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Economic and environmental assessment of different hydrogen production and transportation modes

Marlene Sayer *, Amela Ajanovic, Reinhard Haas

Institute of Energy Systems and Electrical Drives, Energy Economics Group, TU Wien, Vienna, Austria

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ABSTRACT

Hydrogen is widely considered as the energy carrier of the future, but the rather high energy losses for its production are often neglected. The major current hydrogen production technology is steam methane reforming of fossil gas, but there is a growing interest in producing hydrogen sustainably from water using electrolysis. This article examines four main hydrogen production chains and two transportation options (pipeline and ship) from North Africa to Europe, analyzing the costs and environmental impacts of each. The core objective is to determine the most promising hydrogen provision method and location from an economic and ecological point of view, including the required transport. An important finding of this analysis is that both options, importing green hydrogen and producing it in Europe, may be relevant for a decarbonized energy system. The emphasis should be on green hydrogen to achieve carbon emission reductions. If blue hydrogen is also considered, attention should be paid to the often-neglected methane emissions upstream.

1. Introduction

Hydrogen is largely considered as a carbon neutral energy carrier of the future, often neglecting the rather high energy losses for hydrogen provision (=production, storage, transport and distribution). As, on earth, hydrogen can be mostly found in molecular forms, it has to be produced from various sources. To date, hydrogen is predominantly utilized in the production of ammonia and methanol and for oil refining, primarily sourced from hydrocarbons in fossil gas or coal. We are currently navigating through a phase called mid-transition [1], where there is an endeavor to shift toward hydrogen production from renewable energy sources (RES) to mitigate emissions.

In Ajanovic et al. [2], a comprehensive review of the literature on selected hydrogen production technologies was conducted. This review included an economic and environmental analysis of hydrogen production at the point of use (excluding transportation costs) without delving into the various electricity sources for electrolysis. Today, the discussion on production technologies is becoming even more imminent, with different players in the energy sector pushing for different solutions. On the one hand, hydrogen produced with steam methane reforming (SMR) or coal gasification adding carbon capture, utilization and storage (CCUS) is from certain players praised as an essential bridging technology in the transition to a sustainable hydrogen economy [3]. On the other hand, others argue that only hydrogen from electrolysis with electricity from RES shows clear environmental benefits compared to using fossil fuel directly or indirectly for hydrogen production [4,5]. And on top of that, there is the discussion of whether green hydrogen should be imported from countries with favorable renewable electricity generation conditions, resulting in higher full-load hours of the electrolyzers but having higher transport costs and hydrogen losses on the way, or if the hydrogen should be locally produced in the country of use [6].

Therefore, the core objective of this paper is to investigate the techno-economics and the environmental impact of four defined hydrogen production chains (grey, blue, yellow, green). In the case of a production location outside of the designated hydrogen hub, the two main hydrogen transport possibilities (pipeline and ship) from North Africa to Europe are analyzed. The specific investment costs of the hydrogen plant, the full load hours per year, the electricity or fossil fuel price and the costs of the respective hydrogen transport method play an important role and they are included in our calculations. The major contribution of this paper is to show which production methods at which locations, including the required transport, are currently most promising from an economic and ecological point of view. This means that hydrogen transport is only available to a limited extent and is associated with higher costs compared to studies that focus on the future. In detail,

* Corresponding author.
E-mail addresses: sayer@eeg.tuwien.ac.at (M. Sayer), ajanovic@eeg.tuwien.ac.at (A. Ajanovic), haas@eeg.tuwien.ac.at (R. Haas).

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we intend to answer the following questions:

a. What is the cheapest chain of hydrogen provision for Austria?
b. What are the corresponding carbon emissions?
c. What is the cost and emissions difference between locally produced and imported green hydrogen in view of additional transport costs and emissions?

To answer these questions, selected hydrogen production chains and possible transport technologies and routes are analyzed. In this work, two production technologies, namely SMR and electrolysis, are considered. Four types of production are distinguished depending on the form of energy supplied and whether, in the case of fossil gas, part of the greenhouse gas (GHG) emissions is captured. For better understanding, the “colors of hydrogen” scheme (see Ajanovic et al. [2] for more details) is applied according to Fig. 1.

In the analysis of hydrogen transport, the focus lies on longer-distance transportation since the distribution part is the same for all hydrogen production options. Therefore, two transport options, transport via pipeline and transport by ship, are analyzed in more detail. In the latter’s case, two further process steps are necessary, namely liquefaction and reconversion, which will be discussed in more detail.

The recent surge in interest in hydrogen, as evidenced by the comprehensive works of the International Energy Agency [7,8] and the International Renewable Energy Agency (IRENA) [9,10], underscores the need for a more focused examination of production and transportation costs. Existing studies primarily focus on either a single technology, only production or transportation issues, or provide an economic or environmental analysis. Studies that examine all aspects within one work and also include different production sites (within the analyzed country and imports) could not be found. The following overview thus first addresses studies from recent literature that combine the cost aspect of hydrogen production and emissions, followed by an analysis of separate parts mentioned above. From each part, where relevant to this study, conclusions were drawn to also compare to our main findings in the result section of this paper. For that, it has to be noted that, in general, studies vary significantly regarding the hydrogen production technologies and locations they analyze and the supply chain components they cover (e.g., to include or not include storage or distribution).

Newborough and Cooley [11] conducted one of the key studies on the primary production techniques and all related issues, including the costs and emissions. They conclude that green hydrogen generation will become more affordable than alternatives, such as blue hydrogen as a result of less expensive renewable power and electrolyzers. They also highlight green hydrogen as the most environmentally friendly option. A possible cost reduction of hydrogen production via electrolysis to 2 €/kg H_2 in the year 2040 is being calculated by Terlouw et al. [12], making it competitive with SMR, even under historically low gas prices. Considering recent price increases, electrolysis could become economically viable sooner. Regarding emissions, it is found that purely renewable production causes the least emissions. However, a hybrid approach combining electrolyzer operation with wind energy and grid electricity from a renewable mix is deemed most advantageous for cost-effective and environmentally friendly production [12].

Oni et al. [3] focus specifically on the economic and environmental analysis of blue hydrogen production methods such as SMR, autothermal reforming, and fossil gas decomposition, indicating that autothermal reforming results in lower emissions. However, since only blue hydrogen production technologies are compared, no conclusions can be drawn regarding the comparison of different production methods. Carbon capture and storage (CCS) specifically for hydrogen production from coal in China is being studied by Li et al. [13] and show very high CO_2 savings compared to other studies. The cost due to CCS increases the process cost by about 44–60%. In summary, renewable hydrogen production shows the lowest emissions when compared comprehensively with common production technologies, with a positive outlook for future cost reductions in electrolyzers. However, emission estimates and conclusions vary widely depending on calculation methods and assumptions. For example, Li et al. [13] estimate emissions ranging from 4.92 to 10.90 kg CO_2/kg H_2 for coal-based hydrogen production after CCS installation, suggesting that those emissions are close to those from solar electricity-based hydrogen production. In contrast, Longden et al. [5] calculate emissions ranging from approximately 8 (bituminous coal) to 5 (lignite) kg CO_2/kg H_2, leading to different conclusions, namely that hydrogen generated using fossil fuels is incompatible with the switch to a sustainable energy system. Even when a portion of the emissions are caught for blue hydrogen, significant fugitive methane emissions occur, which most analyses do not account for. They claim that electrolysis will become considerably cheaper in the future.

Bartels et al. [14] undertook a purely economic examination of several production technologies and concluded that grey hydrogen was the most cost-effective way at the time of the investigation. However, they note that other approaches may become less expensive in the future. Yukesh Kannah et al. [15], who present a techno-economic review of several production technologies, continue to recommend SMR as the most cost-effective way of production. The production, though with SMR but with additional CO_2 capture, is investigated by Pruvost et al. [16]. They conclude that an 80% capture rate can be achieved cost-effectively before combustion. For the missing 20%, the cost increases from 35 €/ton to 150 €/ton and therefore, a capture of the last 20% after incineration is recommended. They also investigate the use of green electricity to run the reformer and conversion to solid carbon (turquoise hydrogen).

Nikolaidis and Poullikkas [17] examined 14 production processes and discovered that thermo-chemical pyrolysis and gasification have the best possibilities of being competitive in the future. However, since decarbonization of the energy sector is an important goal, green hydrogen production via electrolysis will be essential. For this reason, Shiva Kumar and Lim [18] present a comprehensive overview of the

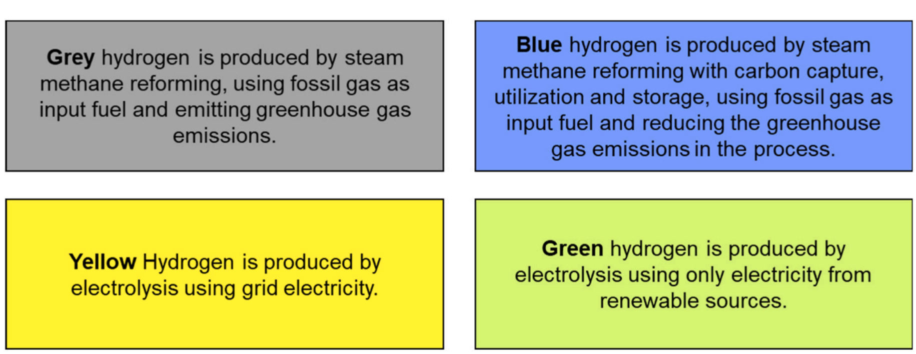

Fig. 1. Colors of hydrogen analyzed in this work.
(Note, we distinguish the two researched renewable electricity inputs by applying light green for photovoltaics (PV) and dark green for wind.).

techno-economic prospects of different electrolysis technologies. Nami et al. [19] compare hydrogen production with alkaline electrolyzers with production from fossil gas and find that with today's investment costs, a gas price of 30 €/MWh and an electricity price of 30 €/MWh, a CO_2 tax of 90 €/tCO_2 would make hydrogen from alkaline electrolyzers more cost-effective. A general long-term cost reduction of 24% for alkaline electrolyzers and 56.5% for PEM electrolyzers has been calculated by Yang et al. [20].

The main conclusion drawn from the studies regarding the costs of different production processes is that, currently, SMR remains the cheapest option. However, significant cost reductions in electrolysis are anticipated. The success of achieving these reductions will largely depend on the market ramp-up of electrolysis. The pace at which electrolysis is integrated into the market will be pivotal in attaining these objectives. Odenweller et al. [21] demonstrate that despite a surge in project announcements, the availability of green hydrogen is projected to remain limited (<1% of final energy demand) until 2030 in the European Union and until 2035 globally. This phenomenon can be explained through the principle of exponential growth, wherein initial sluggish progress requires time to evolve into significant growth rates. Nevertheless, once a breakthrough is achieved, market expansion can accelerate rapidly, as evidenced by the trajectory of photovoltaics, for instance. However, the scaling up of electrolysis capacities presents a more intricate challenge. The current low levels of installation entail uncertainty regarding the realization of market projections. Additionally, simultaneous advancements in supply, demand, and infrastructure are imperative, entailing substantial costs. Moreover, there exists the possibility of overestimating the potential of green hydrogen [21].

However, the literature also highlights that the comparison of electrolysis costs with conventional hydrogen production technologies should not be limited solely to costs. Other potential revenue streams, such as oxygen as a byproduct of electrolysis, should also be considered to reduce overall costs. In many instances, when oxygen is integrated into models, it is marketed as a medical gas, as illustrated in Moradpoor et al. [22], deriving a price of 20 €/ton. Maggio et al. [23] examine on-site hydrogen production for hospital use and identify numerous benefits stemming from this dual production setup. They suggest that the hospital could achieve independence from external oxygen suppliers and additionally utilize hydrogen as a backup energy source for emergencies. Their analysis suggests that this arrangement could prove cost-effective if the market price of oxygen exceeds 3–4 €/kg. A parallel conclusion is drawn by Squadrito et al. [24], indicating that an oxygen market price of 3 €/kg is necessary to attain economic viability within a 20-year investment horizon. In addition to the aforementioned conventional production technologies, natural hydrogen is also gaining prominence in scientific discourse. In Lapi et al. [25], a cost comparison is made between natural hydrogen discovered in Mali and hydrogen produced through SMR and electrolysis from various countries. The analysis clearly demonstrates that natural hydrogen, with costs at 1 USD/kg H_2, emerges as the most cost-effective option. It is noted that this hydrogen discovery benefits from favorable geological conditions in Mali, which may differ in other locations.

Another strain of literature comprises studies investigating the potential of hydrogen imports into Europe. Sens et al. [26] focus very specifically on the cost of green hydrogen using local production in Europe versus production in North Africa and delivery to a demand center in Germany. They predict a decrease in hydrogen production costs in the well-suited areas from 3 €/kg H_2 to 2 €/kg H_2 in 2050, with very high technical potential in North Africa. Even if transport costs are included, they arrive at hydrogen costs of 3 €/kg H_2 with delivery by pipeline from North Africa, while production in Germany would cost 4.5 €/kg H_2. Timmerberg and Kaltschmitt [27] deal specifically with the procurement of hydrogen from North Africa but with subsequent blending into existing fossil gas pipelines. That large quantities of hydrogen can be imported into the EU at lower costs than self-production has been demonstrated by Nuñez-Jimenez and De Blasio [28] in three scenarios spanning up to the year 2050. The authors, however, highlight the importance of avoiding the repetition of existing patterns of energy dependencies in hydrogen and thus advocate for diversification through long-distance imports. Srettiwat et al. [29] also examine a longer import route, specifically imports from Namibia, in addition to Morocco. They find that, under the given assumptions, imports from Namibia are more cost-effective than local production in Belgium. Contrasting findings are presented in Galimova et al. [30], which compare production costs in Germany and Finland with the production and transportation costs for hydrogen from Morocco and Chile. The analysis calculates that imported hydrogen will be 39–70% more expensive in Germany and 43–54% more expensive in Finland compared to locally produced hydrogen. Eckl et al. [31] come to a somewhat more balanced conclusion in their study, which examines the economic feasibility of supplying solar hydrogen from Portugal to a pipeline in Germany or producing it locally. The analysis reveals significant cost disparities between production in Portugal, with 2.09 €/kg H_2 and Germany 3.24 €/kg H_2, although the discrepancy diminishes when considering the entire value chain to the delivery point in Germany. This implies that varying assumptions and calculation methods yield markedly different results, which do not present a clear-cut argument either for or against hydrogen imports. This could partly stem from the fact that there is currently no substantial hydrogen trade in operation, as most of the produced quantities are immediately consumed within industrial areas. Even in cases where hydrogen trading occurs, it typically involves a single supplier distributing to various nearby industries [9]. Nonetheless, the IEA forecasts a significant increase in hydrogen export projects by 2030, totaling 12 Mt. H_2/yr. These projections break down regionally, with Latin America accounting for 3 Mt. H_2/yr, Australia for 2.7 Mt. H_2/yr, Europe (inter-European trade) for 1.79 Mt. H_2/yr, Africa for 1.7 Mt. H_2/yr, North America for 1.1 Mt. H_2/yr, the Middle East for 1.0 Mt. H_2/yr, and Asia for 0.7 Mt. H_2/yr. The primary focus lies on hydrogen production via electrolysis, constituting 88% of export volumes. The produced hydrogen is intended for direct exports or facilitated by ammonia as a carrier for long-distance shipping [32].

The IEA's assumptions regarding the anticipated hydrogen trade are also visible in the scientific discourse, particularly within the context of comparing hydrogen and electricity as energy vectors under certain assumptions. D'Amore-Domenech et al. [33] conclude that water transport in the onshore-to-onshore scenario by hydrogen pipelines is cheaper than electricity under the assumptions of a 2 GW power transmission and a distance of about 1000 km in deep waters. For the offshore to onshore scenario with the 600 MW capacity, there is a lower cost for transport in the power cable. Another comparison of energy volume transport in the form of hydrogen using pipelines or electricity in submarine cables is by Miao et al. [34]. They find that the installation cost of pipelines per km is higher than of electricity cables but has a higher transmission capacity. The energy losses of power cables are higher, while pipelines generally have higher operating costs due to gas compression. In the cases studied, transportation via pipelines over longer distances was more cost-effective.

Cerniauskas et al. [35] investigate already available fossil gas infrastructure and the conversion of the German grid to hydrogen transport. The result of the study is that 80% could be converted and the hydrogen costs would then be reduced by more than 60% in contrast to the construction of new pipelines. Building on lower-cost pipeline transportation, Patel et al. [36] are exploring a 'Hydrogen Interconnector System' (HIS) for transporting electricity over long distances. The idea is to convert the hydrogen back into electricity at the demand center in gas turbines or fuel cell plants. They compare the proposed system with high voltage direct current systems and find them competitive in 2050. Besides pipeline transport, Rong et al. [37] extend the analysis to the transportation of compressed gas hydrogen, liquid hydrogen, and liquid organic hydrogen carriers in combination with the necessary storage. D'Amore-Domenech et al. [38] and Graf [39] investigate additional options like ship transport besides the already discussed transport possibilities. Johnston et al. [40] especially focus on the shipping route from Australia to Rotterdam and investigate the transport of liquid hydrogen, ammonia, liquified natural gas, methanol and liquid organic hydrogen carriers. The emphasis on liquid organic hydrogen carriers is taken in Reuβ et al. [41], with a focus on smaller quantities of hydrogen and seasonal storage in caverns, while Cui and Aziz [42] concentrate on transporting hydrogen using methanol and ammonia. The costs of the entire value chain from production to hydrogen transport from electrolysis are analyzed by Martin et al. [43], with a dynamic cost model based on Norway. In addition to hydrogen, ammonia and efuels are modeled for fuel consumption for long-distance truck transport, short-distance maritime transport and short-distance air transport. They conclude that the best options are hydrogen for long-haul truck transport, ammonia for short-haul maritime transport, and hydrocarbon efuels for short-haul air transport. This study has been extended in Martin et al. [44], where 150 technical-economic parameters were identified that could potentially increase costs. Cost reductions ranging from 41% to 68% for renewable fuels by 2050 were calculated. The review by Faye et al. [45] also focuses on the entire value chain. The literature review is complemented by a discussion of the state of the art of respective technologies. Meanwhile, Alabbadi et al. [46] specifically emphasize hydrogen production through nuclear energy, along with its transport and storage. The mentioned options, such as liquid organic hydrogen, methanol, and ammonia for simplified transportation, albeit with greater conversion losses, present an alternative to pure hydrogen transport that warrants further exploration in future works, however, it is not being covered in this work.

Numerous researchers, including Ozbilen et al. [47], Parra et al. [48], Valente et al. [49],Sanchez et al. [50] and Mio et al. [51], conduct an environmental assessment of greenhouse gas emissions for different hydrogen production methods. Some lay a specific focus on certain technologies, for example, Lotrič et al. [52] and Zhao et al. [53] on electrolyzers, Aydin and Dincer [54], especially on clean hydrogen production methods (including also nuclear electricity), Diab et al. [55] on turquoise hydrogen and Bauer et al. [56] and Howarth et al. [4] on grey and blue hydrogen. According to Howarth et al. [4], utilizing blue hydrogen releases 18–25% fewer GHG emissions than grey hydrogen but still emits 20% more than using natural gas or coal for heating purposes. The emission accounting is even expanded by Al-Qahtani et al. [57] to evaluate other environmental issues that arise during production. Moreover, Rinawati et al. [58] expand the field of study by researching hydrogen-based power generation life cycle assessments.

When counting the emissions during the hydrogen emission process, it becomes evident that green hydrogen through electrolysis is the most environmentally friendly option as per findings of Acar und Dincer [59] and Ozturk and Dincer [60], who find that the lowest emissions occur when the electrolyzer is powered by solar. An analysis similar to this one, conducted by Cho et al. [61], offers location-specific calculations, concentrating on production technologies with potential for commercialization. Wind electrolysis shows the lowest global warming impact among the technologies studied, while biogas reforming demonstrates the highest impact. According to the calculations by Maciel et al. [62], optimal ecological efficiency is attainable when hydrogen is produced from hydropower, followed by wind and photovoltaic sources. Dincer [63] has previously conducted a thorough analysis of the environmental effects of producing green hydrogen. In summary, while the literature presents varying results regarding the choice of renewable electricity generation with the lowest emissions, all studies concur that only renewable generation truly yields low CO_2 emissions.

Other authors primarily focus on life cycle assessments of hydrogen transportation and distribution, like Lucas et al. [64], Wulf et al. [65] and Frank et al. [66]. Tayarani and Ramji, 2022 [67] primarily focus on two transportation modes, namely pipelines and trucks and find that all investigated pipeline routes contain lower emissions than similar routes by trucks.

Other authors primarily focus on life cycle assessments of hydrogen transportation and distribution. Tayarani and Ramji, 2022 [67] concentrate specifically on two transportation modes, pipelines and trucks and conclude that all investigated pipeline routes contain lower emissions than similar routes by trucks. This consensus on pipelines having lower environmental impacts than truck transportation is evident among the analyzed studies, except for very short transport distances (100 km), as found by Wulf et al. [65]. Transport via shipping was not considered in the mentioned studies. Additionally, Frank et al. [66] highlight the necessity of preparing hydrogen for transportation by increasing its energy density via compression, liquefaction, or chemical conversion. Liquefaction poses the greatest challenge due to its high energy intensity and dependence on the electricity mix of the respective country. It is important for future studies to consider these variations depending on where liquefaction occurs.

As evident from the preceding section, many studies of life cycle assessments exist that examine the environmental impacts of hydrogen production at a specific location or assess various transport options separately. However, comprehensive evaluations encompassing the entire hydrogen chain, including production and transport, are scarce in the literature. Three studies were found that focus on such holistic assessments. The most comprehensive study in this regard is conducted by Kolb et al. [68], which investigates local production in Germany and imports from Chile, Canada, and Morocco. The study concludes that, under certain conditions, the emissions of the entire import chain can be lower than those of local production. In the specific case of the base case scenario, emissions from hydrogen sourced from wind in Canada or hydrogen from PV have lower associated emissions. However, it is noted that shipping distance plays a significant role in emissions, and the use of grid electricity for hydrogen liquefaction substantially increases CO_2 emissions. Hren et al. [69] calculate the emissions, energy footprints and acidification eutrophication, human toxicity potential, and eco-cost for eleven hydrogen production sources, including the related supply chains and conclude that glycerol and alcohol waste steam reforming and water electrolysis with renewable electricity has the lowest greenhouse gas emissions. The focus of Vilbergsson et al. [70] lies in comparing Iceland-produced hydrogen with the resulting transport requirement to Austria or Belgium to locally produced hydrogen in the named countries. They conclude that the electricity mix is the most influential part of the emissions, whereas transport emissions do not play a significant role. Therefore, hydrogen production in Iceland emits fewer GHG emissions. The authors calculate higher than average emissions of the respective electricity mix since they assume that when additional hydrogen capacities are built, additional peak capacities (mostly gas-fired power plants) are used and not the share of renewable generation of the respective country. Lee et al. [71] also conclude that the power mix of the production site plays a critical role.

The existing literature on hydrogen production and transportation presents a comprehensive overview of various technologies and methodologies. A critical observation reveals that only a few studies explicitly compare all facets of production and transportation chains holistically, integrating both techno-economic and environmental analyses. Notably, prior research often overlooks upstream fugitive methane emissions from fossil gas, a crucial factor highlighted by Refs. [48,72,73]. Further, the distinction of different regional production sites for renewable power generation, including possible increased transportation costs due to longer distances, are often not regarded, hence not showing the broader picture of renewable generation costs. Comparisons between local production and imported hydrogen entail different costs and emissions and must, therefore, be examined separately. To our knowledge, such comprehensive analyses comparing production in Austria versus North Africa (Morocco and Tunisia) have not been published previously despite numerous politically motivated discussions on this topic. Given the high uncertainty of many input parameters, particularly in cost estimations, previous studies rarely conduct sensitivity analyses, which are vital for providing comprehensive insights. Our study not only presents the main case study but also includes sensitivity analyses with two outlier case studies (low and high costs or emissions), as point estimates could be misleading. All of the aforementioned points are addressed holistically in this study to facilitate a comparison of costs and emissions among the selected chains under the assumed conditions.

In this paper, in Section 2, the method is outlined. The results of the economic analysis and the environmental assessment are outlined in Section 3. Finally, Section 4 provides major conclusions of this work.

2. Methods

The method used in this paper is divided into a techno-economic analysis and a carbon emission assessment of defined hydrogen supply chains. For this purpose, the processes of SMR (grey), SMR and CCUS (blue), electrolysis with electricity input from the power grid (yellow), and electrolysis with electricity from PV and wind (green) are used. The production location of the grey, blue, and yellow hydrogen is assumed to be in a hydrogen hub, in this analysis in Austria. For green hydrogen, production can be at the hydrogen hub in Austria (local production) and in a country with favorable climatic conditions for renewable electricity production. In the case of PV, Morocco, and the case of wind, Tunisia is used since approximate capacity factors of 21 % and 43 % can be achieved, which was derived from Pfenninger and Staffel [74]. Further information can be found in the mentioned references [75,76].

Since the different production types and locations are to be compared with each other, the system is simplified. Steps such as storage of hydrogen in the country of consumption, local distribution and hydrogen consumption are not included, as these factors are the same for all supply chains. However, storage that occurs during production, for example, for intermediate storage during electrolysis up to transport, is considered. A graphical representation is shown in Fig. 2.

We exclude the emissions that occur during the manufacturing and construction of power plants, fossil gas extraction sites, or hydrogen production facilities for the environmental assessment in line with the European Commission accounting method [77]. In the analysis of transport costs and emissions, only the transport of pure hydrogen (gaseous or liquid) via pipelines or ships is considered. Other hydrogen carriers, such as liquid organic hydrogen carriers or ammonia, are not included, as researched by Niermann et al. [78] and Hurskainen and Ihonen [79]. Blue hydrogen production also considers all associated costs and emissions of hydrogen capture, transport, and storage or use. Here it is assumed that CO_2 cannot be stored permanently in the country of the hydrogen hub due to the legal situation and non-existing CO_2 storage facilities, as it is the case in Austria [80].

2.1. Techno-economic analysis

For the cost comparison of each of the hydrogen production chains, the total hydrogen costs $C_{H2_{Total}}$ are calculated. Those include the costs of each section of the supply chain, namely hydrogen production C_{H2_P}, hydrogen transportation C_{H2_T} and other processes $C_{H2_{OP}}$ as per system boundaries displayed in Fig. 2.

$$C_{H2_{Total}} = C_{H2_P} + C_{H2_T} + C_{H2_{OP}} \ (€ / \mathrm{kg}) \tag{1}$$

The production costs (C_{H2_P}) are calculated using the investment costs of the hydrogen production facility ($IC_{Ely/SMR}$, *in* $€/kW$), other project costs (e.g., compressor, installation, analysis and infrastructure) (IC_{Other}, *in* $€/kW$), the capital recovery factor (α), the annual operating, maintenance and repair costs ($C_{O\&M_t}$, *in* $€/kW-year$), the full load hours (FLH) and the fuel or electricity costs ($C_{fuel/ele}$, *in* $€/kWh$): and the efficiency of the production system (η):

$$C_{H2_P} = \frac{(IC_{Ely/SMR} + IC_{Other}) \bullet \alpha + C_{o\&m}}{FLH} + \frac{C_{fuel/ele}}{\eta} \ (€ / \mathrm{kg}) \tag{2}$$

and the calculation of the capital recovery factor (α) with discount rate (r) and service life (n)

$$\alpha = \frac{(1+r)^n \bullet r}{(1+r)^n - 1} \tag{3}$$

The costs of fossil gas C_{fuel} for grey and blue hydrogen and of electricity obtained from the power grid C_{ele} (yellow hydrogen) are based on historical cost data, whereas the costs for electricity from PV and wind $C_{PV/Wind}$ is calculated based on the local topological conditions. The full load hours (FLH) are, therefore, different for the locations of Austria (local production), Morocco and Tunisia and the costs are calculated as follows:

$$C_{PV/Wind} = \frac{(IC_{PV/Wind} + IC_{Other}) \bullet \alpha + C_{o\&m}}{FLH} \ (€ / \mathrm{kWh}) \tag{4}$$

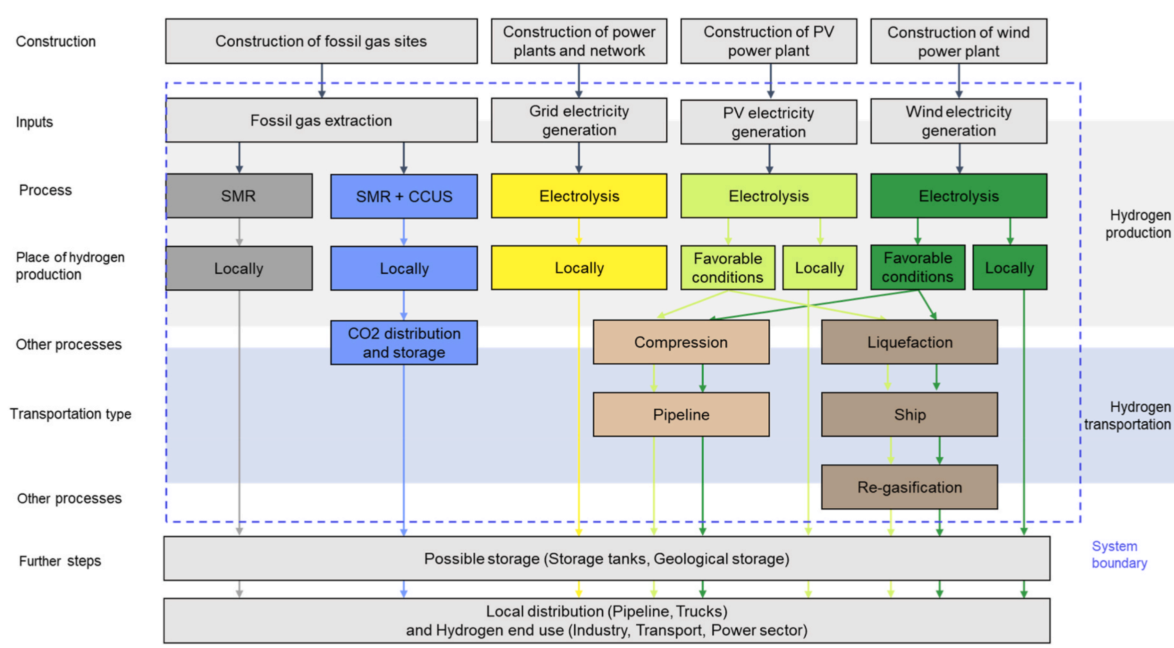

Fig. 2. Outline of the investigated hydrogen supply chains and definition of system boundaries.

The efficiency of the hydrogen production system (η) is based on efficiency assumptions in the literature on SMR, CCUS and PEM Electrolysis. A PEM electrolyzer was chosen because it responds very well to power fluctuations, which is needed in the case of direct PV and wind inputs. The transport costs C_{H2_T} of each pipeline and ship were taken from IRENA [9] and extrapolated to the respective distances.

Other processes costs $C_{H2_{OP}}$ include CO_2 transportation and storage costs in the case of blue hydrogen, compression as a required process chain before pipeline transportation and liquefaction and re-gasification in the case of transportation via ship.

It is important to note that we only calculate production and transportation costs, given the system boundaries and parameter inputs. This analysis does not provide any guidance on how the actual market prices for hydrogen might evolve due to energy market conditions (e.g., oligopolistic market power) which are highly uncertain.

The input data for the economic analysis are given in the following tables, including the sources used. Parameters are collected from scientific literature and industry reports. No potential subsidies on renewable electricity generation or any taxes were included in the analysis for comparability reasons. Table 1 gives the data used for the main case study. It is very difficult to obtain reliable data for investment costs in the literature. Usually, it is not clearly stated to which plant size the cost data refer, which elements are included (only stack or overall system), and from which year these data originate. For this reason, a sensitivity analysis of certain parameters with two outliers case studies (low and high costs) is also carried out in a further step. The data used can be found in Table 2. In general, we tried to harmonize the parameters for all four production technologies. We also include the balance of plant costs in line with IRENA [10], hence calculating production investment costs. Other essential parameters besides the investment costs are the full load hours of the hydrogen production plants and the fuel or electricity costs. As the latter are affected by a range of variation, a sensitivity analysis is also performed in that case (Table 2). In the case of green hydrogen production, as assumed here from PV and wind, the full load hours are also very different depending on the location. They were taken from the assumptions regarding the PV or wind electricity production location. The data for the cost calculation of the electricity from PV and wind and the regions considered (Local, Tunisia and Morocco) are given in Table 3.

Table 4 shows the parameters of the transport costs by means of pipelines and ships. These depend, in each case, on the distance to be transported. The transport volume was assumed to be rather low (small-medium according to Ref. [9]) since the transport infrastructure is not yet developed. In this situation of small hydrogen flows, road transport might still be an cheaper option [89], which has not been considered in this analysis. With higher volumes, however, the costs would also decrease accordingly. To illustrate how the total costs would change with the mentioned cost reductions, Table 5 displays the input parameters for the sensitivity analysis covering the transport costs. Cost reductions of 15% and 30% were taken in each case. The transport costs also include the costs for compression (pipelines) and liquefaction and re-gasification in the case of transport by ship.

Table 1
Calculation data for main case study [2,8,74,81–84].

Parameters	SMR		Electrolysis	
	Grey	Blue	Yellow	Green
Production investment costs (€/kW)	1100	1878	2400	2400
Operation and maintenance costs including CO_2 storage and transport costs (€/kW)	52	103	44	44
Interest rate	0.05	0.05	0.05	0.05
Depreciation period	25	25	20	20
Full load hours	8322	8322	8322	1314–3767
Fuel or electricity costs (€/kWh)	0.05	0.05	0.09	0.04–0.07
Efficiency (LHV)	0.76	0.69	0.66	0.66

Table 2
Calculation data for high and low-cost case studies [2,8,10,81,85–87].

Parameters	Sensitivity case	SMR	Electrolysis
Overall investment costs (€/kW)	High costs	1321	3200
	Low costs	991	1616
Operation and maintenance costs (€/kW)	High costs	62	44
	Low costs	47	44
Fuel or electricity costs (€/kWh)	High costs	0.07	0.11
	Low costs	0.03	0.08
Efficiency (LHV)	High costs	0.74	0.5
	Low costs	0.85	0.8

Table 3
Calculation data for electricity costs from PV and wind [74,88].

Parameters	PV		Wind	
	Local	Morocco	Local	Tunisia
Investment costs (€/kW)	876		1299	
Operation and maintenance costs (€/kW)	35		52	
Interest rate	0.05		0.05	
Depreciation period	25		25	
Capacity factor	0.15	0.21	0.3	0.43

Table 4
Calculation data for transport and other process costs [8,9].

Parameters	Ship		Pipeline	
	Tunisia	Morocco	Tunisia	Morocco
Transport costs, including compression (€/kg)	0.84	1.09	1.25	1.5
Transport distance pipeline (km)	400	400	1900	2400
Transport distance ship (km)	800	1800	0	0
Liquefaction (€/kg)	0.88	0.88	0	0
Re-gasification (€/kg)	0.009	0.009	0	0

Table 5
Calculation data for sensitivity analysis on transport and other process cost [8,9].

Parameters		Ship		Pipeline	
	Sensitivity case	Tunisia	Morocco	Tunisia	Morocco
Transport costs, including compression (€/kg)	15%	0.72	0.93	1.07	1.27
	30%	0.59	0.76	0.88	1.05
Liquefaction (€/kg)	15%	0.75	0.75	0	0
	30%	0.62	0.62	0	0
Re-gasification (€/kg)	15%	0.007	0.007	0	0
	30%	0.006	0.006	0	0

2.2. Environmental assessment

All greenhouse gas emissions along the process chain are evaluated in the environmental assessment according to the system boundaries described in Fig. 2. This means that only exogenous GHG emissions are included. GHG emissions that occur during the production of facilities or infrastructure are not considered following the calculation method of the European Commission, which reads “Electricity qualifying as fully renewable according to the methodology set out in Directive 2018/2001, shall be attributed zero greenhouse gas emissions” [77]. Thus, the calculated GHG emissions are lower than the full life cycle emissions (cradle-to-grave).

The total emissions $CO_{2\ eq\ _{Total}}$ of the respective process chain, within the system boundaries, consist of the emissions that occur in the hydrogen production process $CO_{2\ eq\ _P}$, the upstream emissions $CO_{2\ eq\ _{UPS}}$ (electricity generation or upstream fugitive methane emissions) and, in the case of green hydrogen production outside the hydrogen hub, the transport emissions $CO_{2\ eq\ T}$.

$$CO_{2\ eq\ Total} = CO_{2\ eq\ P} + CO_{2\ eq\ UPS} + CO_{2\ eq\ T}\ \left(\text{kg CO}_{2\text{eq}}/\text{kg H}_2\right) \tag{5}$$

Upstream fugitive methane emissions are also taken into account, according to the calculations of Howarth und Jacobson [4]. We base the values on the time horizon of GWP100, as commonly used, for better comparison with the reported figures on the emission intensity of the electricity grid. It must, however, be noted that methane emissions are thus included in the calculations at a lower level. Since methane has a disproportionally large effect on near-term temperature because of its shorter lifespan, the emission metric GWP100 has an approximate uncertainty of 50% for methane as mentioned in the newest IPCC report [90]. As the scientific literature increasingly shows the importance of accounting for methane emissions along the entire value chain, especially in Europe and Australia [91] the sensitivity analysis examines three leakage rate case studies, including the IPCC default rate of 1.7% [5].

We exclude climate consequences on hydrogen leakages in this work as researched by Hormaza Mejia et al. [92] and Ocko and Hamburg [93]. Recent findings by Cooper et al. [94] suggest that while methane emissions of fossil gas and hydrogen within the supply chain have similar emission rates, the effect on global warming is less significant. Nevertheless, the issues of hydrogen leakages should be addressed in further studies. Also, the water usage and the acidification potential of sulfur dioxide released on soil and water are highly relevant and the latter was discussed thoroughly by Amin et al. [95], however not included in this study.

As electricity input for yellow hydrogen production, we consider the Austrian electricity mix of 2021 according to the European Environment Agency [96]. In the sensitivity analysis, we apply the electricity mix of Europe in the high emissions case study and a lower emission intensive year (2019) of Austria in the low case study. For green hydrogen, no emissions apply in the case of local production due to the accounting method used in this analysis. A CO_2 capture rate of 85% has been assumed for blue hydrogen production [4].

In pipeline transport, the key elements of compression as preparation and transport emissions (e.g., recompression along the way) were investigated. The technical data is taken from the following sources [39,65,66,97,98]. To operate the compressor, the electricity mix of the respective country [99,100] and for electricity inputs required along the pipeline, the electricity mix of the EU was used.

In the case of transport by ship, liquefaction (here also with the electricity mix of the respective country), shipping and reconversion (EU electricity mix) were included [9,39,101]. The vessel was assumed to be operating on heavy fuel oil. Hydrogen losses along the transport routes were not considered for either transport option since pure green hydrogen was produced with no emissions based on the calculation method, as only the required energy input increases.

For both transport options, it is difficult to obtain reliable figures since, in the case of pipelines, these exist but are only used for small distances and ship transport of liquid hydrogen is only just emerging. The first ship started its journey in 2022 from Australia to Japan [102]. One kg of hydrogen is used as the functional unit for the GHG impact of CO_2 equivalents (kg $CO_{2\ eq}$/kg H_2). All energy input data, such as hydrogen production efficiency, are used identically to the economic analysis.

3. Results

3.1. Techno-economic analysis

Production cost calculations have shown that grey hydrogen production has the lowest total cost when externalities such as GHG are not incorporated by means of carbon tax or certificates, see Fig. 3. Investment costs only play a minor role, as costs of fossil gas account for the majority of those costs. On the contrary, regarding the higher costs for all production chains in which electrolyzer technology is used, the investment costs play a slightly higher role in the case of yellow hydrogen and a substantially higher one for all cases of green hydrogen production. It is important to note here that grey hydrogen has been and is still the dominating production method. The SMR plants are in the GW range, having already experienced high economies of scale, while electrolyzer capacities are still substantially smaller. When blue hydrogen is being regarded, it is in-between, the part of the SMR technology is mature, but the process of CCUS is still under development, with a particular uncertainty regarding the storage aspects of carbon.

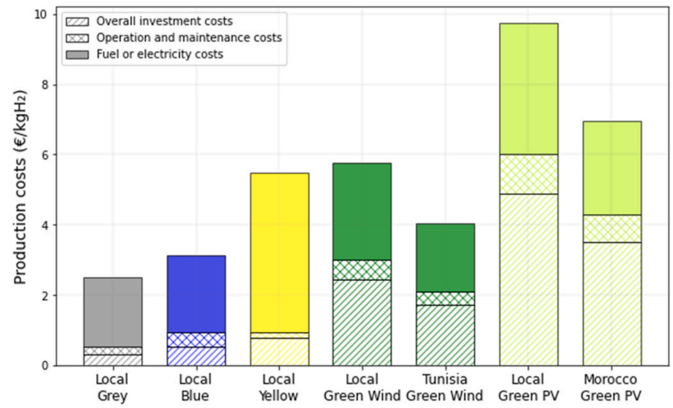

Fig. 3. Comparative analysis of hydrogen production costs of different technologies (colors) and regions for the main case study (local is in this case production at the assumed hydrogen hub in Austria).

The investment costs play a smaller role with yellow hydrogen since the utilization of the electrolyzer is very high, as the grid electricity is available evenly throughout the year. It is important to emphasize that in a decarbonized energy system, yellow hydrogen would also be fully renewable when electricity storage technologies are being used. In the mid-transition phase, especially when no subsidies are utilized and required storage capacities are not in place, efforts are made to maintain a constant utilization of electrolyzers, particularly when replacing existing SMR facilities, for example, in fertilizer production. In that continuous operation case, fossil sources would be used during specific hours. The same regarding investment costs also applies to grey and blue hydrogen production. Green hydrogen, in contrast, relies on the production capacities of PV and wind and thus achieves a much lower number of full load hours. Therefore, green hydrogen production depends on the climatic conditions of the region of operation of the renewable power plan. In more favorable regions, higher operations hours of renewable electricity hence electrolyzer operation can be achieved and lower costs [15]. Fig. 4 shows the hydrogen production costs of wind and PV, respectively, in the considered hydrogen hub (Austria), as well as in Tunisia and Morocco. Due to the higher utilization of the electrolyzer, the generation costs in Tunisia and Morocco are significantly lower.

On a more specific note, it can be clearly seen that green hydrogen from wind is the cheaper option when compared to PV powered, even when considering the most suitable production sites for both. This lies in the fact that on average PV powered electrolyzers have the lowest normalized efficiency, according to Ozturk and Dincer [60]. However, due to different operating patterns, a combination of PV and wind can result in higher utilization and lower costs. This hybrid approach should be considered in further research, as by Sens et al. [26].

However, a pure comparison of production costs at different locations is not permissible since the location where the hydrogen is being used is also relevant. In the case under consideration, the hydrogen is consumed in Austria, so additional transport costs are incurred in the case of production from Tunisia and Morocco. For this purpose, the two

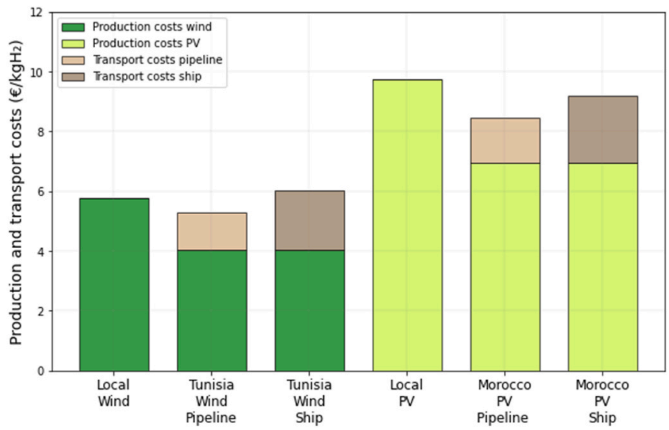

Fig. 4. Comparative analysis of hydrogen transportation cost and renewable hydrogen production (Local, Tunisia and Morocco).

possibilities of pipeline and ship transport are considered. Our analysis indicates that pipeline transport is generally cheaper and therefore preferable in the case that it is possible. The total costs of hydrogen production in the case of pipeline transport are lower in both cases (PV and wind) in Morocco and Tunisia, respectively. When comparing the transport costs by ship, only the PV production costs in Morocco are slightly cheaper than the locally produced green hydrogen from PV. As transport costs depend on the distance, the calculated costs are very location specific. No assumptions can be drawn for hydrogen import from locations further away. Table 6 depicts the exact results of the calculations of each defined process chain for the main case study.

However, since the cost savings from hydrogen imported from North Africa are relatively low due to the transport costs, but additional hydrogen losses or additional energy consumption and, in the case of the use of fossil fuels, also GHG emissions occur, the question arises whether locally produced hydrogen is not the preferred option in the status quo, with low volumes and only cost being accounted. However substantial cost reductions in hydrogen transportation are to be expected, which can make importing hydrogen the viable option in the future, see Ref. [28]. In Morocco only, 19% (2021 values [99]) and in Tunisia, 3% (2021 values [100]) of the generated electricity comes from renewable sources, meaning that additional renewable generation is urgently needed for own consumption. Nearly all of the additional electricity production in Morocco, namely 60%, is produced by coal power plants, making it one of the countries with the highest carbon intensity of electricity worldwide [103]. Moreover, according to new studies, enough potential for additional renewable electricity generation capacities exists within the EU. Kakoulaki et al. [104] analyze the technical potential of renewable energy in Europe, considering environmental constraints, land use restrictions and various techno-economic parameters. They conclude that the available renewable electricity potential far exceeds the electricity demand and the demand for hydrogen generation by electrolysis in all countries studied.

Except for the case of purely green hydrogen, where the costs are accounted for by newly built PV or wind power plants, the energy input costs are a dominant factor. Those costs fluctuate at the moment and provide a high uncertainty factor. That is why two further case studies (low and high cost) are being considered as sensitivity analysis. In those case studies, the investment, operation and maintenance, fossil gas and electricity costs and efficiencies of the hydrogen production facilities are included with their upper and lower limits, with the results displayed in Fig. 5.

The sensitivity analysis shows significant cost variations for all technologies, but the hydrogen production costs using electrolysis are still the highest. However, this will change in the future because a combination of cost reductions of green electricity production and electrolysis and further efficiency improvements can lead to an 80% cost reduction, according to IRENA [10]. From 2030, green hydrogen production is expected to be cheaper than blue hydrogen production [105].

A sensitivity analysis was also carried out concerning the transport costs, revealing that in all case studies, costs are below those of local production when there is only a 15% reduction in total transport costs, as depicted in Fig. 6. Given that this analysis considered very low to moderate hydrogen transport volumes, such cost reduction becomes achievable with higher transport volumes in the future.

3.2. Environmental assessment

It is evident from the emission calculation that grey hydrogen by SMR has the highest emissions in the main case study, see Fig. 7. Blue hydrogen, likewise, with over 9 kg $CO_{2\ eq}$/kg H_2, is in no way an alternative to green hydrogen (with no emissions according to the defined system boundaries and emission calculations according to the methodology set out in Directive 2018/2001 [77]). This is due to the fact that the capture rates are not 100%, the use of additional processes for carbon capture and then further transport of the carbon and storage requires a large amount of energy and last but not least due to the still used fossil raw material of fossil gas. It is becoming increasingly clear in the literature that there are much higher emissions associated with the use of fossil gas than initially thought, mainly due to the high methane emissions upstream [106]. Methane is emitted during fossil gas extraction and along the entire transport process. Partly through regular leakage, malfunctions, and equipment failure [107]. In our calculations, we include a relatively small amount of methane emission simply because we use the time horizon of 100 years for calculating the global warming potential (GWP). In this metric, according to the newest IPCC report (AR6), methane has a 29.8 times higher GWP than CO_2, whereas when using 20 years as a metric, it has 82.5 times higher GWP due to its shorter lifetime [108].

In addition to the 9 kg $CO_{2\ eq}$/kg H_2 emitted during the hydrogen production process, the IEA noted in the 2021 hydrogen report [83] that methane emissions occurring upstream at the production and storage of fossil gas result in additional emissions of 1.9–5.2 kg $CO_{2\ eq}$/kg H_2 (2.7 kg $CO_{2\ eq}$/kg H_2 on average globally). Those figures appear to be in line with our calculations. Nevertheless, the actual rates appear to be much

Table 6
Results of the economic assessment - main case study.

Production chain	Production costs (€/kg)	Transport costs (€/kg)	Production and transport costs (€/kg)
Grey Local[a]	2.49	0	2.49
Blue Local	3.12	0	3.12
Yellow Local	5.49	0	5.49
Green Wind Local	5.77	0	5.77
Green Wind Tunisia- Pipeline	4.02	1.25	5.27
Green Wind Tunisia- Ship	4.02	2.00	6.02
Green PV Local	9.73	0	9.73
Green PV Morocco - Pipeline	6.95	1.50	8.45
Green PV Morocco - Ship	6.95	2.25	9.20

[a] Local is in this case production at the assumed hydrogen hub in Austria.

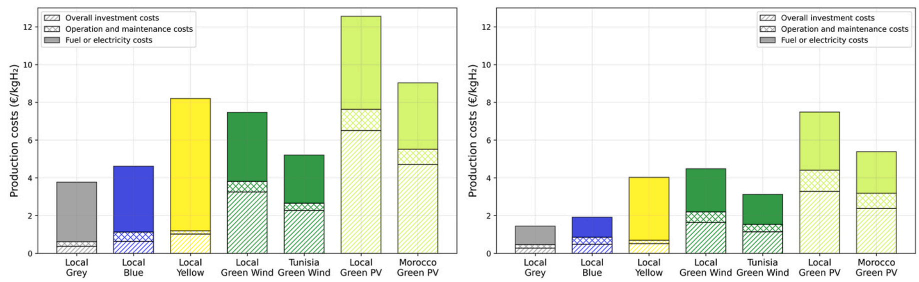

Fig. 5. Sensitivity analysis of hydrogen production costs of different technologies (colors) and regions for a high (left) and low-cost (right) case study.

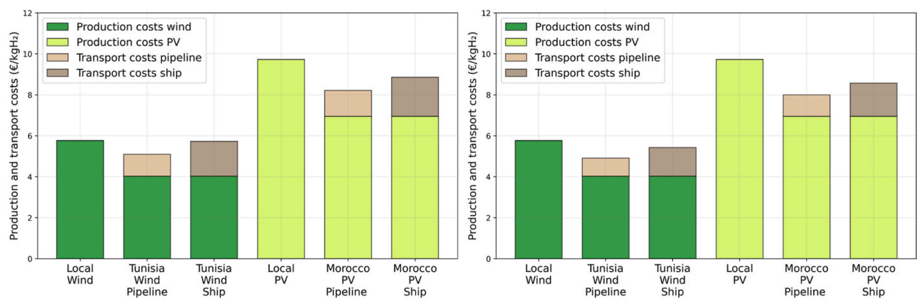

Fig. 6. Sensitivity analysis with a 15% (left) and a 30% reduction of hydrogen transportation costs.

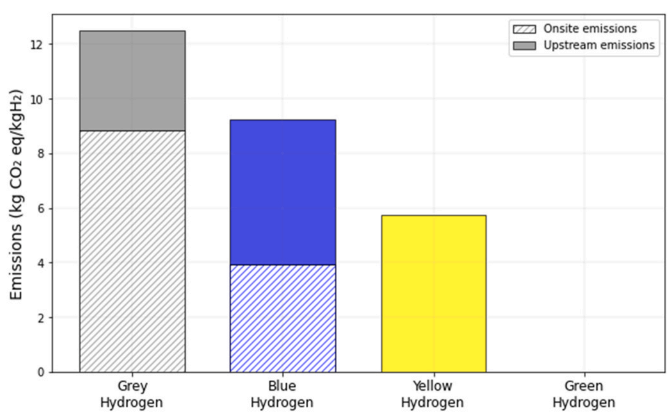

Fig. 7. Comparative analysis of hydrogen production emissions (GWP100) of analyzed technologies (colors) for the main case study.

higher than previously predicted, as research, including measurements in the US and Canada, suggests [109–112]. Bauer et al. [56] applied leakage rates ranging from 0.2% to 8%, demonstrating overall emission from 11 to 30 kg $CO_{2\ eq}$/kg H_2. Unfortunately, there is no reliable statistic for the fugitive emissions from fossil gas, as they depend on the technical equipment and processes [106]. However, studies suggest that they are 50–60% higher than in previous studies [109]. For this reason, we conducted a sensitivity analysis by varying the leakage rates (from 3.5% to 4.3% and 1.7%) and the efficiencies of the generation processes in line with the sensitivity analysis of the economic assessment, which can be seen in Fig. 8.

Also, in the two outlier case studies (low and high emissions) of the sensitivity analysis, it can be seen that the emissions of blue hydrogen do not drop drastically because the local capture of CO_2 does not affect the upstream emissions and more energy has to be utilized, which increases them further. Currently, blue hydrogen is considered by a few people as a bridging technology before a complete transition to green hydrogen [113] and carbon capture and sequestration were being promoted heavily a few years back. However, this term is only used to keep fossil industries in business so that they can continue to develop and operate the gas infrastructure [106] and the promotion of carbon capture and sequestration has also is also far from the expected goals. The new worldwide database of CCUS projects of the IEA [114] illustrates this.

What is significant, however, is the increase in emissions of yellow hydrogen when it is produced using the EU electricity mix. Emissions are more than tripled and more CO_2 is produced than with grey hydrogen. The EU electricity mix currently contains only a relatively small share of renewable energies and therefore causes higher emissions than Austria's electricity mix, which is more renewable due to its historically grown hydropower. This shows the importance of a switch to renewable energy sources, especially in the electricity sector, where great low-cost alternatives to fossil generation already exist. Then hydrogen could also be produced cost-effectively within the EU with relatively low emissions.

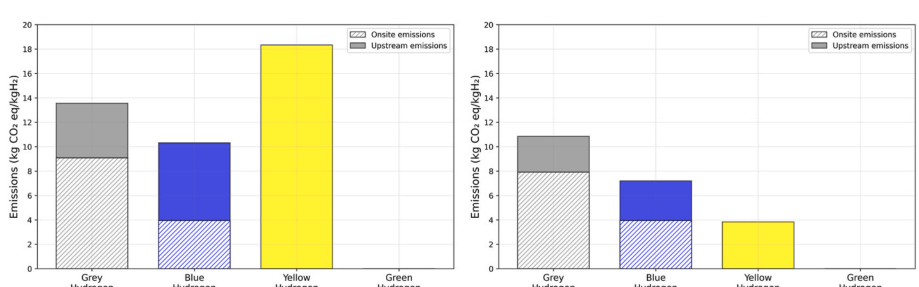

Fig. 8. Sensitivity analysis of hydrogen production emissions of different technologies (hydrogen colors) for a high (left) and low-emission (right) case studies.

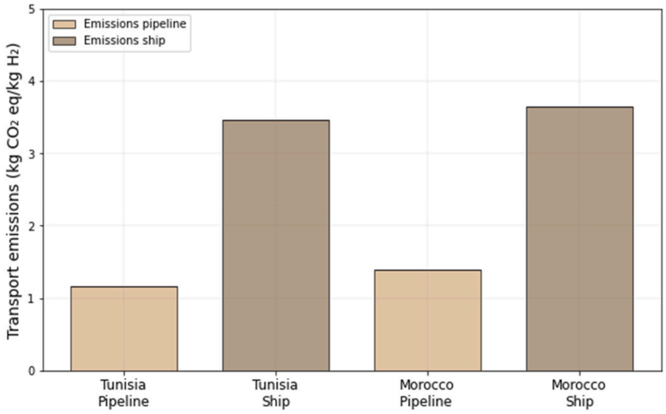

Fig. 9. Comparative analysis of hydrogen transportation emissions by pipeline or ship from Tunisia and Morocco.

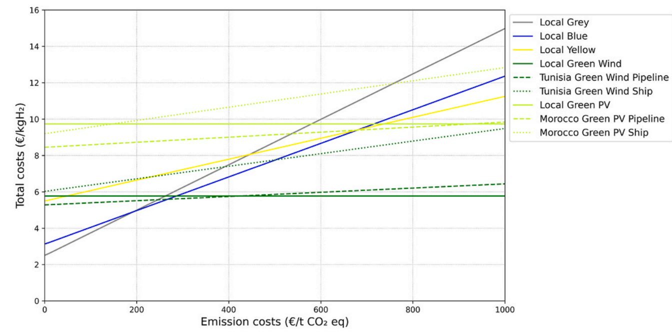

Fig. 10. Total hydrogen costs (production and transportation) including CO_2 costs from 0 to 1000 €/t $CO_{2\ eq}$ (main case study).

Once emissions from hydrogen transport are also taken into account, green hydrogen production in Tunisia and Morocco also involves a share of emissions. As can be seen in Fig. 9, pipeline transport has the better environmental balance. In both countries studied, the hydrogen transport path via pipelines has lower emissions. The transport distance also plays a role, since the longer the hydrogen has to be transported, the higher the emissions. This distinction is relatively smaller in the case of transport by ship, since the largest share of emissions occurs during liquefaction of the hydrogen. Table 7 indicates the GWP of all hydrogen pathways investigated in this analysis.

To demonstrate the impact of emissions on the total costs per kg of hydrogen, a carbon price is now implemented. This ranges from 0 to 1000 € per tonne of CO_2, as shown in Fig. 10. It is evident that a significant price increase occurs, especially for grey hydrogen. Blue hydrogen becomes competitive with grey hydrogen even before an emission price of 200 € per tonne of CO_2. Looking ahead, future cost reductions for green imported hydrogen quantities will be important and can be reached by higher import volumes and technological learning of the electrolyzers, as previously discussed.

4. Conclusion

In this study, four defined hydrogen production chains (grey, blue, yellow, green) and, in the case of a production site outside the designated Austrian hydrogen hub, the two main hydrogen transport options (pipeline and ship) from North Africa to Europe from today's perspective are investigated regarding economic and environmental aspects.

The major conclusions are: First, production cost calculations show that grey hydrogen production has the lowest total cost, but this changes when externalities such as greenhouse gas emissions are considered by means of a CO_2 price. Only in grey hydrogen production investment costs play a minor role, whereas for yellow and green hydrogen, they are significant. This is because grey hydrogen has been and still is the currently dominating production method, with large-scale SMR plants already in place and high economies of scale achieved. Blue hydrogen production is in-between since SMR technology is mature, but the process of CCUS is still under development, with some uncertainty regarding the storage aspects of carbon. In the case that emissions are considered by means of a carbon tax, both technologies experience some cost increase, as those production methods cause the largest amount of emissions.

Second, when assuming fully green hydrogen production, the full load hours of the electrolyzer are lower as the production depends on the climatic conditions of the region of operation of the renewable power plant. In more favorable regions, higher operation hours of renewable electricity, hence green hydrogen production can be achieved at lower costs. Green hydrogen from wind is cheaper than PV-powered hydrogen, even when considering the most suitable production sites for both.

Third, with yellow hydrogen production, the costs decrease further, as the same utilization rates as grey and blue hydrogen production can be achieved since electricity from the power grid is always available. In this case, however, emissions increase. Depending on the electricity mix of the respective country, substantial increases in emissions can occur. The sensitivity analysis showed that if the EU electricity mix is used for hydrogen production instead of the Austrian electricity mix, emissions will increase threefold. Thus, the electricity mix has a strong impact on hydrogen production emissions and yellow hydrogen cannot be used in a fully carbon neutral energy system. Only when hydrogen is produced using green electricity overall CO_2 emissions can be reduced. Therefore, a rapid expansion of renewable electricity generation should be one of Europe's greatest efforts and goes hand in hand with a sustainable hydrogen economy.

Fourth, the analysis indicates that pipeline transport is generally cheaper than ship transport and, therefore, preferable, but transport costs depend on distance, making it location-specific. As this study focuses on the current perspective and assumes the transportation of small-medium volumes of hydrogen, the cost savings from imports from North Africa under these specific conditions are limited. However, cost reductions can be anticipated for higher volumes of hydrogen and with a more extensive expansion of infrastructure.

Table 7
Results of environmental assessment – main case study without CO_2 costs, excluding locally produced green hydrogen due to zero emissions.

Production chain	Onsite emissions (kg $CO_{2\ eq}$/kg H_2)	Upstream emissions (kg $CO_{2\ eq}$/kg H_2)	Transport emissions (kg $CO_{2\ eq}$/kg H_2)	Overall emissions (kg $CO_{2\ eq}$/kg H_2)
Grey Local	8.84	3.65	0	12.49
Blue Local	3.94	5.29	0	9.24
Yellow Local	0	5.76	0	5.76
Green PV Morocco Pipeline	0	0	1.16	1.16
Green PV Morocco Ship	0	0	3.46	3.46
Green Wind Tunisia Pipeline	0	0	1.39	1.39
Green Wind Tunisia Ship	0	0	3.64	3.64

In general, green hydrogen is expected, to play an important role in the transition to a fully renewable energy system, as outlined in the REPowerEU plan [104]. However, it has been shown that some challenges remain, such as the higher costs compared to conventional hydrogen production, the integration of emissions into adequate pricing mechanisms and the expansion of transport infrastructure, including cost reduction. In addition to focusing on hydrogen imports, equal importance should be given to building hydrogen production capacity within Europe. With this, supply chains can be shortened and a lower energy dependency can be achieved. For hydrogen imports, fossil gas pipelines should be converted when possible since the construction of new pipelines, especially transport by ship, is more expensive. In any case, it should be ensured that fully green hydrogen is imported. When considering blue hydrogen, it is essential to also include methane emissions, which already occur upstream and thus cannot be fully captured.

CRediT authorship contribution statement

Marlene Sayer: Conceptualization, Data curation, Formal analysis, Methodology, Validation, Visualization, Writing – original draft, Writing – review & editing. **Amela Ajanovic:** Conceptualization, Data curation, Funding acquisition, Writing – review & editing, Supervision. **Reinhard Haas:** Conceptualization, Data curation, Funding acquisition, Supervision, Writing – review & editing.

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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NOMENCLATURE

AR6	Sixth Assessment Report
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CO_2	Carbon dioxide
$CO_{2\ eq}$	Carbon dioxide equivalent
GHG	Greenhouse gas
GWP	Global warming potential
H_2	Hydrogen
IRENA	International Renewable Energy Agency
LHV	Lower heating value
PEM	Polymer electrolyte membrane
PV	Photovoltaics
RES	Renewable energy sources
SMR	Steam methane reforming

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