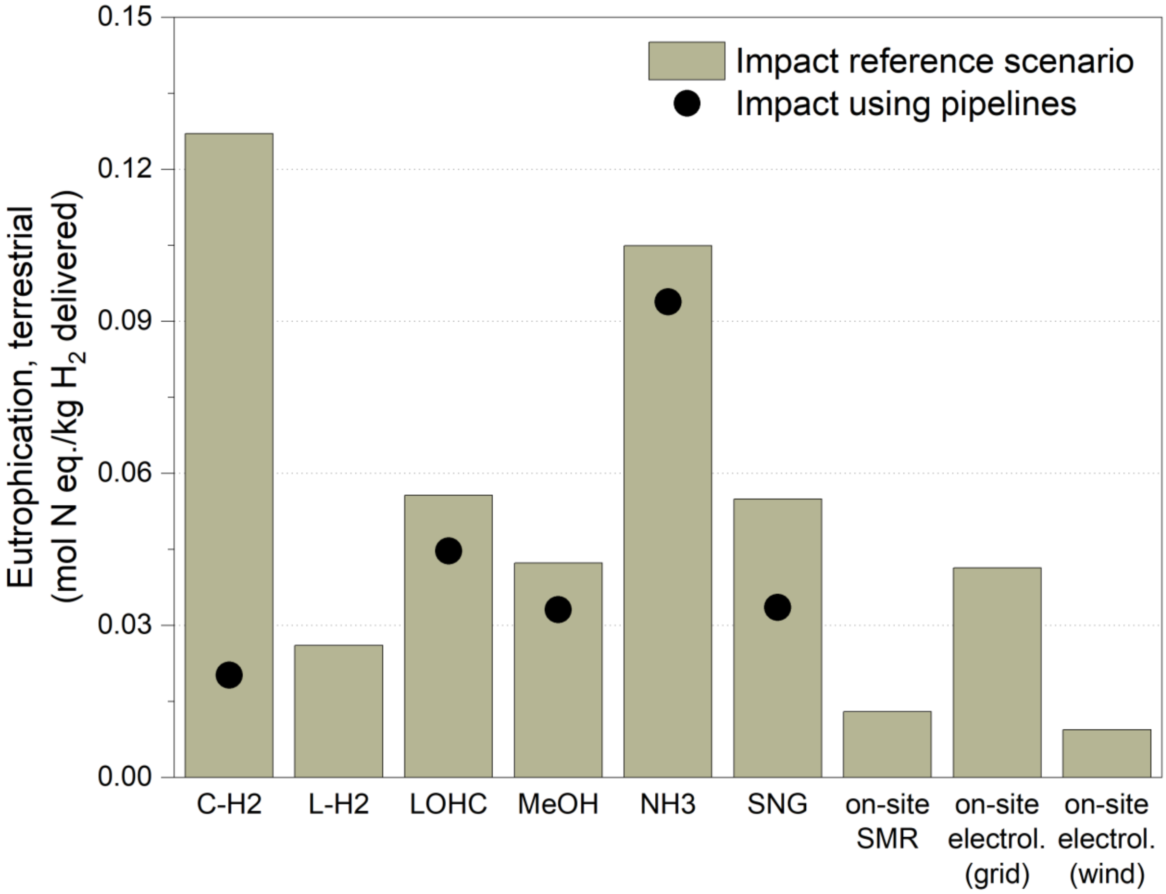


Source: JRC (2024)

4.7 Eutrophication, terrestrial

In Figure 18 the results for terrestrial eutrophication are reported in terms of moles of nitrogen equivalents. The unit indicates the critical load exceedance of the area where the eutrophying substances deposit. The culprits for the impact are the emissions of nitrogen oxides and ammonia to the atmosphere. Results are in line with the marine eutrophication impact (Section 4.5), with the sources of nitrogen oxides being the main responsible for the impact (i.e., burning of biofuel on ships, direct emissions, mining operations). As for marine eutrophication, transportation by pipeline exhibits a lower impact compared to shipping due to the lower amount of fuels burned for the delivery. The compressed hydrogen pathway by ship shows a significantly higher impact compared to the other pathways because of the larger amount of fuel needed for shipping. Conversely, the larger impact of the ammonia pathway is due to ammonia losses and nitrogen oxide emissions along the delivery chain.

Figure 18. Eutrophication, terrestrial results

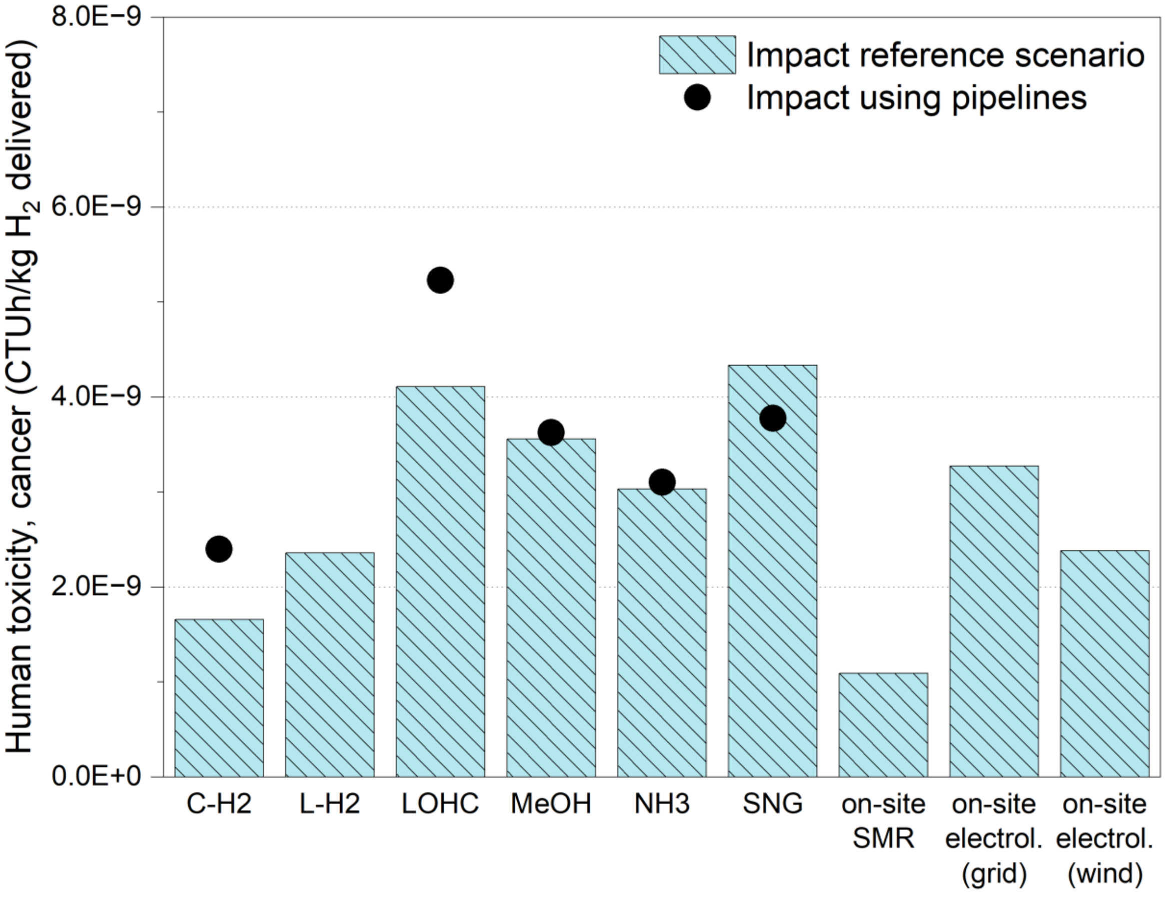


Source: JRC (2024)

4.8 Human toxicity, cancer

The impact results for the carcinogenic emissions are shown in Figure 19 in terms of comparative toxic unit for human (CTUh). The unit expresses the estimated increased in morbidity in the total human population per unit mass of a chemical emitted, using the USEtox model. On-site SMR results to be the best hydrogen delivery pathway for this impact category, while the delivery of LOHC by pipeline results to be the worst. For the latter, the main culprits prove to be the emissions of hexavalent chromium, resulting from the landfilling of slag resulting from steel production via electric arc furnaces, and the emissions of benzo(a)pyrene during coking to produce pig iron. Given the larger amount of steel needed to produce the LOHC pipelines and storage tanks, the LOHC option results to be the most harmful in terms of carcinogenic emissions. On the other hand, the low amount of steel needed for the SMR pathway leads to a low impact for this category. As for the difference between pipelines and ships, there is not a clear trend. While the impact is higher for SNG when ships are used due to the steel required for the additional infrastructure to liquefy the gas, store it, and ship it, the shipping impact is lower for LOHC since two pipelines are needed to transport the DBT back and forth. Compressed hydrogen results to be the best solution among the imported options. The high impact associated to on-site electrolysis is mainly linked to the large amounts of steel required for electricity generation.

Figure 19. Human toxicity, cancer results

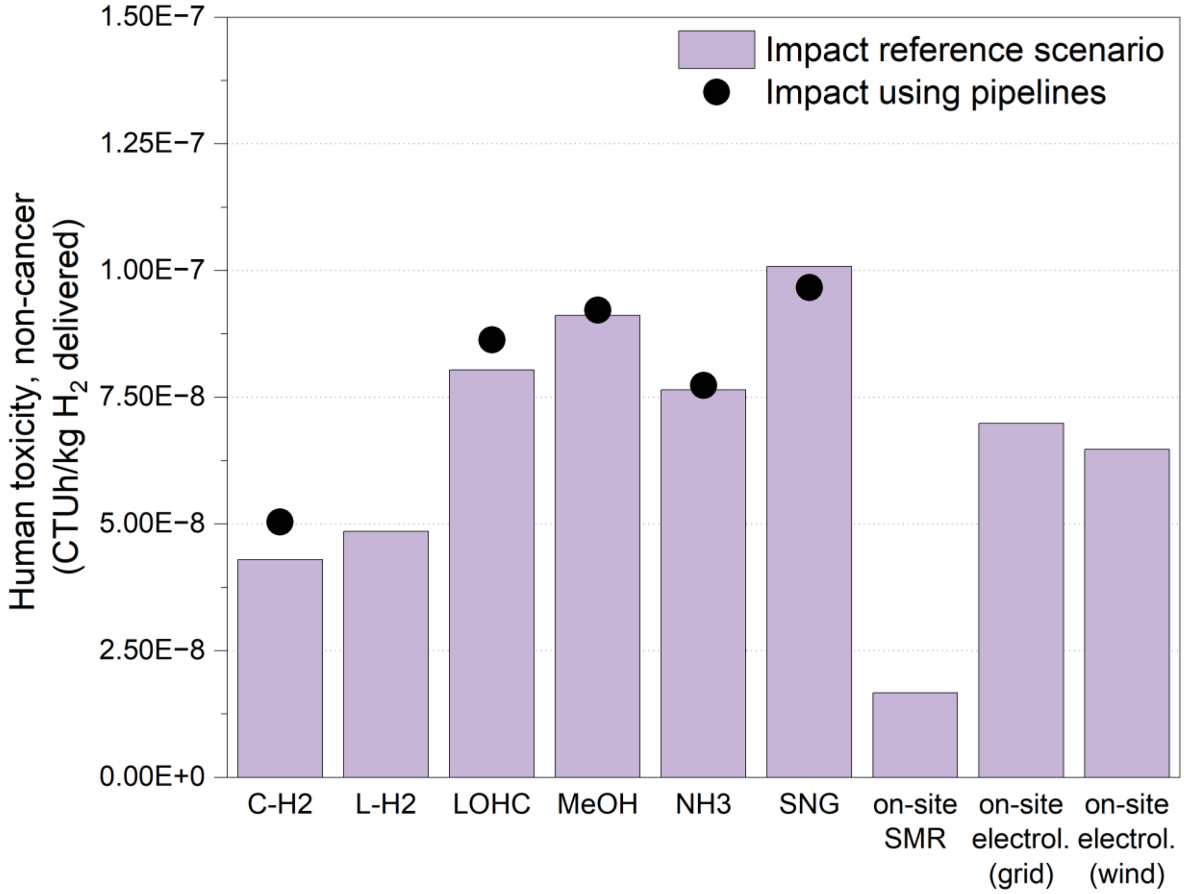


Source: JRC (2024)

4.9 Human toxicity, non-cancer

In Figure 20 are reported the results for the human toxicity category (excluding cancer) in terms of comparative toxic unit for human (CTUh). On-site production via SMR results as the option leading to the lowest damage. The second-best option results to be the delivery of renewable hydrogen on site in a compressed or liquid form. The impact for this category could be attributed to several processes, including the treatment of copper slag (arsenic emissions) for electricity generation, and the production of photovoltaic cells (silver emissions). The impact is therefore proportional to the amount of electricity and PV panels used for the delivery of hydrogen. On-site renewable electrolysis generates a larger impact than off-site renewable electrolysis due to the larger use of copper for wind turbines compared to PV panels per kWh produced in the two locations.

Figure 20. Human toxicity, non-cancer results

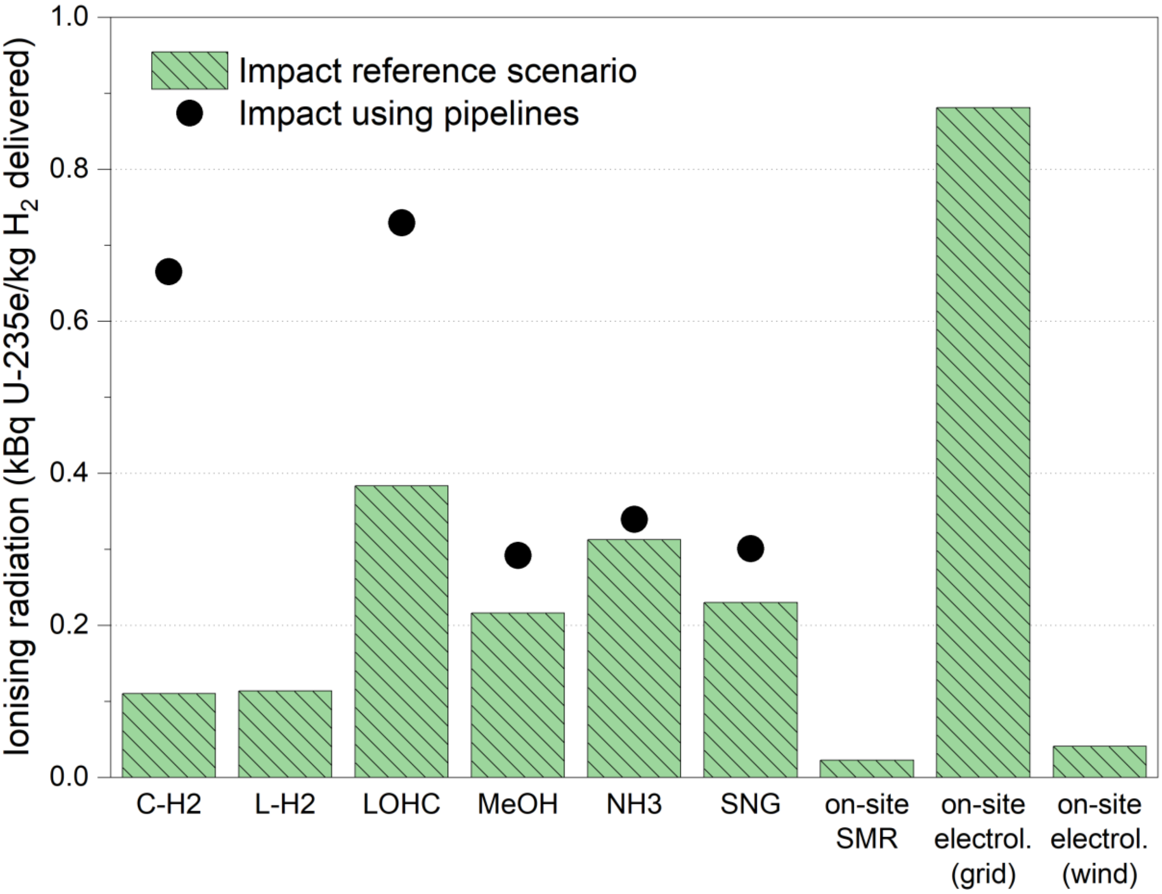


Source: JRC (2024)

4.10 Ionising radiation

In our case study, ionising radiation is mainly linked to the use of nuclear energy for electricity production. Results for the different pathways are shown in Figure 21 in terms of kilo-becquerel (kBq) of uranium-235 equivalents. Results indicate that the impact is strictly correlated to the consumption of grid electricity. This is due to the fact that part of the electricity consumed in Europe in 2030 is assumed to be from nuclear power (3.1.1). Among the pathways considered, on-site hydrogen production via electrolysis powered by the grid mix results to be the option with the highest potential ionising radiation impact. Despite the low share of electricity expected to be sourced from nuclear in the Netherlands in 2030, the high electricity consumption required for electrolysis makes this option the most impactful for this category. Most of the impact is generated during the treatment of tailings from uranium milling and from the treatment of spent nuclear fuel. Among the imported options, hydrogen delivered via LOHC results to be the most impactful for this impact category due to the electricity demand in the dehydrogenation process at the use site. Transportation by pipeline generates a higher impact due to the higher electricity demand compared to transportation by ship. Since the outcomes for this category are strictly dependent on the fraction of nuclear power in the grid mix, different results would be obtained if other energy sources than nuclear were used to generate electricity consumed on-site or to operate the pipelines. The best options in terms of ionising radiation result to be on-site production via renewable electrolysis and on-site SMR, due to the minimal consumption of nuclear electricity.

Figure 21. Ionising radiation results

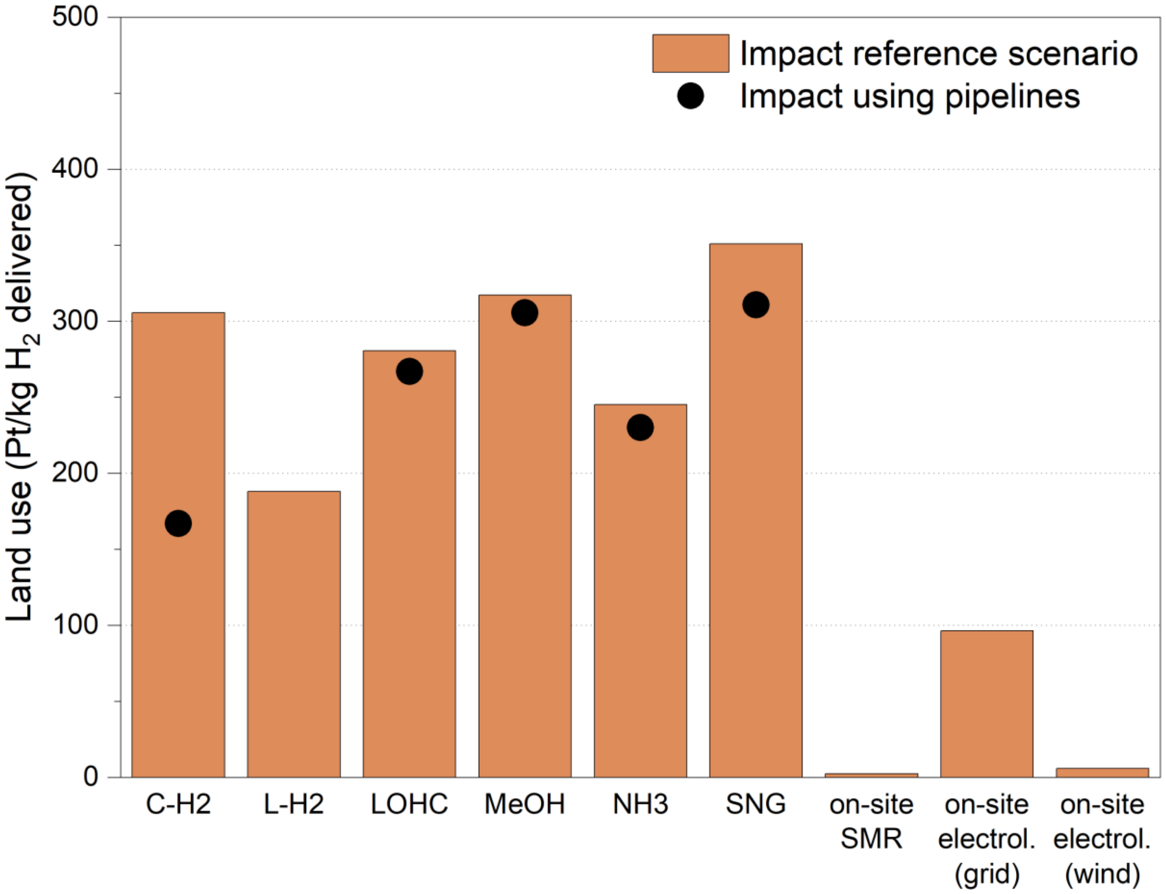


Source: JRC (2024)

4.11 Land use

Results for land use expressed in points (Pt) representative of the soil quality index are presented in Figure 22. Production on-site significantly reduces the impact on soil quality since it requires less land to deliver hydrogen, especially in the SMR and renewable electrolysis case. Electrolysis powered by the grid mix shows a larger impact than SMR due to the fraction of electricity sourced from solar and biomass, which require large land areas. Among the imported options, compressed hydrogen by pipeline and liquid option are the ones requiring less land, while SNG, methanol, and compressed hydrogen by ship are the ones with the highest footprint. For SNG and methanol, the higher impact is linked to the extra land occupied by the photovoltaic panels used to produce the electricity needed for carbon capture. On the other hand, the high land use in the compressed hydrogen scenario via ship is due to the land surface occupied to grow the biomass for biodiesel.

Figure 22. Land use results

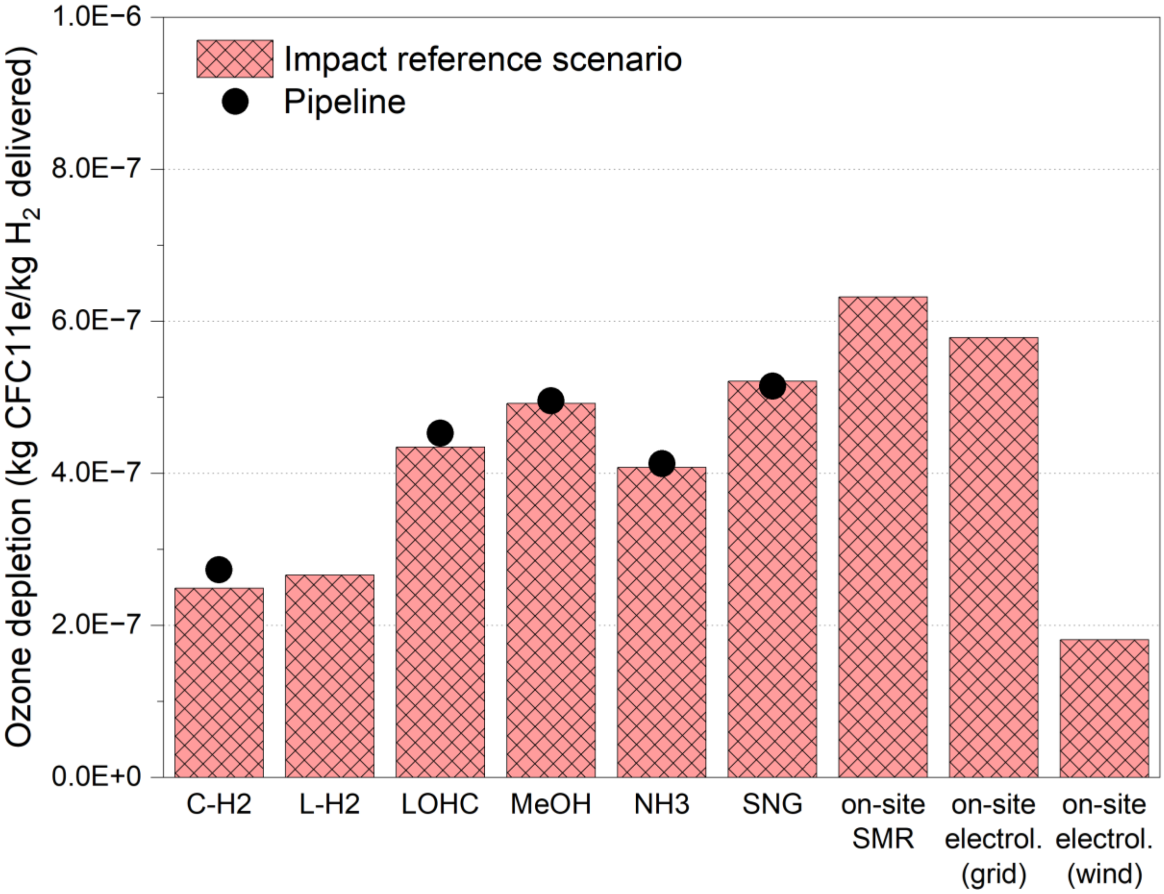


Source: JRC (2024)

4.12 Ozone depletion

Results for the ozone depletion category in terms of kilograms of trichlorofluoromethane are presented in Figure 23. Results show that importing hydrogen would reduce the impact compared to producing it on-site via SMR or electrolysis powered by the grid mix; however, on-site production via renewable electrolysis results in the lowest impact. The carrier options generating the lowest ozone-depleting emissions result to be compressed and liquid hydrogen. Most of the impact for this category is related to the emissions of halocarbons (e.g., halomethanes, CFCs, HFCs), which in our case study are mainly emitted during the transportation of natural gas (97 % of the impact in the case of SMR, and 71 % in the case of on-site electrolysis) and the production of tetrafluoroethylene (75 % of the impact in the case of L-H_2), used for the electrolyser membranes and the photovoltaic cells. Given that the main sources of ozone-depleting emissions are not related to the transportation modes considered in the assessment, no significant difference is noticed for the ship vs. pipeline scenarios.

Figure 23. Ozone depletion results

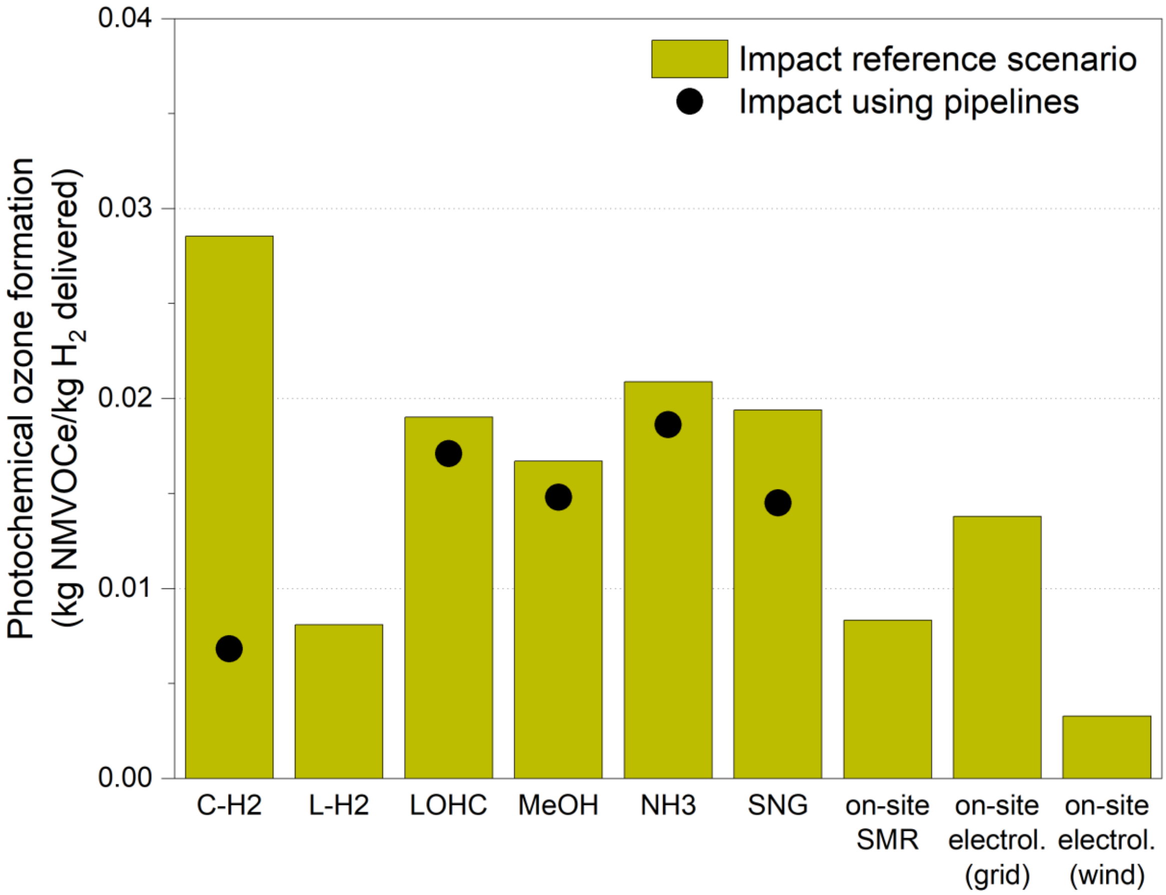


Source: JRC (2024)

4.13 Photochemical ozone formation

Results for the photochemical ozone formation category in terms of kilograms of non-methane volatile organic compound equivalents are presented in Figure 24. This impact is linked to the emissions of nitrogen oxides, non-methane volatile organic compounds, sulphur dioxide, and carbon monoxide. In the reference scenario, a large part of the impact is generated during the shipping phase with the burning of biodiesel. Given the larger amounts of ships (and hence biodiesel) needed to transport hydrogen in a compressed form, impacts are higher for this delivery pathway. For the same reason, transportation by ship generates higher impact compared to pipelines for all the carriers considered. Similar to the particulate matter category, it is important to highlight that the formation of ozone is problematic in populated areas due to its deleterious effects on human health. If emissions happened distant from the coast, the impact on human health could be reduced. For scenarios where hydrogen is transported by pipeline, the impact arises from several activities such as the manufacture of PV cells and the flaring of natural gas used along the supply chain. The best pathway for this impact category is on-site hydrogen production via renewable electrolysis. On-site production via SMR follows, because of the low emissions of nitrogen oxides compared to the transported options.

Figure 24. Photochemical ozone formation results

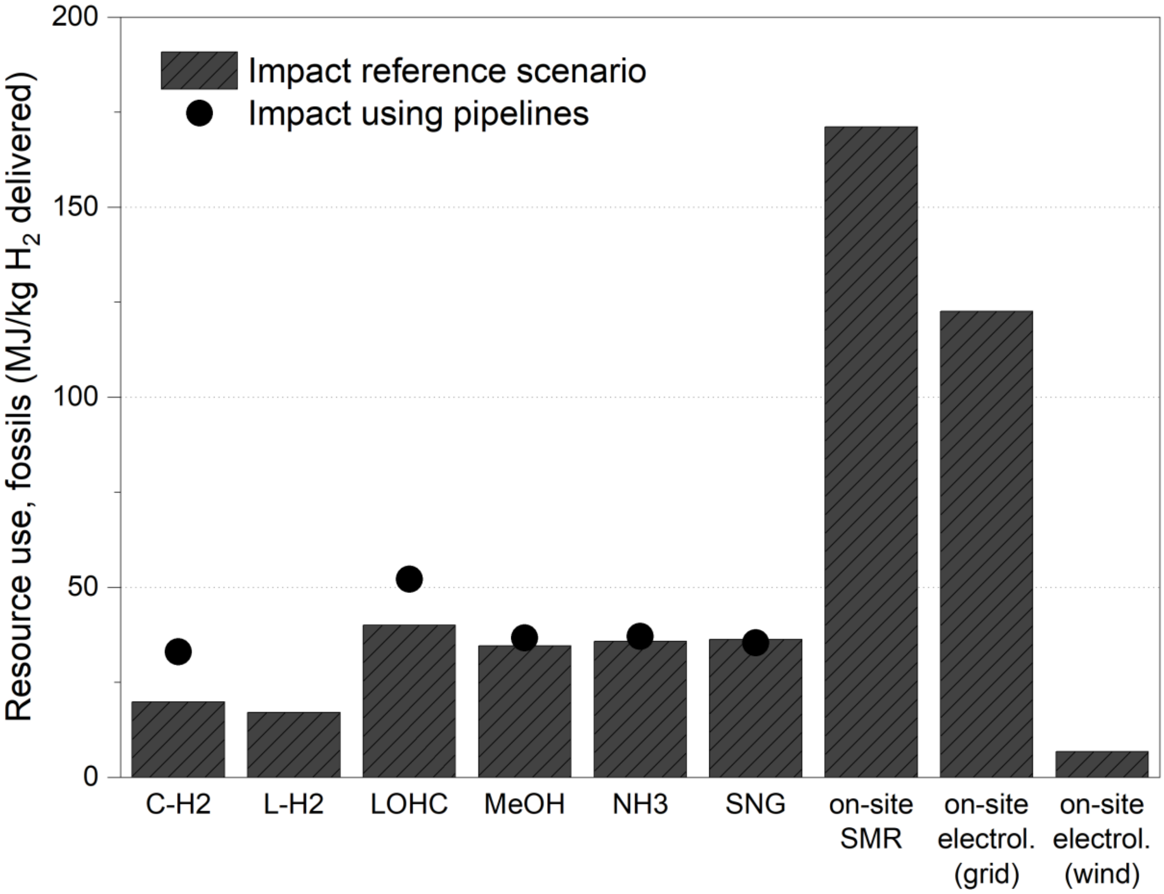


Source: JRC (2024)

4.14 Resource use, fossils

Impact results for the use of fossil resources expressed in MJ (Figure 25) show a clear advantage for importing renewable hydrogen than producing it on-site using entirely (SMR) or partially (electrolysis powered by the electricity grid mix) fossil fuels. Nevertheless, the option showing the lowest impact is the production of renewable hydrogen on-site. Among the imported options, delivery via liquid hydrogen appeared to be the one consuming less fossil resources. Transportation by pipeline show a larger impact than by ship due to the fossil component in the electricity grid mix used to transport the fluids in pipelines, compared to the biologically sourced diesel used on ships.

Figure 25. Resource use, fossils results

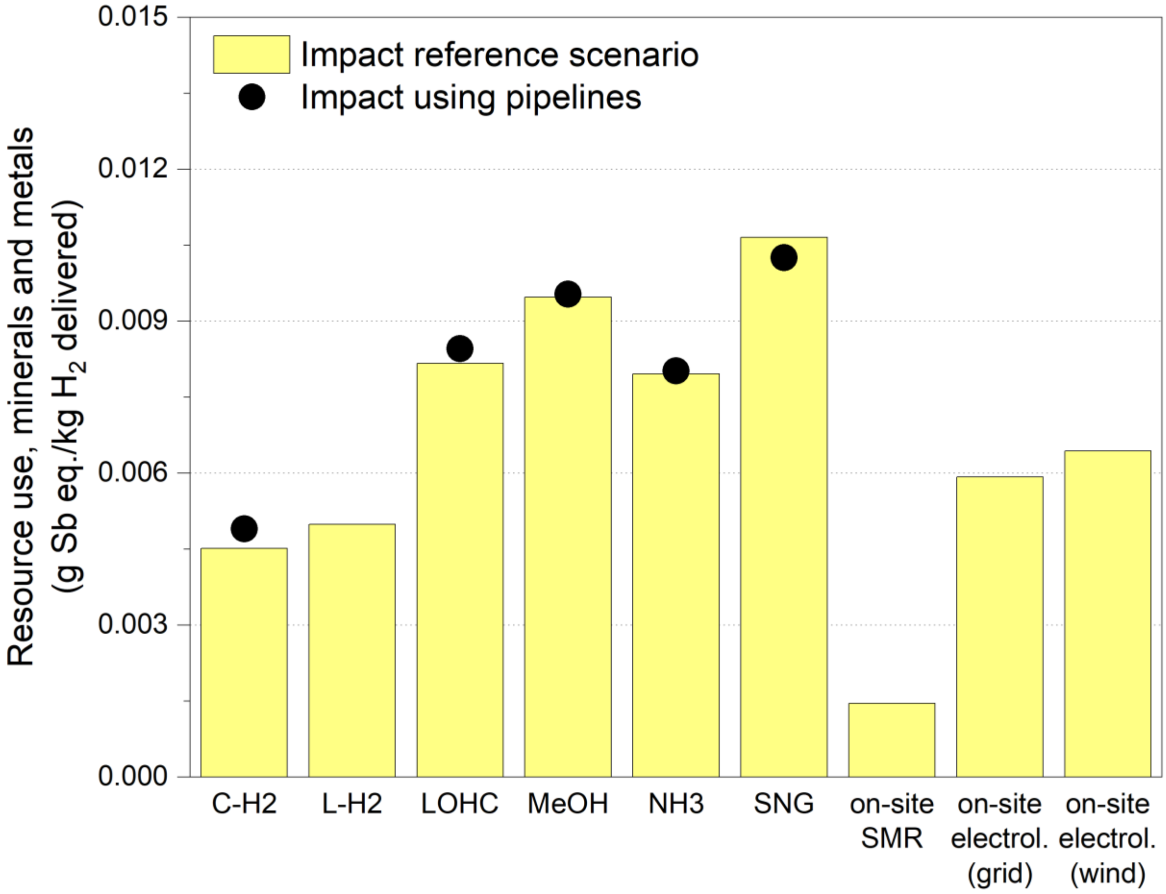


Source: JRC (2024)

4.15 Resource use, minerals and metals

Results for the use of minerals and metals expressed in grams of antimony equivalents are presented in Figure 26. Different to fossil resources, shipping renewable hydrogen consumes more minerals and metals than producing hydrogen on-site via SMR. The impact for the imported options is mainly linked to the use of two metals in the photovoltaic plant: copper and silver. The impact is therefore proportional to the amount of hydrogen (and therefore PV energy) needed for the different pathways. Given that raw materials used for hydrogen production are the main driver for the impact, there is not a significant variation in the results when ships or pipelines are considered. However, transportation by pipeline show slightly larger impacts due to the solar component of the electricity needed to transport the fluids. The exception is SNG, where additional solar electricity is needed to liquefy the gas before shipping. Electrolysis on-site generates a large consumption of resources, mainly linked to the use of tellurium for the wind farm infrastructure. It is noteworthy that the impact from catalysts along the delivery chain appears to be negligible compared to that resulting from the use of minerals in the PV panels.

Figure 26. Resource use, minerals and metals results



Source: JRC (2024)

4.16 Water use

Water use impact results expressed in cubic metre of water equivalents deprived are shown in Figure 27. Impacts are calculated using the AWARE method (Boulay et al., 2018), which assess the relative available water remaining per area in a watershed, after the demand of humans and aquatic ecosystems has been met. In line with most categories, production on-site shows lower impacts compared to the imported options. On-site renewable electrolysis is the option with a lower impact to provide hydrogen, while ammonia and methanol prove to be the options with a higher impact. Impact is mainly due to the water consumed for electrolysis, for electricity production, and for cooling processes. It is important to notice that the impact depends on the location where water is consumed. For instance, the impact from using freshwater in Portugal is approximately 40 times higher than the one of using it in the Netherlands, due to the different availability of water resources in the two countries. For this reason the impact for on-site renewable electrolysis pathway is almost negligible compared to the other options. The difference in the impact between on-site electrolysis powered by wind electricity and by the grid is due to the water consumed to produce the electricity. Based on the ecoinvent inventories and the EF characterization factors for water use, the production of 1 kWh via wind turbines in the Netherlands was estimated to consume approximately 4 litre-equivalents (L-e), while the assumed average Dutch grid mix production consumes approximately 40 L-e/kWh. For comparison, the production of electricity via PV panels in Portugal was estimated to consume 18 L-e/kWh. The impact from hydrogen production on-site via the grid mix is almost entirely (98 %) dependent on the electricity production, with the natural gas component contributing for almost half of the impact and solar PVs for 32 %. Despite the predominance of wind electricity in the forecasted Dutch grid mix (see Table A1), its contribution to the water use impact is minimal (8.5 %). The reason is that the supply chain and manufacture of wind mills does not consume as much water as the combustion of natural gas for electricity production[23] or as the production of silicon for PV panels[24]. After on-site hydrogen production from wind electricity, on-site SMR is the option generating the lowest water use impact. In line with many other environmental impact categories, compressed hydrogen by pipeline and liquid hydrogen are the options impacting less on water resources. The higher impact for the ammonia and methanol pathways is mainly linked to the high cooling requirements in the production processes. Since this water is assumed to be withdrawn in a country with limited availability of freshwater (i.e., Portugal), the impact becomes relevant. The reforming process in the SMR and SNG pathways require a lot of cooling water as well. However, since this water is assumed to be withdrawn from a country with higher water availability (i.e., the Netherlands), the overall impact results to be much lower.

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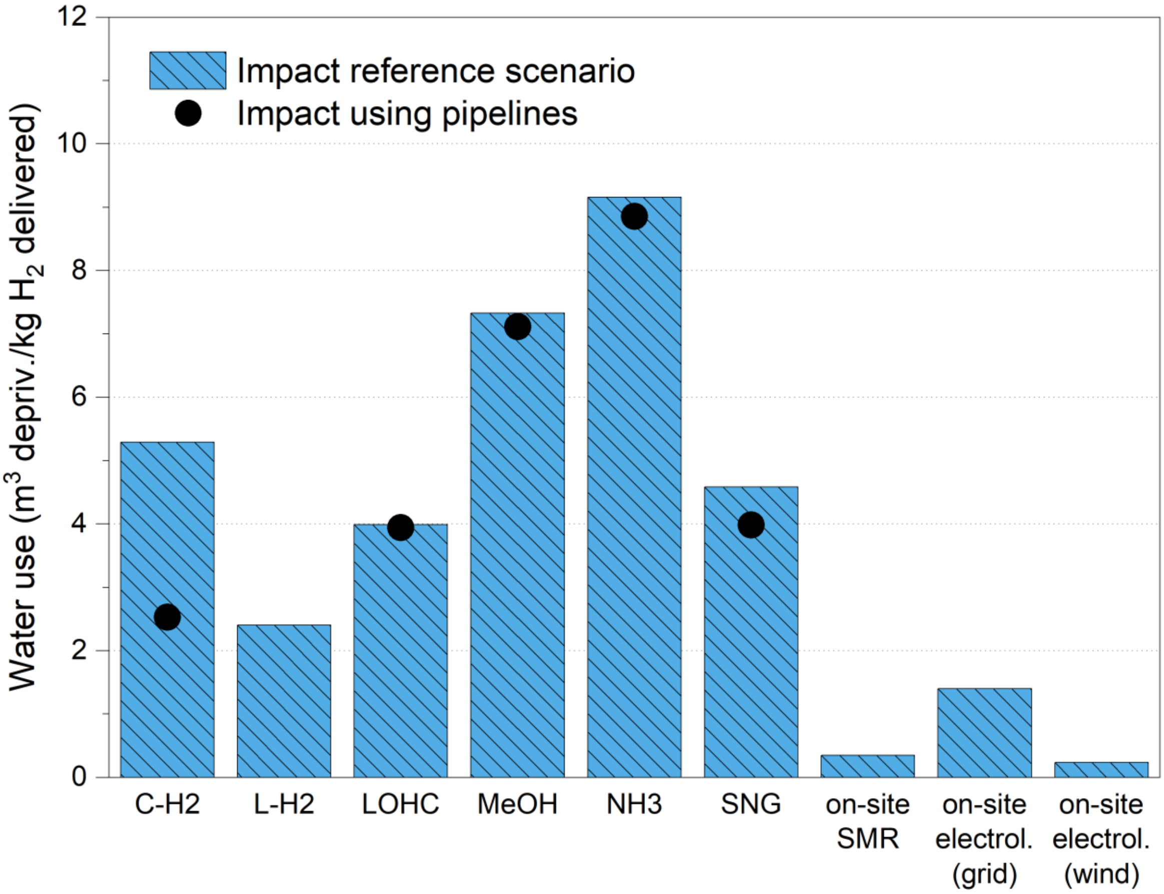
[23] Approximately 1.2 L of decarbonised water are assumed to be consumed per kWh in a natural gas combined cycle power plant (Wernet et al., 2016)

[24] Forty per cent of the cooling water in the silicon production is assumed to be lost to the atmosphere (Wernet et al., 2016)

Figure 27. Water use results



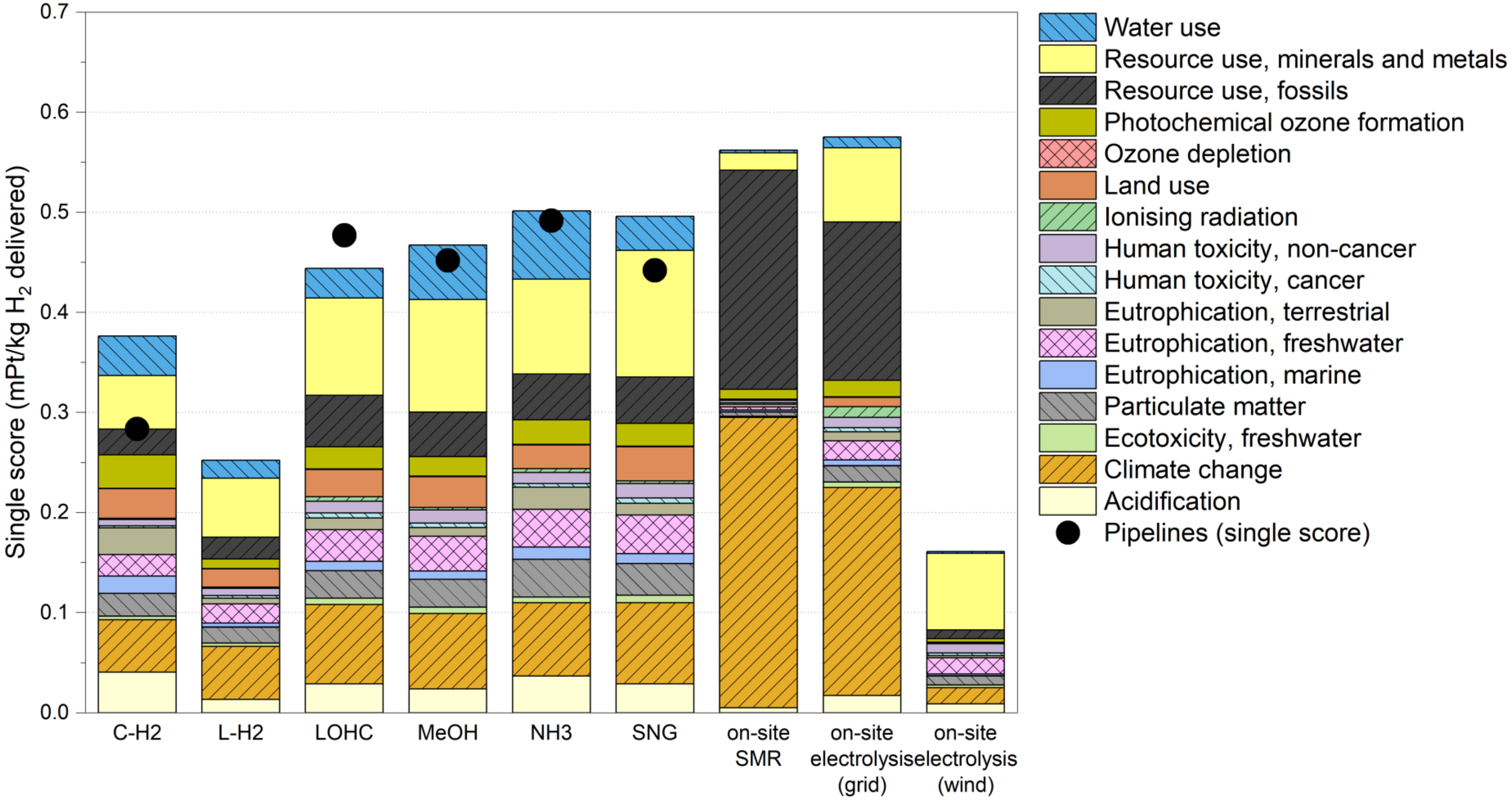
Source: JRC (2024)

4.17 Single score results

Results after normalization and weighting (see section 2.2.2) are presented in Figure 28. Results presented so far indicated the absolute potential impact arising to deliver the functional unit. To support the interpretation of these absolute results, the EF method requires normalization and weighting of the absolute impacts. Once normalised to the average global per capita emissions, results are multiplied by the set of weighting factors (Table 1) to obtain a final single score expressed in milli-points (mPt). Results are divided per impact category for the reference scenario (i.e., transportation by ship), while only the single score impact is shown for the pipeline cases (black circles).

Although producing hydrogen on-site via renewable electrolysis is the most environmentally friendly option, results suggest that delivering renewable hydrogen from a different location would have a lower environmental impact than producing it on-site using SMR or grid-powered electrolysis. Electrolysis powered by the grid could generate an impact similar to SMR in 2030. Notwithstanding the ambitious EU green deal plans, the EU grid will still partially rely on fossil fuels for electricity generation. Given the large amount of electricity needed for electrolysis, the impact from the fossil component of the grid mix would significantly affect the overall sustainability of hydrogen production. Although hydrogen production from SMR performed best in many environmental impact categories analysed in this report, the priority given by the EF methodology to the climate change category makes this pathway the worst option together with on-site grid-powered electrolysis. The environmental impact from this pathway can be almost entirely attributed to the consumption of fossil resources, namely natural gas, and to the emissions of greenhouse gases from its processing and use. If carbon dioxide was captured from the exhaust gas of the SMR plant, the climate impact from this pathway could be reduced and potentially be lower than the imported renewable hydrogen pathways. However, a detailed assessment of this pathway should be performed to understand all the environmental consequences, such as the additional demand for natural gas and additional methane losses to capture the carbon dioxide (Howarth and Jacobson, 2021). Among the imported options, the one generating the lowest impact is liquid hydrogen transported by ship, followed by compressed hydrogen transported by pipeline. Transportation of compressed hydrogen by ship significantly increases the overall impact for this pathway, due to the large amount of fuel needed for the ships. This results in increased impacts in several environmental categories, such as acidification, eutrophication, land use, and water use. Packing hydrogen into more convenient carriers for transportation increases the overall impact of the delivered hydrogen. This is mainly due to the additional energy and materials needed for the packing and unpacking processes. No significant difference was noticed among the carriers when all the environmental impacts were considered. If ships were used for transportation, LOHC and methanol appear to be slightly better options. If pipelines were to be used, SNG would be the least environmentally impactful solution followed by methanol. Nevertheless, transporting compressed hydrogen by pipeline in place of chemical carriers would significantly reduce the overall environmental impact of hydrogen delivery.

Figure 28. Single-score impact assessment results after normalization and weighting according to the Environmental Footprint method. Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered. See Section 2 and 3 for all the assumptions.



Source: JRC (2024)

5 Sensitivity analyses

In this section, the results from the sensitivity analysis are presented. The analysis is performed by varying one parameter at a time, to understand how a certain factor can affect the results. The climate change impact and the single score results are both presented when relevant. The parameters that are expected to affect the most the results and that allow to extend the scope of the present analysis to different scenarios are investigated. The parameters include: electrolyser efficiency (5.1), electricity generation (5.2), short-term climate impact (5.3), losses (0), shipping fuel (5.5), distance (5.6), water source (5.7), energy for unpacking (0), carbon capture and storage (0), efficiency of the processes (5.10), and impact assessment method (5.11). Other minor sensitivity analyses, such as alternative approaches to address multifunctionality and the catalyst choice for SNG synthesis, are presented in Section 5.12.

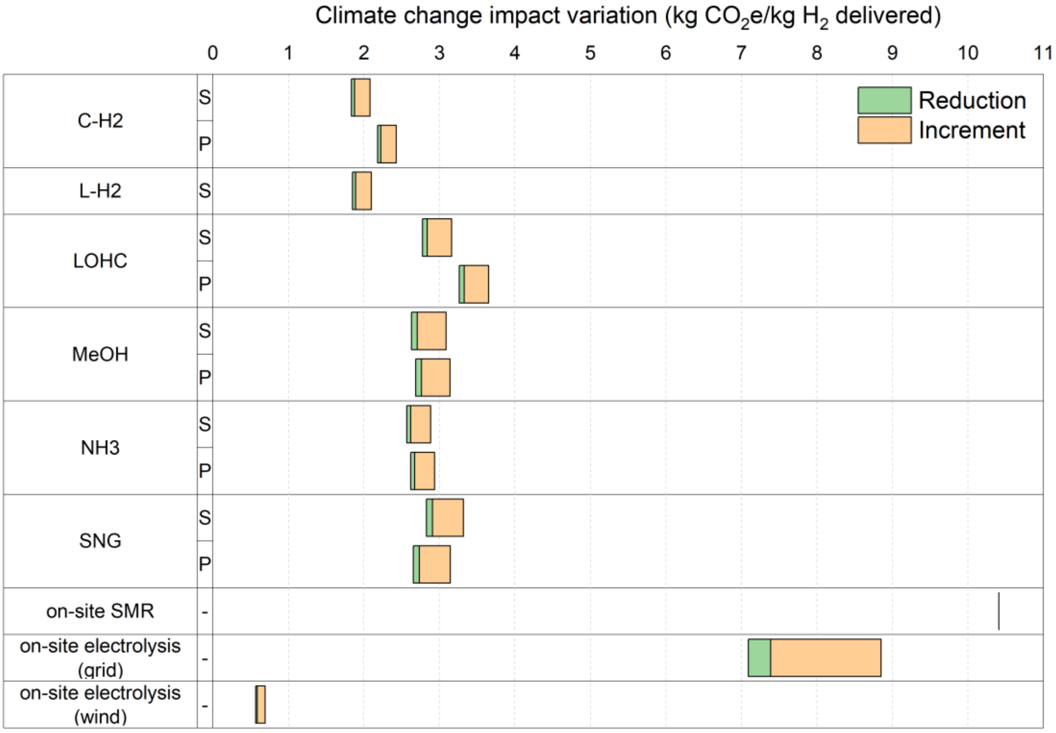
5.1 Electrolyser efficiency

Figure 29 and Figure 30 show the results of the sensitivity analysis varying the efficiency of the electrolyser for the climate change impact category and the single score impact, respectively. The efficiency of the electrolyser was varied from a reference value of 50 kWh/kg H_2 to 48 kWh/kg H_2 for the best-case scenario (green variation in Figure 29 and Figure 30) and to 60 kWh/kg H_2 for the worst-case scenario (orange variation).

Results show a significant variation of the climate impact only for the on-site electrolysis powered by the grid: given the relatively high carbon intensity of the grid mix assumed for the Netherlands in 2030, a variation in the electricity consumption of the electrolyser significantly affects the final footprint of the hydrogen delivered. In the worst-case scenario, the impact from on-site electrolysis powered by the grid would reach almost 9 kg CO_2e per kilogram of hydrogen delivered. For the other pathways, the effect of the electrolyser efficiency on the carbon intensity of the hydrogen delivered is less substantial: an improvement of 2 kWh per kg of hydrogen results in a reduction of the carbon intensity from 0.02 kg CO_2e/kg H_2 for on-site electrolysis powered by wind energy to 0.08 kg CO_2e/kg H_2 for the methanol and SNG pathway. A lower efficiency of the electrolyser would increase the footprint of the pathways up to 0.4 kg CO_2e/kg H_2 delivered in the case of methanol and SNG. This additional impact would lead to a carbon intensity of the hydrogen delivered higher than the Taxonomy emission threshold for the manufacture of hydrogen. The on-site SMR pathway is shown just as reference since not affected by this parameter.

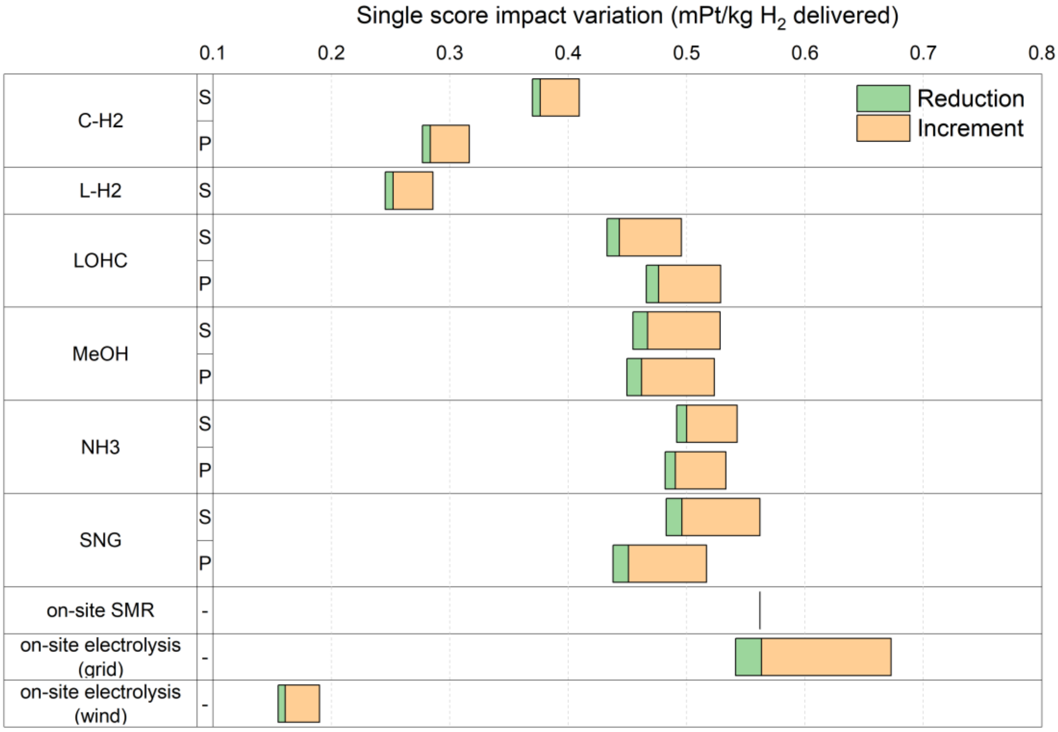
When all the environmental categories are considered (Figure 30), impacts reduce by 2 - 4 % in the best-case scenario and increase by 8 – 19 % in the worst-case scenario. On-site electrolysis powered by the grid is the option showing the highest variations, mainly linked to the lower or additional fossil fuels used to produce hydrogen. The ranking among the different delivery options does not change with the efficiency of the electrolyser.

Figure 29. Sensitivity analysis results for the climate change impact category varying the efficiency of the electrolysers. The values indicate the variation with respect to the global warming impact obtained for each pathway in the reference scenario. For imported options, results are presented both for transportation by ship (S) and pipeline (P).



Source: JRC (2024)

Figure 30. Sensitivity analysis results for the single score impact varying the efficiency of the electrolysers. For imported options, results are presented both for transportation by ship (S) and pipeline (P). Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.



Source: JRC (2024)

5.2 Electricity generation

In this section, the sensitivity of the results to the impact of renewable electricity input (5.2.1) and the electricity grid mix (5.2.2) is presented.

5.2.1 Renewable electricity generation

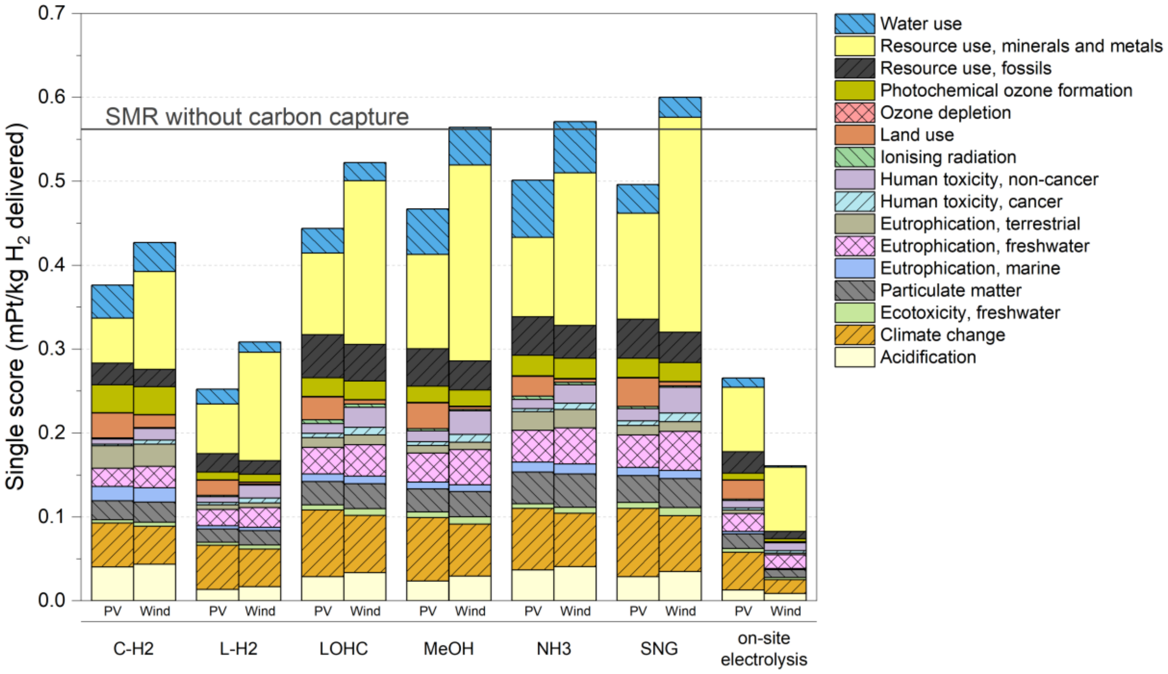
Two aspects have been investigated regarding renewable electricity generation: i) the type of renewable source (5.2.1.1), focusing on solar and wind power, and ii) the environmental impact of the renewable electricity infrastructure (5.2.1.2).

5.2.1.1 Renewable source: solar vs. wind

In the reference scenario, hydrogen is assumed to be produced via PV electricity in Portugal and wind electricity in the Netherlands (see Section 3.1.1). A sensitivity analysis was performed to investigate how the impacts would vary if a different renewable source was used in the two countries, namely wind power source in Portugal and PV power in the Netherlands. To do so, the different capacity factors for the renewable energy sources were considered. Solar PVs are assumed to have a 35 % lower capacity factor in the Netherlands compared to Portugal (i.e., 9 % vs 14 %), and onshore wind turbines a 30 % lower capacity factor in Portugal compared to the Netherlands (i.e., 16 % vs 24 %), based on ecoinvent data (Wernet et al., 2016). Converting this into environmental impacts, it means that solar PVs in the Netherlands produce electricity with an impact that is 55 % higher than in Portugal, and wind turbines in Portugal produce electricity with an impact that is 44 % higher than in the Netherlands. Single-score results for the hydrogen delivery pathways varying the source of renewable source used in Portugal and the Netherlands are presented in Figure 31. The SMR and electrolysis powered by the grid options are not shown in the figure because they are unaffected by the source of dedicated renewable electricity, but the single-score impact for SMR without carbon capture is shown for comparative purposes.

Although the environmental impact of a certain renewable energy source is linearly proportional to its efficiency (assuming the same lifetime), the impact from using different renewable sources, such as wind turbines or PV panels, depends on the different supply chains for the infrastructure needed. Therefore, even though wind electricity generates a larger environmental impact in Portugal compared to the Netherlands, its environmental impact might still be lower than solar electricity in Portugal. This is actually the case for the climate impact, with electricity from wind turbines in Portugal generating lower GHG emissions than PV panels. The reason can be ascribed to the different materials needed for the infrastructure, and the different energy sources in the producing countries. While most of the climate impact of wind turbines can be attributed to the production of steel, concrete, and glass fibre, for PV panels, most of the impact comes from the production of silicon and aluminium, with the use of coal in China playing an important role. Despite a larger climate impact, using PV panels in Portugal proves to be a less impactful solution when the single-score impact is considered. If wind power was used in place of PVs for operations in Portugal, impacts would increase on average by 18 %. For some pathways, the environmental footprint of imported renewable hydrogen may be higher than SMR without carbon capture. The largest increase can be seen for the consumption of minerals and metals due to the large consumption of copper per unit of energy produced, which overcompensates for the impact reduction in categories such as climate change and water use. An opposite trend can be noticed at the use site (Netherlands), where using PVs to produce hydrogen would significantly increase the environmental impact of the hydrogen produced. This is mainly linked to the low capacity factor of PVs in the Netherlands: while the climate impact of on-site electrolysis powered by PVs would result in a lower impact than imported liquid hydrogen due to lower hydrogen losses along the delivery chain, hydrogen production in the Netherlands via dedicated PV plant may result in a larger environmental footprint than imported liquid hydrogen due to the larger use of materials to fulfil the same function.

Figure 31. Sensitivity analysis results for the single score impact varying the source for renewable electricity both at the hydrogen production site and delivery site. For the imported options, results are shown only for transportation by ship. Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.



Source: JRC (2024)

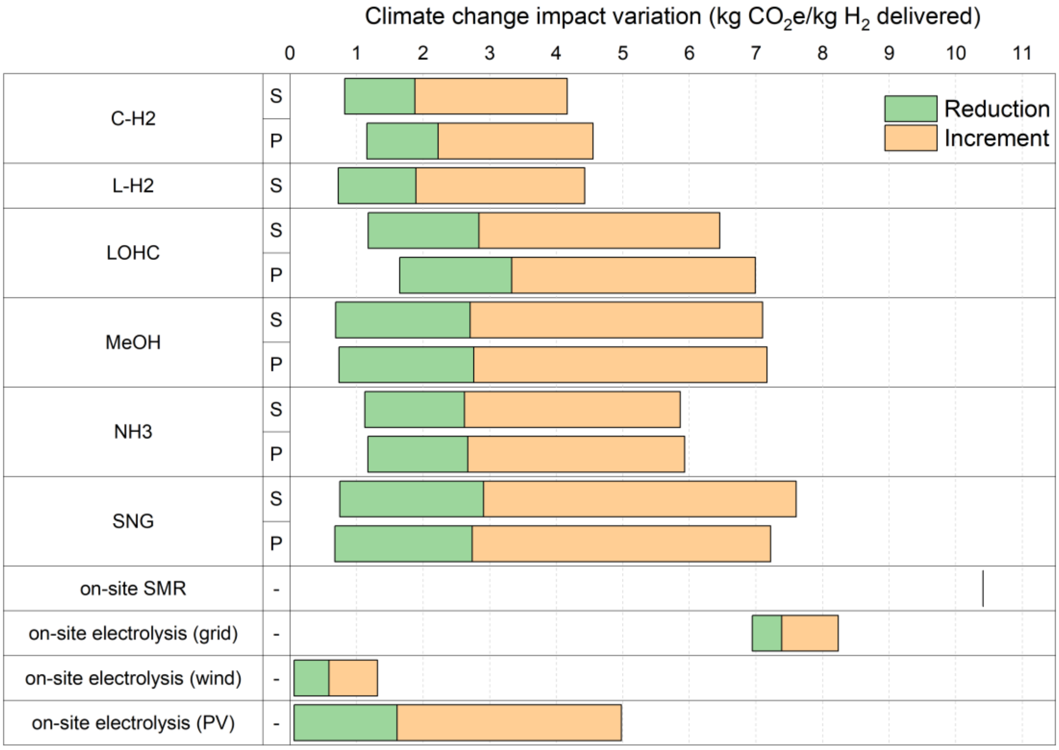
5.2.1.2 Environmental impact renewable infrastructure

In the reference scenario, optimistic assumptions from the Hydrogen Council (2021) on the impact from renewable electricity generation were made (3.1.1). Here we assessed how the impacts would vary if the current impact from renewable electricity generation from the ecoinvent database was considered (i.e., worst-case scenario). According to ecoinvent, current climate impact from PV electricity generation in Portugal (62 g CO_2e/kWh) is more than 3 times higher than the prospective value considered by the Hydrogen Council. Since in our reference scenario the ecoinvent PV dataset was edited to reflect the Hydrogen Council emission factor by reducing all the inputs by two thirds, all the environmental impacts from PV electricity generation in this sensitivity analysis are 3.2 times higher. The same approach is used for wind electricity at the hydrogen use site: inputs and impacts from wind electricity generation are increased by 2.4 times to reflect the current ecoinvent emission factor (24 g CO_2e/kWh) for on-shore wind electricity production in the Netherlands. Impacts were increased also for the renewable components of the electricity grid mixes used along the delivery chain: while in the reference scenario the same impacts for solar (20 g CO_2e/kWh) and wind (10 g CO_2e/kWh) electricity were considered across Europe (e.g., to move hydrogen in the pipeline or to dehydrogenate the carriers at the use site), in the sensitivity analysis the ecoinvent dataset for renewable electricity generation in the different countries were used. Therefore, the impact from solar electricity in the Dutch grid mix will be for instance higher than the Portuguese one due to the lower capacity factor. The additional scenario considering hydrogen production on-site via a dedicated solar PV plant is also included in the analysis for comparative purposes. An emission factor of approximately 30 g CO_2e/kWh was considered for PV electricity in the Netherlands, given the lower capacity factor.

The climate and single score results considering the current emission factors for renewable electricity production are presented by the orange “increment” bars in Figure 32 and Figure 33, respectively. Results show that the embodied emissions from the renewable electricity generation are a crucial parameter for determining the sustainability of renewable hydrogen delivery. When looking at the climate impact (Figure 32), the impact increases from a minimum of 0.7 kg CO_2e/kg H_2 for on-site renewable electrolysis to a maximum of 4.7 kg CO_2e/kg H_2 for SNG transported by ship. In the Netherlands, importing renewable hydrogen from a distant location proves to be more climate friendly than producing it on-site via electrolysis powered by the grid also in this scenario. However, if embodied emissions from solar electricity will not fall in the coming years, the impact from imported solar-powered hydrogen would be significantly higher than hydrogen produced on-site via wind power. The same cannot be said for hydrogen produced on-site via solar power: depending on the capacity factor for the solar power installation, importing hydrogen from a sunnier area could make sense from a life-cycle GHG emission perspective. Considering the current emission factors for PV production, importing hydrogen from Portugal would generate less GHG emissions than producing it on-site from local PVs. If emissions from PV manufacture were to decrease (reference scenario), the climate impact of hydrogen produced locally via solar power would be slightly lower (1.6 kg CO_2e/kg H_2) than the impact of the best options for delivered hydrogen (1.9 kg CO_2e/kg H_2) despite the lower capacity factor. The best option for imported hydrogen remain compressed and liquid hydrogen also in the worst-case scenario, with an impact of 4-4.5 kg CO_2e/kg H_2 delivered. This impact is more than 3 times the impact of producing hydrogen on-site via current wind electricity (1.3 kg CO_2e/kg H_2). As for the other options, the impact considering current embodied emissions from renewables increases proportionally to the amount of energy needed at the hydrogen production site for the extra hydrogen and the packing stage. Synthetic natural gas proves to be the worst option given the large amount of electricity needed for the packing stage, while ammonia is the option affected the least by the embodied impact of solar electricity. Nevertheless, the impact of hydrogen delivered via ammonia would increase from 2.7 kg CO_2e/kg H_2 in our reference scenario to 5.9 kg CO_2e/kg H_2. The ranking among the options is similar when all the environmental categories are considered (Figure 33). The striking difference is that on-site SMR performs significantly better than all the imported options (including the compressed and liquid hydrogen pathways) and on-site electrolysis powered by PVs when current embodied emissions of renewable energy sources are considered. Moreover, on-site electrolysis powered by the grid results in a similar (slightly worse) environmental footprint to compressed and liquid hydrogen pathways, performing significantly better than the options requiring the packing of hydrogen into chemical carriers. The reason can be ascribed to the lower influence that the embodied emissions from the renewable infrastructure have on on-site electrolysis powered by the grid: in fact, less electricity is needed for this delivery pathway, and renewables (in particular solar) represent only a share of the total mix. The largest impact of the imported options are linked to several impact categories, but in particular to the larger use of minerals, metals, and land, and to the higher toxic emissions.

In Figure 32 and Figure 33, a scenario where the impact from solar and wind electricity is considered null is also shown (green “reduction” bars). Although this assumption is unrealistic and unreasonable from an LCA perspective, it is aligned with the methodology of the EU delegated act for determining the greenhouse gas emissions of renewable transport fuels of non-biological hydrogen (European Commission, 2023), such as hydrogen produced via electrolysis powered by solar or wind electricity. This methodology may be used also for the Taxonomy regulation to assess the impact of hydrogen production (European Commission, 2022). Therefore, this best-case scenario for renewable electricity generation could tell whether the hydrogen imported would meet the Taxonomy criterion for sustainable hydrogen manufacture (i.e., life-cycle GHG emissions lower than 3 kg CO_2e/kg H_2). Similarly to the worst-case scenario, the impact from the renewable electricity infrastructure has a primary role in the carbon and environmental footprint of the hydrogen delivered. The climate impact is reduced by a minimum of 6 % for the on-site electrolysis (grid) option to a maximum of 75 % for the SNG transported by pipeline option. The on-site SMR pathway is not affected by the parameter investigated here. The climate impact of the hydrogen delivered varies from a virtual zero for on-site electrolysis powered by wind electricity to a maximum of 1.6 kg CO_2e/kg H_2 for the LOHC by pipeline pathway. All the pathways except for on-site SMR and on-site electrolysis (grid) would provide hydrogen with a carbon footprint below the Taxonomy threshold for sustainable hydrogen. The hydrogen delivered could also be classified as renewable fuel of non-biological origin according to the renewable energy directive. Interestingly, when the embodied emissions from the renewable infrastructure are considered to be null, the best delivery options appear to be SNG and methanol due to the lower energy requirements at the use-site and the lower hydrogen losses compared to liquid hydrogen. On-site electrolysis powered by the grid would still not be eligible, due to the fossil component in the electricity mix leading to a hydrogen carbon footprint much higher than 3 kg CO_2e/kg H_2. The trend noticed for the climate impact is this time reflected also in the overall environmental footprint: with the renewable infrastructure, mainly solar, being the main responsible for the large environmental impact of the different delivery options, the overall impact of the hydrogen delivered is substantially reduced when the impact of the renewable infrastructure is not accounted for. On-site renewable electrolysis is still the best option, followed by the liquid hydrogen and compressed hydrogen delivered by pipeline. Differently from the climate impact, SNG and methanol perform slightly worse due to the additional infrastructure required along the delivery chain. Liquid organic hydrogen carriers and ammonia follow, with larger impacts mainly linked to the non-renewable component of the electricity required at the use site.

Figure 32. Sensitivity analysis results for the climate change impact category varying the impact from the renewable electricity source. The values indicate the variation with respect to the global warming impact obtained for each pathway in the reference scenario. Results are shown both for deliveries by ship (S) and pipeline (P).



Source: JRC (2024)

Figure 33. Sensitivity analysis results for the single score impact varying the impact from the renewable electricity source. Results are shown both for deliveries by ship (S) and pipeline (P). Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.

Source: JRC (2024)

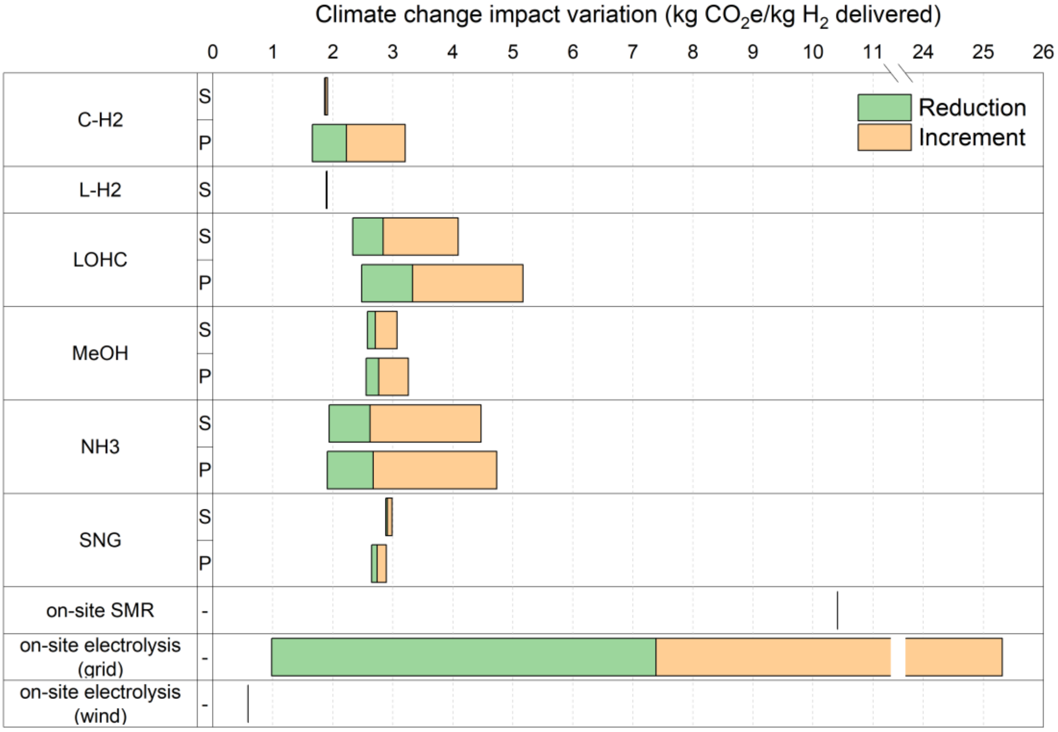
5.2.2 Electricity grid mix

Two electricity grid mixes are considered in our assessment: a European mix for the electricity consumption taking place between the hydrogen production site and the use site (e.g., electricity consumed by the pipeline compressors), and a Dutch mix for the electricity consumed at the use site (e.g., for the unpacking stage). In the reference scenario, the mixes are based on the EU Fit for 55 targets (see Section 3.1.1). Similarly to the other sensitivity analyses, a best-case and worst-case scenario are assumed for the electricity mixes to understand the effect of this parameter on the results. Although the Fit for 55 targets are already quite ambitious, a best-case scenario where the European and the Dutch grid mixes are fully decarbonized is considered. For this scenario, the fossil component of the mixes (see Annex I) is replaced by wind and solar power with the same proportions assumed for the reference scenario. In the worst-case scenario, the current grid mixes available in the ecoinvent 3.9 database were used. Mixes considered in the worst-case scenario rely much more on fossil resources compared to the reference scenario. For instance, fossil fuels currently account for more than 60 % in the Dutch electricity mix. Results are presented for the climate impact in Figure 34, and for the EF single score in Figure 35.

As expected, the largest sensitivity to the grid mixes is seen for the on-site electrolysis pathway powered by the grid. The climate impact varies from a minimum of approximately 1 kg CO_2e/kg H_2 when the electricity mix powering the electrolyser is assumed to be fully renewable to more than 25 kg CO_2e/kg H_2 when the current Dutch grid mix is considered. Depending on the impact of the electricity powering the electrolyser, it makes more or less sense from an environmental perspective to import hydrogen from a different location. In a country heavily reliant on fossil fuels where the electrolyser would not be powered by renewable sources, importing renewable hydrogen would avoid a lot of GHG emissions. In the worst-case scenario for the European grid mix, imported hydrogen would have a climate impact ranging from 1.8 kg CO_2e/kg H_2 for compressed hydrogen delivered by ship to 5.2 kg CO_2e/kg H_2 for hydrogen delivered via LOHC through pipelines. On the other hand, if the grid mix powering the electrolyser was already fully renewable (this could be the case of Sweden for instance), importing renewable hydrogen from a different location would make little sense from an environmental perspective. The environmental impact of grid electricity also affects the choice of transportation: when the grid is fully renewable, transportation by pipeline show a slight advantage compared to ships powered by biodiesel. The exception is LOHC, which shows higher impacts when transported by pipeline even in the best-case scenario for the grid mix. The reason is the additional pipeline required to transport back the dehydrogenated LOHC. When the electricity powering the pipelines relies heavily on fossil fuels, transportation by ship guarantees lower impacts. For instance, transporting compressed hydrogen and LOHC by pipeline result in a hydrogen carbon footprint more than 1 kg CO_2e/kg H_2 higher than by ship. The exception is SNG, which shows a lower carbon footprint when transported by pipeline even in the worst-case scenario due to the extra energy to liquefy and evaporate the SNG when shipped. The pathways involving liquid hydrogen and compressed hydrogen transported by ship are minimally affected, given the small amount of energy consumed at the delivery site. Methanol and SNG are also only marginally affected, given the low amount of electricity needed to transport and unpack them.

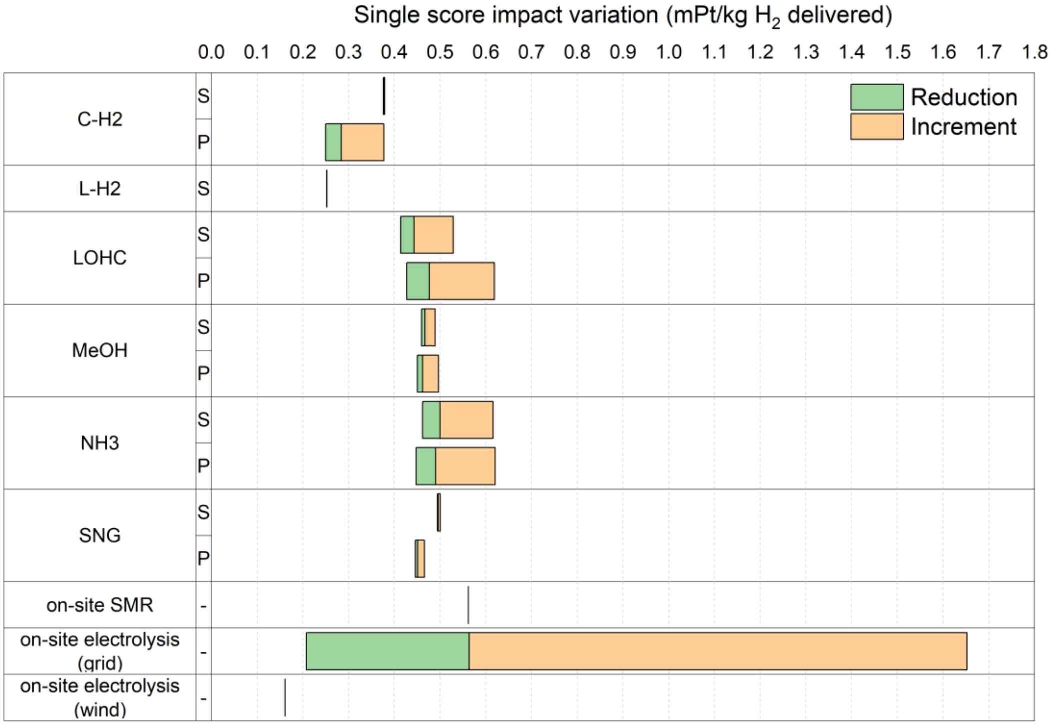
Similarly to the climate results, on-site grid electrolysis is the pathway showing the largest variation also when all the 16 environmental impact categories are considered. Compressed hydrogen by ship, liquid hydrogen, methanol, and SNG are marginally affected. Ammonia and LOHC are the carriers affected the most by this parameter, again due to the higher electricity requirements at the delivery site for unpacking. The variation in the overall environmental performance is mainly driven by the climate change and fossil resource categories, linked to the use of fossil fuels to produce electricity.

Figure 34. Sensitivity analysis results for the climate change impact category varying the impact from the European and Dutch electricity grid mix. For imported options, results are presented both for transportation by ship (S) and pipeline (P).



Source: JRC (2024)

Figure 35. Sensitivity analysis results for the EF single score impact varying the impact from the European and Dutch electricity grid mix. For imported options, results are presented both for transportation by ship (S) and pipeline (P). Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.



Source: JRC (2024)

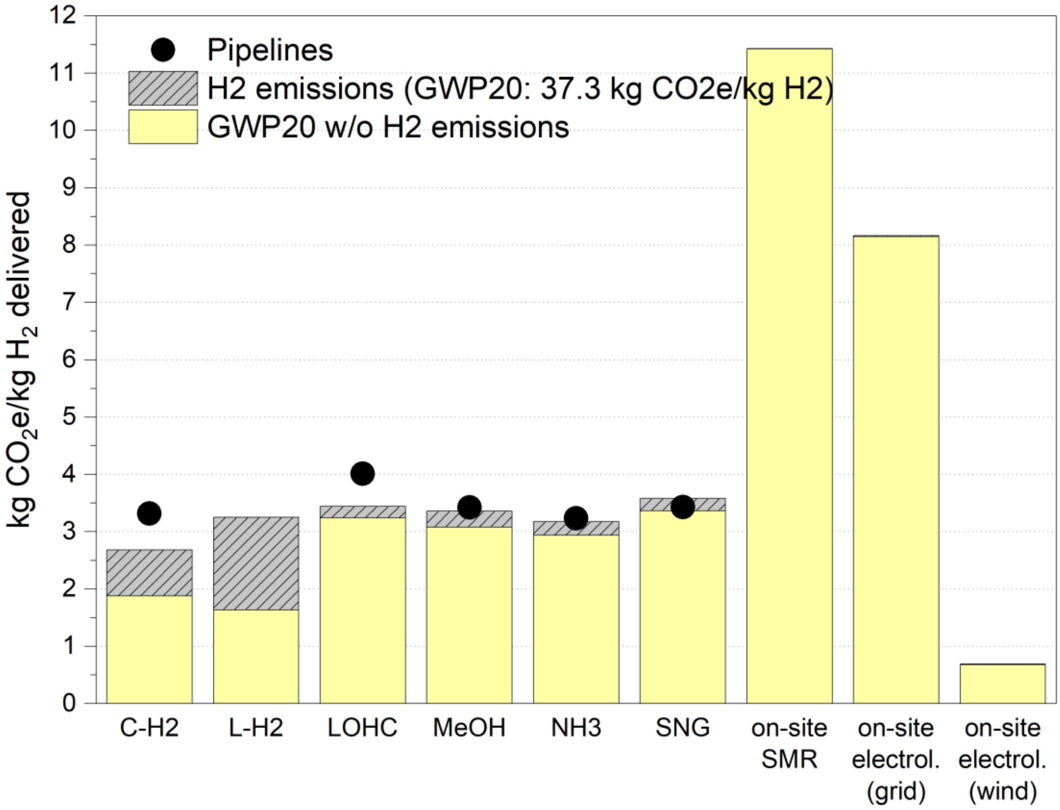
5.3 Short-term climate impact (GWP_{20})

In Figure 36 the climate change impact results using the global warming potential (GWP) metric with a timeframe of 20 years (GWP_{20}) are presented. The method is based on the 6th assessment report of the Intergovernmental Panel on Climate Change (IPCC, 2021). The difference with the impacts presented in Section 4.2 is the time horizon considered: 20 vs. 100 years. Since the gases responsible for climate change have a different lifetime in the atmosphere, the climate impact of the emissions depends on the time horizon considered since the gases are emitted. Greenhouse gases with a short lifetime have a higher impact when shorter time-horizons are considered: for instance, the GWP over 20 years of methane is 82.5 kg CO_2e/kg compared to 29.8 kg CO_2e/kg over 100 years. The GWP_{20} metric is mainly used to understand the potential climate change effect of an activity in the short term. The GWP_{20} of hydrogen emissions was also included in the assessment, considering the value proposed by Sand et al. (2023): 37.3 ± 15.1. Similarly to methane, hydrogen has a short lifetime in the atmosphere (approximately 2 years), which leads to a higher indirect global warming potential value over 20 years compared to 100 years (Arrigoni and Bravo Diaz, 2022). The contribution from hydrogen emissions to the overall GWP_{20} impact is represented with grey bars with a diagonal pattern in Figure 36.

The 20-year climate impact of the hydrogen delivered ranges from a minimum of 0.7 kg CO_2e/kg H_2 for hydrogen produced on-site via renewable electricity to a maximum of 11.4 for hydrogen produced via SMR. All pathways show a larger impact compared to the GWP_{100} values, due to the emissions of short-lived greenhouse gases (namely methane) and indirect greenhouse gases (namely hydrogen) along the delivery chain. Excluding hydrogen emissions, the largest change in the GWP can be noticed for on-site SMR due to the emissions of methane in the reforming activity and along the natural gas supply chain. The GWP increase for the other pathways is strictly linked to the amount of electricity consumed, due to the emissions of methane from the supply chain of the fossil fuels used for the electricity infrastructure, such as PV panels.

When hydrogen emissions are included in the assessment, the GWP20 increases significantly mainly for the liquid hydrogen pathway: the impact of the hydrogen delivered doubles from 1.6 kg CO_2e/kg H_2 when hydrogen emissions are excluded to 3.2 kg CO_2e/kg H_2. Compressed hydrogen follows, with an increase of 0.8 kg CO_2e per kilogram of hydrogen delivered. The other pathways show a much smaller increase (0.2-0.3 kg CO_2e/kg H_2 delivered) due to the lower hydrogen losses along the delivery chain. When the short-term climate impact of the different options is considered, compressed hydrogen transported by ship proves to be the best imported option. The liquid hydrogen pathway shows impacts in line with the ones involving chemical carriers, which range from a minimum of 3.2 kg CO_2e/kg H_2 for the ammonia pathway to 3.6 kg CO_2e/kg H_2 for the SNG pathway. In Section 0 the variation in the impact varying the assumptions on hydrogen (and ammonia) losses is presented.

Figure 36. GWP_{20} results



Source: JRC (2024)

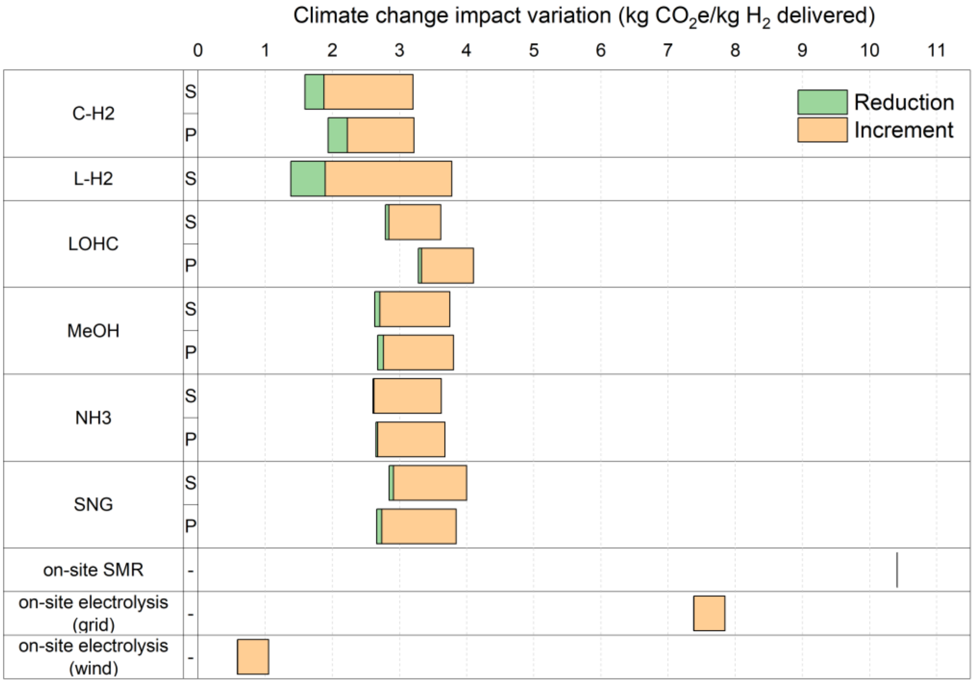
5.4 Losses of hydrogen and hydrogen carriers

In this section, the change in impact varying the amount of hydrogen and of chemical carriers (i.e., ammonia, SNG) lost to the atmosphere along the delivery chain is presented. The range of emissions considered is the one presented in the inventories for the different pathways (Section 3).

In Figure 37 the variation of the climate impact is shown. The impact variation shown in Figure 37 depends on the losses of direct (carbon dioxide, methane) and indirect (hydrogen) greenhouse gases, and to the additional processes needed to make up for the lost hydrogen and chemical carriers. No indirect greenhouse effect was considered for ammonia emissions (European Commission, 2018). The pathway affected the most by the losses is liquid hydrogen, due to the large range of losses considered. Current loss estimates are extremely high for liquid hydrogen, but are expected to be significantly reduced in the coming years (Arrigoni and Bravo Diaz, 2022). If emissions were not reduced in the coming years and if the worst values for hydrogen losses found in the literature were considered, the impact of the hydrogen delivered via the liquid hydrogen pathway could be well above the Taxonomy threshold of 3 kg CO_2e/kg H_2. The impact of hydrogen delivered via liquid hydrogen in the worst case (3.8 kg CO_2e/kg H_2) would be similar to the (worst) impact of hydrogen delivered via LOHC, methanol, ammonia, and SNG. Compressed hydrogen proves to be the best option even in the worst-case scenario. The best-case scenarios for losses do not show significant variations with respect to the reference scenario, since losses were assumed to be minimized by 2030. In the best-case scenario, liquid hydrogen results to be the best pathway, leading to a carbon footprint of the hydrogen delivered of approximately 1.4 kg CO_2e/kg.

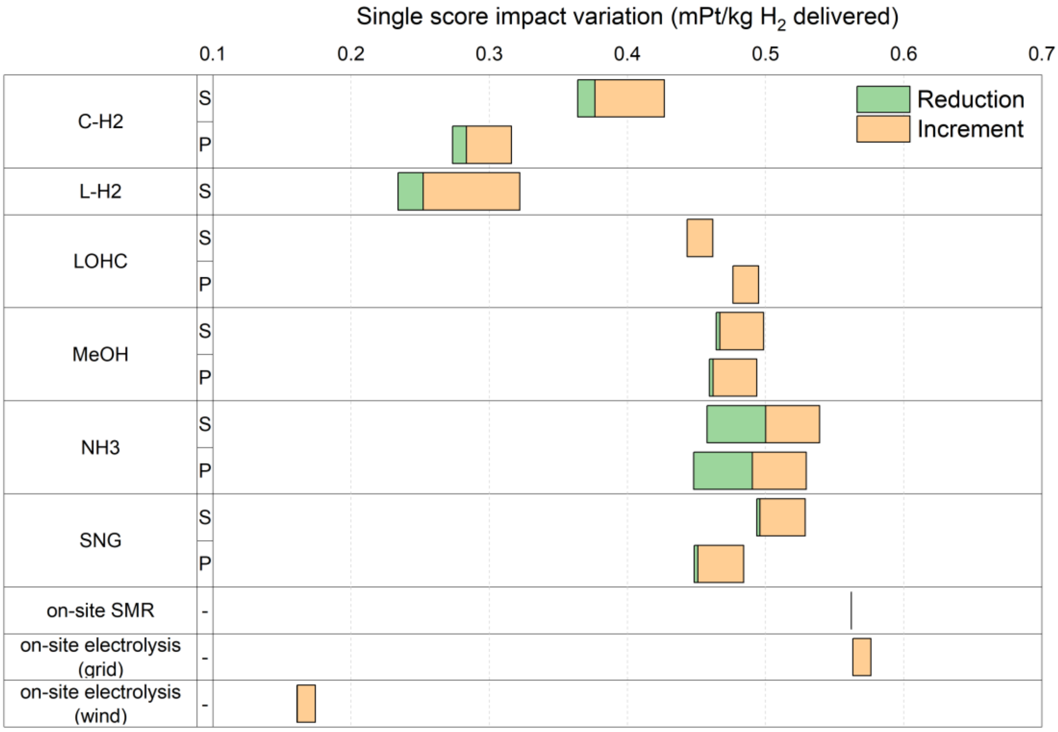
The impact variation considering all the 16 EF environmental impact categories is shown in Figure 38. Similarly to the climate change results, the pathway affected the most by this parameter is liquid hydrogen. However, while the climate impact of the liquid hydrogen pathway in the worst-case scenario was comparable to the one of the pathways involving chemical carriers, the overall environmental footprint of the liquid hydrogen pathway results to be significantly better even in the worst-case scenario. In the best-case scenario, the liquid hydrogen pathway performs better than the compressed hydrogen one as well. The ammonia pathway shows also a significant impact variation depending on the amount of hydrogen and ammonia lost. In the best-case scenario, ammonia via pipeline proves to be the best pathway among the different chemical carriers. However, ammonia by ship result to be the worst option (together with SNG by ship) in the worst-case scenario due to the large environmental impact of ammonia emissions.

Figure 37. Sensitivity analysis results for the climate change impact category varying the losses of hydrogen and ammonia along the delivery chain. For imported options, results are presented both for transportation by ship (S) and pipeline (P).



Source: JRC (2024)

Figure 38. Sensitivity analysis results for the EF single score impact varying the losses of hydrogen and ammonia along the delivery chain. For imported options, results are presented both for transportation by ship (S) and pipeline (P). Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.



Source: JRC (2024)

5.5 Shipping fuel

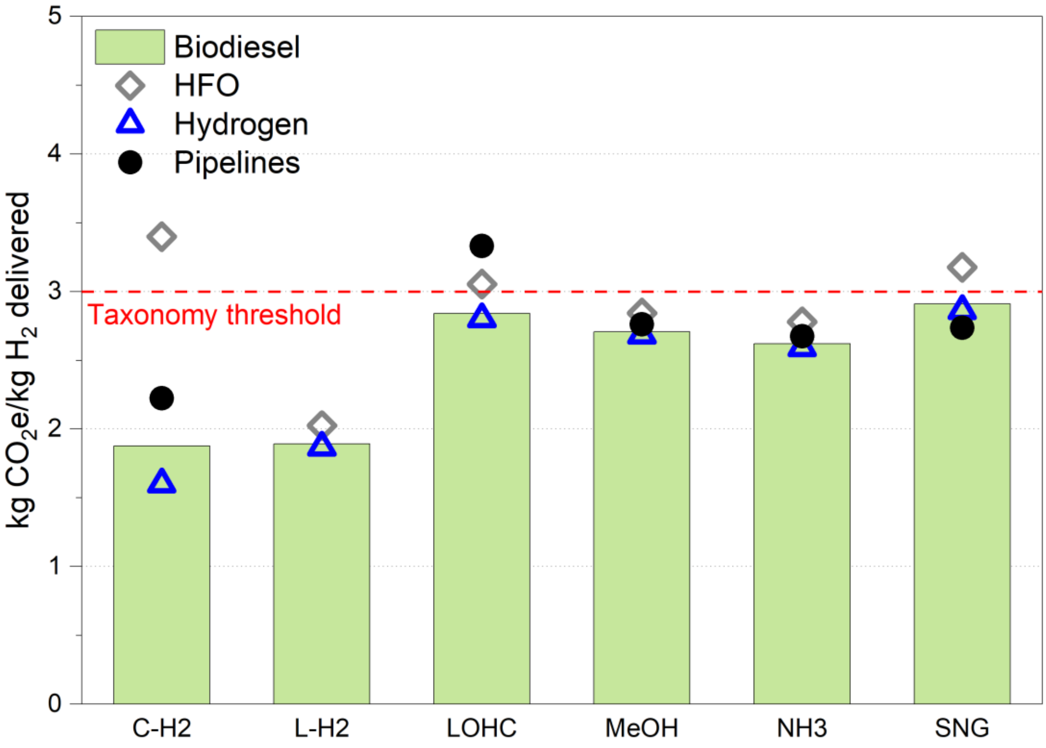
To understand how the environmental impact of the hydrogen delivered might vary using a different fuel to power the ships, three options were considered: biodiesel (reference scenario), heavy fuel oil (worst-case scenario), and renewable hydrogen (best-case scenario). Potential future maritime fuels like ammonia, methanol, or SNG were not included in the assessment, as their impacts are expected to fall within the range of the options analysed. The amount of heavy fuel oil (HFO) and hydrogen needed for the delivery was calculated based on the lower heating value of the different fuels, assuming for simplicity the same efficiency for the engine. As regards the emissions, values available on GaBi were used for the combustion of HFO (Sphera Solutions GmbH, 2021). Apart from the emissions of carbon dioxide (3.12 kg CO_2/kg HFO) and methane (60 mg CH_4/kg HFO), emissions per tonne of HFO combusted correspond to the factors provided in Section 3.1.5 for biodiesel. As for hydrogen, emissions reported by Kanchiralla et al. (2022) were considered: 13.6 g NOx, 1.53 g CO, 0.28 g PM10, and 0.035 g NMVOC per kg of hydrogen burned. A hydrogen loss of 0.5 % was assumed in line with the assumption for hydrogen boilers (3.1.6). For simplicity, it was assumed that the hydrogen used as fuel on-board is stored in a compressed form and that its presence does not reduce the amount of hydrogen (or hydrogen carrier) delivered per ship.

The results are presented in Figure 39 for the climate change impact category and in Figure 40 for the single score impact including all the 16 environmental categories. The impact from all stages of the delivery chain is shown (i.e., not only the shipping stage), to understand the role that the shipping fuel could play in the sustainability of the hydrogen delivered. For comparison, also the results in case pipelines were used are shown.

The climate change impact results show that the fuel used for shipping does not significantly affect the overall greenhouse gas emissions for most pathways. The reason is that in the reference scenario, the transportation stage plays a minor role in the carbon intensity of the hydrogen delivered (see Section 4.2). The exception is the compressed hydrogen pathway, which would deliver a hydrogen with a carbon footprint 81 % higher in case HFO were used instead of biodiesel and 15 % lower in case renewable hydrogen were used. Heavy fuel oil increases the climate impact for all pathways mainly because of the fossil carbon dioxide emitted during transportation. For three pathways (C-H_2, LOHC and SNG), the use of HFO on-board would lead to a carbon footprint of the hydrogen delivered larger than the Taxonomy emission threshold. On the other hand, the use of renewable hydrogen does not lead to a significant reduction of the climate impact. The reason is that the climate impact of producing the PV panels used to generate renewable hydrogen is not significantly lower than the one of producing biodiesel. Moreover, the hydrogen lost to the atmosphere during production and use indirectly contribute to the climate impact.

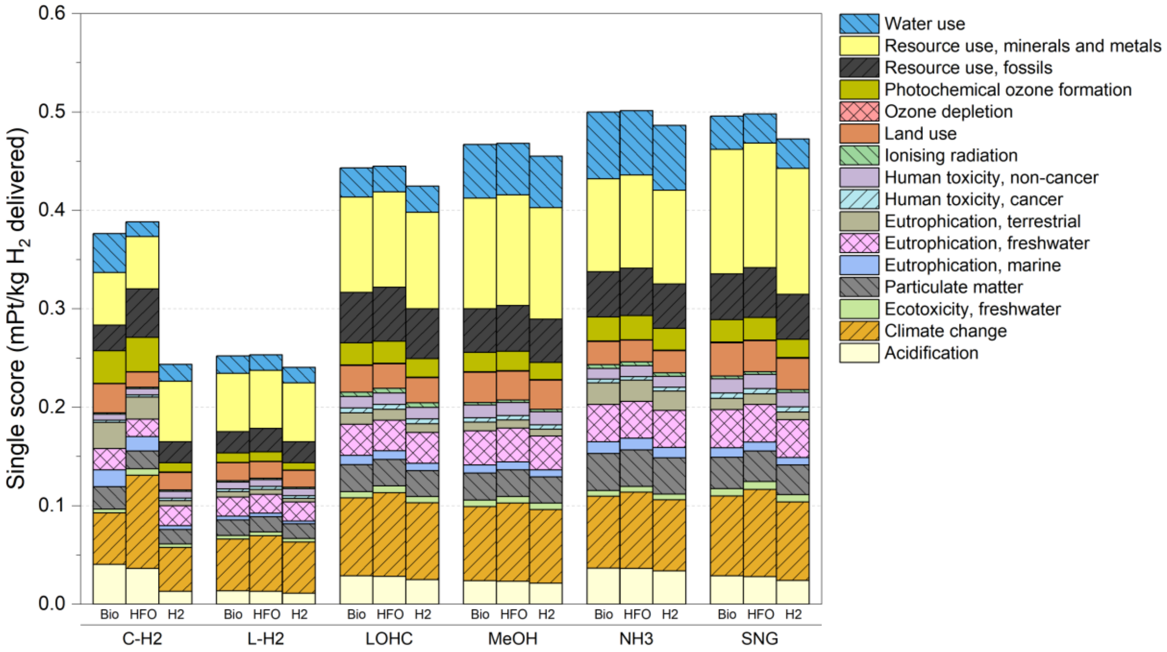
Different observations can be made when all the sixteen environmental impact categories are considered (Figure 40). Interestingly, the use of HFO on-board does not lead to a significant increase of the overall environmental impact of the hydrogen delivered. The higher climate impact of HFO is in fact compensated by its higher energy density, leading to lower emissions of pollutants such as NOx and particulate matter per kilogram of hydrogen transported. On the other hand, the use of renewable hydrogen on-board could significantly reduce the environmental impact of all pathways: from a reduction of 2.5 % for methanol to a 35 % reduction for compressed hydrogen. The reduction can be mainly attributed to the lower particulate matter and NOx emissions. Given the primary role that these emissions play in the overall environmental impact of the compressed hydrogen pathway, using hydrogen on-board would make the compressed hydrogen option as favourable as the liquid hydrogen pathway in terms of overall environmental sustainability.

Figure 39. Comparison of the climate change impact of the hydrogen delivered by ship fuelled either by biodiesel (reference scenario), heavy fuel oil, or renewable hydrogen, or by pipeline.



Source: JRC (2024)

Figure 40. Single score impact of delivering 1 kg of hydrogen considering different fuels for shipping: biodiesel (bio), heavy fuel oil (HFO), and renewable hydrogen (H2).



Source: JRC (2024)

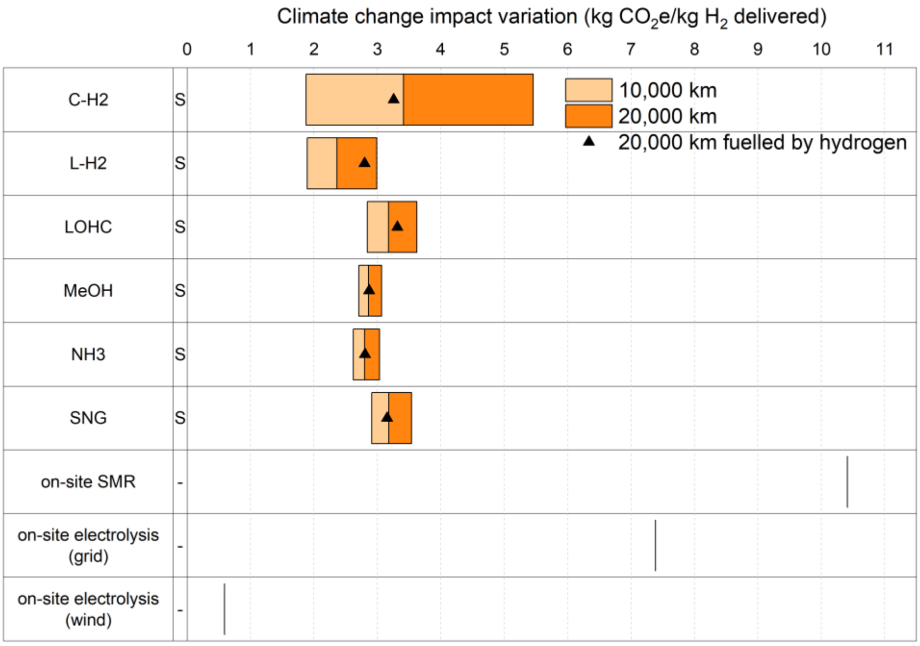
5.6 Distance

In the reference scenario, a distance of 2,500 km from the hydrogen production site to the use-site was assumed. In this sensitivity analysis we investigated how the impacts would change if longer distances (i.e., 10,000 and 20,000 km) were considered. For this analysis, the direct (i.e., fuel combustion) and indirect (i.e., fuel and infrastructure production) impact from transportation is assumed to increase linearly with the distance. Although this assumption may be oversimplistic, the goal was to understand whether absolute results and ranking could be significantly affected by this parameter. Considering the distances involved, we only considered transportation by ship to be a feasible option. Results are presented in Figure 41 for the climate change impact category, and in Figure 42 for the single score impact. Unlike the previous Sections, the reference scenario (2,500 km) in Figure 41 and Figure 42 is represented by the starting point of the bars, while the point between the two extremes indicates the results with a 10,000 km distance.

Results from the sensitivity analysis show that the distance is an important parameter for the sustainability of importing hydrogen. When considering a distance of 10,000 km, comparable to the distance between the Persian Gulf and northern Europe via the Suez Canal, the climate impact increases from a minimum of 6 % for the methanol option to a maximum of 82 % for compressed hydrogen. The least impactful option in terms of GHG emissions is the liquid hydrogen one, delivering hydrogen with a carbon footprint of approximately 2.4 kg CO_2e/kg H_2. Ammonia and methanol follow with an impact of approximately 2.8 kg CO_2e/kg H_2, proving that the use of chemical carriers requiring less energy for transportation becomes more appealing when longer distances are considered. Transporting compressed hydrogen over long distances proves to be the worst option in terms of climate impact, due to the large volumes that need to be transported. This becomes even more evident when a distance of 20,000 km is considered: the impact of compressed hydrogen delivered by ship reaches values above 5 kg CO_2e/kg H_2 even when ships are fuelled by biodiesel. When distances of 20,000 km are considered, comparable to the distance between Australia and Europe, the difference in the climate impact between hydrogen transported as liquid hydrogen or as ammonia and methanol becomes minimal. For all three cases, the climate impact is about 3 kg CO_2e/kg H_2. The use of SNG and LOHC prove to generate slightly higher climate impacts, due to the larger amount of fuel assumed to be needed for transportation. If renewable hydrogen were used as fuel on-board instead of biodiesel (using the same assumptions presented in Section 5.5), climate impacts reduce: life-cycle emissions would span from a minimum of 2.8 kg CO_2e/kg H_2 for liquid hydrogen and ammonia to a maximum of 3.3 kg CO_2e/kg H_2 for LOHC.

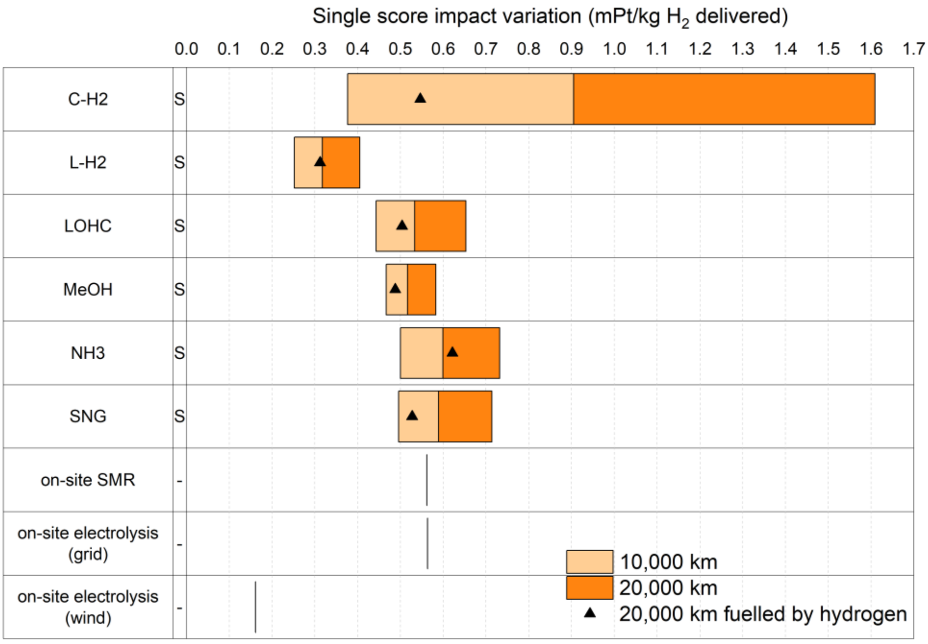
When all the environmental impact categories are considered, liquid hydrogen emerges as the most favourable option. The overall environmental impact of transporting liquid hydrogen across a distance of 20,000 km is lower than that of importing hydrogen via other carriers across a distance of 2,500 km. The use of hydrogen as fuel on-board could significant reduce the overall environmental impact of the hydrogen delivered, particularly in the compressed hydrogen pathway. Among chemical carriers, methanol stands out as the one with the least environmental impact when delivering hydrogen over long distances.

Figure 41. Sensitivity analysis results for the climate change impact category varying the distance. For imported options, results are presented both for transportation by ship (S) and pipeline (P). The reference scenario is represented by the starting point of the bars, while the point between the two extremes indicates the results with a 10,000 km distance. Results for a scenario where hydrogen is transported for 20,000 km using renewable hydrogen as fuel on-board are also presented (triangles).



Source: JRC (2024)

Figure 42. Sensitivity analysis results for the EF single score impact varying the distance. For imported options, results are presented both for transportation by ship (S) and pipeline (P). The reference scenario is represented by the starting point of the bars, while the point between the two extremes indicates the results with a 10,000 km distance. Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered. Results for a scenario where hydrogen is transported for 20,000 km using renewable hydrogen as fuel on-board are also presented (triangles).



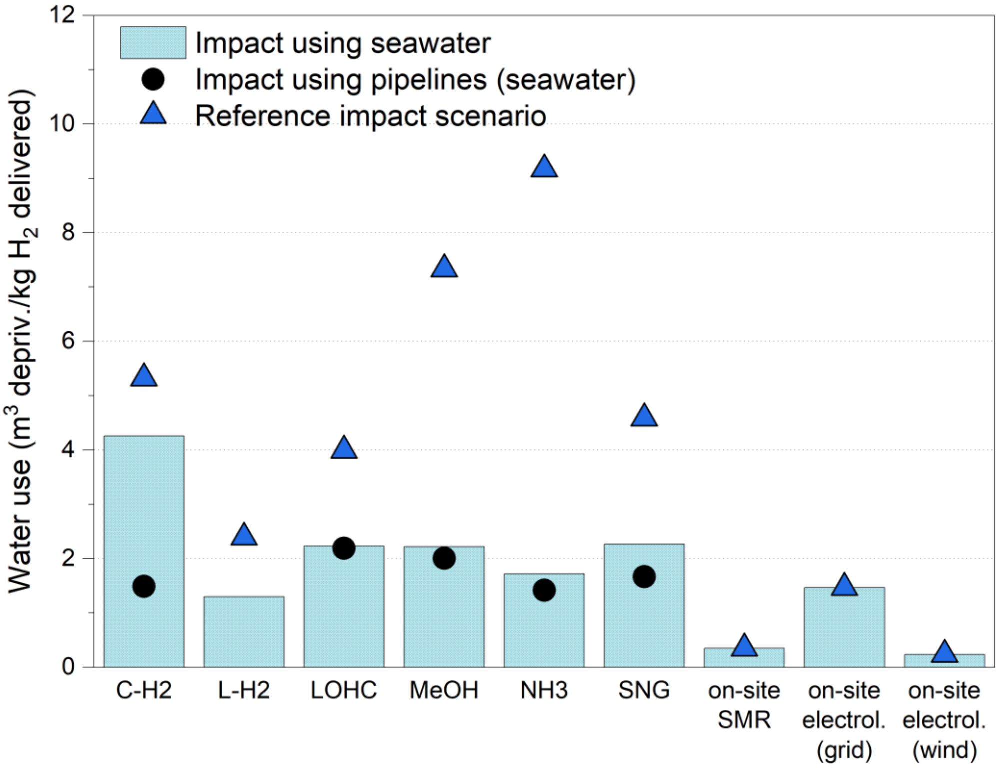
Source: JRC (2024)

5.7 Water source: freshwater vs. seawater

In the reference scenario, processes at the hydrogen production site in Portugal are assumed to rely on the use of freshwater. In this sensitivity analysis, we investigate how the environmental impact of the hydrogen delivered changes when seawater is employed as an alternative water source instead of freshwater. The substitution of water sources has implications not only for water-use impact, but also for other environmental impact categories due to the additional processes required for seawater treatment. For water uses with stringent quality requirements, such as electrolysis, a reverse osmosis filtration step is considered for desalination purposes. An ecoinvent inventory for "Tap water {GLO}| tap water production, seawater reverse osmosis, conventional pretreatment, enhance module, two stages" is utilized for the assessment. This inventory includes the emissions of brine to the sea and has been adapted to our context by altering the source of electricity used in the process. In terms of cooling water, for the sake of simplicity, we did not account for any system consequences (e.g., different infrastructure durability) when substituting freshwater with seawater.

In Figure 43 the water-use impact for the hydrogen delivery using seawater is compared against the reference impact scenario. The water-use impact for the imported hydrogen options reduces significantly, particularly for the options with higher cooling needs. However, the water-use impact for the imported options remains higher than that of the on-site alternatives, with the exception of on-site grid electrolysis. On-site grid electrolysis shows a larger water-use impact compared to imported liquid hydrogen produced from seawater. Given that seawater has a null characterization factor for water use, the impact for the imported options should be attributed to other water uses throughout their life cycle. Most of the impact can be traced back to water consumption in the production of PV panels and biodiesel.

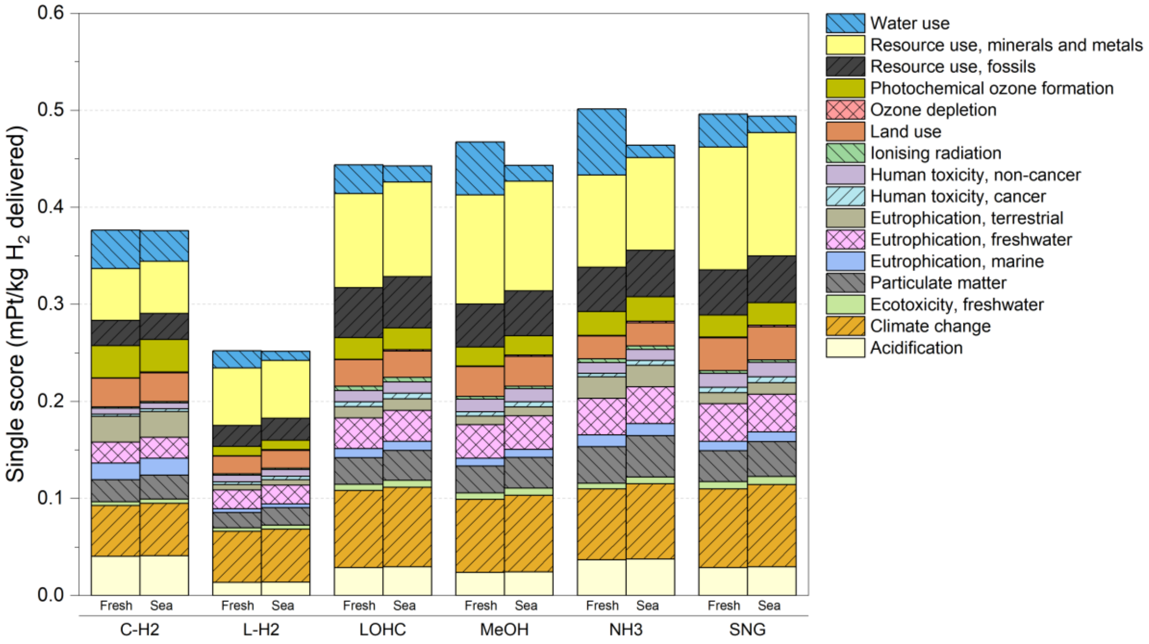
Figure 43. Sensitivity analysis results for the water use impact varying the water source at the hydrogen production site. The reference scenario is represented by the blue triangles, while the light blue bars indicate the water impact use when seawater is considered. Results are expressed in cubic metre of water equivalents deprived per kilogram of hydrogen delivered.



Source: JRC (2024)

In Figure 44, single-score results for the various imported options are presented. The different water source does not seem to significantly affect the overall environmental impact for most of these options: the lower water-use impact from using seawater is in fact compensated by higher impacts in other environmental impact categories due to the additional purification steps. The climate impact of the delivered hydrogen increases on average by 4 %, due to the extra electricity needed for desalination and the production of polyvinylidene chloride (PVDC) assumed to be used as filtration material. In addition to water-use, four environmental impacts result to be significantly affected by the change in water source: ozone depletion human toxicity (cancer), ecotoxicity, and particulate matter, with the average impact increasing by 170 %, 20 %, 16 %, and 13 %, respectively. The high increase in ozone depletion is due to the (highly uncertain) emissions of volatized non-recycled solvent used for the production of the reverse osmosis membrane. The increase in the other impacts is mainly linked to the emission of dioxins, chlorides, and PM2.5 respectively for human toxicity, eco-toxicity, and particulate matter, resulting from the production of PVDC.

Figure 44. Single score impact of delivering 1 kg of hydrogen considering different sources for water used at the hydrogen production site: freshwater (Fresh), and seawater (Sea).



Source: JRC (2024)

5.8 Energy for unpacking

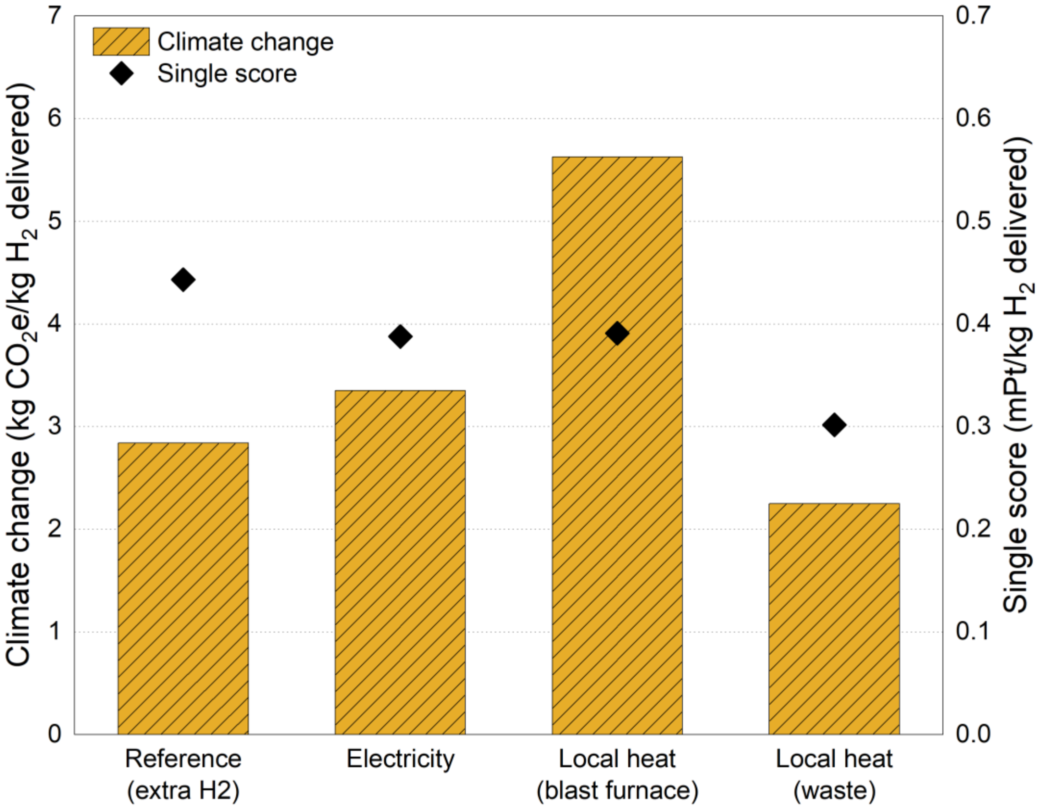
In the reference scenario, energy required for unpacking resulted to be a crucial parameter for the environmental impact of the options involving chemical carriers, due to the extra hydrogen that needs to be produced for the heating needs at the unpacking site. In this Section, a sensitivity analysis on the environmental impact of the hydrogen delivered by varying the heating source at the use site is presented. The dehydrogenation of DBT is used as emblematic case study. In the reference scenario, extra hydrogen is assumed to be delivered via LOHC for the heating needs of the dehydrogenation phase. In the alternative scenarios, heat is assumed to be produced via electricity or sourced from local industries, namely a blast furnace for steel production or a waste incineration plant.

Results are presented in Figure 45 both for climate change (left y-axis) and the single score impact (right y-axis). The impact of hydrogen delivered via LOHC proves to be heavily dependent on the heating source at the delivery site: if local burden-free heat were available at the delivery site (see “waste” bar in Figure 45), the climate and single score impacts reduce by approximately 30 % (yet they would still be larger than the liquid hydrogen pathway). On the other hand, if the emissions to generate the heat are attributed to heat (e.g., “blast furnace” bar in Figure 45), the impact results higher than the reference scenario. In the case of blast-furnace heat, whereas the climate impact would be higher (due to the GHG emissions form the blast-furnace treatment process), the single-score impact would be lower, because the renewable infrastructure needed to produce the extra hydrogen can be avoided. Similarly, if local grid electricity was used to generate heat, the climate impact of the hydrogen delivered would be higher but the single-score impact would be lower.

It is important to point out that the evaluation of the impact associated to heat available at the delivery site strongly depends on the methodology adopted for the assessment. In the reference scenario and in this sensitivity analysis, the cut-off approach adopted by ecoinvent was used (Wernet et al., 2016). This approach attributes all the impact generating the by-product (e.g., heat in the case of waste incineration, and blast furnace gas in the steel case) to the producer, while only the impact from the treatment of the by-product is attributed to the user. This approach is extremely favourable for the user when no treatment is needed for the by-product, such as the case for heat from waste incineration. Other approaches attribute part of the impact from the activity generating the valorised by-product to the producer and part to the user (e.g., “allocation at the point of substitution” approach in ecoinvent or the Circular Footprint Formula of the Product Environmental Footprint methodology). If part of the emissions from incineration were attributed to the hydrogen delivered, its impact would increase significantly.

To conclude, the impact of the hydrogen delivered would reduce if heat that would otherwise be lost was available at the use site, as common sense suggests. However, if additional treatment were needed to produce heat (e.g., blast-furnace example) or heat was considered as a co-product rather than a waste (e.g., if the producer profits from the sale of the heat), the actual environmental impact should be investigated in more detail by tailoring the assumptions to the individual case considered.

Figure 45. Sensitivity analysis results for the LOHC pathway varying the heating source for the unpacking stage. Results are shown only for deliveries by ship. Both climate change (left y-axis expressed in kg CO_2e/kg H_2) and single score (right y-axis expressed in mPt/kg H_2) results are presented.



Source: JRC (2024)

5.9 Carbon capture and storage for on-site SMR

In the reference scenario for on-site SMR, all of the carbon dioxide produced in the process is assumed to be emitted to the atmosphere. In the future, part of these emissions could be captured and stored to reduce the climate impact of the process. In this sensitivity analysis we preliminary assessed how the environmental impact of hydrogen produced on-site via SMR would vary if part of the carbon dioxide was captured and stored. For the assessment, the life cycle inventory from Antonini et al. (2020) for SMR with carbon capture was considered, assuming that 90 % of the CO_2 emissions from the reforming process are captured. The CO_2 generated from the combustion of the tail gas after hydrogen separation is not assumed to be captured for economic reasons (Wei et al., 2024). Since the tail gas has less CO_2 and a higher heating value compared to the reference SMR without carbon capture, slightly less natural gas is needed for the combustion. Overall the SMR process including carbon capture is assumed to generate slightly lower CO_2 compared to the reference SMR, but a significant part of these CO_2 (approximately 55 %) is assumed to be captured and stored. Methyl diethanolamine is assumed to be used as solvent for the capture. A simplified inventory for SMR with carbon capture from Antonini et al. (2020) is presented in Table 15. The inventory was adapted to our context by changing the source of electricity, assumed to be the future Dutch grid. Once captured, CO_2 is assumed to be transported for 200 km by pipeline to an underground facility. For the preliminary nature of the assessment, only the electricity needed for transportation is included, while the impact arising from the pipeline and storage infrastructure is not considered. The electricity needed for transportation is assumed to be 0.00948 kWh per kilogram of carbon dioxide transported over 200 km (Antonini et al., 2020).

Table 15. Simplified inventory for steam methane reforming with carbon capture

Inputs	Amount	
Natural gas	3.35	kg
Electricity	0.257	kWh
Diethanolamine[25]	0.164	g
Nickel-based catalyst	0.202	g
Fe-Cr and Cu-Zn catalyst	1.08	g
Zeolite powder	0.883	g
Water (pure)	7.54	kg
Water (cooling)	381	kg
Outputs		
Hydrogen	1.00	kg
Emissions to air		
Carbon dioxide	4.02	kg
Methane	40.7	mg

Source: JRC (2024) based on Antonini et al. (2020)

The climate impact of the SMR pathway almost halves when carbon capture and storage (CCS) is considered, reducing from 10.4 kg $CO_2e/kg\ H_2$ for the reference SMR scenario to 5.5 kg $CO_2e/kg\ H_2$. However, the climate impact remains significantly higher than the renewable hydrogen options. To reach a climate impact comparable to the best imported options for our case study, more than 95 % of the CO_2 emitted by the SMR process should be captured. To have a climate impact below the taxonomy threshold, and similar to the one of the imported renewable hydrogen via chemical carriers in our case study, approximately 83 % of the CO_2 should be captured and stored. It should also be noted that this reduction do not take into account the emissions from building the CO_2 transport and storage infrastructure. The single-score impact of the SMR option with CCS (SMR + CCS) is compared to the other hydrogen delivery options in Figure 46. The single-

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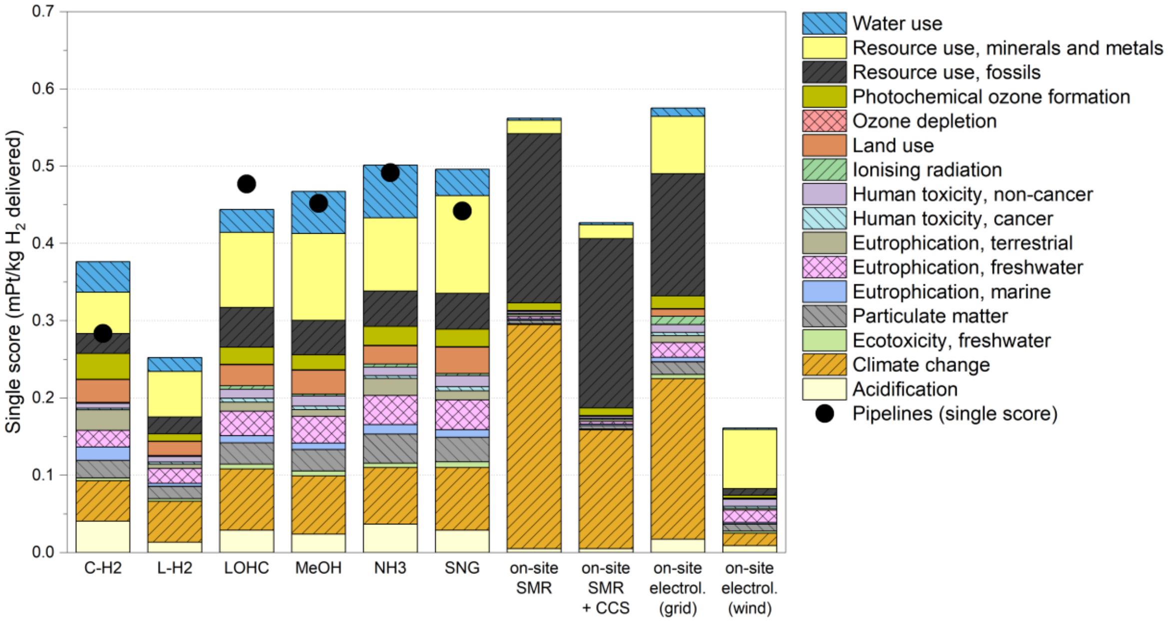
[25] Diethanolamine is used as a proxy for methyl diethanolamine

score environmental impact of the SMR + CCS option reduces by 24 % compared to the reference SMR pathway. While the climate impact reduces by 47 %, the impact in the other environmental categories increases due to the additional energy and material needed to capture and store the CO_2. In particular, a significant increase emerges for the land use category (+ 23 %), due to the electricity production infrastructure. Overall, the SMR option with CCS show a smaller environmental footprint than renewable hydrogen imported via chemical carriers, but still a significantly larger footprint than the best import options (e.g., 70 % higher than the liquid hydrogen option). It is noteworthy that even if 95 % of the CO_2 was captured to match the climate impact of the imported liquid hydrogen option, the single score impact would still be higher mainly due to the consumption of fossil resources.

Figure 46. Single-score impact results for the different hydrogen delivery pathways, including on-site steam methane reforming production with carbon capture and storage (SMR + CCS).



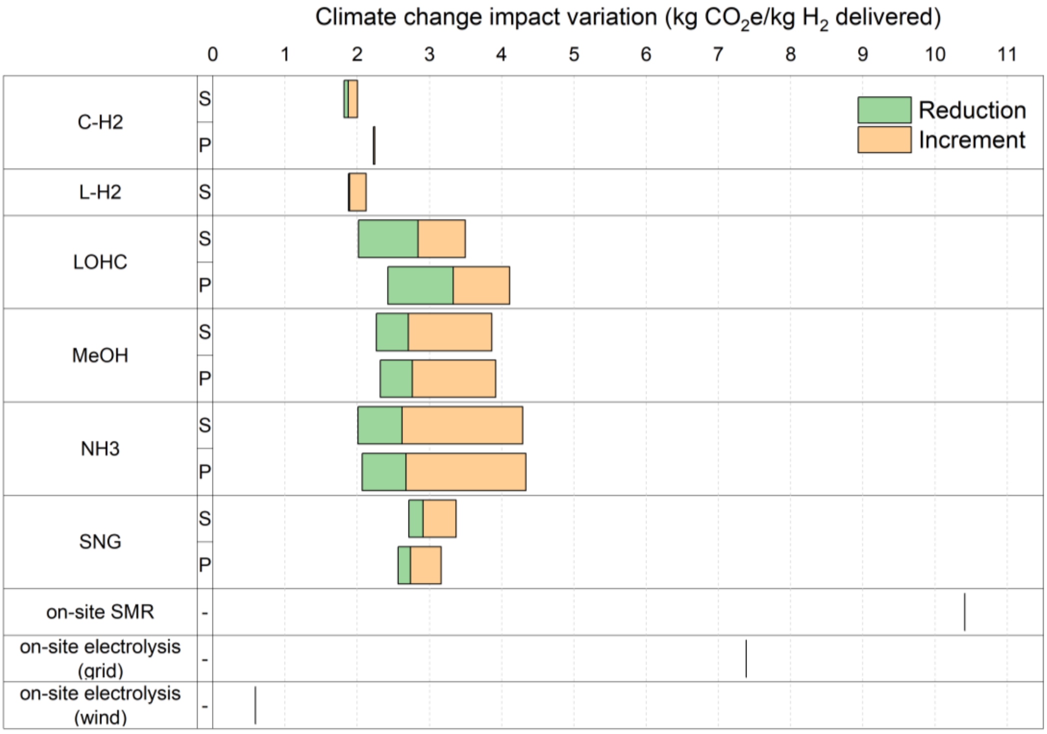
Source: JRC (2024)

5.10 Efficiency of the processes

The impact of the hydrogen delivered varying the efficiency of the processes along the delivery chain, such as the electricity consumption to pack and unpack the hydrogen, is presented in Figure 47 for the climate change impact category, and in Figure 48 for the single score impact. In this sensitivity analysis, all the parameters not considered in the previous Sections were investigated. The parameters include all the values presented in the uncertainty ranges in the inventory tables presented in Section 3. Taking ammonia synthesis as an example (Table 6), in this sensitivity analysis the input of hydrogen, electricity, catalysts, and water, are varied according to range presented in Table 6. This analysis also includes the sensitivity on the amount of hydrogen stored in the salt cavern and the composition of SNG.

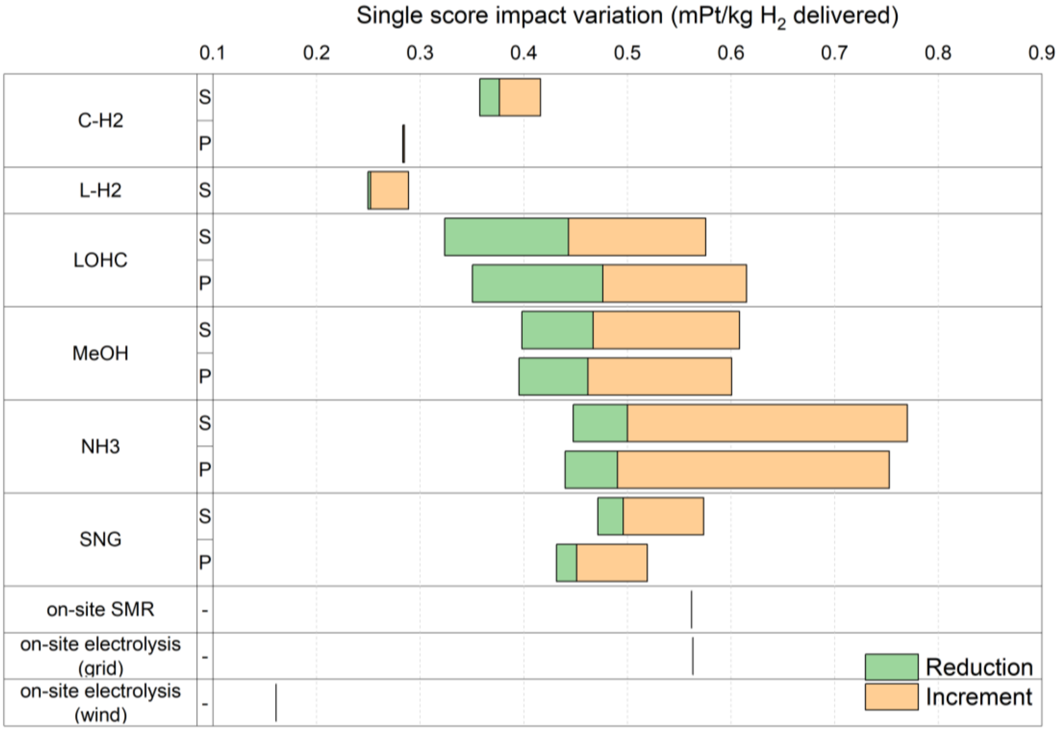
Results show a large range in the results for pathways involving chemical carriers. Compressed and liquefied hydrogen exhibit a small uncertainty range, due to the lower number of processes along the delivery chain in an early development stage and to the exclusion of parameters, such as hydrogen losses, already addressed in the other sensitivity analyses. For the chemical carriers, the lower uncertainty is seen for the SNG pathway, since it relies for the most part on the mature technologies developed for natural gas. The greatest uncertainty is with ammonia, primarily because large-scale facilities for its cracking are currently unavailable. Best-case scenarios for the chemical carriers reduce significantly their impact, but still deliver hydrogen with a larger environmental footprint than the reference compressed and liquid hydrogen options. On the other hand, if the worst efficiency found in the literature for the processes along the delivery chain would materialize, the impact of the hydrogen delivered would significantly increase. Limited to climate change, the impact for hydrogen delivered via chemical carriers would be well above the Taxonomy threshold of 3 kg CO_2e/kg. When all the environmental categories are considered, the impact would exceed the one of on-site SMR and on-site electrolysis powered by the grid for most pathways. In terms of process impacts, mainly related to the energy consumption along the delivery chain, it is difficult to determine the superiority of one chemical carrier over another. The results for all carriers fall in fact within the uncertainty range. However, when looking at the best-case scenarios, LOHC seems to show a higher potential.

Figure 47. Sensitivity analysis results for the climate change impact category varying the efficiency of the processes along the delivery chain. The values indicate the variation with respect to the global warming impact obtained for each pathway in the reference scenario. For imported options, results are presented both for transportation by ship (S) and pipeline (P).



Source: JRC (2024)

Figure 48. Sensitivity analysis results for the single score impact varying the efficiency of the processes along the delivery chain. For imported options, results are presented both for transportation by ship (S) and pipeline (P). Results are expressed in milli-points (mPt) per kilogram of hydrogen delivered.



Source: JRC (2024)

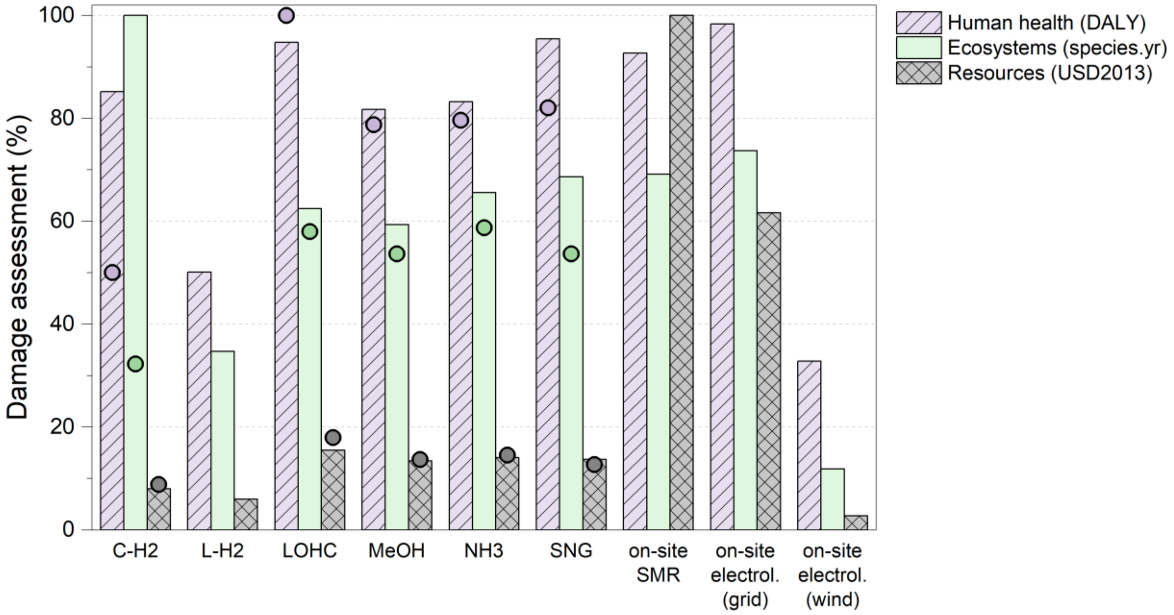
5.11 Impact assessment method

An important factor affecting in particular the single score results is the method used for impact assessment. In the reference scenario, the EF method developed by the European Commission was employed (see Section 2.2.2). In this sensitivity analysis, we aim to investigate how the environmental impact ranking among different hydrogen delivery pathways changes using a different impact assessment method. The alternative method used in this analysis is ReCiPe 2016 (Huijbregts et al., 2016). The impact categories considered by the ReCiPe method are the same as those in the EF method, but impacts are grouped into three areas of protection according to damage pathways: i) damage to human health, measured in disability-adjusted life years (DALY); ii) damage to ecosystem quality, measured in lost species per year; and iii) damage to resource availability, measured in US dollars of surplus costs. The method uses different characterization factors, such as DALY per kilogram of emitted substance, depending on the perspective adopted for assumptions and choices in the model. Three perspectives are considered: i) individualistic, based on short-term interests, undisputed impact types, and technological optimism regarding human adaptation; ii) hierarchist, based on scientific consensus regarding time frame and plausibility of impact mechanisms; and iii) egalitarian, a precautionary perspective taking into account the longest time frame and all impact pathways for which data is available.

Figure 49 presents the damage assessment results using the hierarchist perspective of the ReCiPe 2016 method. This perspective was chosen as the default approach because it is considered the middle-ground scenario and is deemed acceptable by international organizations like the World Health Organization (Huijbregts et al., 2017). Since the impact in the different areas of protection is expressed in different units, the impacts are normalized in Figure 49 for visualization purposes. Characterization factors for hydrogen emissions were added to the method (e.g., DALY/kg H_2), multiplying the characterization factors for global warming of carbon dioxide by 11.6 for the hierarchist perspective (100-year time horizon) and by 37.3 for the individualistic perspective (20-year time horizon). No characterization factor was attributed to hydrogen for global warming in the long-term egalitarian perspective. Results are in line with those obtained with the EF method. Regarding human health, the pathway generating the lowest impact in terms of DALY is on-site wind electrolysis, followed by imported liquid hydrogen by ship and imported compressed hydrogen by pipeline. The same trend is observed for the impact on ecosystems and resource availability. Importing renewable hydrogen via chemical carriers does not show a significant advantage in terms of human health or ecosystem impacts compared to on-site hydrogen production via SMR or grid electrolysis, but provides a significant advantage in terms of resource availability due to the lower consumption of fossil fuels.

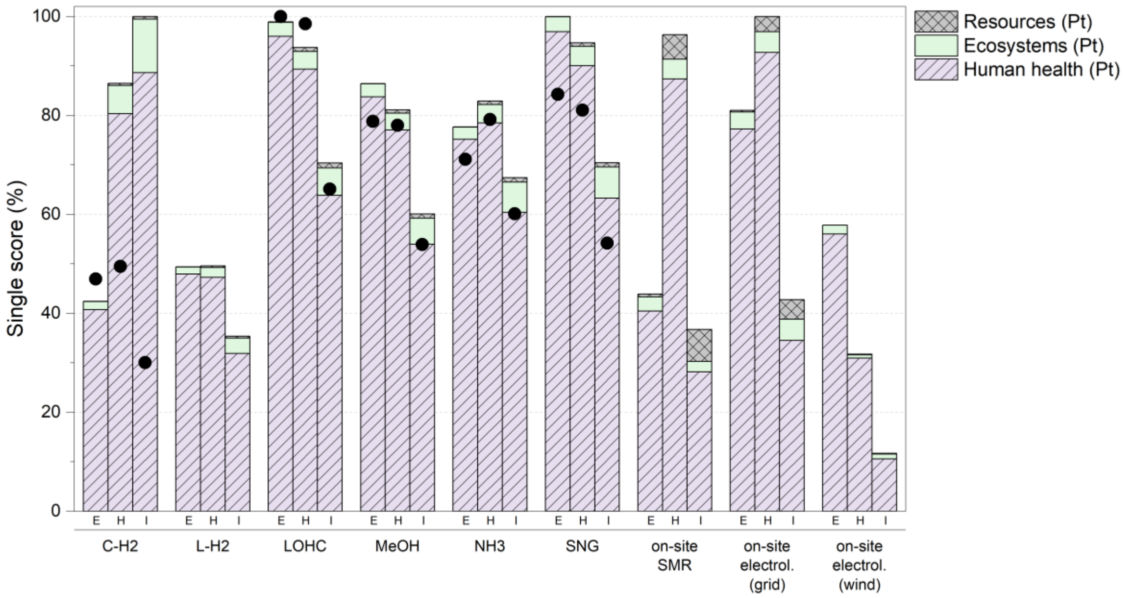
In Figure 50, single scores obtained from the end-point impacts using the ReCiPe method are reported. Although not recommended by the method developers, single scores are shown here to present the differences in impact using different perspectives, i.e., egalitarian and individualist, instead of hierarchist. Single scores are obtained using weighting sets from Eco-indicator 99 for the different areas of protection (PRé Sustainability, 2021). Single score results show that human health is the leading cause of concern with the weighing sets employed, representing more than 90% of the single score impact. The exception are on-site SMR and grid electrolysis, where the use of resources plays a more important role. Ecosystems play a more significant role when the individualist perspective is adopted. When comparing the results from the hierarchist, egalitarian, and individualist perspectives, the ranking of hydrogen delivery pathways' impacts varies. With a hierarchist approach, on-site grid electrolysis, imported LOHC by pipeline, on-site SMR, and imported SNG by ship result in the largest impact, while on-site wind electrolysis, imported compressed hydrogen by pipeline, and imported liquid hydrogen have the lowest impact. The ranking changes when an egalitarian perspective is adopted, showing a net impact reduction for the on-site SMR and imported compressed hydrogen by ship. These two options appear to be the safest when a more precautionary approach is adopted. Imported liquid hydrogen follows in the single score, but presents a better outcome in terms of ecosystems and resources. Finally, when a short-term individualistic perspective is adopted, on-site wind electrolysis proves to be the least impactful option, followed by imported compressed hydrogen by pipeline, imported liquid hydrogen, and on-site SMR. Overall, when all three perspectives are considered, on-site wind electrolysis and imported compressed hydrogen by pipeline and imported liquid hydrogen by ship prove to be the ones with the lowest impact, in line with the results obtained with the EF method. However, it is important to note that on-site SMR shows a better outcome than most options when using a different perspective than traditional impact assessment models. This demonstrates the importance of considering multiple perspectives and methods in environmental impact assessments to obtain a comprehensive understanding of the potential consequences of various hydrogen delivery pathways.

Figure 49. Damage assessment results per kilogram of hydrogen delivered, utilizing the hierarchist perspective of the ReCiPe 2016 method. Damage is presented for the three endpoint areas of protection, which include human health, ecosystems, and resources. Results are normalized to indicate the impact relative to the worst-performing pathway for each area of protection. For imported options, results are presented both for transportation by ship (columns) and pipeline (circles).



Source: JRC (2024)

Figure 50. Single score results per kilogram of hydrogen delivered. Results are obtained applying the weighting sets from Eco-indicator 99 to the impact on the three areas of protection (human health, ecosystems, and resources) calculated with the ReCiPe 2016 method using the egalitarian (E), hierarchist (H), and individualist (I) perspectives. Single scores are normalized to indicate the impact with respect to the worst-performing pathway for each perspective. For imported options, results are presented both for transportation by ship (columns) and pipeline (circles).



Source: JRC (2024)

5.12 Other sensitivity analyses

In this Section, other sensitivity analyses that were mentioned in the life cycle inventory are presented.

5.12.1 LOHC: Credit for hydrochloric acid co-production

The environmental credit of co-producing hydrochloric acid when producing DBT appears to be negligible. The single-score impact of the hydrogen delivered via LOHC reduces by 0.2 % if the co-produced hydrochloric acid were put on the market avoiding the production of the acid via the traditional route.

5.12.2 Methanol and SNG: Heat source for direct air capture (DAC)

In the reference scenarios for methanol and SNG, carbon dioxide was assumed to be directly captured from the air using additional hydrogen as a heat source for the process. In this sensitivity analysis, we aimed to explore how the impact of the methanol and SNG options varies when a fully electric system is employed instead. The results indicate that the differences in terms of climate change are minimal, assuming that the extra hydrogen is produced on-site with a low carbon footprint. When employing a fully electric system powered by PV electricity, the climate change impact of hydrogen delivered via methanol and SNG decreases by 0.2 % and 0.1 %, respectively. The reduction is more pronounced when examining the single score impact, considering the significant role of PV panel production in the overall environmental impact of the delivered hydrogen. Utilizing electricity directly for heat rather than converting electricity into hydrogen requires less electricity and, consequently, fewer PV panels. Overall, the reduction amounts to approximately 2 % for both the methanol and SNG options, which does not significantly impact the comparison's outcomes.

5.12.3 SNG: Catalyst for SNG synthesis

In the reference scenario, nickel supported on magnesium aluminate spinel (Ni 15 wt.%) was considered as catalyst for the synthesis of SNG (Section 3.7.1). However, aluminium oxide was used as proxy for magnesium aluminate spinel in the assessment due to the unavailability of datasets. In this sensitivity analysis, the use of rhodium on alumina (Rh/Al_2O_3) catalyst (rhodium 0.5 wt.%) based on Bargiacchi et al. (2021) was considered to evaluate the impact of this parameter on the variability of the results.

The catalyst choice proves to affect significantly the results of the SNG pathways, increasing the single score result by 17 % in the scenario involving ships and 21 % in the pipeline scenario. The difference could be ascribed to the high impact associated with the rhodium production process, affecting mostly the acidification and eutrophication categories. In the acidification impact category, the increase of the hydrogen delivered results to be over 50 % due to the ammonia emissions in the mining operations. This sensitivity analysis shows the potential importance of choosing catalysts with a low environmental impact.

5.12.4 SNG: Heat co-production from steam reforming

In the reference scenario, we assumed that the waste heat generated in the steam reforming of SNG is not utilized. In this sensitivity analysis, the impact of this credit on the environmental impact of the hydrogen delivered is assessed. The heat produced (0.14 kWh/kg H_2) is assumed to be transformed into electricity substituting for local electricity production (i.e., the Dutch grid mix assumed for 2030).

Results show that this additional credit for SNG would not affect significantly the environmental impact of the hydrogen delivered. When all the 16 environmental impact categories are considered, the impact of the hydrogen delivered reduces by 0.3 %.

6 Conclusions

This study aimed at comparing the environmental life cycle performance of different pathways for delivering hydrogen to an industrial cluster in the north of Europe in 2030. Production on-site via SMR or electrolysis were compared to the import of renewable hydrogen from a location where renewable energy is cheaper. The Netherlands and Portugal were selected as production and delivery site, respectively, for the purpose of this study. Six different hydrogen carriers were considered: compressed hydrogen, liquid hydrogen, ammonia, dibenzyltoluene (LOHC), methanol, and synthetic natural gas. The Environmental Footprint impact assessment method, which comprises 16 environmental impact categories and aggregates the results under a single score, was used for the assessment.

Results are subject to a high level of uncertainty due to the prospective nature of the assessment, to the early development stage of many of the technologies being considered on a large scale, and to the low robustness level of some environmental impact assessment models. Moreover, single-score results are calculated using the normalization and weighting factors proposed by the EF method, but different outcomes could be obtained if a different hierarchy of environmental priorities was considered. In addition, results are referred to a well-defined geographical context and time horizon, and they are affected by the numerous assumptions made throughout the study. Although an extensive sensitivity analysis was conducted to validate the results across a wide range of settings, caution should be exercised when extrapolating the current findings to different case studies. Based on this premise, the following conclusions can be drawn:

- The environmental performance of hydrogen supplied to an industrial user can vary significantly depending on the production technology and the delivery pathway;
- When feasible, the least environmentally impactful way of supplying hydrogen is to produce it on-site via abundant renewable sources (e.g., wind power in the Netherlands);
- Importing renewable hydrogen can significantly reduce GHG emissions compared to producing hydrogen on-site via fossil fuels (e.g., via steam methane reforming or electrolysis powered by an electricity grid that partially depends on fossil fuels). In the reference scenario, the use of imported renewable hydrogen results in CO_2e savings ranging from 4 to 9 kg per kg of hydrogen, depending on the specific delivery pathway considered;
- Limiting the scope of the assessment to GHG emissions can lead to unintended consequences in terms of other environmental impacts. While all the delivery options would guarantee a supply of hydrogen with a lower global warming potential than on-site production, in our reference scenario producing hydrogen locally via SMR would generate lower impacts in 12 of the 16 environmental impact categories considered, including the use of natural resources such as water, land, and minerals and metals. Nevertheless, when the overall environmental impact is summarized in a single-score result using the EF method, all the delivery options would guarantee an environmental advantage compared to on-site fossil-based productions (without carbon capture);
- For the considered case study, the options with the lowest environmental footprint to deliver hydrogen over long distances appear to be the shipping of liquid hydrogen and the transportation of compressed hydrogen by pipeline;
- Energy and resources required to pack and unpack hydrogen into more convenient chemical carriers for transportation (i.e., ammonia, LOHC, methanol, and SNG) make these options less attractive in terms of environmental impacts. Even with the most optimistic assumptions for process efficiencies for these chemical carriers, their environmental performance may still fall short of liquid hydrogen and compressed hydrogen transported by pipeline;
- No significant difference was observed in the environmental impacts of the pathways involving chemical carriers (ammonia, LOHC, methanol, and SNG). While ammonia appears to be a slightly better option in terms of climate change impact, SNG transported by pipeline result to be the option generating a marginally lower impact among the carriers when all the 16 environmental impacts are considered;

- In terms of mineral and metal use, the environmental impact is driven by the infrastructure for renewable electricity generation (i.e., solar PV panels). The impact from specific hydrogen infrastructure such as catalysts for hydrogenation and dehydrogenation appears to be negligible in the reference scenario. However, the use of alternative, more polluting catalysts, such as rhodium for SNG synthesis, could increase the overall impact of the hydrogen delivered by more than 20 %;

- Water-use impact is directly influenced by the availability of freshwater in the country where water is used. Our findings indicate that on-site hydrogen generation in water-rich nations like the Netherlands through SMR or renewable electrolysis is a more sustainable choice in terms of water use compared to importing hydrogen from water-scarce countries, such as Portugal. Carriers such as ammonia and methanol prove to be the worst options in terms of water use due to the higher cooling needs during production;

- PV panels manufacture plays a critical role in the environmental performance of the solar-generated hydrogen delivered. To guarantee that imported hydrogen offers an environmental advantage over conventional hydrogen production methods based on fossil fuels, the environmental impact associated with generating electricity through PV panels must significantly decrease;

- Emissions stemming from electricity generation at the delivery site significantly influence the sustainability of importing hydrogen compared to producing it on-site. Additionally, they impact the environmental performance of delivery options that utilize electricity at the delivery site (e.g., for dehydrogenating the chemical carrier). The liquid hydrogen option seems to be the least susceptible to the environmental impact of the electricity grid at the delivery site;

- Hydrogen losses along the delivery chain could noticeably increase the environmental impact of the hydrogen delivered, due both to the indirect greenhouse effect of hydrogen emissions and to the additional processes required to make up for the lost hydrogen. This impact may be particularly relevant in the short term. However, even when the impact from hydrogen losses is included, the options more prone to losses (liquid and compressed hydrogen) still exhibit a lower environmental impact compared to using hydrogen carriers;

- Longer distances than the ones considered in the reference scenario increase the environmental impact of the hydrogen delivered. The options affected the least by this increase are methanol and ammonia, delivering hydrogen with a similar carbon footprint than liquid hydrogen when distances comparable to a distance between Australia and Europe are considered. Nevertheless, these options still produce a larger impact in other environmental impact categories.

7 Recommendations and future work

Based on the results obtained in the analysis, the following recommendations can be given to policymakers and stakeholders to minimize the environmental footprint of hydrogen delivery:

- Prioritizing on-site hydrogen production utilizing local abundant renewable sources when viable;
- Focusing research and development efforts on hydrogen transportation methods, such as pipelines for compressed hydrogen and maritime transport for liquid hydrogen, which have been identified as environmentally preferable for long-distance transport within European contexts;
- Reducing the environmental footprint of renewable electricity infrastructure, particularly solar PV panels, by enhancing material efficiency and employing renewable sources in their manufacture;
- Optimizing energy efficiency throughout the supply chain of chemical carriers involved in hydrogen distribution, with special attention to the delivery phase;
- Shortening the import distance for renewable hydrogen;
- Preventing hydrogen losses along the delivery chains in order to minimize the short-term climate impact of compressed and liquid hydrogen pathways;
- Investigating further the potential of renewable hydrogen and e-fuels as on-board fuel options;
- Conducting comprehensive environmental LCA to identify the best hydrogen supply chain for each case study, since results are context-dependent and subject to a high level of uncertainty. The LCA should not be limited to the climate change impact, but a more holistic approach such as the Environmental Footprint method should be used to avoid unintended consequences in terms of other environmental impacts (e.g., water use, toxicity potential).

The following additional work is recommended for the future:

- Continual monitoring of the progression of the technologies explored in this study to regularly update results and reduce uncertainty around the efficiency and emission profiles of the processes forming the hydrogen supply chain;
- Expanding investigations to include diverse geographic regions, future time frames (e.g., beyond 2050), alternative transportation methods (including trucks and trains), and various hydrogen production pathways (e.g., auto-thermal reforming, pyrolysis). This broader scope would allow extending the findings of this study to a wider array of potential scenarios;
- Utilizing prospective LCA databases to assess the variability of our results under different scenarios generated by Integrated Assessment Models (Sacchi et al., 2022). In general, more research on prospective LCA methodology is needed to develop robust tools for investigating the potential environmental impact of uncertain future activities. Research on how to adapt the Environmental Footprint method (e.g., characterization, normalisation, and weighting factors) to prospective assessments is also recommended;
- Conducting social impact assessments of hydrogen delivery options using tools like Social LCA. This could involve examining the potential social implications and risks to human populations and the environment that could arise from accidents along the hydrogen delivery chain;

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List of abbreviations and definitions

ATR	Autothermal reforming
CCS	Carbon capture and storage
C-H_2	Compressed hydrogen
CO	Carbon monoxide
DAC	Direct air capture
DALY	Disability-adjusted life years
DBT	Dibenzyltoluene
EF	Environmental footprint
GHG	Greenhouse gas
GLO	“Global” as geographic region in the ecoinvent datasets
GWP	Global warming potential
GWP_{100}	Global warming potential over 100 years
GWP_{20}	Global warming potential over 20 years
HFO	Heavy fuel oil
ISO	International standard organization
JRC	Joint Research Centre
L-H_2	Liquid hydrogen
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
MeOH	Methanol
Mt	Million tonnes
mPt	milli-Points
NH_3	Ammonia
NMVOC	Non-methane volatile organic compound
NOx	Nitrogen oxides
PEM	Proton exchange membrane
PM10	Particulate matter with a diameter of 10 micrometres or smaller
PRIMES	Price-induced market equilibrium system
PV	Photovoltaic
RER	“Europe” as geographic region in the ecoinvent datasets
SNG	Synthetic natural gas
SMR	Steam methane reforming

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Annex I: Electricity mixes

In Table A1 the electricity sources (%) forecasted for 2030 in the EU and the Netherlands (NL) are presented. In the table, the corresponding ecoinvent datasets used for the assessment are also shown. For the reference scenario, the same adjustments made for wind and PV electricity datasets to reflect the average emission factors for 2030 reported by Hydrogen Council (3.1.1) were considered. Therefore, the environmental impact of 1 kWh produced from PV or wind is assumed to be the same in Portugal, the Netherlands and Europe: 20 g CO_2e/kWh for PV electricity, and 10 g CO_2e/kWh for wind electricity. This assumption does not account for the different capacity factors of PV and wind turbines across Europe, but it accounts for the potential emission reduction in their manufacture in the next years. In the sensitivity analysis, emission factors from the ecoinvent database considering the different capacity factors across Europe were considered. Electricity from PV in the Netherlands generates approximately 100 g CO_2e/kWh when the ecoinvent dataset is used, compared to the 62 g CO_2e/kWh for PV electricity in Portugal.

Table A1. Electricity mixes assumed for 2030 in the EU and the Netherlands, and the corresponding ecoinvent datasets used for the assessment. *Datasets adjusted to reflect the average emission factors for 2030 reported by Hydrogen Council (2021).

Electricity source	EU (%)	NL (%)	Ecoinvent dataset (electricity production)
Nuclear energy	16.3	2.23	Nuclear {NL}, pressure water reactor
Biomass-waste	5.30	1.80	Heat and power co-generation {NL}, biogas, gas engine
Hydro (lakes)	6.03	0.06	Hydro {IT}, reservoir, alpine region
Hydro (run of river)	5.44	0.00	Hydro {NL}, run-of-river
Wind (onshore)	26.4	30.4	Wind {NL}, >3MW turbine, onshore*
Wind (offshore)	7.85	28.0	Wind {NL}, 1-3MW turbine, offshore*
Solar	13.8	13.3	Photovoltaic {NL}, 570kWp open ground installation, multi-Si*
Geothermal heat	0.23	0.00	Deep geothermal {DE}
Solid fossil fuels	4.40	0.00	Hard coal {NL}
Petroleum products	0.26	0.07	Oil {NL}
Natural gas	14.0	24.2	Natural gas {NL}, combined cycle power plant (50 %) Natural gas {NL}, conventional power plant (50 %)

Source: JRC (2024)

Annex II: Electrolyser inventory

The inventory for the PEM electrolyser (Table A2) is adapted from Table S9 of D'Angelo et al. (2021). In their work, the authors provide the inventory for 5 MW PEM electrolysers in 2018 and in 2040. Data were interpolated for this study to obtain the impact in 2030. Palladium was used as proxy for iridium due to the lack of inventory data for its production. For more information about lifetime of the components see the orginal source.

Table A2. Electrolyser inventory

Inputs		
Platinum {GLO}| market for | Cut-off, U	4.97E-08	kg
Palladium {GLO}| market for | Cut-off, U	4.97E-07	kg
Copper, anode {GLO}| market for copper, anode | Cut-off, U	1.33E-06	kg
Steel, unalloyed {GLO}| market for | Cut-off, U	2.94E-05	kg
Titanium, primary {GLO}| market for | Cut-off, U	0.00035	kg
Aluminium, primary, ingot {IAI Area, EU27 & EFTA}| market for | Cut-off, U	1.79E-05	kg
Tetrafluoroethylene {GLO}| market for | Cut-off, U	3.55E-05	kg
Activated carbon, granular {GLO}| market for activated carbon, granular | Cut-off, U	5.96E-06	kg
Metal part of electronics scrap, in copper, anode {GLO}| market for metal part of electronics scrap, in copper, anode | Cut-off, U	5.46E-07	kg
Tetrafluoroethylene {GLO}| market for | Cut-off, U (for gasket)	6.95E-06	kg
Acrylonitrile-butadiene-styrene copolymer {GLO}| market for | Cut-off, U (for gasket)	1.42E-05	kg
Aniline {RER}| market for aniline | Cut-off, U (for gasket)	4.37E-06	kg
Acetic anhydride {GLO}| market for acetic anhydride | Cut-off, U (for gasket)	4.81E-06	kg
Purified terephthalic acid {GLO}| market for | Cut-off, U (for gasket)	7.85E-06	kg
Nitric acid, without water, in 50 % solution state {RER w/o RU}| nitric acid production, product in 50 % solution state | Cut-off, U (for gasket)	2.94E-06	kg
Hydrochloric acid, without water, in 30 % solution state {RER}| tetrafluoroethylene production | Cut-off, U (for gasket)	1.16E-05	kg
Graphite {GLO}| market for | Cut-off, U (for gasket)	3.84E-05	kg
Lubricating oil {RER}| market for lubricating oil | Cut-off, U (for gasket)	4.27E-08	kg
Water, decarbonised {DE}| market for water, decarbonised | Cut-off, U	0.000977	kg
Water, deionised {Europe without Switzerland}| market for water, deionised | Cut-off, U	0.00763	kg
Electricity, medium voltage {GLO}| market group for | Cut-off, U	0.000891	kWh
Heat, district or industrial, natural gas {GLO}| market group for | Cut-off, U	0.00784	MJ
Heat, from steam, in chemical industry {RER}| market for heat, from steam, in chemical industry | Cut-off, U	6.23E-05	MJ
industrial machine, heavy, unspecified {RER}| market for industrial machine, heavy, unspecified | Cut-off, U	1.42E-08	kg
Plaster mixing {GLO}| market for | Cut-off, U	6.95E-05	kg
Calendering, rigid sheets {GLO}| market for | Cut-off, U	6.95E-05	kg
Output		
Hydrogen	1.00	kg

*Source: JRC (2024)****, adapted from D'Angelo*** *et al. (2021)*

Annex III: Energy consumption for transportation

For the sensitivity analysis, best-case and worst-case scenarios were considered. In Table A3 and Table A4 the values considered for biodiesel consumption on ships and electricity consumption for pipelines are reported, respectively.

Table A3. Fuel consumption range considered for the sensitivity analysis in kt of biodiesel per 1 Mt of hydrogen delivered over 2 500 km

Carrier	Reference	Min	Max
C-H_2	534	481	587
L-H_2	47	42	52
LOHC	77	67	94
MeOH	48	43	53
NH_3	56	42	62
SNG	27	24	30

Source: JRC (2024)

Table A4. Electricity consumption range considered for the sensitivity analysis (MWh per 1 Mt of hydrogen delivered)

Carrier	Reference	Min	Max
C-H_2	4.57	4.11	5.03
LOHC	2.71[26]	2.44	2.98
MeOH	0.39	0.35	0.43
NH_3	0.62	0.56	0.68
SNG	0.62	0.56	0.68

Source: JRC (2024)

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[26] Includes the electricity for transporting the dehydrogenated DBT back to the hydrogen production site

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