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Techno-economic analysis of hydrogen and green fuels supply scenarios assessing three import routes: Canada, Chile, and Algeria to Germany

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ABSTRACT

This paper presents a detailed techno-economic analysis of hydrogen production and import routes to Germany, assessing the economic viability and strategic benefits of hydrogen imports from Algeria, Chile, and Canada. Utilizing the bespoke HydrogenPathway Explorer tool, which integrates economic, energy, and process engineering frameworks, the study evaluates the cost implications and logistical challenges of these routes. This analysis draws on extensive literature reviews and data from major databases and technical reports processed through a high-level interface that facilitates deep economic and energy insights.

The results reveal that current hydrogen costs from Algeria are approximately 5.3 EUR/kg H_2. Although initial costs for hydrogen shipped from Canada and Chile are higher (around 8.7 EUR/kg H_2 and 6.5 EUR/kg H_2, respectively), projections for 2030 indicate that Chilean imports could drop to about 4.8 EUR/kg H_2, becoming highly competitive. By 2050, costs are expected to further decrease, with Algerian pipeline imports potentially reaching 3.4 EUR/kg H_2, Canadian imports around 4.1 EUR/kg H_2, and Chilean imports approximately 3 EUR/kg H_2. The analysis also highlights a significant reduction in transportation costs by 2050, suggesting that liquid hydrogen may become the preferred form of energy for imports from Canada and Chile.

The study underscores the importance of diversifying import sources and optimizing supply chains to enhance Germany's hydrogen strategy, contributing to global sustainable energy transitions and the attainment of climate goals.

1. Introduction

The Renewable Energy Directive III (RED III) is one of the cornerstones supporting the European Union's (EU) strategy to reach climate neutrality by 2050 within the European Green Deal [1]. It will place binding ambitious targets for renewable energy and hydrogen production that member states, including Germany, must match with their national plans. The RED III would boost the share of renewable energy to at least 42.5 % in its overall energy mix by 2030, revised upwards from 32 %. The difference in the degree of ambition is due to developing climate ambition and the effect of the COVID-19 pandemic on the geopolitical front. The proposal also works on increasing the target for renewable energy under the REPowerEU Plan, which will cut the EU's dependence on Russian fossil fuels by 45 % by 2030. Essential to the Paris Climate Agreement, this will mean that the move to a hydrogen-based system will require substantial scaling up of renewable energy (RE). Policymakers are urged to make this happen and the hydrogen infrastructure development that will sustain the growing market for hydrogen. Having underlined economic efficiency, the analysis insists on an integrated approach to support hydrogen along the entire value chain: from production to infrastructure. Genovese et al. [2] underlined the necessary integration of planning between electricity and gas networks while Schlüter [3] showed that in the energy field holistic planning of measures is clearly advantageous in contrast to an uncoordinated approach. Germany can set up solid regulations and domestic production at the earliest time possible to offer a competitive advantage

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while pursuing the 2030 targets, combat high import levels, and ensure that sustainability is reached in this energy transformation.

As the global community grapples with the urgent need for decarbonization, the pursuit of sustainable and renewable energy sources has taken center stage. Among the myriads of promising options, hydrogen stands out due to its high energy content and environmental friendliness. When derived entirely from renewable sources, it is termed "green hydrogen" [4], having a null carbon intensity. According to "Green Hydrogen Organisation" [4], "Green hydrogen" is defined as hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity through a process called electrolysis. This green hydrogen has the potential to be utilized directly, liquified or converted into other energy carriers – known as e-fuels-, such as e-ammonia, e-methanol and e-methane. These e-fuels offer the advantage of being cost-efficient to be safely stored and transported than hydrogen. Green hydrogen-based e-fuels are gaining increasing attention as sustainable energy carriers contributing to the reduction of greenhouse gas emissions. e-Ammonia, e-methanol and e-methane are relatively cost-efficient to transport, but each has specific requirements: e-ammonia can be transported as a liquid under pressure or in cryogenic conditions. Existing infrastructure (tankers, pipelines, and storage facilities) used for transporting and storing natural gas can be adapted for e-ammonia with some modifications [5]. Methanol is liquid at room temperature, making it easier to transport. It can be transported using existing infrastructure, such as chemical tankers, trucks, rail cars, and pipelines [6]. e-Methane produced from hydrogen, which is gaseous at room temperature, can make use of the existing pipeline infrastructure [7]. The economics of transport depend on the distance, infrastructure adaptation or construction costs, and the specific safety requirements for each substance, see also [8,9].

In the case of Germany, one of the means of achieving a sustainable and climate-neutral energy system, is leveling out the use of fossil fuels. By 2030, Germany plans to ramp up the national electrolyzer capacity, with an increase on the previous target of 5 GW, aiming now at 10 GW [10]. The theoretically installed capacity would produce about 33 TWh of green hydrogen annually. However, the national hydrogen demand within Germany for 2030 will consequently be between 95 and 130 TWh. This high demand will necessarily involve large imports of hydrogen, accounting for 50–70 % of the total requirement, respectively, 45–90 TWh [11]. Establishing pipeline transport from neighboring countries and a robust import framework is within the German strategy to stabilize the hydrogen supply. Surplus electricity by renewable power generation in particular is to be utilized, e.g. in the country's windy Northern parts. Fig. 1 illustrates the projected roadmap for hydrogen energy targets extending to the years 2030–2050.

As far as the expansion and growth post-2030 go, Germany anticipates a rise in the hydrogen demand that will escalate even further,

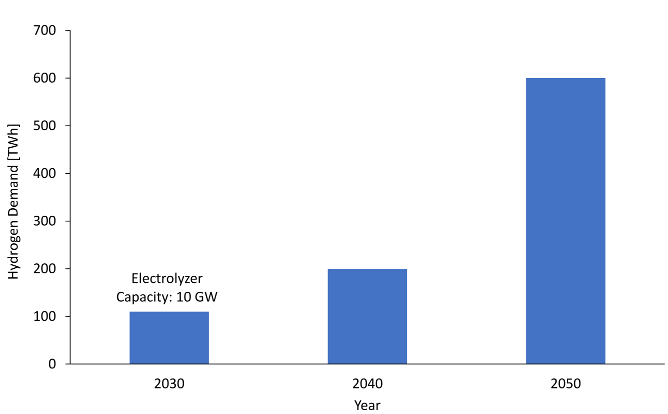

Fig. 1. – Governmental German Hydrogen Target. Data elaborated and averaged from different sources: 2030 from Ref. [11], 2040 from Refs. [12,13], 2050 from Refs. [12,13].

ranging between 100 and 300 TWh. Whereas domestic production capacity may rise, there still will be a need for imports to fulfill the remaining demand, currently estimated between 240 and 640 TWh.

Building on the above presented state of play, this research aims to contribute to the scientific field by providing a comprehensive techno-economic analysis of production and transport routes of green hydrogen, both in gaseous and liquid form, and its derivatives, namely e-methane, e-ammonia and e-methanol. The analysis includes:

1. Examining the efficiency and cost-effectiveness of water electrolysis and the conversion to e-ammonia, e-methanol, liquid hydrogen and e-methane.
2. Assessing the logistical requirements and costs associated with transporting and storing these energy carriers.
3. Evaluating current and projected pricing.

Current literature, as reviewed in the ScienceDirect and Web of Science databases, shows limited comprehensive studies on the entire value chain of green hydrogen-derived e-fuels. This research aims to address these gaps by:

1. Providing a thorough review of existing literature on green hydrogens derivatives, identifying research gaps, and opportunities for further investigation.
2. Developing a numerical model for the techno-economic analysis of green hydrogen and its derivatives, integrating various components of the value chain.

The novelty of this research lies in its comprehensive and integrated analysis of the entire value chain of the energy carriers considered, from production to application, considering economic, and technical aspects.

The paper will then evaluate the feasibility of some routes to import hydrogen to integrate native production, considering geopolitical, economic, and logistic issues, with a particular focus on options for import from different regions with significant renewable energy resources and of interest for the Germany import strategy for hydrogen and hydrogen derivatives. The countries of Algeria, Canada, and Chile are scrupulously evaluated to represent North Africa, North America and South America regions, respectively. This research compares costs, and infrastructure requirements between the different transportation methods that use pipelines, and shipping of hydrogen and its derivatives.

To the purpose a computational simulator, HydrogenPathway Explorer, has been developed to comprehensively analyze alternative pathways for hydrogen production, storage, and transport. This tool generally explores technical and economic performance from various routes for hydrogen production, storage, transport, and usage. The HydrogenPathway Explorer allows the modeling of scenarios that can be designed to attain or make decisions based on elaborated simulations of the hydrogen supply chain.

2. Literature review

As stated in the introduction, Germany is estimated to lead in establishing a robust home market for hydrogen technologies. International cooperation could serve as part of the strategy with partnerships formed with countries like Norway, Denmark, Austria, Italy, Canada, Namibia, Australia, and various nations in South and West Africa, all suitable to generate wind and solar power for hydrogen production. In conclusion, Germany's hydrogen strategy is ambitious, in coherence with the broader EU strategy for renewables in RED III and the REPowerEU Plan. Increasing national production capacity in combination with international solid partnerships is of the essence to supporting Germany in meeting its demand for hydrogen and ultimately contributing to the general climate neutrality goal of the EU by 2050.

The primary focus of this energy transition is the decarbonization, and a vigorous hydrogen economy through the use of hydrogen as a versatile energy carrier can store and distribute renewable energy. Therefore, this paper discusses the in-depth analysis of the German in-country production capabilities for hydrogen. Potential import routes to supplement domestic production are evaluated. This study, based on current technologies regarding production and infrastructure readiness, along with the economic assessment, will provide a strategic setup toward the achievement of the hydrogen goals for Germany by 2030 and 2050. The hydrogen economy takes on a unique role in the world energy system transition to sustainable development.

The hydrogen production strategy in Germany is to have extensive utilization of its renewable energy capacity. Already in 2013, research by Winkler-Goldstein and Rastetter [14] pointed out that importance of Power-to-Gas (PtG) technology for Germany, defining it as "opportunities for hydrogen to be fed into the existing natural gas grid network." According to them, PtG technology can utilize extra renewable energy, converting it into hydrogen and storing it later. This technology is, therefore, very critical in trying to limit the imbalance of renewable energy sources arising from the intermittent nature, especially wind and solar power. Also in Ref. [14], it was indicated that the integration would link hydrogen production with renewable energy systems, as the authors stated that "there are over 40 caves currently used for natural gas storage with a total volume of 23.5 billion cubic meters and 400,000 km gas grid available in Germany", and the German Technical and Scientific Association for Gas and Water was referred as association supporting already this technology. Effectively, the grid will be more stable and can operate as a long-term storage solution for energy. This flexibility is essential in Germany because, as demonstrated by Kockel et al. [15], the temporal and spatial distribution of energy generation and demand does not always align. Several studies emphasize the performance of hydrogen on sector coupling, where renewable energy can be used in the various applications of transport, industry, and heating [16]. However, viewed from an economic analysis, the cost of hydrogen production is still high today; thus, the case for more technological advances and securing economies of scale remains to be justified. The infrastructure development that will be required for hydrogen supply, storage, and distribution is enormous. Investments in pipelines, storage facilities, and refueling stations are necessary to support the widespread use of hydrogen [17]. There must be a firm policy and regulatory framework for stakeholders and off-takers that can facilitate investments in hydrogen technologies.

In numerous pilot and demo plants, hydrogen production technologies are tested in their integration with renewable energy sources.

- The H2Mare project is to produce hydrogen directly at the site of offshore wind farms using electrolysis [18]. This project will demonstrate the possibility of integrating hydrogen production into large-scale renewable energy generation on an industrial scale.
- The HyPerformer initiative supports regional hydrogen projects that integrate production through infrastructure to end-use applications [19]. These projects aim at making hydrogen hubs that can serve as models for broader deployment.
- Lhyfe Schwäbisch Gmünd [20] is a large-scale green hydrogen production plant in Schwäbisch Gmünd, initiated in October 2023. Powered by renewable energy from hydro, wind, and solar sources, it supports local industry, including the "H_2-Aspen" industrial park and a JET H_2 filling station. The 10,000 m^2 facility, equipped with a 10 MW electrolyser, will produce and purify hydrogen, with funding by the state of Baden-Württemberg and the EU to advance sustainable infrastructure.

Five works estimate that hydrogen production costs in Germany range between 3 and 6 EUR/kg H_2, emphasizing the need for technological advancements to reduce these costs [14,17,21–23]. Studies by Bhandari and Shah [21], as well as Kirchem and Schill [24], emphasize that cost reductions through technological improvements and economies of scale are essential for the economic viability of hydrogen production. Ashari et al. [25] highlight that regional adaptation is a strategic issue for deploying hydrogen technologies effectively, comparing the progress in Germany and South Korea [23]. Research indicates that repurposing existing natural gas infrastructure for hydrogen transport is more economical than building new networks [26]. Scheller et al. [23] pinpoint hydrogen and synthetic fuels as the central pillars ensuring that climate goals can be achieved. Without them, no scenario reaches the latter. Hydrogen should account for about 4 % of final energy demand in 2030, but this share still falls short of governments' expectations, which talk about 90–110 TWh. Domestic production is therefore expected to reach up to 14 TWh, overachieved in some scenarios. By 2050, the share of hydrogen and synthetic products amounts to about 24 % of final energy demand and is key to bringing about fulfillment under more stringent climate targets. The study signals rather immense economic effects of these energy carriers – an added value of up to 16 billion EUR per year by 2050. Peterssen et al. [27] examine the dynamics of green hydrogen to attain a climate-neutral energy system in Germany and emphasize the role of hydrogen importation prices and caps on Photovoltaic (PV) installations. They built a scenario that needed hydrogen importation prices ranging from 1.25 to 5 EUR/kg H_2. They found that even with PV installation limits ranging from 300 GW to no cap, hydrogen made a massive difference in attaining this energy transition. More precisely, at a mid-range import price of 3.75 EUR/kg H_2 and variously sized PV capacities between 300 GW and 900 GW, the demand for hydrogen is about 1200–1300 TWh, and imports provide between 60 % and 85 % of the supply. Multiple studies highlight that substantial investments in infrastructure are required for hydrogen supply, storage, and distribution, necessitating firm policy and regulatory frameworks to facilitate these developments [17,25,28–31]. Lux et al. [22] and Scheller et al. [23] indicate that hydrogen must account for about 24 % of final energy demand by 2050 to achieve climate neutrality goals in Germany. With the expected deficit in domestic production, Germany is looking at different supply options for future hydrogen requirements.

Most studies project hydrogen transport costs to be below 1 EUR/kg H_2, particularly when utilizing existing infrastructure or importing from nearby regions [26,32–37]. For instance, Kanz et al. [33] estimate shipping liquefied hydrogen (LH_2) from North Africa to Germany costs between 0.47 and 1.55 USD/kg H_2, depending on distance and conditions. Some researchers point out that many cost estimates lack consideration of taxes and regulatory expenses, which could significantly impact overall costs [38,39]. According to Hampp et al. [40], these include pipelines from neighboring countries such as Denmark and Spain and shipping liquefied hydrogen from regions like North Africa, among others. Lately, these alternative possible import routes of supply have to converge economically and logistically if there is to be a stable supply of hydrogen into operations. In this regard, the high solar irradiation of North Africa makes the region a candidate for hydrogen production using solar electrolysis. Several authors underscore the importance of international partnerships for hydrogen imports, especially from regions with high renewable energy potential like North Africa and Scandinavia [32–37]. Sizaire and Gençer [37] researched whether hydrogen may assist in the decarbonization of the German industrial sector specifically. Their model uses linear programming and concludes that to meet current demand for industrial hydrogen while domestically producing electrolytic hydrogen, the country would require infrastructure investments such as 22 GW of electrolyzer capacity, 30 GW of solar, and 15 GW of wind. This design would provide hydrogen at a levelized cost of approximately 5 USD/kg H_2. The analysis strongly suggests that Germany might consider importing hydrogen, above all from nearby Norway, through pipelines laid under the sea, as being more cost-efficient and environmentally friendly. There are significant cost reductions if such imports are pursued, meeting concurrently the shallow carbon intensiveness targets — once again showing how strategic international cooperation and infrastructure are in decarbonizing Germany.

In their study, Kockel et al. [41] focus on the global warming potential (GWP) of hydrogen production and import paths to Germany. Using a modular life cycle assessment, the authors identify key environmental drivers across the production, conversion, transportation, and reconversion stages. Their findings emphasize the critical role of electricity sources in hydrogen production and conversion, as well as the efficiency of subsequent processes, including carbon capture rates for blue hydrogen, in determining GWP. The reliance on hydrogen imports in countries with high demand but limited domestic production highlights the need to optimize supply chains to minimize CO_2 emissions.

Literature shows how multidimensional an effort is in the establishment of a hydrogen economy in Germany. It includes production technology development, strategic import routes, policies, and economic and environmental issues. The delivered insights will serve for the improvement and optimization of hydrogen supply chains, further ensuring a sustainable and resilient energy future in Germany. While the use of green hydrogen for e-ammonia and methanol production is promising, their widespread adoption will depend on the cost of renewable electricity, the efficiency of electrolyzers, and the development of robust and safe transport and storage systems. Additionally, the commercial viability of these e-fuels will also depend on market prices, government regulations, and incentives that promote the use of clean energy sources. The success of Germany's hydrogen strategy will therefore depend not only on technological innovation but also on the ability to create a supportive regulatory and financial ecosystem for large-scale deployment. While innovative projects and policy frameworks are paving the way for hydrogen market development, achieving a sustainable hydrogen economy will require substantial investments and stronger international cooperation to ensure stable and cost-effective supply chains.

For this reason, the present paper provides a comprehensive techno-economic analysis of Germany's hydrogen production capabilities and potential import pathways, integrating current infrastructure readiness and cost projections to assess the feasibility of a sustainable hydrogen supply chain. Unlike previous research, this work combines a comparative assessment of regional hydrogen import options with an in-depth evaluation of infrastructure adaptation strategies, offering actionable insights to accelerate hydrogen market development.

3. Materials and methodology

The present paper aims at analyzing and presenting the feasibility in terms of technology and economic efficiency of several hydrogen import routes from different countries to Germany. In order to do so, a multi-tool adoption strategy has been exploited, as shown in Fig. 2.

Fig. 2 gives a complete methodological framework for assessing optimal ways of importing hydrogen and e-fuels, as shown in Fig. 3, and the methodology is broken into six detailed phases. In the production phase, much focus is directed toward producing hydrogen via water electrolysis. This uses the HRSIM Tool, which analyzes the energy performance and the efficiency of hydrogen production from RES. HRS Simulator (HRSim) is a numerical tool that allows the design and simulation of hydrogen refueling stations (HRS), including hydrogen production via water electrolysis. The tool has already been validated and tested. Further, the study also examines the auxiliary power, and the amount of compression energy used, which completes the entire energy requirement and efficiency. The conversion phase will involve the conversion of hydrogen to e-fuels or liquid hydrogen. The analyses of the conversion processes are carried out in the ASPEN Tool through a simulation approach. The next step is international transportation, including debunkering, and bunkering operations. The fourth phase includes the reconversion of the various energy carriers into gaseous hydrogen and is carried out in the ASPEN Tool. The fifth phase considers the national distribution of gaseous hydrogen.

All the outputs of these steps are utilized in the techno-economic toolkit to perform techno-economic and resource analyses to study the economic feasibilities of various hydrogen distribution pathways in handling national production and international hydrogen imports. It highlights the least costly or highly efficient routes for distributing hydrogen, considering production, conversion, and transportation costs.

The sixth and final phase brings together previous analyses to establish the most appropriate import pathway for hydrogen. The steps help to provide a basis on which policymakers and critical stakeholders should make their decisions on the strategic planning and implementation of hydrogen infrastructure. An overall integrated approach would, therefore, ensure the lucid assessment of hydrogen production, conversion, distribution, and economic viability elaborately. It strongly supports strategic energy planning and policy development in targeted sectors to ensure that the import and utilization of hydrogen are optimized effectively and sustainably for future energy needs.

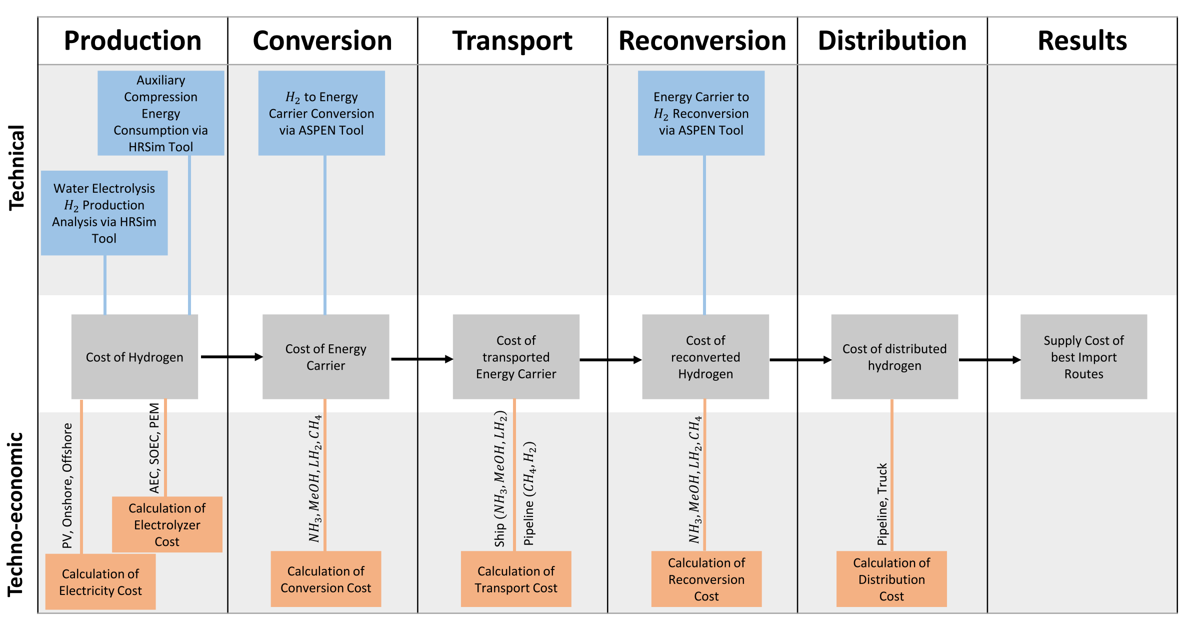

Fig. 2. – Methodology for assessing hydrogen import routes supply chain.

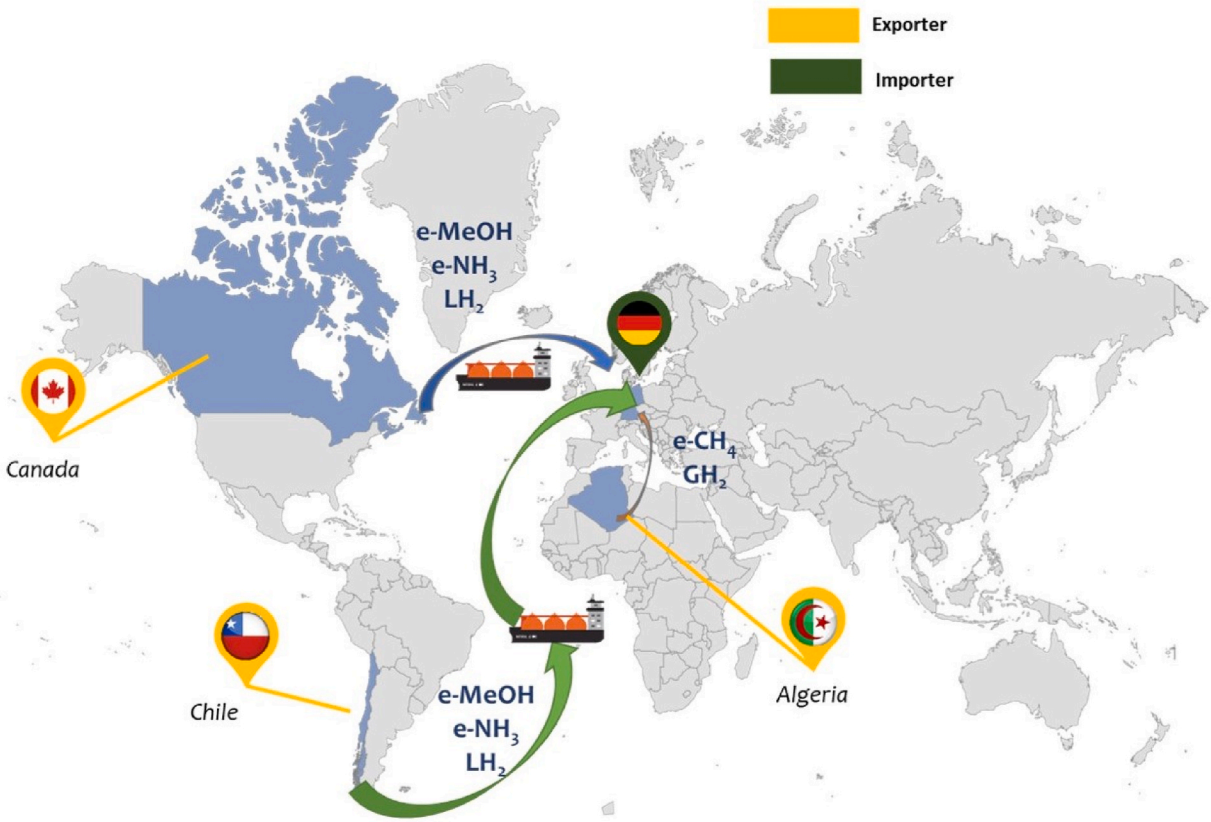

Fig. 3. – E-Fuel import route.

3.1. Selection of three exporting countries

With regards to the methodology, the import routes have been conceptualized by pulling together at least three different and realistic hydrogen import routes with well-detailed supply chain analysis from the production stage to national distribution. This step was considered as a key activity to ensure a sustainable hydrogen supply to Germany under the consideration of multiple import routes with maximized supply chain efficiency, minimized environmental impact, and assured economic viability. The selection of import routes for sustainable hydrogen is a complex process under geopolitical considerations, technological feasibility, and economic factors. Amongst others, three regions are considered as main possible exporting regions to Germany: South America, North America, North Africa. Considering the production technologies, transport options, regulation and economics, countries in each region are typically rather similar. Therefore, the focus will be on providing the value chain for one country per region only and assume that this represents the region well enough: Chile, Canada, and Algeria. These three countries were selected as case studies representing three different regions. There are more optional exporting regions, but for instance it makes more sense for Australia to trade hydrogen to Asia and Eastern Africa than to Central Europe – simply due to distances and given demand by that time. The routes utilized in this study are known or planned routes for hydrogen imports or bilateral cooperation agreements to increase the international supply of hydrogen of Germany by 2030 [10]. This work does not include a sensitivity analysis, as the model is highly flexible and can be applied to other regions or countries according to the needs of the analysis.

Each proposed route presents its unique features in terms of hydrogen production capacities, transportation logistics, and diplomatic relationships. The main aspects of the proposed routes are summarized in Table 1.

The first proposed country is Canada to export e-ammonia, e-methanol, and liquid hydrogen. Canada is an attractive partner for Germany

Table 1
Main aspects of the proposed import routes.

Aspect	Canada	Chile	Algeria
Energy Carrier	e-Ammonia, e-methanol, Liquid Hydrogen	e-Ammonia, e-methanol, Liquid Hydrogen	e-Methane, Gaseous Hydrogen
Production Method	Renewable energy and electrolysis	Renewable energy and electrolysis	Renewable Energy and Electrolysis
Conversion Process	Hydrogen to e-Ammonia and e-Methanol	Hydrogen to e-Ammonia and e-Methanol	Hydrogen Combined with CO_2 to Produce e-Methane
Transportation method	Shipping	Shipping	Pipeline Transport
Re-conversion Process	Reformed Back Into Hydrogen	Reformed back into hydrogen	Reformed Back into Hydrogen
Local Distribution	Transport And Industry Sectors	Transport and industry sectors	Transport and Industry sectors
Trade Relationship	Strong And Stable Trade Relationship With Germany	Emerging trade relationship with Germany	Established Trade Relationship with Germany
Key considerations	Stable political environment; shipping costs and infrastructure challenges	Potential for renewable energy production; shipping costs and infrastructure development required	Infrastructure Constraints; Geographic Proximity to Europe

because it is resource-rich in renewable energy resources, has a stable political environment, and has strong trade relations with Germany. Additionally, the geographic proximity of Canada to major U.S. ports can facilitate efficient transportation via ocean shipping, reducing logistical complexities and costs. Therefore, the hydrogen that will be produced in Canada will then be used in the vicinity as feedstock for producing e-ammonia and e-methanol, or liquified to obtain liquid hydrogen. The other advantage is the potential of using the transportation stage, where these carriers can be shipped to Germany and, after utilization, be reverted to hydrogen, where they can be distributed into sectors such as transport or industry. This import route becomes more plausible under the current consideration to strengthen the already good trade relationship between of the two countries, in addition to efforts to extend cooperation in the hydrogen sector. With Canada's National Hydrogen Strategy [42], the country has determined low carbon hydrogen production as key for their energy transition to achieve Canada's net-zero goals by 2050 and to strengthen export markets to USA, Japan, South Korea, China and the EU. By 2024, the production of low carbon hydrogen is 3450 tons per year, with projections of 12.37 Mt per year by 2050 in a high hydrogen production scenario. Additionally, recent research [43] suggests that Canada's green hydrogen generation potential is 439.92 Mt from offshore and onshore wind energy [44] and 205.69 Mt from PV energy sources [45].

The second route, that of Chile, would be a high-potential country as regards significant sources of renewable energy and a strategic location on the coast of the Pacific. The potential for low-cost hydrogen in Chile from renewable energy arises mainly from solar, wind power. Chile's Atacama Desert, with very high solar irradiation levels, has been noted to be one of those strategic locations for producing solar hydrogen [8]. Chile has an ambitious national hydrogen strategy, which would be placing them as hydrogen exporting leaders. They foresee EU countries – mainly Germany, Netherlands and Belgium – would be the main markets for their production [46]. Similarly, the hydrogen would then be converted into liquid hydrogen, e-ammonia and e-methanol, later shipped to Germany. Like the Canadian situation, the carriers are either used on arrival or converted into hydrogen through formation. What makes it a promising project is the new emerging trade routes; this opens up between Chile and Germany and their willingness to explore new possible hydrogen trade partners. However, associated with it is the development of shipping infrastructures and handling costs to ensure feasibility.

The third option suggests the import of synthetic e-methane and gaseous hydrogen from Algeria. Given that Algeria's infrastructures for natural gas are already existing and mature, it is also located geographically close to Europe in comparison with the other shortlisted regions. Hydrogen would be produced in Algeria using renewable resources and mated with carbon dioxide (CO_2) to generate e-methane. On the other hand, using pipelines to transport e-methane or gaseous hydrogen can be transported to Germany, where it can also help existing networks of natural gas, which probably exist and can be quickly adapted. At the point of destination, e-methane could be re-converted into hydrogen or used as it is to reach various sectors of application at the local level. This route takes advantage of the strategic proximity between Algeria and Italy. Importing hydrogen from Algeria to Italy would capitalize on a well-established partnership built upon long-term natural gas trade agreements. This existing relationship not only ensures a reliable energy supply but also leverages existing infrastructure and logistical channels. Moreover, the geographical proximity of Algeria to Italy across the Mediterranean Sea simplifies shipping logistics, making it a cost-effective route for hydrogen importation. This strategic alignment would further strengthen economic ties between the two nations. Another support for this route is the established trade linkage of Algeria with Germany and rising interest in increasing hydrogen exports. Its potential for scalability, however, is limited by infrastructure and would take detailed feasibility studies of the same.

All three pathways underline strategic partnerships and technological advancement, for which securing a sustainable hydrogen supply is indispensable for Germany. They are in line with the ambitious decarbonization objectives of Germany and contribute to advancements towards a sustainable energy future.

3.2. Technical modelling

3.2.1. Hydrogen generation

The Fuel Cell and Hydrogen Research Team, see at authors' list, developed a simulation tool with the basis of a dynamic, zero-dimensional model with lumped parameters [47–54]. The current design targets the energy performance simulation in a hydrogen infrastructure, from the production to using this energy vector, as shown in Fig. 4. It includes general energy management rules to integrate renewable sources effectively, to ensure that hydrogen generation process can utilize the variability and availability of renewable energy sources to enhance the overall system efficiency and sustainability. Through dynamic modeling, this tool could be used to design real-time operations and transitions in the hydrogen infrastructure. The complex interactions taking place in natural systems are reduced for a simplified model with lumped parameters to be adopted in this tool, which, hence, helps to carry out simulations with meaningful results but without much help from computational resources. This tool is majorly designed to evaluate the performance of energy through hydrogen infrastructure. These include the efficiency of production methods, the effectiveness of storage solutions, and the performance of hydrogen utilization technologies. The developed computational tool provides a full assessment and optimization platform for hydrogen infrastructure. Scenarios are run through renewable energy sources, and consequently, strategies become available that could be most efficient and, at the same time, cost-effective in hydrogen production, storage, and use.

For the purpose of the present analysis, the tool has been run with various technologies for electrolysis, where Alkaline Electrolysis Cells (AEC) is the most mature technology in this field. Additional advanced technologies are Proton Exchange Membrane (PEM) electrolysis or Solid Oxide Electrolyzer Cells (SOEC), where the second is much more efficient but also should become cheaper due to active innovation now carried out in this area by the European Union. PEM electrolysis presents high efficiency with a broad operational flexibility; it makes possible the integration of variable renewable energy sources into grid applications, such as wind and solar power. Durability was one of the critical discoveries in recent years that enabled significant steps toward cost-effective PEM electrolyzers, crucial for making them viable for large-scale hydrogen production [55,56]. SOEC technology works at high temperatures (700–1000 °C) that can enable the process of electrolysis to be more efficient [57–61]. This characteristic is most important in integration with industrial processes, which generate excess heat. However, SOEC systems still need to be commercialized and need more studies on specific issues of material stability and system life [21].

To better represent the evolution of technology, the nominal efficiency values have been considered variable over the years, to depict a gradual rise in the efficiency of all the water electrolysis technologies from today to 2050. AEC technology, for instance, sees an increase from 60 % during today to 70 % by 2050. Towards the same trends are PEM electrolysis, along with SOEC with its heat integration. Remarkably, the SOEC without heat integration starts from 82.5 % today and grows to 89.1 % in 2050, presenting significant technological advances in well-performed development. The lifetime considerations show that AEC (Alkaline Electrolysis) and PEM technologies have a lifetime of up to 80,000 h, while for the SOEC technology, this lifetime is much smaller, 43,800 h. This may, in fact, affect the long-term viability and maintenance costs of SOEC systems. Degradation rates per 1000 h seem to lean at supporting this claim, with SOEC technologies presenting higher degradation rates in general, particularly the present data for applications onshore and offshore, indicating much faster efficiency losses over time than AEC and PEM technologies.

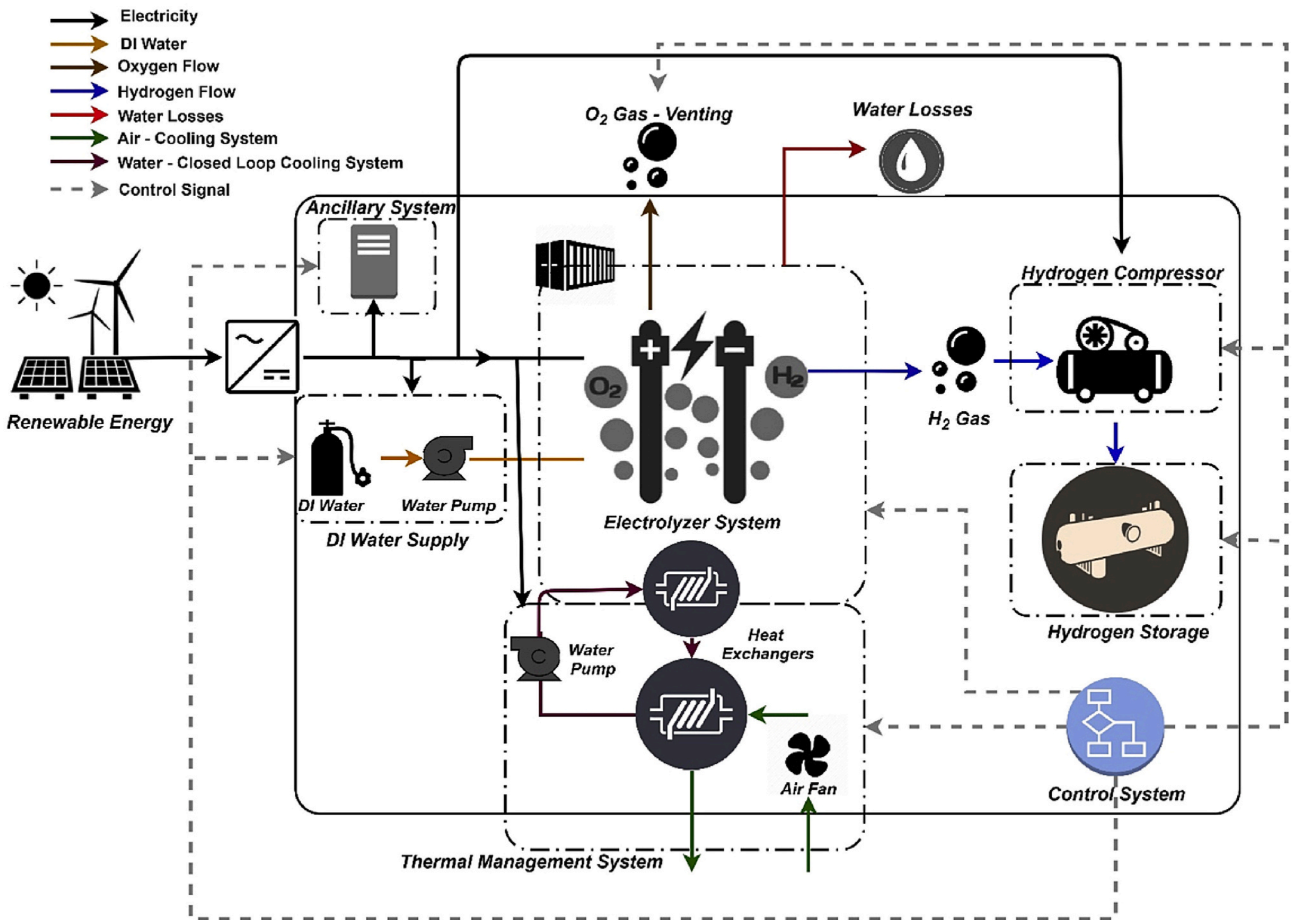

Fig. 4. – Hydrogen Production Simulation Tool. Reproduced with copyrights from [50].

3.2.2. *Generation and transformation of E-fuels*

The e-fuels generation processes, along with hydrogen liquefaction process, are schematically presented in Fig. 5. The processes underlying the simplified plant schematic involve a considerable degree of complexity. In this paper, for the sake of clarity and brevity, these processes are not depicted in full detail. Actually, various stages must be considered, including the preparation and feeding of working fluids, their conveyance to reactors, potential recirculation for refining product output, the separation of the desired product from by-products, the utilization of waste energy fluids for heat recovery, energy recuperation through depressurization, and the final delivery of the product.

Fig. 5 represents the process complexity for producing e-fuels from hydrogen and all its transformation. The production of e-methane involves three main subprocesses: CO methanation, the Water-Gas Shift (WGS) reaction, and CO_2 methanation. Section a) illustrates the liquid hydrogen delivery. Section b) depicts schematically the processing of methanation. Green hydrogen mainly reacts with CO_2, to trigger the three subprocesses [6]. Section c) regards the e-methanol phase production, where the catalytic hydrogenation of CO_2 occurs [6]. Section d) involves the e-ammonia production process. Here, green hydrogen reacts with nitrogen [62]. The Haber-Bosch process is used for e-ammonia synthesis. The cost drivers in this step are primarily the catalysts, raw material costs, and the energy efficiency of the reactions. Hydrogen represents the main gaseous stream to be fed, but a stoichiometric amount of CO_2 is necessary to accomplish the process [63]. It should be noted that in this study, nitrogen and carbon dioxide are acquired externally through purchase, and no air capture production plants are considered for their generation.

Particular importance is given to the so-called balance of plant, which is provided with equipment necessary for realizing mechanical, thermal, and fluid-dynamic processes. Fluid movers and pressurizers are essential, along with heat exchangers that warm, cool, and recover heat. Being very accurate in terms of model inputs and outputs, it ensures complete transparency of energy and mass flow requirements together with all the key performance indicators needed for an assessment of the system's efficiency.

The hydrogen generation model is central to the process, receiving inputs and making them into hydrogen. The generated hydrogen flows to the next processing unit for further conversion into e-fuels. It is during this process that hydrogen is chemically reacted to e-fuel, thermochemical reactions leading to the formation of e-methane, e-methanol, and e-ammonia. The thermochemical process interacts with the hydrogen production model, which uses hydrogen as feedstock for the synthesis of e-fuel.

The e-fuels plants must be intended totally green and clean, where all the sections requiring external energy are powered through electric energy, derived from renewables. The electrification of e-fuel plants marks a pivotal shift towards sustainability in the production of e-ammonia, e-methane, and e-methanol. These facilities are powered entirely by electricity derived from renewable energy sources, ensuring that the entire production process is both green and clean. By utilizing renewable electricity, the plants avoid the emissions associated with conventional energy sources, as all operational energy requirements—from compressors and pumps to heating processes—are met with electrical energy. This not only reduces the carbon footprint of e-fuel production but also aligns with global energy transition goals, turning these plants into models of modern, sustainable industrial operations.

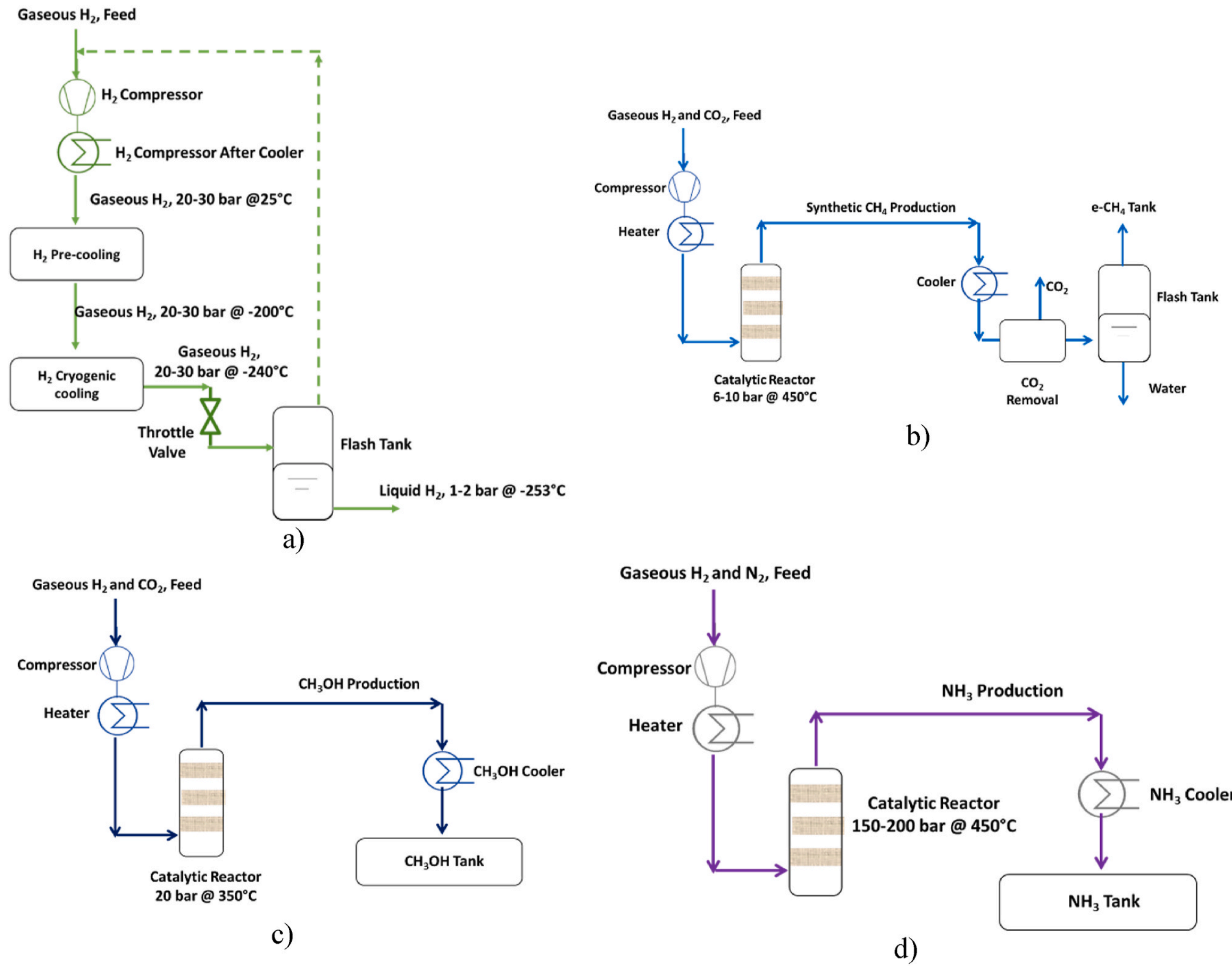

Fig. 5. – e-Fuel generation process: a) Liquid hydrogen, b) e-Methane, c) e-Methanol, and d) e-Ammonia.

A high-level interface manages the computational flows and has been meticulously developed to ensure that the sub-toolkits interact seamlessly based on specific requirements. The balance of the plant integrates a few critically essential components that are necessary for operating and maintaining the system:

- Electromechanical devices, that control the fluids and gases in the system, like compressors, pumps, and movers.
- Thermal components, that includes heaters and coolers in the system to control the reaction or process temperature.
- Fluid-dynamic systems, including the piping and other flow control parts of fluids, with gases passing through the system.

The main energy KPI evaluating the energy conversion efficiency ε, is defined in Eq. (1):

$$\varepsilon = \frac{E_{e-fuel}}{\frac{E_{th}}{\eta_{heat}} + E_{el} + E_{H2}} \quad \text{Eq. 1}$$

The primary useful energy in this context is derived from the specific e-fuel produced, E_{e-fuel}. The denominator accounts for all the energy inputs required for processing, including thermal $\frac{E_{th}}{\eta_{heat}}$ and electrical energy needs E_{el}, as well as the chemical energy of incoming fluids like hydrogen E. All processes are assumed to be green and clean, meaning thermal energy from external combustion sources is excluded (biofuel combustion invariably results in CO_2 emissions, with the sole exception being the combustion of hydrogen, which does not emit CO_2). Instead, thermal requirements, necessary for the thermal preparation of the working fluids, are met through electrification using electrical heaters to accommodate the energy conversion process. Additionally, electric energy is utilized to operate fluid movers and pressurizers, such as compressors and pumps, essential for system functionality.

For brevity, the layouts of the reconversion plant are not depicted. However, succinctly, the processes involved are the reverse of those shown in Fig. 5. Hydrogen is reformed through a thermochemical reconversion process when necessary and when required. This involves processing e-fuels, specifically by cracking ammonia [64] and steam reforming methane [65] and methanol [66]. The processes are endothermic, meaning they absorb heat. Consequently, it is essential to account for the thermal and electrical energy required during this phase. Therefore, the e-fuels reconversion process aims to investigate the process energy efficiency, defined in Eq. (2), as well as the main KPI in terms of mass flows, electrical energy and thermal energy. Similar to Equation (1), Equation (2) demonstrates that the useful energy is represented by the reconverted hydrogen (E_{H2}), while the denominator encompasses the energy requirements of the reconversion processes.

$$\varepsilon = \frac{E_{H2}}{\frac{E_{th}}{\eta_{heat}} + E_{el} + E_{e-fuel}} \quad \text{Eq. 2}$$

3.2.3. Bunkering-debunkering hubs

Once the e-Fuels are produced, they need to be shipped via an export hub, for the bunkering operation, and once they arrive, they need to be processed at an import hub, for the debunkering operations.

Regarding the export hub, the energy carriers' electricity consumption per kilogram is considered to be 0.005 kWh/kg for e-ammonia, 0.01 kWh/kg for e-methanol, and very high for liquid hydrogen, 0.61 kWh/kg. For loss per day due to boil-off, it is negligible in the case of e-ammonia and e-methanol but up to 0.005 % per day for liquid hydrogen, whose boil-off rate changes up to that value. The flash rate for liquid hydrogen represents the percentage of flash gas and can reach up to 0.001 %. The common factor for all energy carriers is that the duration of storage is fixed at three days. The production capacity for e-ammonia in tons per annum ranges around 4,148,833 tons yearly, around 6,296,250 approx. for e-methanol, and about 1,496,500 for liquid hydrogen. Capacity per storage tank varies, with e-ammonia at 34,100 tons per tank, e-methanol at 51,750 tons per tank, and hiquid hydrogen at 12,300 tons per tank.

e-Ammonia presents a consistent profile, where electricity use is low, making it an economical choice with high tank capacity, reducing the number of tanks needed for large-scale storage. In addition, the capacity and the tank capacity per year are higher for e-methanol compared to e-ammonia, even though electric use is labeled as moderate, so this is an option where cost and storage will change compared to others as a bit more dynamic. But liquid hydrogen fluctuates in electricity used variability because it is more complex and expensive to manufacture and store. Essential aspects of storage and transportation for Liquid Hydrogen are the minimal boil-off and flash rates. The best energy carrier for an export hub would depend on a multiparameter evaluation balancing cost, capacity, and operational efficiency.

Similarly, the analysis of import terminal involves different parameters, such as capacity factors, capital expenditures (CAPEX), yearly capacities, and other operational metrics. For three major energy carriers— e-ammonia, e-methanol, and liquid hydrogen (LH_2)—assessments were done. The capacity factor for each type of carrying medium is assumed to be 80 %. The value is the ratio of actual output to potential maximum output if the process works under ideal conditions.

The tool accounts also for boil-off losses, defined as percentage loss per day to atmosphere, which are effectively nil for e-ammonia and e-methanol; for liquid hydrogen, its vaporization rate is temperature-dependent but can be as high as 0.005 % per day. The storage time, in all cases, is set to 20 days. e-Ammonia has a relatively consistent profile, concerning the CAPEX per kilogram and electricity usage being moderate; thus, it is moderately cost-effective in terms of the need for large tank capacity and hence reduction of tanks needed in case of large-scale storage. e-Methanol has a lower CAPEX and electricity than e-ammonia, with a higher yearly capacity and tank capacity; hence, it is a plausible alternative in terms of the slight change in cost and storage dynamics. Particularly importance is that Liquid Hydrogen has the highest CAPEX and electricity use variability, underpinning complexity and cost intensity to produce and store it. The minimal boil-off and flash rates are critical for liquid hydrogen storage and transportation. This indicates, overall, from the table, that several parameters need to be considered to find an appropriate energy carrier by the import terminal, balancing cost, capacity, and operational efficiency.

3.2.4. International transportation

International transportation is considered via two potential options: liquid e-fuels are transported via ship, while gaseous e-fuels are transported via pipelines.

Regarding liquid e-fuels international shipping parameters, the tool considers evaluates the same three types of energy carriers as in subsection 3.2.3 across different years (today, 2030, and 2050), highlighting their transportation from Canada and Chile. All energy carriers maintain a capacity factor of 80 %, indicating the efficiency of the shipping process. Regarding the gaseous e-fuels international transport, gaseous hydrogen and e-methane are analyzed, and their transport is designed to occur via pipelines from Algeria to Germany. It includes critical parameters such as the lifetime of the energy carrier, distance, energy consumption, pressure losses, and details of compressors used. The analysis is done having a pipeline lifetime of 40 years, matched with the lifetime for hydrogen transportation from Algiers to Lohr am Main (via Ceuta), using 3538 km as length. The pipelines are designed with admissible pressure losses of 0.1 bar/km to ensure efficient transport over long distances while maintaining ideal pressure. Outlet and distribution pressures are set at 30 barg for AEC/PEM and ten barg for SOEC, with the distribution network pressure maintained at 80 barg. These are very important since the gases must flow under these pressure levels to ensure the integrity and flow rate through the pipeline over a long-distance from Algiers to Lohr am Main via Ceuta. To traverse such a long distance, pressure management has to ensure that an efficient transportation system is guaranteed about the energy consumed; hence, there is a need for a suitable compression mechanism at the source of pressurized gases or every station. Table 2 illustrates the main parameters.

The details for compressors for e-methane and hydrogen portray their differences about the way these gases should be compressed. For e-methane, the compressor ration $\frac{p_{out,i}}{p_{in,i}}$ is set at 1.25 per stage, so at the first compression station, five stages are required; at other compression stations, two stages are needed. For hydrogen, it is 1.1 per stage, so the first compression station requires five stages; the rest of the compression station will require two stages. This suggests that hydrogen uses a lower pressure ratio per stage; it takes many stages, though, to reach the developed compression. Several compression stations are required to maintain the pressure and flow within the pipeline, and the total losses in pressure are 353.8 bar. The actual number of compression stations used will depend on configuration, but most include the first compression station and the remaining at regular intervals along the created line. The infrastructure needs careful planning, with the number and type of compression stations adequately installed to allow efficient and cost-effective gas transport over long distances. Eq. (3) is used to calculate the energy needed for the re-compression stations. Overall e-methane transport consumes 5.3735 kWh/kg, whereas hydrogen consumes 5.8398 kWh/kg. This means greater energy throughput as the hydrogen moves over comparative distances, indicating higher energy needs for compression in the case of hydrogen because of its lower density and thus larger specific volume.

$$e_{pipeline} = \frac{k}{k-1}\frac{R \bullet T_{in,i}}{MW} \bullet \left[\left(\frac{p_{station_1}}{p_{in,electrolyzer}}\right)^{\frac{k-1}{k}} - 1\right] + \sum_{i=2}^{N_{station}} \frac{k}{k-1}\frac{R \bullet T_{in,i}}{MW} \bullet \left[\left(\frac{p_{out,i}}{p_{in,i}}\right)^{\frac{k-1}{k}} - 1\right] + e_{BoP} \quad \text{Eq. 3}$$

Long-distance transport of e-methane through pipelines appears more affordable than hydrogen because of low CAPEX and energy consumption. Yet hydrogen, even with higher costs and energy penalties, is a vital component of the future energy system. However,

Table 2
Main Parameters of Gaseous Hydrogen and e-Methane for International Distribution via Pipeline.

Parameter	Value	Unit of Measure
Admissible Pressure Losses	0.1	bar/km
AEC/PEM Outlet Pressure, $p_{in,electrolyzer}$	30	barg
SOEC Outlet Pressure, $p_{in,electrolyzer}$	10	barg
Distribution Network Pressure. $p_{station_1}$	80	barg
Methane Heat capacity Ratio, k	1.31	–
Hydrogen Heat capacity Ratio, k	1.41	–
Methane Molecular Weight, MW	16	kg/kmol
Hydrogen Molecular Weight, MW	2	kg/kmol
Compressor Adiabatic Efficiency, $\eta_{compressor}$	0.6	–
Compressor mechanical Efficiency, η_m	0.9	–
Compressor Electrical Efficiency, η_{el}	0.9	–
Specific Energy consumption of BoP, e_{BoP}	1.2	kWh/kg

making this scheme even more interesting, the SouthH2 project will annually import 4 million tonnes of hydrogen from North Africa by 2030. The EU is targeting up to 10 million tonnes of green hydrogen imports. More than 70 % of them will be repurposed gas pipes, which allows for strategic reuse not only in cost and environmental considerations but also in saving time.

3.2.5. National distribution

Once the liquid e-fuels arrive, they are reconverted to hydrogen in gaseous form, that need to be further distributed at national level. The national distribution of hydrogen has been evaluated via two different options: via trucks or via pipelines.

Regarding trucks, over the years, there has been considered a decreasing trend in the factor to reflect continuing technological improvements and potential economies of scale as hydrogen technology further matures and the production capacity grows. The route length is set to 531 km, which corresponds to the distance between two fixed infrastructural points, Rotterdam – Lohr am Main, using existing logistics in their interconnection.

The other option is the transport of the transformed energy carriers by pipeline. The 40-year life of the pipelines is being considered and reflects the expectation of long-term durability and consistent performance in decades, which are essentials of any investment in infrastructure. The capacity factor is set to 0.75, determining the proportion of time in a year over which the pipeline will be operated at total capacity. A high capacity factor is used to mark robust infrastructure use. The compression energy consumption has been calculated similarly to the international distribution via pipeline, by considering the parameters reported in Table 3.

3.3. Techno-economic modelling

The economic analysis will shed light on the financial viability of hydrogen and is used to determine the supply costs of hydrogen in Germany. The techno-economic analysis requires a comprehensive and comparable evaluation method to assess the economic viability of different hydrogen transportation routes. The main considerations are shown in Table 4. The method for determining the Levelized Cost of Hydrogen (LCOH) was chosen because it enables a detailed calculation of the specific hydrogen production costs. It allows external factors such as energy prices and labor costs to be considered in addition to capital and operating costs over the entire lifetime of the plant. This enables a comparative analysis of diverse technologies, locations and scenarios, a prerequisite for informed investment and policy decisions. All required data is given in the appendix. The hydrogen offered at the costs calculated here can either be imported to Germany or produced directly in Germany. The total supply costs for hydrogen ($Supply\ Cost_{c,y,r,e,ec,t,d}$) in EUR/kg_{H_2} consist of the following components:

$$Supply\ Cost_{c,y,r,e,ec,t,d} = Cost^{Production}_{c,y,r,e} + Cost^{Conversion}_{c,y,r,ec} + Cost^{Transport}_{c,y,r,e,ec,t} + Cost^{Reconversion}_{c,y,r,e,ec,t} + Cost^{Distribution}_{y,d} \quad \text{Eq. 4}$$

$Cost^{Production}_{c,y,r,e}$ represents the cost per unit of hydrogen in $EUR/\ kg_{H_2}$, which is produced with electrolyzer *types e* in the years y, taking into account all the expenses related to hydrogen production over the facility's lifespan. For countries c, the used electricity is produced by the renewable energy technologies r, while for Germany only the electricity mix from the grid is considered. $Cost^{Conversion}_{c,y,r,ec}$ in EUR/kg_{H_2} are the costs associated with converting hydrogen into either liquid hydrogen (LH_2), e-ammonia (e−NH_3), e-methanol (e−$MeOH$) or e-methane (e−CH_4), including the expenses for the conversion units, material and energy expenses. Gaseous hydrogen (GH_2), for which no conversion is necessary completes the energy carrier ec. $Cost^{Transport}_{c,y,r,e,ec,t}$ in EUR/kg_{H_2} covers the costs of transporting hydrogen or its derivatives from the production site to the destination via t. For $Cost^{Transport}_{c,y,r,e,ec,Ship}$, bunkering and debunkering is considered. $Cost^{Reconversion}_{y,ec}$ in EUR/kg_{H_2} are the expenses associated with re-converting either liquid hydrogen, e-ammonia, e-methanol, or e-methane back into gaseous hydrogen. $Cost^{Distribution}_{y,d}$ in EUR/kg_{H_2} encompasses the costs of distributing gaseous hydrogen to end-users, ensuring that it reaches its final point of use. Distribution d can be carried out either through trucks or pipelines.

For Germany, only $Cost^{Production}_{c,y,r,e}$ and $Cost^{Distribution}_{y}$ are considered, since neither (re-)conversion nor transportation is necessary.

Each part of the total supply cost is represented by the following function:

$$Cost^{Process}_{c,y,r,e,ec,t,d} = \frac{CAPEX^{Process}_{c,y,r,e,ec,t,d} * \left(OPEX^{Process}_{fix_{r,e,ec,t,d}} + CRF^{Process}_{c,y,r,e,ec,t,d}\right)}{CF^{Process}_{c,y,r,e,ec,t,d} * 8,760\ h} + OPEX^{Process}_{var_{c,y,r,e,ec,t,d}} \quad \text{Eq. 5}$$

where $Process = [Production, Conversion, Transport, Reconversion, Distribution]$.

The weighted average cost of capital (WACC) is uniform and assumed to be 8 % for all investments. Given the WACC, the capital recovery factor ($CRF^{Process}_{c,y,r,e,ec,t,d}$) is used to calculate the annualized cost of an investment, accounting for the time value of money over a specific period. It converts a present value (the total initial investment) into an annuity (equal annual payments).

3.3.1. Production

The analysis of the production cost of hydrogen considers three different types of electrolyzers: AEC, SOEC, and PEM. The capital expenditures $CAPEX^{Production}_{y,e}$ are given in EUR/kg_{H_2} and vary between y and e. The fixed operational expenditures $OPEX^{Production}_{fix_e}$ are set in percentage (%) of initial capital expenditures. Depending on the electrolyzer e's lifetime, the capital recovery factor $CRF^{Production}_{e}$ is given in %. The electrolyzer runs with the same capacity factor as the corresponding renewable technology, such that $CF^{Renewable}_{c,y,r}$ in Fig. 6 is used. The formula for calculating the variable operational expenditures $OPEX^{Production}_{var_{c,y,r,e}}$ is:

Table 3
Main KPIs of gaseous hydrogen national distribution via pipeline.

Parameter	Value	Unit of Measure
Admissible Pressure Losses	0.1	bar/km
E-fuels Reconversion Pressure	10	barg
LH_2 Reconversion Pressure	10	barg
Distribution Network Pressure	60	barg

Table 4
Notations.

Symbol	Description	Characteristics
c	Country of production of energy carrier	Algeria, Canada, Chile, Germany
y	Year investigated	Today, 2030, 2050
r	Type of renewable energy	PV, Wind Onshore, Wind Offshore
e	Type of electrolyzer	Alkaline Electrolyzers or Alkaline Electrolysis Cell (AEC), Solid Oxide Electrolyzers (SOEC), Proton Exchange membrane Electrolyzers (PEM)
ec	Transport medium of the hydrogen	Liquid hydrogen (LH_2), e-Ammonia (e−NH_3), e-methanol (e-$Me\ OH$), e-methane (e−CH_4), Gaseous hydrogen (GH_2)
t	Transport type of the energy carrier	Ship, Pipeline
i	Stage of transportation	Bunkering, Ship, Debunkering
d	Distribution type of the hydrogen	Truck, Pipeline

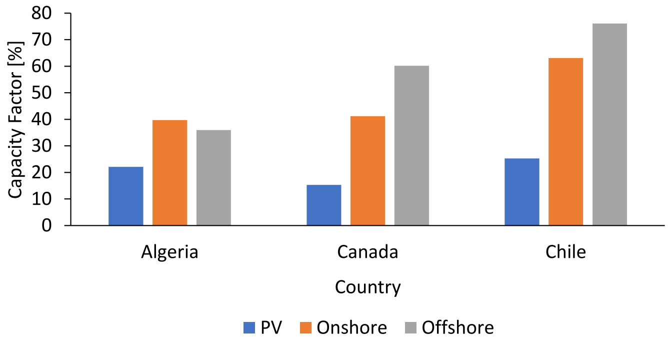

Fig. 6. – Capacity factor of PV, wind onshore and wind offshore for Algeria, Canada and Chile based on [67].

$$OPEX^{Production}_{var_{c,y,r,e}} = \left(LCOE_{c,y,r} + \frac{CRF^{Production}_{e} * SRC^{Production}_{c,y,r,e}}{CF^{Renewable}_{c,y,r} * 8,760\ h}\right) * \left(\frac{LHV}{\eta_{y,e}}\right) + I^{Production} * C^{Production} \quad \text{Eq. 6}$$

The cost of the electricity is $LCOE_{c,y,r}$ and is given in EUR/kWh. Additionally, there are the specific infrastructure cost IC, that are required for each energy source which are assumed to be constant at $0.009\ EUR/kWh$.

In Germany, the electricity costs for the production of hydrogen ($LCOE_{Germany,y,r}$) are not based on the $LCOE_{c,y,r}$. Instead, it is assumed that the 35 % cheapest hourly electricity prices on the electricity exchange for the production of hydrogen are taken into account.

The calculation of stack replacement costs **($SRC^{Production}_{c,y,r,e}$)** involves a number of assumptions. The one-off stack replacement costs are a percentage ($PSRC_{y,e}$) of the original investment costs of the electrolysis plant.

$$SRC^{Production}_{c,y,r,e} = PSRC_{y,e} * CAPEX^{Production}_{y,e} * \frac{LT^{Production}_{e}}{LT^{S}_{c,y,r,e}} \quad \text{Eq. 7}$$

In principle, the stacks must be replaced after a certain number of hours $LTih^{S}_{e}$. This service life differs depending on the type of electrolyzer e but is limited to 20 years. The assumed lifetime is 80,000 h for AEC and PEM, while $LTih^{S}_{e}$ *is* $43,800$ h for the SOEC electrolyzer.

The lower heating value (LHV) is 33.3 kWh/kg_{H_2} and is used in conjunction with the respective efficiency of the electrolyzer ($\eta_{y,e}$, see 3.2.1) to convert the costs into EUR/kg_{H_2}. $I^{Production}$ is the water input for the electrolysis process and is constant with 14 kg_{H_2O}/kg_{H_2}. The cost of the water ($C^{Production}$) is set to $0.0025\ EUR/kg_{H_2}$.

3.3.2. *Conversion*

Once produced, hydrogen can be converted into derivatives, such as e-methanol or e-ammonia. While the derivatives have much better storage and transportation options compared to gaseous hydrogen, this transformation adds an extra layer of cost owing to additional capital and operational expenditure for having conversion facilities. The following equation calculates the variable operational cost $\left(OPEX^{Conversion}_{var_{c,y,r,ec}}\right)$ of converting hydrogen into ec, incorporating various economic and energy-related factors:

$$OPEX^{Conversion}_{var_{c,y,r,ec}} = EC^{Conversion}_{ec} * LCOE_{c,y,r} + I^{Conversion}_{ec} * C^{Conversion}_{ec} \quad \text{Eq. 8}$$

The amount of electricity consumed in the process ($EC^{Conversion}_{ec}$) is given in kWh/kg_{ec}. The necessary input $I^{Conversion}_{ec}$ is in $\frac{kg_{N_2}}{kg_{ec}}$ for e-ammonia, and in $\frac{kg_{CO_2}}{kg_{ec}}$ for e-methanol and e-methane, while $C^{Conversion}_{ec}$ represents the cost of the input in $\frac{EUR}{kg_{N_2}}$ and $\frac{EUR}{kg_{CO_2}}$. $C^{Conversion}_{NH_3}$ is constant over the years and was set to 0.1 $\frac{EUR}{kg_{N_2}}$, while the cost of CO_2 varies over time depending on the country and year, as shown in Table 5 and is given in $\frac{EUR}{kg_{CO_2}}$.

Table 5

Cost of CO_2 input for e-methanol and e-methane in $\frac{EUR}{kg_{CO_2}}$

c	$C^{Conversion}_{c,Today,ec}$	$C^{Conversion}_{c,2030,ec}$	$C^{Conversion}_{c,2050,ec}$
Algeria	0.014	0.012	0.01
Canada	0.014	0.012	0.01
Chile	0.024	0.02	0.016

3.3.3. *Transport*

Transporting hydrogen or its derivatives for long-distance is a particularly arduous process. The transportation of hydrogen is predominantly achieved through maritime routes and the utilization of pipelines. The underlying difference is that distance mainly determines the method to be used, and, most importantly, which method to use concerning costs. Given the distance, transportation via ship is used for Canada and Chile, while transportation via pipeline is only considered for Algeria.

3.3.3.1. *Ship.* The shipping contains cost from the bunkering $\left(Cos\ t^{Bunkering}_{c,y,r,ec}\right)$, the ship $\left(Cos\ t^{Ship}_{c,y,ec}\right)$, and the debunkering $Cos\ t^{Debunkering}_{y,ec}$. For each component i, the variable operational expenditures are given by:

$$OPEX^{i}_{var_{c,y,r,e,ec,Ship}} = EC^{i}_{ec} * EP + \left(BO^{i}_{ec} * DoS^{i}_{ec} + FR^{i}_{ec}\right) * Cb^{i}_{c,y,r,e,ec} \quad \text{Eq. 9}$$

The amount of electricity consumed EC^{i}_{ec} is given in kWh/kg_{ec} and varies between the energy carriers ec. The cost of the electricity is given by EP in EUR/kWh. For $i = [Bunkering]$, EP is equal to the corresponding $LCOE_{c,y,r}$. BO^{i}_{ec} is the rate at which stored energy carriers are lost due to evaporation and is given in percentage per day ($\%/day$). DoS^{i}_{ec} represents the number of days the material is stored or shipped. The rate at which materials are lost due to flashing (FR^{i}_{ec}) is given in percentage ($\%$) and varies between energy carriers ec. The cost of the lost energy carrier before i $Cb^{i}_{c,y,r,e,ec}$ differs between different c, y, r, e and ec. For the computation of the variable operational expenditures for $i = [Ship]$, only $EC^{i}_{ec} * EP$ has to be replaced by $2 * D^{Transport}_{c} * FP$. $D^{Transport}_{c}$ is the distance between country c and destination country Germany and is given in km. $D^{Transport}_{c}$ varies between c and is set to 10,586 km for Canada and 17,006 km for Chile. The fuel cost (FP) is given in $\frac{EUR}{kg_{ec}}/km$ and can vary between different energy carriers.

3.3.3.2. *Pipeline.* The distance between Algeria and the destination is set to 3538 km.

$$OPEX^{Transport}_{var_{Algeria,e,ec,Pipeline}} = EC^{Transport}_{e,ec} * EP \quad \text{Eq. 10}$$

The amount of electricity consumed in the pipeline $\left(EC^{Transport}_{e,ec}\right)$ for ec is given in kWh/kg_{ec} and varies between the electrolyzers e and energy carriers ec.

3.3.4. *Reconversion*

Once the derivatives have reached their destination, they are reconverted into gaseous hydrogen. This means additional cost and efficiency loss upon reconversion into hydrogen.

The following equation calculates the variable operational cost $\left(OPEX^{Reconversion}_{var_{c,y,r,e,ec,t}}\right)$ of reconverting ec into hydrogen, incorporating various economic and energy-related factors:

$$OPEX^{Reconversion}_{var_{c,y,r,e,ec,t}} = EC^{Reconversion}_{ec} * EP + \frac{I^{Reconversion}_{ec} * C^{Reconversion}_{ec}}{Ex_{ec}} + \left(\frac{1}{H_2RR_{ec} * PSARR_{ec}} - 1\right) * Cb^{Reconversion}_{c,y,r,e,ec,t} \quad \text{Eq. 11}$$

$EC^{Reconversion}_{ec}$ is the amount of electricity consumed in the reconversion unit and is given in kWh/kg_{ec}. The necessary input $I_{ec}^{Reconversion}$ is in $\frac{kg_{H_2O}}{kg_{ec}}$ for e-methanol and e-methane, while $C_{ec}^{Reconversion}$ represents the cost of the input $(\frac{EUR}{kg_{H_2O}})$. Ex_{ec} is the amount of hydrogen contained in one unit of ec and is given in kg_{H_2}/kg_{ec}. The H_2 recovery rate (H_2RR_{ec}) and the PSA recovery rate ($PSARR_{ec}$) varies between energy carriers and is given in %. The cost of the lost energy carrier before reconversion $CbR_{c,y,r,e,ec,t}$ differs between different countries c, years y, renewables r, electrolyzers e and energy carriers ec and transports t.

3.3.5. Distribution

Finally, the hydrogen is dispensed locally within the country to reach consumers. This also includes covering the distribution of hydrogen in the destination country. The distribution can be done either by trucks or by pipeline. The distance is set to 531 km. Both options are presented in the following chapters for imported hydrogen and hydrogen produced directly in Germany.

3.3.5.1. Truck

$$OPEX_{Truck}^{Distribution} = 2*\frac{D^{Distribution}}{S^{Truck}}*DC \Big/ V \qquad \text{Eq. 12}$$

$D^{Distribution}$ is the distance between the reconversion unit and the final destination. The average speed S^{Truck} of the truck is set to 80 $\frac{km}{h}$. Driver cost (DC) is 20.9 EUR/h and the volume of the truck (V) is 500 kg_{H_2}.

3.3.5.2. Pipeline

$$OPEX_{Pipeline}^{Distribution} = EC_{Pipeline}^{Distribution}*EP \qquad \text{Eq. 13}$$

$EC_{Pipeline}^{Distribution}$ is the amount of electricity consumed in the pipeline and is set to 1.42 kWh/kg_{H_2}.

4. Results and discussion

4.1. Energy implications in hydrogen supply pathways

The energy analysis is structured around the pathway scheme depicted in Fig. 7, which is divided into five main parts: renewable energy input (1), gaseous hydrogen production (2), conversion process (3), transportation carrier (4), and reconversion process (5). The renewable energy input includes PV and onshore and offshore wind. Hydrogen production is facilitated by mature technologies such as AEC and PEM electrolyzers, as well as the less mature SOEC.

The conversion process involves transforming gaseous hydrogen into more versatile carriers such as liquid hydrogen, e-ammonia, e-methanol, and e-methane. These carriers facilitate the transportation of hydrogen. The final stage of the supply chain involves the delivery of hydrogen to the spill station for its subsequent energy utilization.

Building on the aforementioned framework, this study investigates the supply chain from an energy perspective, focusing on the energy implications inherent within the chain. It is important to note that the energy involvement is quantified as electrical energy, using appropriate conversion factors to maintain a consistent basis for analysis.

The analysis meticulously accounts for all stages of energy involvement, beginning with the energy required for gas compression and circulation through pipelines, which includes managing pressure losses and multiple recompressions. It considers the energy needed for converting hydrogen to e-fuels and liquid hydrogen and continues with the fuel consumption necessary for shipping liquid carriers. The process concludes with the energy required for reconverting the carriers back to gaseous hydrogen.

The hydrogen pathway and production technology are evaluated iteratively, following the conceptual flow-scheme depicted in Fig. 8. This iterative evaluation is based on the chosen production technology

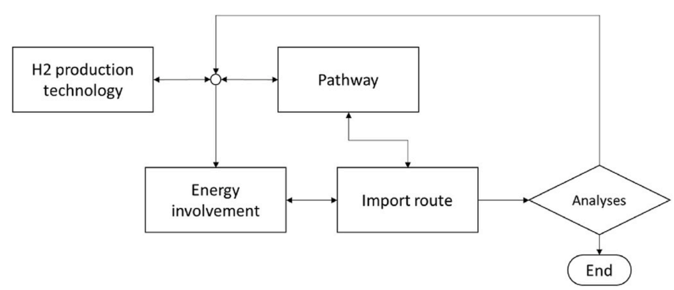

Fig. 8. – Scheme for analyses: pathway and technology detection.

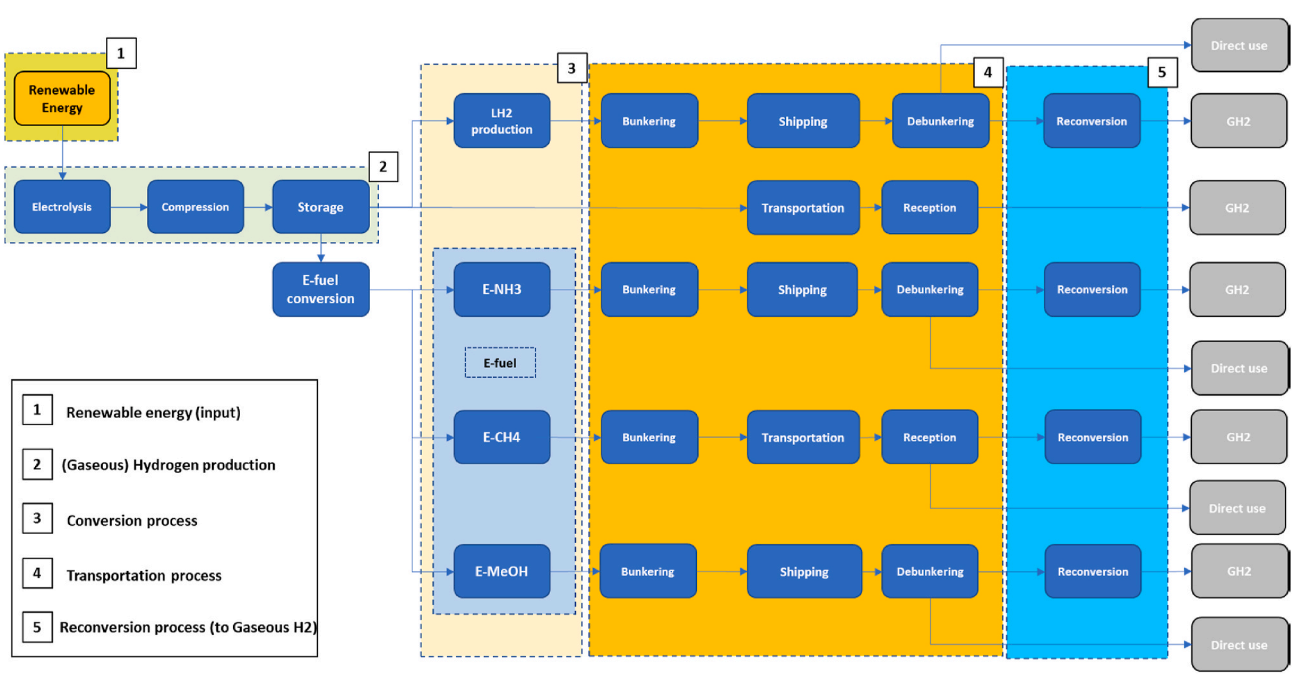

Fig. 7. – Hydrogen pathways.

and transportation pathway, ensuring that energy involvement is accurately assessed. The analysis concludes once the minimum energy consumption across the system is confirmed.

The analyses extend beyond the current technological landscape, offering projections and likely estimates for key future milestones in 2030 and 2050. Results are detailed in Fig. 9(a)–(c), categorized by production technology (AEC, PEM, SOEC).

Before assessing the whole energy involvement in the hydrogen supply chain, Tables 6 and 7 present the key outputs and key performance indicators of the conversion and re-conversion processes that arise from indicators on efficiency and effectiveness of the system.

- Electric Power/kg H_2: Electric power demand per unit mass of hydrogen.
- Thermal Power/kg H_2: Thermal power required per kilogram of hydrogen.
- Reactor Parameters (In/Out) - MFs/kg H_2: Reactor parameters with mass flow in and out per kilogram basis of hydrogen.
- Model Input (Power Supplies): In this case, the amount of each input required to run the system. Inputs are in the form of energy supplies such as electric power, thermal power, and others.
- Model Outputs: The outputs of the models return flow rates of hydrogen and other mass flow variables that are part of the process.

As previously reported, the key results do not account for nitrogen and carbon dioxide production, as they are acquired externally through purchase. Tables 6 and 7, in addition to containing key performance indicators (KPIs), also provide thermodynamic details of the processes and the base-catalysts employed. It is evident that the hydrogen reproduced or reconverted at the end of the sub-chain is invariably less than the initially fed amount, due to the processes having a conversion

Table 6
– Main KPIs of the e-Fuel Generation Process.

KPI	KPI description	Unit of Measure	Value
(450 °C–150–200 bar)	**NH_3**		
mass ratio	m_{H2}/m_{NH3}	kg H_2/kg NH_3	0.201
El. En. Ra.	Electric	kWh_{el}/kg H_2	5.139
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	2.379
LHV efficiency (ε)		%	61.51 %
Catalyst: Fe/Ru based, Input: H_2, N_2			
(470 °C–10 bar)	**CH_4**		
mass ratio	m_{H2}/m_{NH3}	kg H_2/kg CH_4	0.532
El. En. Ra.	Electric	kWh_{el}/kg H_2	2.979
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	1.038
LHV efficiency (ε)		%	69.54 %
Catalyst: Ni/Ru based, Input: H_2, CO_2			
(350 °C–20 bar)	**MeOH**		
mass ratio	m_{H2}/m_{MeOH}	kg H_2/kg MeOH	0.184
El. En. Ra.	Electric	kWh_{el}/kg H_2	4.388
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	0.826
LHV efficiency (ε)		%	88.3 %
Catalyst: Cu/Zn, Input: H_2, CO_2, N_2			

yield less than 1. This leads to a first conclusion: storing hydrogen in chemicals for later re-conversion to hydrogen inevitably results in a lower mass yield (0.86–0.98) compared to the initial input. However, the perspective shifts if the chemical serves as an e-fuel for energy, chemical production, or other industrial uses. Concerning energy conversion efficiency, process optimization will act as a tool for improvement, focusing on enhancing sections such as heat recovery from waste energy flows. This could include upgrading systems to reclaim low-grade heat and other efficiency-enhancing measures across the system.

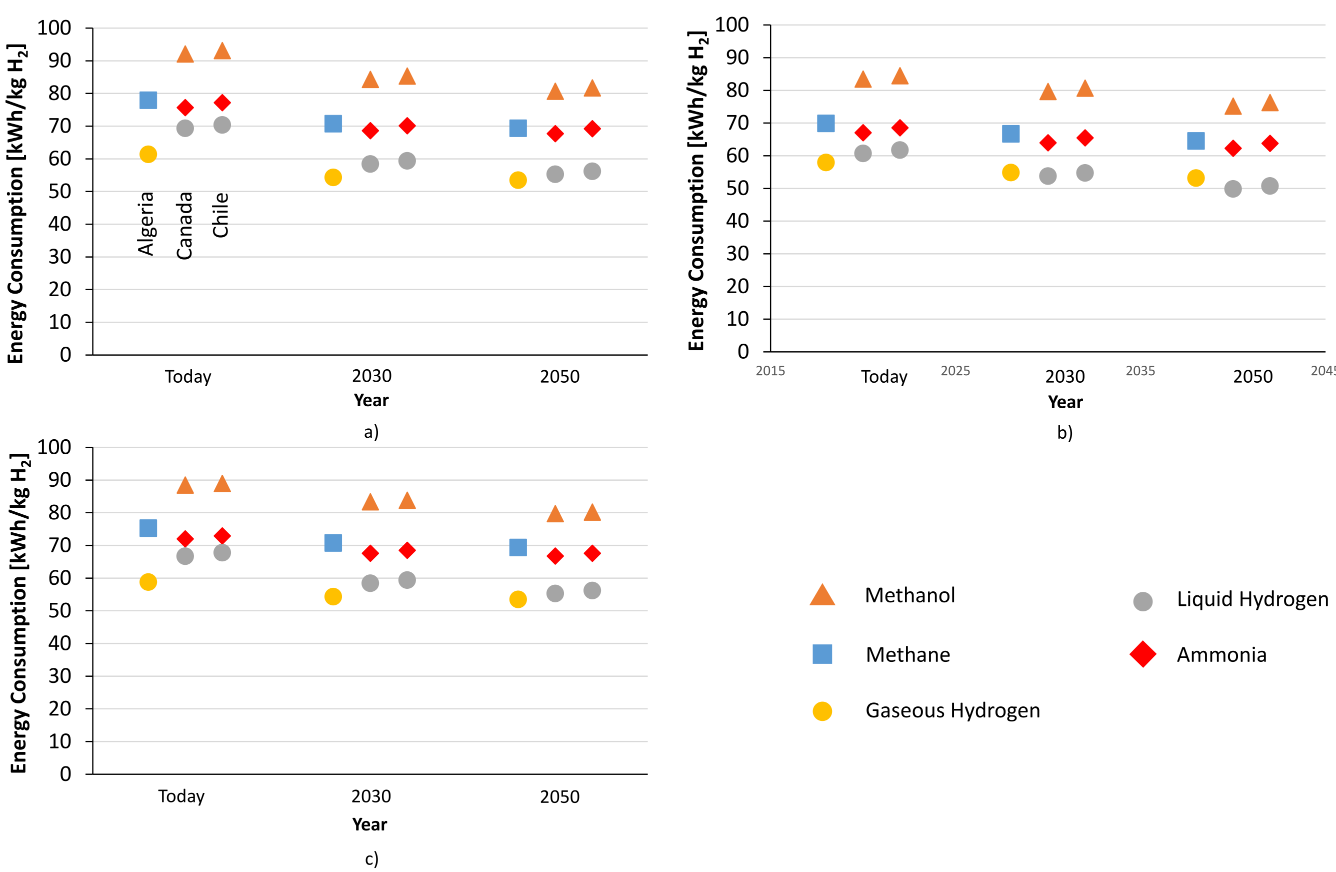

Fig. 9. – Hydrogen pathways considering a) AEC, b) PEM and c) SOEC.

Table 7
– Main KPIs of the e-Fuel Reconversion Process.

KPI	KPI description	Unit of Measure	Value
(380 °C–250 bar)	from NH_3		
mass ratio	m_{H2}/m_{NH3}	kg H_2/kg NH_3	0.174
El. En. Ra.	Electric	kWh_{el}/kg H_2	3.069
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	4.185
LHV efficiency (ε)		%	89.09 %
Catalyst: Ru/Co, Input: NH_3			
(950 °C–20 bar)	from CH_4		
mass ratio	m_{H2}/m_{NH3}	kg H_2/kg CH_4	0.454
El. En. Ra.	Electric	kWh_{el}/kg H_2	0.549
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	11.587
LHV efficiency (ε)		%	74.49 %
Catalyst: Ni based, Input: CH_4, H2O			
(350 °C–20 bar)	from MeOH		
mass ratio	m_{H2}/m_{MeOH}	kg H_2/kg MeOH	0.181
El. En. Ra.	Electric	kWh_{el}/kg H_2	0.882
Th. En. Ra.	Thermal	kWh_{th}/kg H_2	10.045
LHV efficiency (ε)		%	70.19 %
Catalyst: Cu–ZnO/Al_2O_3, Input: MeOH, H_2O			

Fig. 9 a) indicates the highest energy consumption over 90 kWh/kg H_2 in the initial gaseous stage, consistently recorded for today. This figure pertains to hydrogen transport in the form of e-methanol for import routes from Canada and Chile, utilizing primary renewable sources like PV and both onshore and offshore wind plants. The most efficient energy scenario for AEC technology, projected for 2050, utilizes gaseous hydrogen as the carrier, reducing energy consumption to 53.45 kWh/kg H_2.

For PEM technology (illustrated in Fig. 9 b)), the highest energy involvement is about 89 kWh/kg H_2, using e-methanol as the carrier in the current technological scenario. Conversely, the lowest consumption—mirroring the AEC results—stands at 53.45 kWh/kg H_2 for gaseous hydrogen transport routes.

Fig. 9 c) focuses on SOEC-derived hydrogen. The highest consumption recorded here is 84.51 kWh/kg H_2, for e-methanol as the energy carrier for today. The most favorable scenario emerges by 2050, where liquid hydrogen as a carrier sees consumption drop to 49.87 kWh/kg H_2.

Compiling all data, the optimal outcome foresees 2050 using liquid hydrogen as the carrier and SOEC technology as the primary method for producing green hydrogen. In contrast, the least favorable scenario pertains to the current state, involving e-methanol as the transport medium.

Similar analysis applies to Algeria, which is evaluated for supplying either gaseous hydrogen or e-methane derived from hydrogen. The pathway involving e-methane as a medium is undoubtedly more energy-intensive than direct hydrogen supply. This is due to the additional energy required for converting to e-fuel and subsequently reconverting to hydrogen, a process fraught with inefficiencies as previously noted. Nonetheless, the most favorable scenario for Algeria involves projections for 2050 using SOEC technology, with an energy consumption of 53.20 kWh/kg H_2. Currently, the energy implications are slightly higher, at 57.95 kWh/kg H_2 produced.

4.2. *Results of techno-economic modelling*

In Fig. 10, the color blue symbolizes that the hydrogen, e-methane, e-methanol or e-ammonia was produced using electricity from PV systems. Orange represents the use of onshore wind, while gray represents production via offshore wind. For each of the years, the first figure from the left shows the supply costs for the production of hydrogen using AEC, the second using SOEC and the third using PEM electrolysis. The circles symbolize that the hydrogen was exported to Germany as gaseous hydrogen, squares represent the export of the e-methane, while e-ammonia is represented by the diamonds and the triangle symbolizes e-methanol and the circle liquid hydrogen.

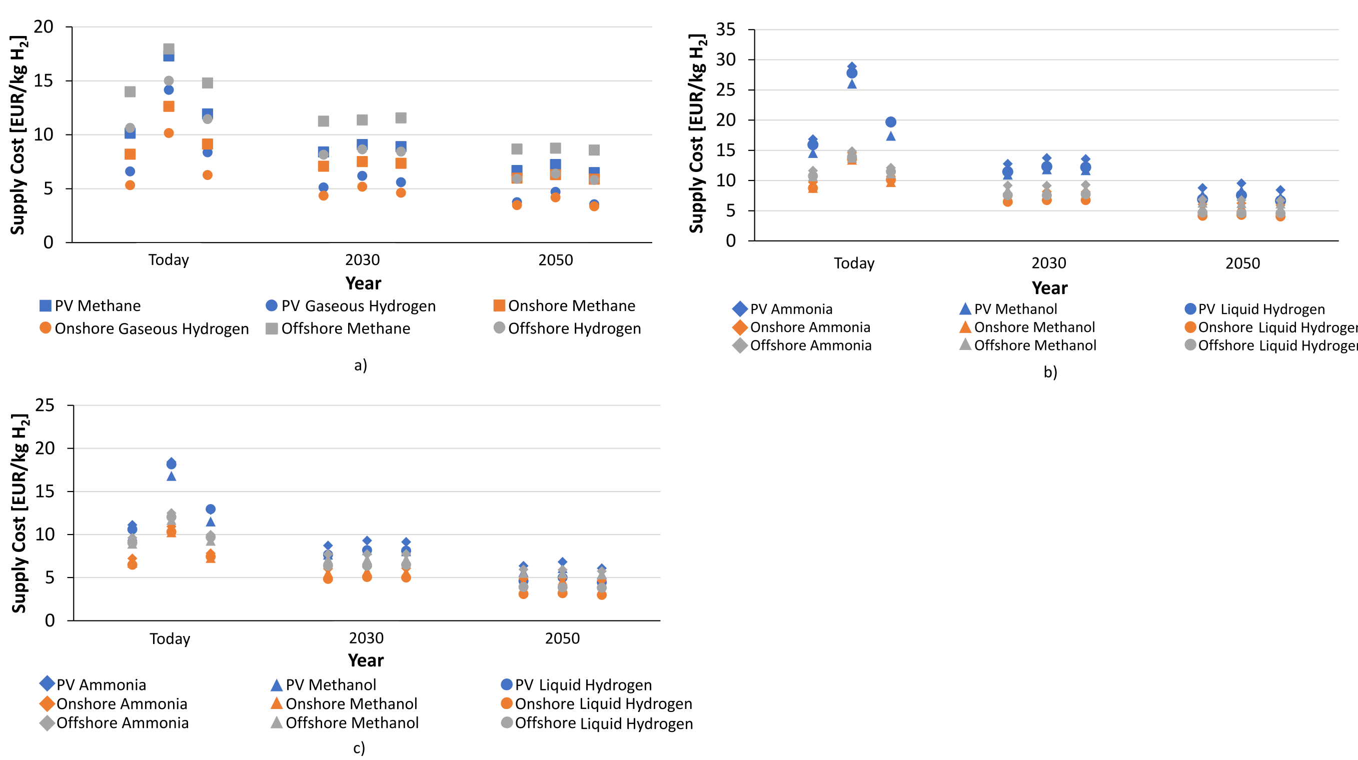

Fig. 10. – Hydrogen Supply Cost for a) Algeria, b) Canada and c) Chile.

Fig. 10 a) shows that the supply costs for hydrogen from Algeria will fall significantly over time. The range of ≈ 5.3–18.0 EUR/kg H_2 today falls to ≈ 3.4–8.8 EUR/kg H_2 in 2050. However, there is little change in the price order. For all years, the production of hydrogen via onshore wind is the most attractive. While the use of PV is only slightly higher, especially from 2030 onwards, the costs for the use of offshore wind are significantly higher. This can be explained by the fact that the very high CAPEX for offshore wind cannot be offset by correspondingly higher capacity factors. SOEC electrolysis is an exception here: as it currently has very high CAPEX, the costs of hydrogen production from PV electricity are similar to those of offshore wind power plants, as it has a lower capacity factor in comparison. Therefore, the costs for hydrogen with SOEC electrolysis with electricity from PV and offshore wind hardly differ initially. Regarding the choice of electrolyzer, it can be said that today the costs for AEC and PEM are significantly lower than for SOEC. However, over time the differences are steadily decreasing, so that by 2050 the costs will have become very similar depending on the type of electrolyzer. It is also important to note that exporting hydrogen as gaseous is always less expensive than exporting hydrogen as e-methane. Although the pure transport of e-methane by pipeline is cheaper than for hydrogen (≈ 1.3 EUR/kg H_2 vs. ≈ 1.5 EUR/kg H_2), the additional costs for conversion and reconversion dominate (≈ 3.2–3.8 EUR/kg H_2), making e-methane ultimately less attractive.

A detailed look at the cost structure of the individual import paths shows the importance of the different supply chain stages. Fig. 11 a) illustrates today's supply costs for hydrogen produced in Algeria using onshore wind and AEC electrolysis, which is exported as gaseous hydrogen. Production costs constitute the majority of the supply cost at approximately 72 %, while transport costs contribute only around 28 %. Among the production costs, variable OPEX represents by far the largest cost block at about 74 %. The variable OPEX is significantly dominated by LCOE, accounting for approximately 84 %, while stack replacement costs (15 %) and water costs (1 %), contributing much less. In transport costs, both CAPEX and variable costs (in this case, the cost of electricity) each contribute 40 %, while the share of fixed OPEX is lower at around 20 %.

As shown for Canada in Fig. 10 b), the decline in supply costs over time is even more pronounced than in Algeria. While today the costs of ≈ 8.7–28.9 EUR/kg H_2 vary from ≈ 6.5–13.7 EUR/kg H_2 in 2030, they will fall to a range of ≈ 4.1–9.6 EUR/kg H_2 by 2050. Identical to Algeria, the production of hydrogen using onshore wind is the cheapest in every year. The biggest difference compared to Algeria is that offshore wind is significantly more attractive for the production of hydrogen than PV. The reason for this is the significantly higher capacity factors of offshore wind compared to PV in Canada (60 % vs. 15 %) compared to Algeria (36 % vs. 22 %). The higher capacity factors, which also affect the use of electrolysis and conversion units, can more than compensate for the significantly higher CAPEX for offshore wind.

With regard to energy carriers, it is clear that transportation via e-methanol is the cheapest option in almost all cases today. The only exception here is the production of liquid hydrogen using onshore wind. Over the years, e-methanol will lose its advantage over transportation as liquid hydrogen, so that from 2030 there will only be minor differences. e-Ammonia is the least attractive transport medium for all combinations. In 2050 the costs of the different paths will have converged significantly. Liquid hydrogen is now most attractive transport medium.

In Fig. 11 b), the cost decomposition for hydrogen produced in 2030 via offshore wind and SOEC electrolysis in Canada, transported as e-methanol, and distributed within Germany via pipeline is depicted. Both conversion and reconversion as well as distribution within Germany by pipeline are considered here. Due to the additional steps in the value chain, the share of production costs for hydrogen in Canada are significantly lower, at about 54 %, than in Algeria. While CAPEX accounts for 13 % and fixed OPEX for 5 %, variable OPEX dominates here with a share of 82 %. The share of LCOE in variable OPEX is particularly high at 92 % in this case, as the capacity factor does not compensate for the very high CAPEX of offshore wind in Canada. The share of stack replacement costs and water costs is 7 % and 1 %, respectively. For conversion costs, fixed OPEX plays a minor role at around 10 %, while variable OPEX contributes more to conversion costs at 50 % compared to CAPEX at 40 %. With a share of 17 %, the costs for CO_2 input contribute significantly less to the variable OPEX of conversion costs than electricity costs at 83 %. For transport costs, the CAPEX of export and import terminals and the ship contribute about 20 %. In variable costs, the fuel costs of the ship (87 %) weigh significantly more than the electricity costs for the export and import terminal. For reconversion costs, variable OPEX again

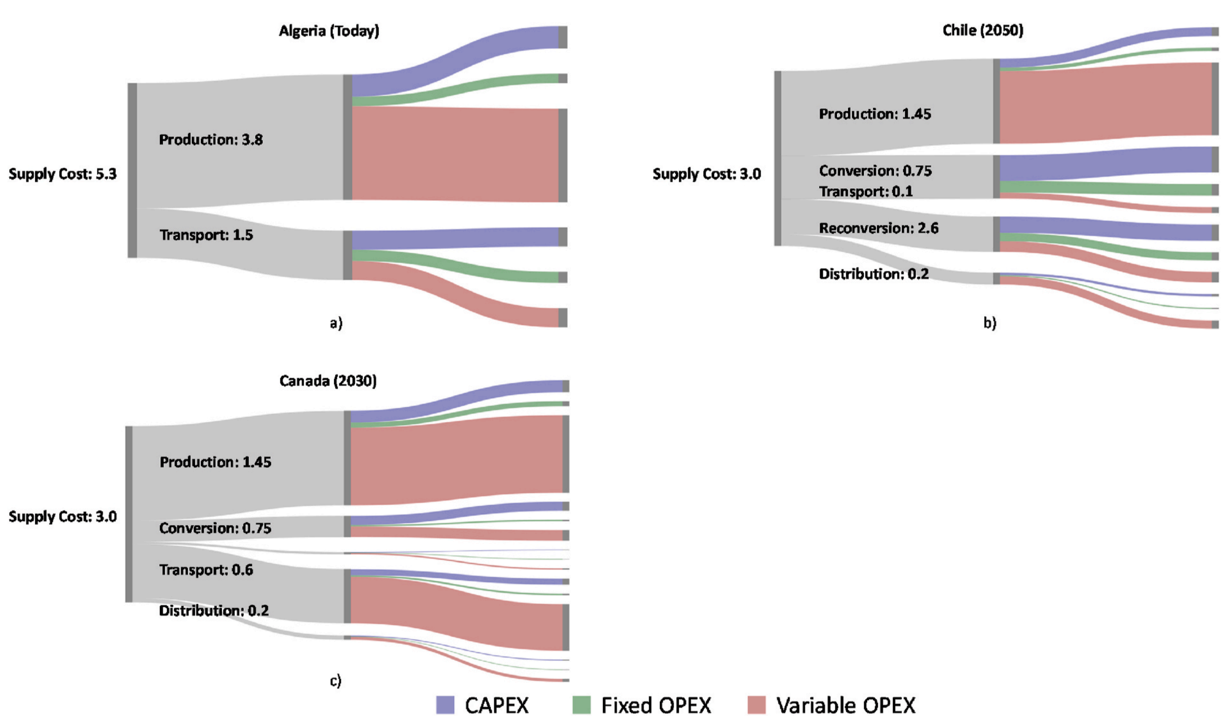

Fig. 11. – Cost decompostion of different hydrogen supply cost.

plays the decisive role, contributing about 85 % the most. The costs for distributing hydrogen within Germany contribute only 2 % to the supply cost. The largest cost driver in distribution costs is once again electricity costs, with a share of 71 %.

The results for Chile (Fig. 10 c)) are very similar to those for Canada. For Chile, onshore wind is the most attractive option for producing hydrogen. This is followed by offshore wind and PV, with the difference becoming smaller over time. Today's costs of ≈ 6.5–18.4 EUR/kg H_2 will decrease to ≈ 4.8–9.3 EUR/kg H_2 by 2030 and reach ≈ 3.0–6.8 EUR/kg H_2 by 2050. Today, electrolysis using AEC is most attractive. For onshore and offshore wind, the choice of electrolyzer is of little importance from 2030 onwards, as the supply costs differ only slightly. Although SOEC electrolysis still has higher CAPEX, this can be offset by the higher capacity factors of onshore and offshore wind and the higher efficiency of SOEC electrolysis. Only when using PV does AEC electrolysis continue to have cost advantages. In 2050, PEM with ≈ 3 EUR/kg H_2 will prevail as the most attractive option for hydrogen production, although the differences to the other technologies are only minor (≈ 3.1 EUR/kg H_2 (AEC) and ≈ 3.2 EUR/kg H_2 (SOEC)). When it comes to the choice of energy source as a transport medium, a similar picture emerges as in Canada. Today, the use of e-methanol dominates, while liquid hydrogen will become increasingly attractive from 2030, as the costs of liquefying and transporting hydrogen will fall sharply over time. In 2050, liquid hydrogen will have cost advantages over e-methanol and e-ammonia for all possible combinations. For example, the costs for liquefying hydrogen when using offshore wind fall from ≈ 1.5 EUR/kg H_2 to ≈ 0.7 EUR/kg H_2 more than with e-methanol (≈ 1.1 EUR/kg H_2 to ≈ 0.6 EUR/kg H_2). The difference in transport costs becomes even clearer: while the costs for shipping liquid hydrogen fall from today's ≈ 2.6 EUR/kg H_2 to ≈ 0.6 EUR/kg H_2 in 2050, the costs for e-methanol remain constant at ≈ 0.19 EUR/kg H_2 over the three time periods. Even if the costs for conversion and transport for liquid hydrogen are higher than for e-methanol, the supply costs in 2050 are lower because there are no costs for reconversion for liquid hydrogen. The distribution of hydrogen is the same for all cases given the year, as in all cases only hydrogen is distributed by pipeline or truck. It turns out that the costs of distributing hydrogen via pipeline are significantly lower than those of distributing it with trucks. The truck costs are initially more than four times as much but decrease over time.

As shown in Fig. 11 c), the supply costs for hydrogen produced in Chile via onshore wind and PEM electrolysis, exported as liquid hydrogen, and distributed in Germany via pipeline consist of production, conversion, transport, and distribution costs. The share of production costs is 48 %, of which about 86 % are due to variable OPEX. The variable OPEX includes costs for water, stack replacement, and LCOE, with the latter contributing 94 %. This share increases continuously to 94 % over the years, as the costs for PEM electrolysis decrease more significantly than for onshore wind power generation in Chile. Conversion costs contribute 25 % to the total costs, with CAPEX for liquefaction making a significantly higher contribution at 60 %, compared to fixed and variable OPEX at 27 % and 13 %, respectively. Unlike other energy carriers, transport costs for liquid hydrogen contribute a significantly higher share to the supply costs at 20 %. While variable OPEX (costs for electricity at import and export terminals and fuel costs for the ship) only have a small share, CAPEX dominates with a share of 47 %. Fixed OPEX contributes 23 %. For all three cost components, the costs for the ship are particularly important. Distribution costs contribute only 7 % to the supply costs. Similar to the case shown in Fig. 11 b) for Canada, variable OPEX (electricity costs) dominate here with a share of 70 %.

The presentation of the results differs for Germany. As described in 3.3.1, electricity is purchased from the electricity exchange for the production of hydrogen in the country. It is therefore not necessary to differentiate between the costs for PV, onshore wind and offshore wind. While a distinction is made between the various electrolyzers, it is not necessary to differentiate between energy carriers, as the hydrogen is not converted. Furthermore, it is not necessary to consider transportation costs; only the distribution costs within Germany by truck or pipeline are taken into account.

The trend is similar to the other countries. As shown in Fig. 12, while the range of supply costs is still very wide today (≈4.1–10.2 EUR/kg H_2), it narrows significantly by 2030 (≈3.8–5.1 EUR/kg H_2) and finally falls to a range of ≈3.4–4.3 EUR/kg H_2 by 2050. The picture is similar to electrolyzers. While AEC followed by PEM is significantly cheaper than SOEC electrolysis today, the gap decreases sharply over time. The gap between AEC and SOEC of ≈ 5.6 EUR/kg H_2 falls to ≈ 0.85 EUR/kg H_2 in 2030, and finally ends at ≈ 0.5 EUR/kg H_2 in 2050. This is largely due to the sharp decline in the CAPEX of SOEC over time. For example, CAPEX for SOEC still amounts to 2.545 EUR/kW today, falling to 727 EUR/kW by 2030 and finally costing 455 EUR/kW in 2050. Although SOEC will still be significantly more expensive than AEC and PEM (both 182 EUR/kW) in 2050, the higher efficiency of SOEC (79 %) compared to AEC and PEM (both 70 %) will help to ensure that costs converge significantly by 2050. In terms of distribution, it should be noted that the use of the pipeline each year and each type of electrolyzer is more attractive than the use of trucks. However, as the CAPEX of the truck decreases over time, but remains constant for the pipeline, the gap becomes increasingly smaller. The reason for this is that it is assumed that the CAPEX for the trucks will fall from 1.12 EUR/kg H_2 today to 1.00 EUR/kg H_2 in 2030 and then finally amount to 0.5 EUR/kg H_2 in 2050. The OPEX (12 % of CAPEX) and the costs for the driver (approx. 20.9 EUR/h) are assumed to remain constant over the years. Ultimately, the cost development leads to the gap between the two options continuing to narrow over time (0.48 EUR/kg H_2 today vs. 0.45 EUR/kg H_2 in 2030 vs. 0.33 EUR/kg H_2 in 2050), but not enough to close it completely, so that transport via pipelines should be preferred to transport via trucks.

5. Discussion and conclusions

The global hydrogen economy is still in its early stages of development, with multiple potential pathways emerging. This research aimed to provide a comprehensive assessment of future hydrogen production and import routes to Germany, complemented by energy and economic analyses to identify the most viable and feasible routes and methodologies.

The study utilized a robust review of the current state of hydrogen "domestic production" in Germany and prospective imports from external countries. A dedicated numerical tool, named HydrogenPathway Explorer, was developed for this purpose. This tool integrates economic, energy, and process engineering toolkits, each developed in specific computational environments, facilitating the analysis and delivery of key performance indicators (KPIs) that support technical decision-making.

A thorough literature review was conducted using prominent research databases like Scopus, Web of Science, and Google Scholar, along with technical reports from agencies such as IEA and IRENA. For the development of the tool, standard performance calculators and software like MS Excel, Matlab/Simulink, and ASPEN Plus were employed.

The findings are managed by a high-level interface within the HydrogenPathway Explorer, which processes results for further detailed economic and energy analyses. The outcomes underscore the strategic insights derived from the integration of multidisciplinary toolkits in assessing the feasibility of hydrogen supply chains.

The findings indicate that hydrogen from Algeria could be sourced today at a cost of approximately 5.3 EUR/kg H_2. While the cost of hydrogen shipped from overseas remains high initially (e.g., ≈ 8.7 EUR/kg H_2 from Canada and ≈ 6.5 EUR/kg H_2 from Chile), by 2030, Chilean imports could become more competitive, with supply costs dropping to ≈ 4.8 EUR/kg H_2. This could offer a valuable complement to pipeline imports from Algeria, which are projected to reach ≈ 3.4 EUR/kg H_2 by 2050. The analysis suggests that direct imports of gaseous hydrogen

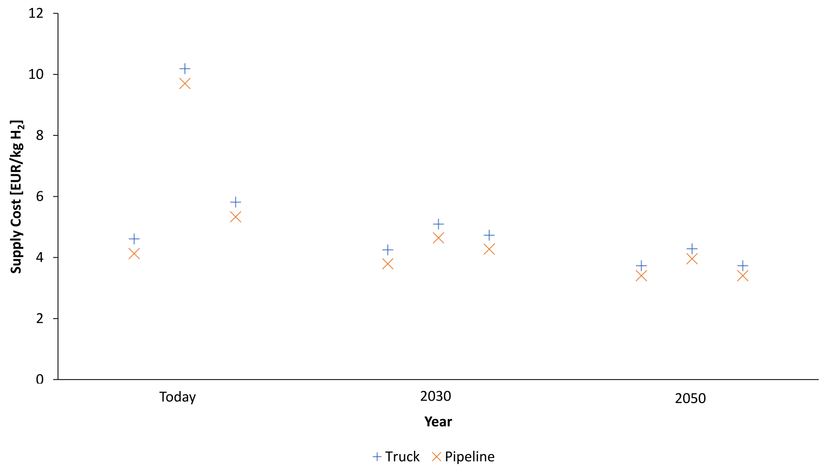

Fig. 12. – Supply cost for Germany.

from Algeria should be prioritized over e-methane as an energy source. By 2050, hydrogen imports from Canada are expected to reach ≈ 4.1 EUR/kg H_2, and from Chile, ≈ 3 EUR/kg H_2. Notably, the sharp decline in transportation costs by 2050 suggests that liquid hydrogen will become the preferred form of energy for imports from both Canada and Chile.

The analysis also identifies significant potential for reducing hydrogen supply costs. A critical factor is the capacity utilization of renewable energy sources, which not only influences the cost of electricity for electrolysis but also plays a decisive role in determining the costs of electrolyzers and conversion processes. The analysis assumes that electrolyzers and conversion units operate only when the associated renewable energy plants are generating electricity. As this approach relies exclusively on renewable energy sources and excludes the use of grid electricity, there is further potential for cost reductions. For instance, supplementing low-cost solar power with another, albeit more expensive, energy source could lower the overall cost of hydrogen and its derivatives by improving the utilization of electrolysis and conversion equipment. Additional cost reduction potential exists if derivatives, such as e-ammonia and e-methanol, are not reconverted to hydrogen but instead used directly. This is particularly relevant for e-ammonia and e-methanol, as their cost advantages over liquid hydrogen in terms of conversion and transportation remain intact when reconversion is avoided. Furthermore, these derivatives have substantial direct demand in various sectors, including the chemical industry.

As final consideration, the investigated case-study indicates that LH_2 imports will surpass e-ammonia and e-methanol in cost-competitiveness by 2050, mainly due to lower reconversion costs. In the short term, e-ammonia remains preferable due to its existing infrastructure and lower conversion losses. Key policy actions include investing in hydrogen transport infrastructure, providing subsidies for electrolyzers and purchase agreements, and establishing standardized hydrogen certification frameworks to facilitate international trade.

The range of results underscores the significant influence of key parameters on the supply costs of different hydrogen pathways. The techno-economic methodology employed in this study offers valuable insights and can serve as a powerful tool for analyzing emerging systems characterized by inherent uncertainties. The clarity provided by this approach is of crucial importance for the comprehension of complex systems in transition. Furthermore, the flexibility of this approach renders it useful for decision-making in different regions and with different data availability.

This study provides a focused analysis on the supply costs of various hydrogen pathways, excluding cost-driving factors such as taxes and profits. It also does not consider the environmental impact associated with different hydrogen pathways. It is evident that the financial aspect constitutes merely a fraction of the total considerations, albeit a progressively substantial one. Looking ahead, comprehensive value chain analyses and feasibility studies could be undertaken, crucial to sharpen plans for these routes and pave the way for successful implementation.

While the scope is limited to existing and emerging hydrogen technologies, future advancements could significantly reshape hydrogen production and import value chains. Building a supply cost curve using the results of this paper would be an interesting avenue for further exploration, offering deeper insights into the economic landscape of hydrogen production.

These analyses have the potential to be integrated to identify the most viable strategies to ensure a reliable, and sufficient supply of hydrogen to meet Germany's future energy needs; as such, they could guide policymakers, industry stakeholders, and researchers in optimizing hydrogen production and importation for a sustainable and resilient energy system.

CRediT authorship contribution statement

Karl Seeger: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Matteo Genovese:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Alexander Schlüter:** Writing – review & editing, Writing – original draft, Supervision, Project administration, Investigation, Funding acquisition, Data curation, Conceptualization. **Christina Kockel:** Writing – review & editing, Validation, Project administration, Methodology, Funding acquisition, Conceptualization. **Orlando Corigliano:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Edith B. Díaz Canales:** Writing – review & editing, Writing – original draft, Investigation, Data curation, Conceptualization. **Aaron Praktiknjo:** Writing – review & editing, Validation, Supervision, Resources, Project administration, Funding acquisition, Conceptualization. **Petronilla Fragiacomo:** Writing – original draft, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used DeepL Pro in order to enhance linguistic variety and proficiency. After using this tool/service, the authors reviewed and edited the content as needed and takes full responsibility for the content of the publication.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2025.02.379.

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