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Hydrogen for climate neutrality: conditions for deployment in France and Europe

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In parallel with the 2020 recovery plans, the European Commission, France, Germany and other EU Member States have simultaneously announced ambitious hydrogen development strategies, representing more than €50 billion of investment by 2030. The ultimate goal is to contribute to the achievement of climate neutrality.

This *Study* aims to identify the main challenges to the development of hydrogen technologies, so that they can effectively contribute to achieving a sustainable carbon-neutral system. Due to its relatively low energy efficiency, which affects its technical and climate performance compared to alternatives, the priorities for hydrogen utilization should be industry (chemicals, refining, steel) and certain long-distance transport sectors (aviation, maritime). Furthermore, the deployment of infrastructure should be closely linked to the production modes adopted, to hydrogen's role in heavy duty transport, and to the hydrogen supply strategies between domestic supply and imports.

KEY MESSAGES

The relatively low energy efficiency of hydrogen compared to other energy carriers indicates that it is not meant to replace natural gas in the energy system. Nevertheless, it is useful for the decarbonization of certain applications, primarily in industry and transport, and could play an essential role in the balancing and security of the electricity system. The rapid development of these new markets requires the dissemination of radically new technologies, equipment and supply systems, the success of which depends on the implementation of support policies on both the supply and demand sides.

In a carbon neutral system, hydrogen must be produced from renewable or nuclear electrolysis, while hydrogen production based on natural gas and carbon capture and storage (CCS) could only play a role in a transition period if it fulfils conditions of climate and economic viability that are not currently met. The cost of hydrogen from electrolysis varies according to the electricity source mobilized. Even when accounting for expected technological progress, long-term costs will remain higher than the fossil fuel alternatives that hydrogen must replace. However, it will offer an economically viable solution in sectors where there are little or no alternatives.

Long-term hydrogen infrastructure needs depend on strategic supply and demand choices, including the role of natural gas and CCS-based hydrogen, the use of hydrogen for power generation and heavy-duty transport, and cross-border supply decisions on hydrogen and derived fuels.

Cross-border hydrogen trading can be economically attractive, but raises issues of energy supply geopolitics, industrial specialization and the setting of sustainability standards.

STUDY

N° 02
January
2022

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1. INTRODUCTION

The year 2020 saw an unprecedented interest in hydrogen technologies in the European Union (EU) and globally, driven by the publication of several hydrogen deployment strategies and investment plans for their operationalization. For example, the EU has set a target of building an electrolyser capacity of 40 GW to produce 10 Mt of hydrogen (333 TWh) by 2030, while France is targeting an electrolyser capacity of 6.5 GW, along with €7.2 or even €9.1 billion of public investment by that date (Elysée, 2021; European Commission, 2020; MTE, 2020). These strategies follow smaller national initiatives, such as the hydrogen plan launched in 2018 in France, which mobilized €50 million mainly to support pilot projects for hydrogen production and use (MTES, 2018).

In the EU, these cumulative targets aim for the installation of an electrolyser capacity of 27.8 GW, or 70% of the European target for 2030, while six other Member States are still preparing their own strategies (European Commission, 2020; Hydrogen Europe, 2020). These initiatives demonstrate the shared interest on the continent for the development of a European hydrogen industry (**Figure 1**). Several European Member States have announced their participation in an Important Project of Common European Interest (IPCEI) on hydrogen to coordinate its technological development.

The fact that this coincided with the economic crisis following the Covid-19 pandemic and the political will to invest to revive the European economy, materialized by the adoption of a European Union recovery plan of unprecedented scope (European Commission, 2021d), made it possible to release substantial financial resources to initiate the sector's development. Many Member States have chosen to include hydrogen in the recovery plan priorities they have presented to the EU, thus contributing to the achievement of the 37% criterion of expenditure dedicated to climate action.

National hydrogen strategies differ in certain aspects, particularly regarding: the type of hydrogen supported (whether derived from electrolysis with renewable or nuclear electricity, or solely renewable energy, or even blue hydrogen); the inclusion of projects to import hydrogen from other geographical areas or to export to other European countries; and the development of hydrogen transport infrastructure. The ability to make these emerging national visions compatible with each other, with the aim of building a competitive and climate-friendly hydrogen industry, will be one of the key challenges to EU strategies.

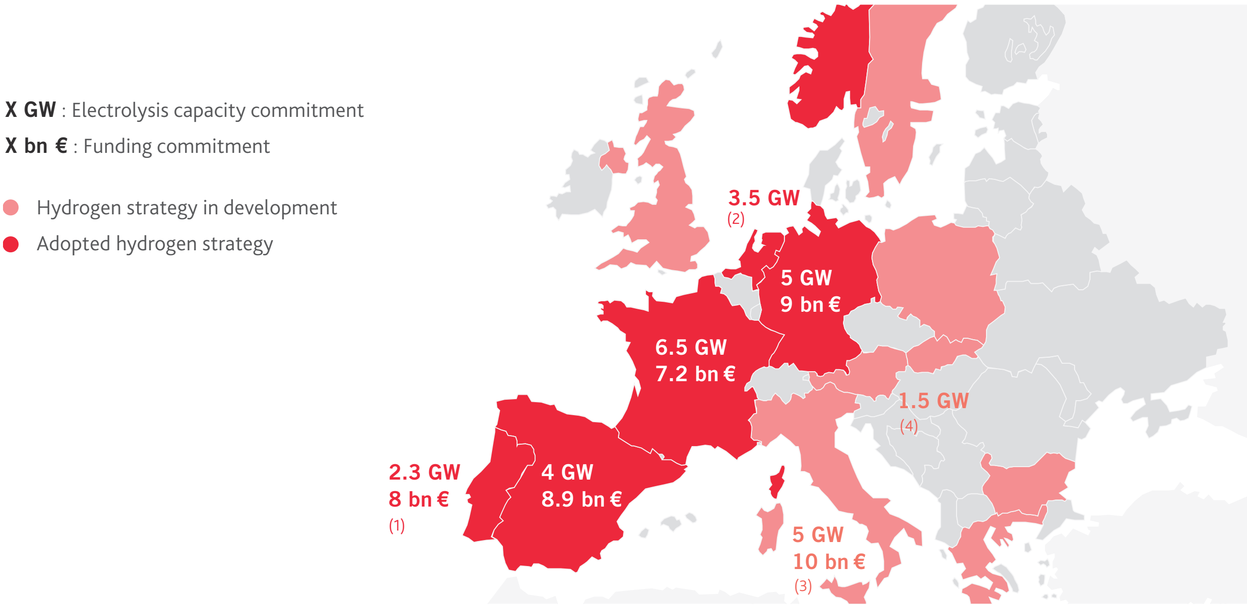
These investment plans are set in the context of strategies to achieve climate neutrality in the EU by 2050, which look to hydrogen as the best option for the decarbonization of key sectors. For the EU, this is in addition to the perceived interest in hydrogen as a means to decrease European dependence on energy imports by replacing a number of domestically-produced fossil energy carriers (fossil methane, coal and oil products), but also that the deployment of hydrogen technologies opens up opportunities for European actors to become industrial leaders for technologies with a key role in the sustainable reduction of worldwide emissions (IEA, 2021b).

The deployment of a new energy sector while ensuring that it contributes to the decarbonization of the energy system in a sustainable manner is nevertheless a major industrial challenge. In terms of demand, many applications targeted by hydrogen plans (industry and heavy transport) currently use very little or no hydrogen or even fossil methane. Regarding the supply side, current global hydrogen production (excluding co-production) is very carbon-based since it is essentially derived from the steam reforming of methane and the gasification of coal.

To define an industrial strategy for hydrogen development that is compatible with the decarbonization of the energy system, the issue of the applications for which hydrogen is to be deployed is fundamental. Hydrogen as an energy carrier is relatively inefficient if we consider its entire production and usage chain, and its production potential is limited by low-carbon electricity resources or the availability of geological CO_2 storage, which underlines the importance of deploying hydrogen as a priority in sectors where it is needed most for emission reduction. Hydrogen for these purposes must also have a low life-cycle carbon footprint, whether it is made using water electrolysis or the combination of carbon sequestration technologies with methane reforming.

This study aims to identify the main conditions for the development of a hydrogen industry in France and Europe. It explores

FIGURE 1. Map of national hydrogen strategies in Europe as of December 2020



Spanish and Italian figures refer to mobilised investments while German and French figures refer to spent public funds.
1. Electrolysis target is 2-2.5 GW and total mobilised investment is 7-9 bn including 1 bn public funding.
2. Electrolysis target is 3-4 GW
3. Figures according to National Hydrogen Strategy Preliminary Guidelines
4. Draft strategy refers to electrolysis target of 1-2 GW.

Source: Hydrogen Europe (2020).

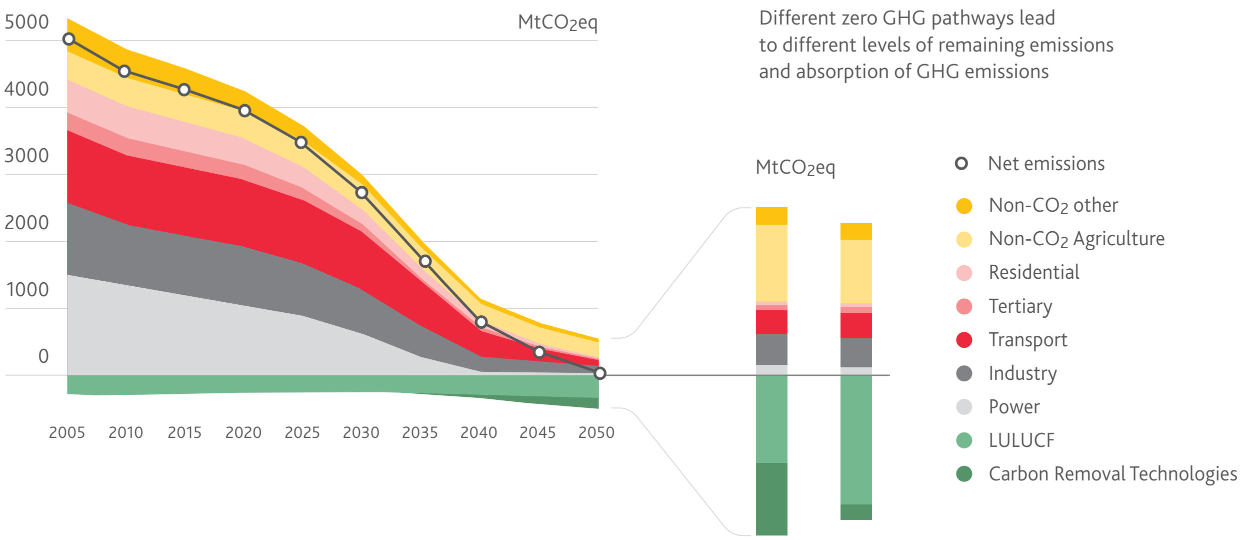
the main hydrogen demand issues (Section 2), and those on the supply side (Section 3), the fundamental parameters of hydrogen transport and storage infrastructure (Section 4), and finally the questions that would be raised by the importation of hydrogen (Section 5), aiming to put the objectives of hydrogen deployment into perspective with the other transformations necessary for the energy transition.

The recent appeal of hydrogen can be directly linked to the strengthening of climate targets both globally and in Europe. Following the adoption of the Paris Agreement and its objective of limiting global warming to less than 2°C and moving towards 1.5°C, the European Union decided to aim for climate neutrality by 2050 (European Commission, 2018a). This target implies a rapid acceleration of the reduction of its greenhouse gas emissions, launching a still ongoing political and legislative discussion on strengthening the 2030 target of reducing emissions by 40% to at least 55% compared to 1990, which implies an accelerated decrease in emissions (see **Figure 2**). The adoption of climate neutrality targets in particular has put on the agenda the issue of decarbonizing "hard-to-abate" sectors such as heavy industry (Waisman *et al.,* 2021).

In this context, the development of a hydrogen industry appears to be a solution. As an energy carrier and chemical reagent, hydrogen has several advantages for the energy system, which are in fact similar to those from several molecules: it can be stored in gaseous or liquid form and has a relatively high energy density in terms of mass, although its low volume density and high potential for leakage pose challenges (IEA, 2019b). Given that it can be produced via potentially low-emission processes, such as electrolysis or from fossil methane coupled with CO_2 capture and storage (CCS), and because it does not emit CO_2 during combustion, hydrogen presents an opportunity for energy applications that cannot do without molecules and for certain industrial chemical reactions.

Developing low-carbon hydrogen production could therefore enable the sustainable decarbonization of existing hydrogen applications (based on fossil fuels without CCS), the demand for which currently stands at 340 TWh/year in Europe, or 10 Mt (Agora Energiewende & Guidehouse, 2021). On the other hand, this hydrogen could be used to develop new industrial processes that are less carbon-intensive, for example for steel-making (IEA, 2019b). Finally, the potential to store hydrogen in gaseous or liquid form could be harnessed for long-distance transport or to produce electricity to complement variable renewable energies during periods when demand exceeds supply. In particular, hydrogen could be key as a means of inter-seasonal storage in the post-2035 horizon and to build demand-side flexibility to balance electricity supply and demand throughout the year, especially in systems with a high proportion of variable renewable energy (RTE, 2021a).

FIGURE 2. Sectoral emissions in the European Union in a scenario to reach climate neutrality by 2050



Source : European Commission (2018a). This Figure does not account for the 2021 proposal for a Fit for 55 Package.

2. CONDITIONS FOR HYDROGEN DEPLOYMENT ACCORDING TO APPLICATION CATEGORY

Given hydrogen's low efficiency when considering its energy chain and the significant industrial transformations often associated with its adoption in end-uses, it is necessary to identify the priorities of its possible applications. Hydrogen could only reduce end-user emissions if its production was climate neutral and if its supply is sufficient and affordable; these issues are analysed in Section 3.

Demand management is also a prerequisite to minimize the costs of the deployment of hydrogen for decarbonization. In its Net Zero by 2050 report, the International Energy Agency (IEA) indicates that without measures for demand side management, which would partly be achieved by shifting consumption towards electricity, the demand in 2050 would be 90% higher than in the net zero scenario (IEA, 2021b).

To achieve these targets, the implementation of measures must be accelerated, for example through the adoption of electric rather than internal combustion engine vehicles and improvements in industrial heat recovery (IEA, 2021b). At the European level and in France, progress so far is insufficient and efforts must be intensified if climate neutrality is to be achieved (European Commission, 2018b; MTES, 2019; Rosenow *et al.*, 2017).

If hydrogen were to be deployed for new applications without energy efficiency efforts, there would be a risk that hydrogen demand would exceed expectations, requiring the mobilization of more expensive sources, even for uses that are "unavoidable" for carbon neutrality (see Section 3.3). This means that a very high energy demand could lead to a more limited role for hydrogen.

How indispensable is hydrogen? For many applications, hydrogen can be substituted by other molecules: while hydrogen has a potentially low greenhouse gas (GHG) balance (see Section 2.1), this is also true for other molecules such as biogas and biomethane, synthetic methane, ammonia, fossil methane coupled with CCS for gaseous carriers, biofuels and synthetic fuels for liquid carriers used in transport (see Box). This dynamic is visible in the two hydrogen trajectories developed by the French electricity transmission system operator RTE. In the "hydrogen+" pathway, the increase in hydrogen consumption compared to the reference pathway is mainly at the expense of biomass carriers (solid biomass, biofuels and biogas) (RTE, 2020a). The Fraunhofer IEE's analysis of hydrogen consumption pathways in Germany to 2050 also notes that the level of demand depends on the proportion of biomass in the mix (Gerhardt *et al.*, 2020).

This means that hydrogen deployment is inversely dependent on the adoption of other low-GHG molecules, for example biomethane in France. However, as with hydrogen, the potential of the latter is limited by biophysical and techno-economic constraints, the evolution of which is uncertain. To properly assess the development of hydrogen, it is therefore important to also consider the issues associated with other molecules.

— Biomethane can be cheaper than hydrogen depending on the electricity used (target of €60/MWh for biomethane injected in France by 2028), but its potential is severely limited by biophysical constraints and biomass production is in competition with other land uses (European Commission, 2018b). These factors also limit the potential of liquid biofuels.

- The use of synthetic methane is constrained by economic conditions: production via the power-to-hydrogen-to-methane process is very energy inefficient (Agora Verkehrswende *et al.,* 2018), which means that for most applications it will face strong competition with other low-GHG energy carriers. Compared to hydrogen, synthetic methane has the advantage of not requiring the adaptation of transport and downstream infrastructure currently used with fossil methane. In theory, this could be significant for dispersed applications for which a hydrogen transport infrastructure would not be cost-effective (e.g., buildings). Synthetic fuels are subject to the same limitations and would only be a solution for certain transport segments that do not have sufficiently abundant alternatives (particularly aviation and maritime) (Ueckerdt *et al.,* 2021). Furthermore, to reduce emissions, synthetic vectors could only use CO_2 from Direct Air Capture (DAC) or sustainably produced biomass, an economically uncertain technology that remains underdeveloped (Transport & Environment & E4Tech, 2021).
- Ammonia is easier to store than hydrogen and can rely on existing transport and storage infrastructure, particularly at ports. While it has the advantage over other molecules of not being carbonaceous, its use is limited by the need to adapt downstream applications and its dependency on hydrogen resources (International Transport Forum - OECD, 2018). It could be particularly useful in the maritime sector.

In addition to vector-specific factors, the development of low-GHG molecules is subject to the dynamics of sectoral path dependency and the creation of supply chains. This is particularly the case for the transport sector (see Section 3.2).

More reliable estimates of hydrogen demand cannot be made until the resolution of several uncertainties surrounding the deployment of potentially low GHG molecules, such as DAC technology costs. This underlines the importance of clarifying the assumptions made for other molecules when estimating the evolution of the hydrogen sector, and vice versa.

Several studies propose classifications of hydrogen applications according to priority level and to their technical and economic opportunity (Agora Energiewende & Guidehouse, 2021; Energy Transitions Commission, 2021a; Mcwilliams & Zachmann, 2021; Ueckerdt *et al.,* 2021)[1].

This study proposes a categorization of applications adapted to the French example, based on the proposal of the Energy Transitions Commission (Energy Transitions Commission, 2021a). The Commission has proposed a classification of hydrogen applications according to two parameters: maturity (a parameter combining technological maturity, economic competitiveness and how easily a sector can use blue hydrogen or hydrogen made by electrolysis), and the level of confidence in the role that hydrogen can play (level of certainty). It results in the four categories represented in Table 1, illustrated by two hydrogen trajectories developed by RTE for 2050 (**Figure 3**).

It seems clear that despite a key role in decarbonizing certain uses, hydrogen will not replace fossil methane in the energy system, which confirms the conclusions of a previous IDDRI study (Bouacida & Berghmans, 2021). Many of the envisaged applications for hydrogen do not currently use fossil methane, and the long-term hydrogen volumes considered are much lower than current fossil methane demand. At the European level, studies have estimated that hydrogen demand in 2050 will be between 300 and 3,000 TWh (see **Table 1**); while current fossil methane demand is about 3,000 TWh (IEA, 2019a).

This section examines the techno-economic (besides lowering production costs), industrial and societal conditions

BOX DEFINITIONS OF MOLECULES WITH POTENTIALLY LOW GHG EMISSIONS

Biogas/biomethane. Biogas is a gaseous carrier, consisting mainly of methane (CH_4) and carbon dioxide (CO_2) from the degradation of organic matter, which can be used directly, for example for electricity generation, but which is often purified; the CO_2 is then extracted from the biogas to form biomethane.

Synthetic methane. This type of methane (CH_4) is produced by a process of methanation from hydrogen and CO_2 from industrial sources, biogas purification or directly captured from air.

Hydrogen. Hydrogen (H_2) gas is produced from fossil fuels (especially fossil methane in Europe) or from the electrolysis of water. It can often, but not always, be used in the same processes as methane from a technical perspective.

Ammonia. Ammonia (NH_3), produced from hydrogen and nitrogen in the air, is used in the chemical industry, particularly for fertilizer manufacture. It can also be used as an energy carrier, especially as a fuel in the transport sector, or as a fuel in power stations and certain industrial furnaces. It does not emit CO_2 when burned.

Liquid biofuels. These are liquid fuels based on organic matter, small proportions of which are typically incorporated into fossil fuels (petrol and diesel).

Synthetic liquid fuels. Produced from hydrogen and CO_2 via the Fischer-Tropsch process for synthetic diesel, petrol and kerosine and by synthesis for methanol. These fuels are characterized by a very low energy efficiency in vehicle engines compared to batteries and fuel cells, which suggests that their use will be limited to applications that lack alternatives (aviation, maritime transport) (Agora Verkehrswende *et al.,* 2018; Ueckerdt *et al.,* 2021).

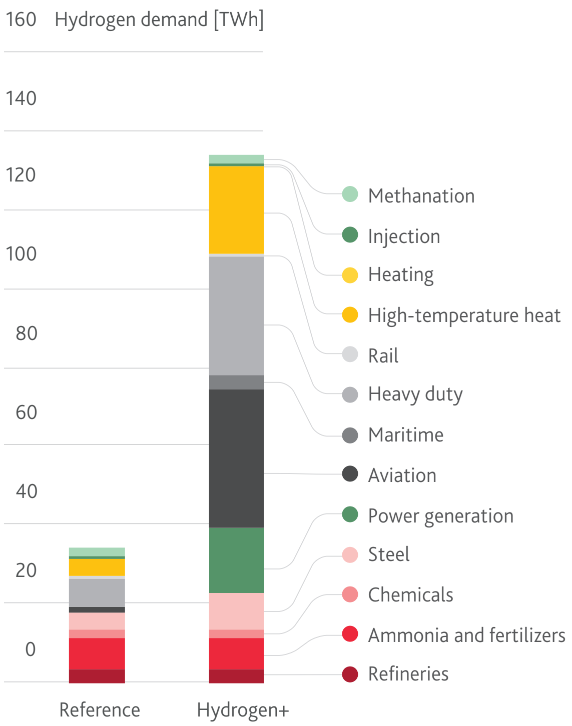
1 See also Liebreich Associates' Clean Hydrogen Ladder (The Economist, 2021).

TABLE 1. Categorization of hydrogen applications for France inspired by (Energy Transitions Commission, 2021a) and provisional estimates of demand volumes by (RTE, 2020a, 2021a).

Application type (ETC, 2021)	Application	Maturity (ETC, 2021)	Certainty (ETC, 2021)	Demand level in France in 2050 According to the RTE "reference" (SNBC) and "hydrogen+" pathways*
Existing uses – aligned with long-term decarbonization	Refineries Ammonia Methanol	high	high	Refineries: 3 TWh Ammonia and fertilizer: 8 TWh Chemicals: 2 TWh
Potentially large-scale uses in the long term, but with significant lead times for deployment	Steel Aviation Maritime Power storage	low	high	Steel: 5-10 TWh Aviation: 1-35 TWh Maritime: 0-4 TWh Electricity production: between 0 and 15 TWh depending on the electricity mix
Uses that are technically feasible, but where relative advantages versus other decarbonization options of hydrogen is unclear	Heavy duty vehicles (HDVs) HT heat Heating buildings Plastics Rail	low	average-low	HGVs: 7-30 TWh HT heat: 4-22 TWh Heating: 0 TWh Plastics: ? Rail: 1 TWh
Potential short-term but transitional uses	Gas grid blending Cogeneration of electricity with fossil methane	average	low	Injection: 1 TWh Methanation: 2 TWh
				Total: 34-143 TWh

* When only one value is given for a use, it is identical in both pathways. These consumption values do not include hydrogen co-production

FIGURE 3. Hydrogen demand outside of the electricity sector in 2050 according to two RTE hydrogen pathways: reference and hydrogen+



Source: RTE (2020b, 2021a).

for the development of hydrogen applications according to their level of priority, on the basis of the categorization of applications proposed in Table 1, providing elements of context of the deployment of hydrogen technologies that has started in France and in the EU. We distinguish three types of end uses.

2.1. Unavoidable applications

The unavoidable applications of hydrogen are defined by the absence of sufficiently low-emission alternatives that are compatible with carbon neutrality and that can cover all needs. In these cases, this will typically mean that blue or green hydrogen could be economically competitive in relation to other carriers, despite the higher cost of hydrogen compared to fossil alternatives.

These applications are in industry and long-distance transport:

— **Existing (industrial) uses** where there will still be a demand in a carbon neutral system: ammonia production, refineries, methanol. The volume of the demand for refineries and ammonia depends on other policy directions in the transition to a system that respects global limits. 90% of ammonia is used in the manufacture of synthetic nitrogen fertilizers (Material Economics, 2019), the use of which must be limited to preserve the nitrogen cycle (Poux & Aubert, 2018); while refineries would be maintained for the processing of biofuels, the deployment of which depends on decisions on which biomass resources are to be used.

— Other applications where the technologies are not yet market-ready, but which could consume large volumes in a carbon-neutral system, include **steel, air and maritime transport**. For air and maritime transport, biomass is a potentially climate-neutral alternative in the form of biofuel. However, the potential for sustainable biomass production is limited by biophysical factors and use conflicts (see above). Several studies highlight the fact that hydrogen-derived fuels would be more efficient in the long term for shipping and aviation in terms of land-use, although biofuels can contribute to the decarbonization of these sectors, especially in a transitional period (Gray *et al.,* 2021; Transport & Environment, 2018b). These considerations underlie the decision to include maritime and air transport in the "unavoidable applications" category. The role of pure hydrogen would probably be limited due to its low density, but its derivatives (especially synthetic kerosene and ammonia) could be used (Clean Sky & FCH, 2020; Dincer & Acar, 2016; Gray *et al.,* 2021; Hansson *et al.,* 2020). It is also important to emphasize that for these two sectors, the main driver for reducing emissions is traffic reduction (Sharmina *et al.,* 2021; Transport & Environment, 2018b).

A study by CISL and Agora Energiewende suggests that the "green premium" paid by consumers for decarbonized end products would be quite low for many products, e.g., +1% for a car made with "green" steel, i.e. with pure hydrogen for the direct reduction of iron ore, which suggests that the additional cost would be acceptable for consumers (CISL & Agora Energiewende, 2021). However, the use of blue or electrolytic hydrogen raises the issue of the international competitiveness of final products (including synthetic fuels), which is discussed in more detail in Section 5.

It is important that public policies support the development of unavoidable applications for achieving climate neutrality. For some uses, additional research and development is necessary, particularly for steel and air and maritime transport.

The applications for hydrogen as a feedstock in industry are a central issue of European hydrogen strategies. For France, the focus is on existing hydrogen uses, with research and development funding going into the steel industry and liquid fuel production. At the European level, hydrogen pilot projects for steelmaking are underway, such as the Arcelor Mittal in Germany or the HYBRIT initiative in Sweden; the H2 Green Steel project in Sweden plans to open a commercial-scale steel plant by 2024.

2.2. Applications where alternatives are available and hydrogen will play an uncertain role

There are several energy uses for which the role of hydrogen is very uncertain from a techno-economic, political and industrial perspective: alternatives exist, but hydrogen may be needed to cover some of the demand.

Heavy road transport (HGVs and buses). In this sector, battery and hydrogen fuel cell electric vehicles are in strong techno-economic competition. As with air and sea transport, biomethane could play a role if biomass is sustainably sourced, but this option is limited in terms of volume given the constraints on biomass (see above). Electrified highways could also be an option in addition to other solutions for journeys on roads that are not electrified (Jöhrens *et al.,* 2020; Wietschel *et al.,* 2019). Battery-powered HGVs are significantly more energy efficient and cheaper to buy and maintain (Transport & Environment, 2018a). However, the longer range, the potentially lower material balance and the shorter refuelling times for hydrogen fuel cell vehicles could give them an advantage (Correa *et al.,* 2017; European Hydrogen Backbone, 2021). For example, in its Net Zero by 2050 scenario, the IEA stated that the parameter defining the choice of propulsion technology for heavy goods vehicles in 2050 is the daily distance travelled, expecting to see an increase in the penetration of hydrogen fuel cell vehicles for trips longer than 400 km/day, along with a fall in the penetration of battery-powered vehicles beyond 500 km/day (IEA, 2021b). Several car manufacturers, such as Mercedes and Renault, have announced that they are starting the series production of battery-powered HGVs with a range of 300 to 400 km (Transport & Environment, 2021); while some manufacturers are also developing fuel cell powered trucks (Hyundai).

It is possible to identify several key factors determining the market shares of the two solutions:

- *Fuel costs*. The decrease in the total ownership costs of hydrogen vehicles is partly conditioned by decreases in the cost of hydrogen produced by electrolysis (Moultak *et al.,* 2017), which represent an important industrial issue (see Section 2.3). In addition, the cost of refuelling stations can account for half the cost of hydrogen at the pump (Cihlar *et al.,* 2020); this proportion is strongly dependent on the flow rate of refuelling stations and therefore on the size of the hydrogen vehicle fleet (Reddi *et al.,* 2017).
- *Path dependency*. In the transport sector, path dependencies are particularly significant, especially because fleets require significant investment in recharging (possibly fast charging for battery-powered vehicles) and refuelling infrastructure.
- *Construction of industrial supply chains*. Building production capacity for battery and fuel cell vehicles is a prerequisite for the deployment of these technologies. There is currently no large-scale production of hydrogen or battery-powered trucks; nevertheless, the battery sector for heavy goods vehicles can benefit from synergies with its counterpart for light vehicles. Territorial dynamics will be key: local investment in hydrogen innovation and industrial ecosystems could guide industrial sectors at an early stage.

These three factors are largely dependent on technology deployment policies and their influence on fleet composition will be revealed over the long term. At an early deployment stage, long-term policy strategies are fundamental to defining the techno-economic conditions for competition between technologies (Roehrl & Riahi, 2000). How should we define public policies for the decarbonization of HGV transport given the techno-economic uncertainties?

It seems relatively certain that HGVs travelling regional distances (less than around 400 km/day) could use battery power, corresponding to 62% of HGV activity in the EU (in terms of tonnes-kilometres) (Transport & Environment, 2020). It could be strategically beneficial to encourage the adoption of battery-powered engines for this type of heavy vehicle, as the industry could capitalize on both the industrial advances and the recharging infrastructure enabled by the mass deployment of battery-powered light vehicles. If we include HGVs making journeys of up to 800 km/day, which account for almost 80% of activity in the EU, this sector is even bigger (Transport & Environment, 2020).

Regarding longer-range HGVs (>400 km), the period up to the next Multiannual Energy Programme (PPE) continues to be an experimental phase during which there should be an investigation into deployment conditions and the acceptability and financing of both technologies, along with the assessment of sectoral progress. In this respect, lessons can be drawn from experiences gained through projects financed as a result of Ademe's "Hydrogen Territorial Ecosystems" call for projects (Ademe, 2021). During this phase, funding for large-scale hydrogen infrastructure should not be initiated to avoid the possibility of stranded assets if HGVs are to rely mainly on electricity, and instead focus should possibly be put on HGV projects located near clusters of high industrial demand (see Section 4).

The first calls for projects in 2018 that generated pilot projects in the French mobility sector focused on buses rather than trucks, but funding for heavy goods vehicles is planned for the next few years, while commercial-scale vehicle provision is developing (Ademe, 2021; Ademe & MTES, 2019; Afhypac, 2021).

Estimates of hydrogen demand in heavy road transport vary widely between studies. In its two hydrogen trajectories, RTE estimates HGV demand in 2050 at 8 TWh in the reference pathway, i.e., 7% of the HGV fleet, and 30 TWh in the "hydrogen+" scenario, i.e. half of the HGV fleet and 20% of regional and urban transport (RTE, 2020a).

High temperature heat in industry. Industry accounted for 19% of French CO_2 emissions in 2018 (Haut Conseil pour le climat, 2021), of which almost two-thirds were due to heat consumption (MTES, 2020). Solutions for decarbonizing industrial heat, in addition to improving energy and material efficiency, involve a shift towards electricity, the use of alternative fuels such as biomass in solid or gaseous form or hydrogen, and finally carbon capture and storage (CCS) (Bataille *et al.,* 2018; Energy Transitions Commission, 2021b). The use of biomass (possibly in the form of biomethane) and CCS is rather constrained (see above), which is why despite having strong technical potential biomass only accounts for a small proportion of process heat in the IEA Net Zero by 2050 scenario and the European decarbonization scenarios (IEA, 2021b; Lenz *et al.,* 2020; Tsiropoulos *et al.,* 2020).

Again, the role of hydrogen will be largely defined by its competition with electricity (Tsiropoulos *et al.,* 2020). Electric technologies can provide energy for all temperature levels, including heat pumps, but also other technologies such as electric arc furnaces (Madeddu *et al.,* 2020). The energy efficiency level of hydrogen and electricity for these processes are in similar ranges when the required temperature is above 1,000°C (Agora Energiewende & AFRY Management Consulting, 2021). Similarly to HGVs, it seems that the next five years will be a transitional phase during which the techno-economic and implementation conditions of electricity and hydrogen will need to be studied and trialled. In industry, it seems strategically appropriate to test hydrogen as a priority in geographical areas where hydrogen is already used and where the technologies to produce it sustainably are being deployed, such as in certain steel and chemical industry clusters, thus taking advantage of a common supply.

Thermal electricity generation. In addition to its role as an energy carrier and chemical reagent, hydrogen could contribute to managing the electricity supply-demand balance - only after 2035 in France according to RTE – , both by absorbing surplus renewable and nuclear electricity, and as a fuel in thermal power plants when the production of variable renewables is low and/or when demand is high (Bossmann *et al.,* 2018; Energy Transitions Commission, 2021a; RTE, 2021c). The deployment of hydrogen for flexibility depends on the electricity mix composition (notably the share of variable renewables) and the adoption of other flexibility solutions, including demand response technologies, biomass thermal generation and pumped storage power stations (Bossmann *et al.,* 2018; Child *et al.,* 2019; RTE, 2021a). Another important parameter would be the presence of a relatively well-developed hydrogen transport and storage infrastructure in the territory (see Section 4.2).

Flexibility needs in France are theoretically limited until 2035, but will become more significant in the long term. Decarbonized thermal generation capacities using biogas, biomethane or hydrogen will then have a role to play, regardless of the scenario, even if the corresponding fuel volumes are low. This is particularly true in the scenarios with no new nuclear and a high proportion of variable renewables. Hydrogen requirements would then be small in terms of volume, but would correspond to relatively large production capacities. Decarbonized thermal generation of between 20 and 30 GW is required for scenarios without new nuclear power, while this need does not exceed 12 GW (similar to the current level) in the other scenarios. These generators would have load factors of around 10% in 2050, compared to 38% in 2019 (RTE, 2021a). The volume of hydrogen used for electricity production would be between 0 and 15 TWh, or about 2% of electricity production (European Hydrogen Backbone, 2021; RTE, 2021a). The role of hydrogen would therefore be even smaller than that of fossil methane in the current French electricity system (38 TWh of electricity, or 6% of production in 2019).

Among the applications for which the role of hydrogen is still uncertain in the long term, HGV transport, high temperature heat and thermal electricity production appear particularly significant for hydrogen consumption volumes and for the transport and storage infrastructure. Therefore, it is even more important that investment decisions in these sectors are based on lessons learned from demand-side pilot projects and the cost dynamics of hydrogen production and transport once the initial projects are launched. In the meantime, long-term strategies must be developed to ensure the coordinated development of industrial sectors and adequate infrastructure.

2.3. Uses where hydrogen is unlikely to play a significant role

For some applications, hydrogen is unlikely to play a key role because it does not offer a least-cost path to climate neutrality, or in other words, because there is an abundance of climate-neutral, cost-effective alternatives.

Low-temperature heat. For low-temperature heat (below 100°C), which is needed for heating buildings and for some industrial uses, electric technologies (heat pumps) are more efficient than hydrogen (Agora Energiewende & AFRY Management Consulting, 2021; Gerhardt *et al.,* 2020). In addition, work by the International Council for Clean Transportation (ICCT) shows that the cost of hydrogen solutions for households would be higher than all-electric heat pumps (Baldino *et al.,* 2020). Another argument for the use of hydrogen in buildings as a complement to electricity is that the electrification of heating would contribute to an increase in peak electricity demand to the extent that it would be more economically efficient and secure to provide heating during periods of high voltage (high consumption and low RE production) via molecules (fossil methane or hydrogen) (Coénove, 2020; Gas for Climate, 2020). Hydrogen could then be used in hybrid heat pumps, which in theory use electricity most of the time and hydrogen at peak times.

However, for France, a study by RTE and Ademe concludes that if the National Low-Carbon Strategy (Stratégie nationale bas-carbone - SNBC) pathway is followed (improved insulation and a switch to efficient electricity solutions), then the peak electricity demand decreases. However, if the switch to electricity occurs without buildings being equipped with a sufficient level of insulation, there is a risk of increasing peak demand, especially if direct electric heating is used. The security of supply then depends on the deployment of flexibility solutions and seems technically possible, especially since other uses are also more flexible (RTE, 2021b; RTE & Ademe, 2020).

In addition, the deployment of hydrogen to buildings would raise significant issues for the gas distribution network, which would have to be adapted at least partially to carry hydrogen, for downstream equipment that would have to be adapted to hydrogen, and for the hydrogen storage system needed to accommodate demand seasonality in buildings. This could lead to high costs, even though hydrogen would only be consumed at peak times(Bouacida & Berghmans, 2021; Gerhardt *et al.,* 2020).

Light transport. Light vehicles (passenger and commercial transport) powered by hydrogen fuel cells do exist. But their higher purchase price, total costs and lower efficiency compared to battery electric vehicles suggest that for most light transport sectors, battery vehicles will have the advantage over fuel cells. Applications where hydrogen vehicles would be appropriate are those where long-range vehicles are needed, such as some commercial vehicles (range over 200-300 km per day). For example, the IEA's Net Zero by 2050 scenario estimates that fuel cell vehicles will account for 10% of the global light vehicle fleet in 2050 (IEA, 2021b). Worldwide sales of electric passenger cars are already well ahead of hydrogen vehicles (IEA, 2021c, 2021d), and some car manufacturers have abandoned development of light duty hydrogen vehicles (Clean Energy Wire, 2020; Volkswagen, 2020). These factors suggest that the role of hydrogen in light transport will be limited to a few uses, representing a small proportion of the fleet.

Blending hydrogen into the gas network. The injection of hydrogen into the fossil methane network is often advocated as a solution to create outlets for blue or green hydrogen during the initial development period when applications are not yet fully developed, and potentially in the longer term to reduce carbon emissions from the network (Hydrogen Europe, 2021; IEA, 2019b). Once the proportion of hydrogen in gas passes a certain level, downstream equipment requires significant modification, particularly in industry and transport; consequently, the proportion of hydrogen that can be integrated without requiring major adaptations is low (IEA, 2019b). A GRTgaz study found that hydrogen could be integrated into most of the French network at a level of 6% in terms of volume (i.e., less than 2% in energy), except in areas with sensitive equipment, which entails major geographical constraints (GRTGaz, 2019). However, given the lower energy density of hydrogen compared to fossil methane, a blend of even 20% hydrogen by volume would only reduce methane emissions by 7% (IRENA, 2021). Blending does not therefore appear to be a short or long-term solution for reducing emissions. Moreover, mixing hydrogen with fossil methane does not give rise to the transformations in processes needed to make the transition to a sustainable low-emission system, unlike the adoption of hydrogen for certain industrial processes, for example. It therefore seems that hydrogen blended with fossil methane has a low climate benefit and is sub-optimal compared to the direct use of pure hydrogen.

Potential public support for applications where the future role of hydrogen is restricted should be limited and targeted only towards segments for which hydrogen is essential to achieve climate neutrality (chemicals, steel industry, aviation and maritime transport). Otherwise there is a risk of diverting limited hydrogen resources to uses where it does not have a key role in reducing emissions and slowing down the decarbonization of industry and heavy transport.

In France, unavoidable applications and those for which hydrogen could play a role (categories 1 and 2) account for between 31 and 130 TWh in the long term (see Table 1), taking into account the long-term RTE pathways (RTE, 2020b, 2021a, 2021c)

Uncertainty over the development of hydrogen applications has resulted in widely varying projections for the long-term need for hydrogen on a scale of 1 to 10 according to various studies (see Table 2). This underlines the importance of the selection of hydrogen applications in deployment policies.

TABLE 2. **European hydrogen demand by 2050 according to different foresight studies.**

Study	European demand by 2050
No-regret hydrogen (Agora Energiewende & AFRY Management Consulting, 2021)	270 TWh
European Commission, pathways to 1.5°C, 1.5LIFE and 1.5TECH (European Commission, 2018b)	710-790 TWh
Bruegel (Mcwilliams & Zachmann, 2021)	295-2 080 TWh
Gas for Climate - *Accelerated Decarbonization Pathway* (used for the European Hydrogen Backbone) (Gas for Climate, 2020)	1,710 TWh
Hydrogen4EU (IFP Energies nouvelles *et al.*, 2021)	3,300 TWh

Source: adapted from Bouacida & Gagnebin (2021)

Estimating the level of hydrogen consumption needed to achieve climate neutrality is key to identifying the transformations required throughout the energy system, primarily the hydrogen supply parameters and the hydrogen infrastructure needs.

3. HYDROGEN PRODUCTION FOR CLIMATE NEUTRALITY: MAJOR LIMITATIONS

Hydrogen is therefore crucial for the decarbonization of certain industrial uses and long-distance transport. The production of hydrogen by electrolysis and with CCS is not currently very developed, and fossil hydrogen is mainly produced on certain industrial sites (notably in refineries and the chemical industry), often as a co-product. For these uses to develop and deliver the expected emissions reductions, the supply of hydrogen must meet climate, industrial and techno-economic conditions. This section aims to understand the main parameters of hydrogen supply for climate neutrality and to identify the conditions for their realization.

3.1. Hydrogen supply with a low greenhouse gas footprint

While hydrogen does not emit CO_2 when burned, its production can generate high GHG emissions. Most hydrogen produced today is derived from steam methane reforming of fossil methane. This process is relatively emission-intensive; for example, hydrogen production is responsible for 900 Mt of CO_2 emissions per year, or about 2% of global emissions (IEA, 2019b). For blue or electrolytic hydrogen to sustainably reduce GHG emissions, it must have sufficiently low life-cycle GHG emissions.

Hydrogen can be produced from electricity and water using the electrolysis process. The main parameter that defines the carbon content of this hydrogen is the electricity used. If this electricity is renewable, the hydrogen is renewable, and sometimes called green hydrogen. Today, electrolysis has a very limited capacity worldwide (300 MW by mid-2021, (IEA, 2021a)) and its potential will depend in part on strategic choices regarding end uses and also the low-carbon electricity resources that are available for hydrogen production, see 3.3 (IEA, 2021a).

Carbon capture and storage technologies could enable the production of blue hydrogen from fossil methane. Given that fossil methane resources are abundant and that gas transport infrastructure is already well developed in Europe, blue hydrogen could theoretically increase the potential for low-carbon hydrogen compared to a scenario where hydrogen is produced by electrolysis only, provided that the economic, environmental, technological and acceptability conditions are met to develop CO_2 storage and transport capacities within the relevant timeframe (see Section 2.2).

The production of blue hydrogen results in GHG emissions at various stages, as illustrated in **Figure 4**: methane is emitted during its production and transport, CO_2 is emitted during methane reforming (even if some of it is captured), and CO_2 and/or methane is emitted in the production of the electricity consumed to capture the CO_2. If SMR (steam methane reforming) is used, energy is also consumed to provide heat and pressure, and these emissions are not necessarily captured (Gorski *et al.,* 2021; Howarth & Jacobson, 2021).

It appears that hydrogen production reliant on CCS will not be a massively available technology in a carbon-neutral system. For this to happen, methane emissions from the fossil methane supply chain would have to be almost zero, CO_2 capture facilities would have to capture all production-related emissions, and sufficient CO_2 storage capacity would have to be available, even though those facilities are also used for "unavoidable" emissions from industrial processes, while there are potentially zero-emission alternatives for hydrogen through electrolysis.

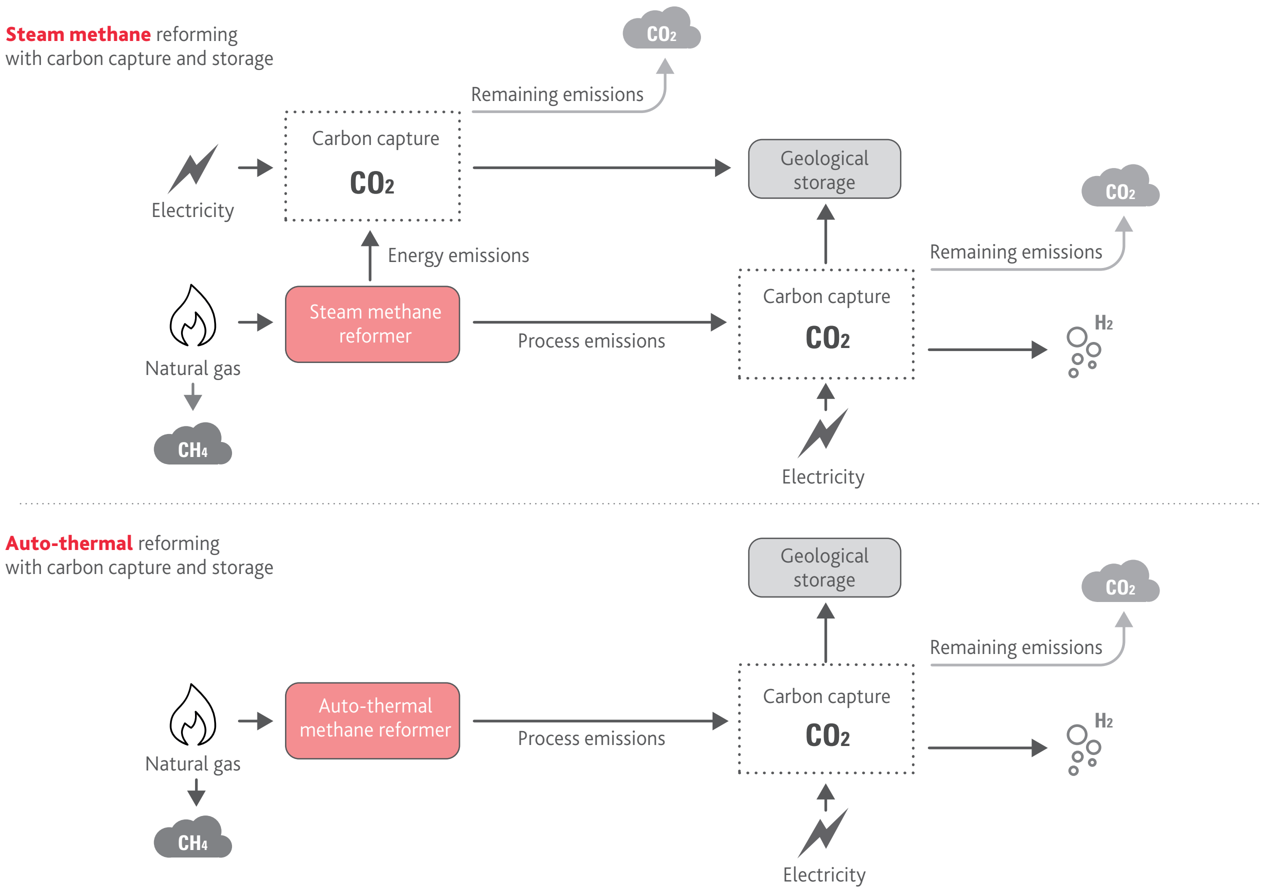
Nevertheless, it is theoretically possible for hydrogen produced from fossil methane and CCS to play a transitional role. If so, the associated conditions in terms of GHG emissions must be examined.

Today, a threshold of 3 kg CO_2 eq/kg H2 of life-cycle GHG emissions has been defined for hydrogen to be considered "sustainable" in the European taxonomy that came into force on 1 January 2022 (European Commission, 2021a).

The production of blue hydrogen at a level compatible with the European taxonomy, or at even lower levels as announced by certain industrial projects (Gorski *et al.,* 2021), requires substantial reductions in its life-cycle emissions compared to the current situation, as illustrated in **Figure 5**. This decrease would be related to a significant reduction in methane leakage along the fossil methane supply chain

\ and a significant increase in the capture rate during reforming, possibly through the adoption of autothermal reforming (ATR) instead of steam methane reforming (SMR) (Bloomberg NEF, 2020; Howarth & Jacobson, 2021). It is also essential that CO_2 leakage during transport and storage is minimized, which requires, among other things, effective detection and monitoring of old oil and gas reservoirs used for CO_2

FIGURE 4. Life-cycle GHG emissions of blue hydrogen



Source: based on Gorski et al. (2021).

(Alcalde *et al.,* 2018).Hydrogen produced by electrolysis, on the other hand, is compatible with the taxonomy threshold and emits less than blue hydrogen when most of the electricity is obtained from nuclear or renewable sources, as is the case with the average French electricity mix, but is not yet the case at the European level (**Figure 5**). Although the taxonomy threshold is 3 kg CO_2/kg H2 today, this figure may be raised in future. It therefore seems desirable to favour hydrogen with the lowest carbon footprint as much as possible, i.e., that produced by electrolysis.

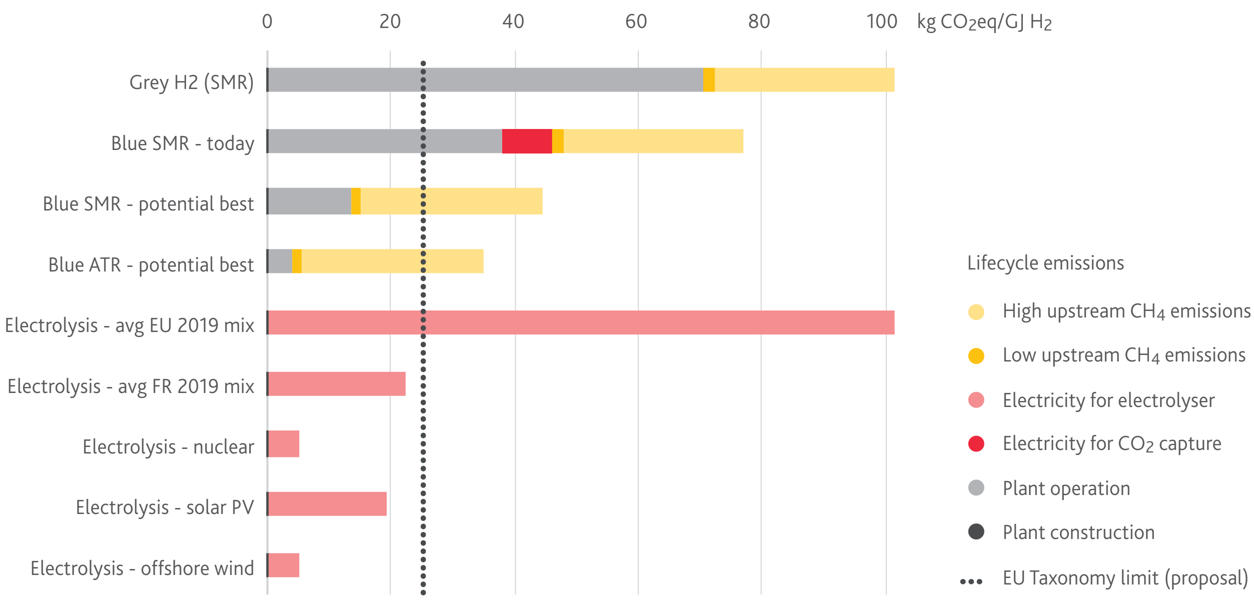
3.2. Blue hydrogen: a timing issue

From an industrial perspective, the installation of CCS on a facility producing hydrogen from steam methane is not self-evident: existing installations using SMR have a low capture rate and their location is not necessarily optimal in relation to CO_2 storage sites (European Hydrogen Backbone, 2021). In addition, there are only six commercial underground CO_2 storage facilities in the world today, including one in Europe (Alcalde *et al.,* 2018).

Furthermore, strong opposition throughout Europe from residents located near CO_2 storage sites projects justifies a preference for offshore reservoirs (Ademe, 2020; Gough *et al.,* 2014) which in Europe are relatively concentrated geographically in the North Sea (Poulsen *et al.,* 2014). To be used elsewhere on the European continent, a transport infrastructure for either hydrogen or CO_2 (by ship or pipeline) would therefore be necessary. The current state of the production chain and transport infrastructure suggests that the scaling up of blue hydrogen production would require significant industrial acceleration, through a planned and coordinated development of gas, CO_2 and hydrogen networks. However, CO_2 storage infrastructure projects have so far been characterized by high cancellation rates: Wang et al. estimate that 43% of CCU and CCS projects announced in the last 30 years have been cancelled, particularly large-scale projects. This high failure rate is thought to be related to the difficulty of securing private investment and the high risk associated with such investments (Karayannis *et al.,* 2014; Wang *et al.,* 2021).

While work on the future role of hydrogen as an energy carrier generally concludes that electrolytic hydrogen will play a dominant role in the long term, visions of the role of blue hydrogen over the next three decades are very mixed. While Hydrogen4EU anticipates blue hydrogen consumption of between 230 and 500 TWh for the EU27 in 2050 (out of a total consumption of 3,300 TWh), Agora Energiewende estimates that in 2050 none of Europe's 270 TWh demand (considering only uses as a

FIGURE 5. GHG emissions during blue hydrogen production through SMR or Autothermal reforming (ATR)



In "Blue SMR – today", 85% of process emissions are captured. "Blue SMR - potential best" corresponds to a capture rate of 95% for process emissions, and 65% for energy emissions; the electricity used for capture is zero-carbon (emission factor at 0 kg CO2/kWh). "Blue ATR - potential best" is a process emissions capture of 95% and zero carbon electricity. The low estimate of methane emissions corresponds to a leakage of 0.2% of methane consumed, and the high estimate corresponds to leakage of 3.5%. The global warming potential (GWP) of methane used is the reference used by the IPCC, i.e. 34 kg CO2eq/kg CH4 over a 100-year horizon.

Source: IPCC (2013), Howarth & Jacobson (2021), Spath & Mann (2001).

feedstock in the industrial sector) will be met by blue hydrogen, even though it will be used until 2030 (Agora Energiewende & AFRY Management Consulting, 2021; IFP Energies nouvelles *et al.,* 2021).

The investment choices for blue hydrogen must be put in perspective with its transitional character and with the risk of stranded assets. If blue hydrogen infrastructure was to become obsolete as early as the 2040s, would it be profitable in the 2020s to invest in production capacities for which the commercial feasibility of high CCS rates by 2030 have not yet been proven? What about hydrogen and CO_2 pipelines, which have a lifespan of about fifty years? The viability of the latter needs to be assessed in the light of possible future uses for electrolytic hydrogen and CO_2 derived from other sources. If blue hydrogen production is not as low in emissions as expected in a "transition" timeframe, there is a risk of locking in blue or grey hydrogen production capacity that is too carbon intensive to meet climate targets.

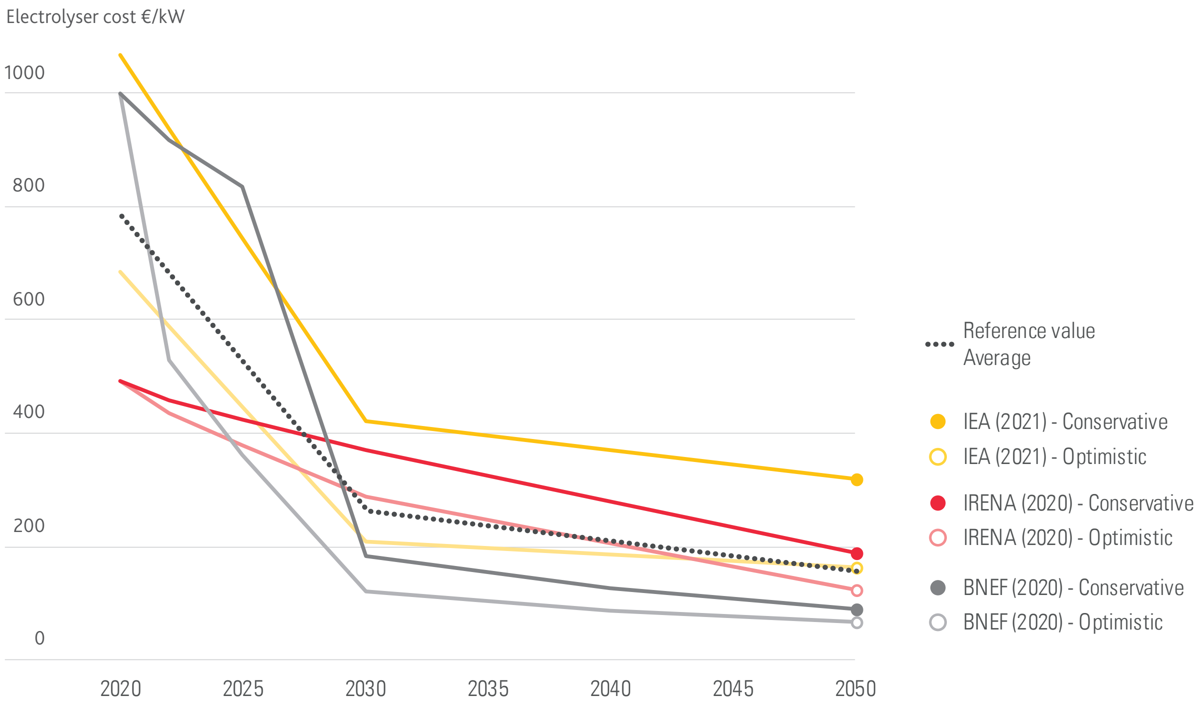
The availability of blue hydrogen resources could also justify the development of additional uses that are not a priority from a climate perspective during the transitional period, without long-term electrolytic hydrogen production being able to cover all of the uses in 2050, for example because of a slower than expected acceleration in the production of electrolysers or the installation of renewable or nuclear capacities.

Finally, consuming blue hydrogen means continuing to consume fossil methane, of which there are limited reserves in Europe, which raises geopolitical issues if gas is still imported. Between 385 TWh and 4,700 TWh of fossil methane would be needed if all hydrogen consumption in 2050 were supplied by blue hydrogen, depending on whether a low or high estimate of demand is assumed, whereas proven reserves of fossil methane in Europe in 2021 are of the order of 21,000 TWh and the EU's current primary energy consumption of fossil methane is less than 3,500 TWh (Agora Energiewende & AFRY Management Consulting, 2021; EIA, 2021; IEA, 2017).

3.3. Electrolytic hydrogen: the challenge of access to low-cost renewable or nuclear electricity

For climate reasons, the hydrogen consumed in France and Europe will have to come mainly from electrolysis fuelled by renewable and nuclear electricity, depending on the electricity mix decisions of the various Member States (Section 3.1). It is therefore necessary to study the conditions under which this pathway can satisfy demand in 2030 and 2050, and the costs associated with these volumes in comparison with alternative energy carriers (fossil or not). Analyses of the parameters of adequacy between supply and demand form the basis of possible support policies in the short and long terms.

FIGURE 6. **Cost of electrolysers until 2050 following a conservative or optimistic scenario, according to BNEF (2020), IRENA (2020), IEA (2021b).**



Sources: BNEF, IRENA et IEA.

The cost of electrolytic hydrogen is essentially the investment cost of the electrolyser and the cost of electricity. Most technical studies concerning the evolution of the cost of electrolysers assume a significant decrease in the next decade, provided that the hydrogen market develops, see **Figure 6** (Bloomberg NEF, 2020; IEA, 2021b; IRENA, 2020). This decrease would mainly come from the standardization of electrolyser production and an increase in module size, which would make it possible to achieve significant economies of scale (IRENA, 2020). An important prerequisite for these reductions is large-scale electrolyser deployment.

Unlike fossil fuels, the cost of hydrogen varies greatly depending on the source and location of the electricity used, which in the case of renewable electricity defines the load factor of the electrical generator.

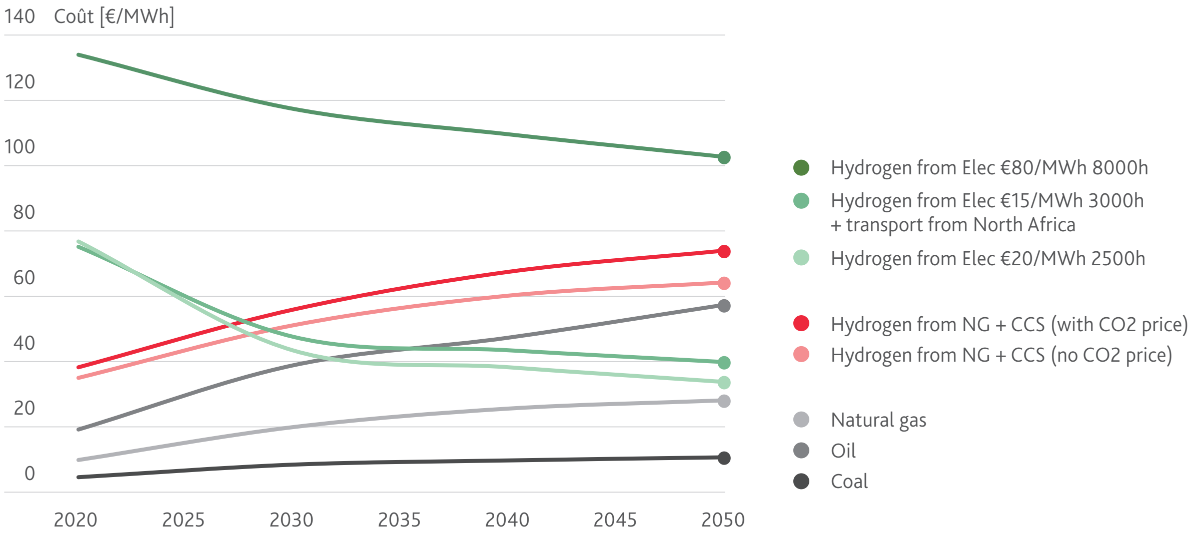
Although some electrolytic hydrogen can be derived from renewable or nuclear surpluses and thus contribute to the supply-demand balance, this method of production would only supply a fraction of the requirement for the decarbonization of applications (RTE, 2021b). Therefore, the deployment of hydrogen for climate neutrality requires dedicated electricity production capacity (even if linked to the general grid).

Figure 7 shows the cost of electrolytic and blue hydrogen, with electricity (1) highly available but moderately expensive (at the "target" cost for the new EPR programme in France), (2) less available but cheaper, with a high load factor corresponding to solar from southern Europe or North Africa for example, with hydrogen pipeline transport costs, (3) with an even lower load factor and more expensive electricity, for example solar in France. **Figure 7** also shows the costs of fossil fuels that hydrogen aims to replace (hydrogen from fossil methane, fossil methane, oil and coal) according to the European reference scenario based on modelling with PRIMES among others (European Commission, 2021c).

The cost parity with the fossil fuels that hydrogen is intended to replace is not a given, even in the long term, and only relates to hydrogen based on inexpensive renewable electricity: while oil and hydrogen from fossil methane without CCS become more expensive as early as the 2030s, coal remains much cheaper in 2050, whereas fossil methane only reaches a cost level close to that of hydrogen by electrolysis after 2045 (excluding taxes), see **Figure 7**. This calls for demand-side support to encourage the uptake of hydrogen in applications where it is needed for decarbonization, and underlines the importance of supply-side policies (including CO_2 taxes) to ensure the long-term competitiveness of hydrogen with respect to fossil alternatives.

It also means that hydrogen cost is closely linked to volume: "cheap" hydrogen is derived from cheap, possibly imported, renewables, available in limited quantities. A strategy of developing uses "with alternatives" (HGVs, high temperature heat, thermal electricity generation), which correspond to very large volumes of hydrogen, would then have to rely on available but "more expensive" hydrogen. The massive development of new end uses will thus lead to an increase in average production

FIGURE 7. Cost of electrolytic and blue hydrogen and fossil alternatives (oil, natural gas, hydrogen from natural gas and coal)



Sources:
Average electrolyser cost BNEF (2020), IRENA (2020), IEA (2021b), electrolyser efficiency from 67% in 2019 to 80% in 2050 (Agora EW, 2018). Cost of hydrogen by natural gas without CCS: IEA (2019c). Cost of hydrogen by natural gas + CCS: Agora Energiewende & AFRY (2021). Interest rate at 10% for electrolysis and fossil methane + CCS, at 5% for fossil methane without CCS. Emissions factor for fossil methane + CCS hydrogen at 1.61 kg CO_2/kg H_2, assuming steam reforming with 95% process emissions capture, 65% energy emissions capture and fully decarbonized electricity, and ignoring methane leakage, based on Spath & Mann (2001) and Howarth & Jacobson (2021). CO_2 price of €70/tCO_2 in 2020, €100/t CO_2 in 2030, €200/t CO_2 in 2050. Cost of transport from Algeria and the North Sea by pipeline based on Gas for Climate (2019) assumptions, presuming half of the pipelines are renovated natural gas pipes and half are new. Cost of oil, natural gas and coal from the European Commission's reference scenario (European Commission, 2021c).

costs, making it more difficult for hydrogen to penetrate into key industrial applications and long-distance transport without a zero-emission alternative. Strategic planning to compare options for these applications and possible demand support policies must take into account this prioritization of supply options.

Even during a transition period, the blue hydrogen option is not competitive with fossil fuels: its cost follows that of fossil methane and remains much higher than oil (**Figure 7**).

To ensure the availability of renewable or nuclear electricity resources for electrolysis in the long term, political decisions on the sizing of the electric vehicle fleet must today give consideration to future hydrogen demand, even if the sector is currently underdeveloped, given the construction time for certain infrastructure. For example, up to fifteen years can elapse following the decision to build a new nuclear reactor before its commissioning (SFEN, 2019).

An alternative proposal, discussed in Section 5, is to import part of the hydrogen demand, which would reduce the demands on the domestic electricity system. This option raises a number of infrastructural, techno-economic, geopolitical and environmental issues.

Our analysis therefore shows that the prices and volumes of electrolytic hydrogen are highly variable according to the costs and volumes of renewable and nuclear electricity, of which only a part of the supply (very sunny or windy areas) compete with fossil fuels in the absence of specific regulations. This reinforces the need to prioritize hydrogen applications and calls for both supply and demand policies to ensure that hydrogen is effectively used to decarbonize key sectors. Furthermore, the deployment of hydrogen is closely linked to that of renewable and nuclear electricity resources, for which reason public and industrial strategies for both must be designed in conjunction.

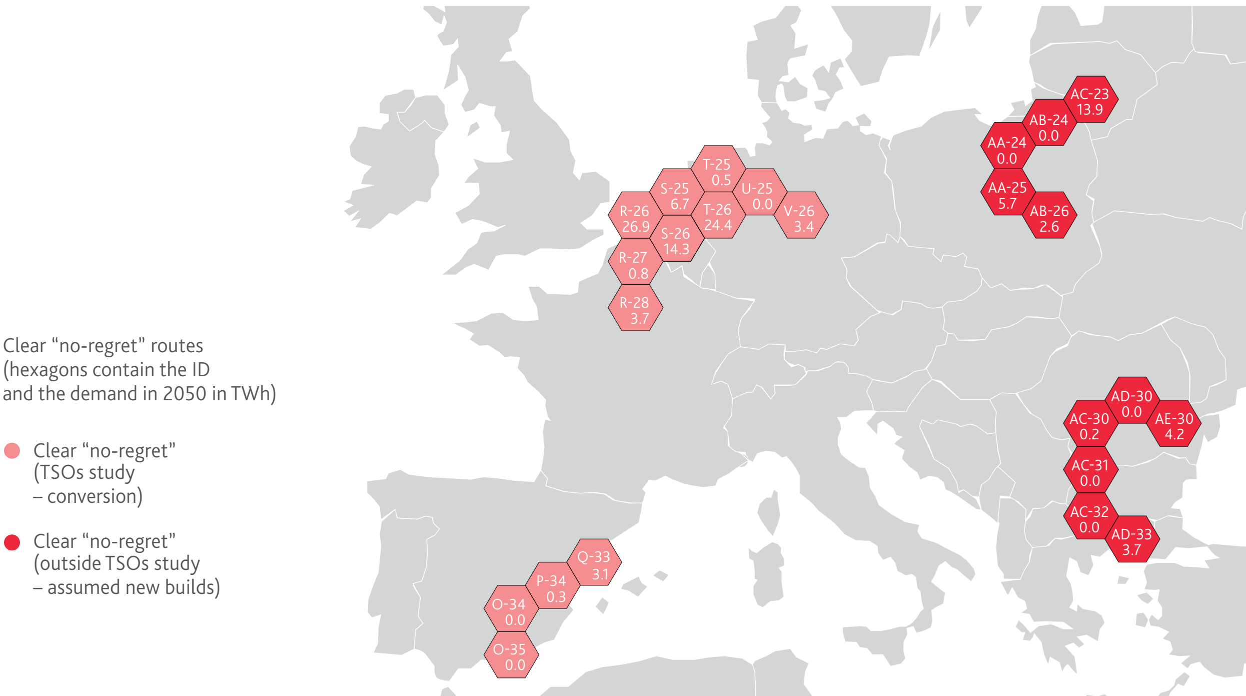
4. DRIVERS FOR MEDIUM AND LONG-TERM HYDROGEN INFRASTRUCTURE NEEDS AND THEIR IMPLICATIONS FOR ENERGY INFRASTRUCTURE

Today, very little hydrogen transport infrastructure exists: only 4,500 km of pipelines are operated worldwide, including 303 km in France, used mainly by hydrogen producers (Shell, 2017) to serve industrial consumers. Large-scale storage has barely been developed (IEA, 2019b) because consumption and production are currently stable and predictable over time, and fossil methane storage is more available.

European strategies favour the development of hydrogen usage in clusters in an initial phase: concentrating hydrogen activities in geographical areas with (1) sites where long-term hydrogen demand is relatively certain (such as industrial sites or ports), (2) promising hydrogen production potential (due to the availability of renewables, nuclear or fossil methane resources and carbon sequestration sites or location on import routes), and (3) hydrogen storage locations to manage seasonal variations in hydrogen production and consumption. This makes it possible to increase hydrogen volumes without having to develop a large infrastructure from the outset (European Commission, 2020; IEA, 2019b; MTE, 2020) and thus avoid stranded costs. A study commissioned by Agora Energiewende identifies areas where the establishment of a hydrogen transport infrastructure would be a "no-regret" investment in the long term, defined as areas with a relatively large demand in 2030 and 2040 and more than 3 TWh in 2050, and where the establishment of a transport infrastructure would be economic in at least three of the four supply scenarios considered (varying degrees of blue or green), as shown in **Figure 8**. For example, such a hydrogen cluster could be developed in an area encompassing Dunkirk, part of Belgium, the Netherlands and Germany, and where (private) hydrogen transport pipes are already in place and could be improved (Agora Energiewende & AFRY Management Consulting, 2021; Creos *et al.,* 2021).

While investment in infrastructure by 2030 at the industrial cluster level may seem strategic, the issue of linking these clusters together in the longer term to form a trans-European hydrogen transport network, as explored by European gas network operators in their European Hydrogen Backbone study, is open to debate (Creos *et al.,* 2021). While German, French and Spanish hydrogen plans remain short on detail on the subject, the EU strategy points out that demand for a trans-European hydrogen transport network would emerge after 2030 (BMWi, 2020; European Commission, 2020; MITECO, 2020; MTE, 2020). In Germany, some of the fifteen or so infrastructure projects pre-selected by the government to receive public funding under the hydrogen IPCEI (important projects of common European interest) aim to link industrial clusters between the northwest and east of the country (National Government Germany, 2021). Foresight studies looking at the development of hydrogen infrastructure are underway in other European countries.

FIGURE 8. "No-regret" zones for hydrogen infrastructure to supply non-energy industrial demand for hydrogen in 2050



Source: Agora Energiewende & AFRY Management Consulting (2021).

AFRY analysis. © 2020 Mapbox © OpenStreetMap.

The timing of development is the key issue here: if the transport infrastructure is implemented when the volumes of hydrogen transported are low, there is a risk that the investments will not be profitable; conversely, a "lack" of transport infrastructure could theoretically limit the supply of hydrogen and therefore slow down the decarbonization of key uses or require more expensive sources (European Hydrogen Backbone, 2021).

The advantage of a hydrogen backbone would be to make its supply more flexible and to reduce its production costs by using larger-scale production in sites where renewables, nuclear power or fossil methane are cheap in Europe and in connected countries, and to envisage the creation of a European hydrogen market. Such a network would also enable a generalization to include a wider array of uses, such as HGV transport (potentially a priority, see Section 3.2). But the investments required would be significant, even if we rely on the conversion of part of the methane network. The European Hydrogen Backbone study estimates €43 to 81 billion of investment by 2040 (Creos *et al.,* 2021).

The high degree of uncertainty regarding the levels and locations of demand and the ways in which hydrogen will be produced complicates the task of assessing infrastructure needs. Technical studies by European gas and electricity network operators are underway in several Member States and at the European level. In this context, it is important to identify the fundamental drivers for the deployment of hydrogen infrastructure, as it impacts the need for electricity and gas infrastructure, and also influences certain hydrogen applications. Three dimensional parameters are described below.

4.1. CO_2 or long-distance hydrogen infrastructure needed for the development of blue hydrogen

If emissions from blue hydrogen production are significantly reduced and it is developed in the EU as part of a transitional phase, a long-distance transport infrastructure for CO_2 or hydrogen will be needed, using either pipelines or sea transport, to facilitate CO_2 storage and to distribute hydrogen for use (see Section 2.2). The hydrogen storage infrastructure to be developed would probably be of a smaller scale, as the existing fossil methane storage infrastructure can absorb fluctuations in demand for steam reforming.

Hydrogen production from fossil methane also raises issues for the fossil methane infrastructure. A substantial proportion of the hydrogen transport infrastructure could be made up of refurbished fossil methane pipelines (Artelys, 2020; Creos *et al.,* 2021; IFP Energies nouvelles *et al.,* 2021). There may be competing demands on existing pipeline networks for fossil methane transport and their modification to transport hydrogen (Artelys, 2020). The Energy Transitions Commission study highlighted the fact that whether or not CCS can be realized in the vicinity of sites of hydrogen demand will be a key parameter in hydrogen/fossil methane competition (Energy Transitions Commission, 2021a).

4.2. Development of the electricity mix and electrolysis production methods will influence the need for hydrogen transport and storage infrastructure

The demand for hydrogen storage and transport infrastructure is strongly determined by developments in the electricity system, in particular the share of variable renewables in the mix.

Firstly, this means that the capacity of thermal power plants operating partly on hydrogen and that ensure supply during periods of stress (low electricity production and/or high demand) are more important to ensure flexibility on an inter-weekly, inter-seasonal and inter-annual scale (RTE, 2021a), see Section 3.2. For the mobilization of biogas or hydrogen power plants to ensure security of supply, it is essential that the fuel is available quickly. For hydrogen this means that the correct sizing of storage infrastructure is particularly important. Furthermore, there is a necessity for either production and storage sites to be located near to thermal power plants, which is not always straightforward given the uneven territorial distribution of salt caverns (Bloomberg NEF, 2020; Le Duigou *et al.,* 2017; Tlili *et al.,* 2019), or for a relatively dense hydrogen transport infrastructure to be established. If necessary, to ensure the security of supply it could be beneficial to pool hydrogen storage resources at the European level via interconnections (RTE, 2021a).

In addition, an electricity mix with greater dependency on variable renewables means more variability in hydrogen production over time, as electrolysers will not be in operation when renewable and nuclear generation is insufficient and supply is based on fossil or decarbonized thermal (RTE, 2020b), whereas hydrogen demand in industry and transport is relatively predictable and not particularly seasonal. Hydrogen supply may therefore require enhanced transport and storage infrastructure.

Security of electricity supply and hydrogen considerations could therefore justify the establishment of a hydrogen network connecting industrial demand clusters, especially in the case where the electricity mix relies heavily on variable renewables. Given the low load factor of these hydrogen-fired power plants (see Section 3.2) – around 10% in France according to RTE scenarios – and the cost of developing a hydrogen infrastructure, the assessment of electricity mix choices must also include the implications for the hydrogen network. The analysis of the links between hydrogen production and infrastructure requirements highlights the need for concerted planning of the electricity, hydrogen and methane networks to ensure the optimization of costs and resilient supply .

4.3. Long-distance road transport, a diffuse need that can impact the development of hydrogen infrastructure

The role of hydrogen in heavy goods road transport may also become a driver for the development of the long-term hydrogen infrastructure. The level at which hydrogen would be used for heavy duty vehicles is still an open question and its development will depend on long-term political strategies, as well as on industrial dynamics and investments at the local level (see Section 3.2).

Since industrial hydrogen users and electricity production are relatively spatially concentrated, the hydrogen infrastructure could be rather limited if confined to these sectors (see above).

On the other hand, if long-distance HGVs, especially those travelling across Europe, also use hydrogen, a relatively dense fuelling infrastructure would be needed. For example, the European Commission's proposal for a revision of the Alternative Fuels Infrastructure Regulation sets a target (still under discussion) to equip the entire road component of the Trans-European Transport Network (TEN-T) with compressed hydrogen stations, with a capacity of at least 2 t/day every 150 km by 2030 (European Commission, 2021e).

Hydrogen stations could be supplied by on-site electrolysers, pipelines or HGVs. The costs of these solutions depend on the hydrogen transport distances, the transported quantities and the need for hydrogen transport infrastructure elsewhere (see Figure 9). For low volumes, HGV transport of liquefied or compressed hydrogen would be the cheapest option, while higher volumes could economically justify transport by pipeline. It is likely that a variety of solutions will be proposed in the first instance. If hydrogen refuelling stations were included in a hydrogen pipeline network, a significant geographical extension of the hydrogen transport network compared to a "no regrets" network might be required.

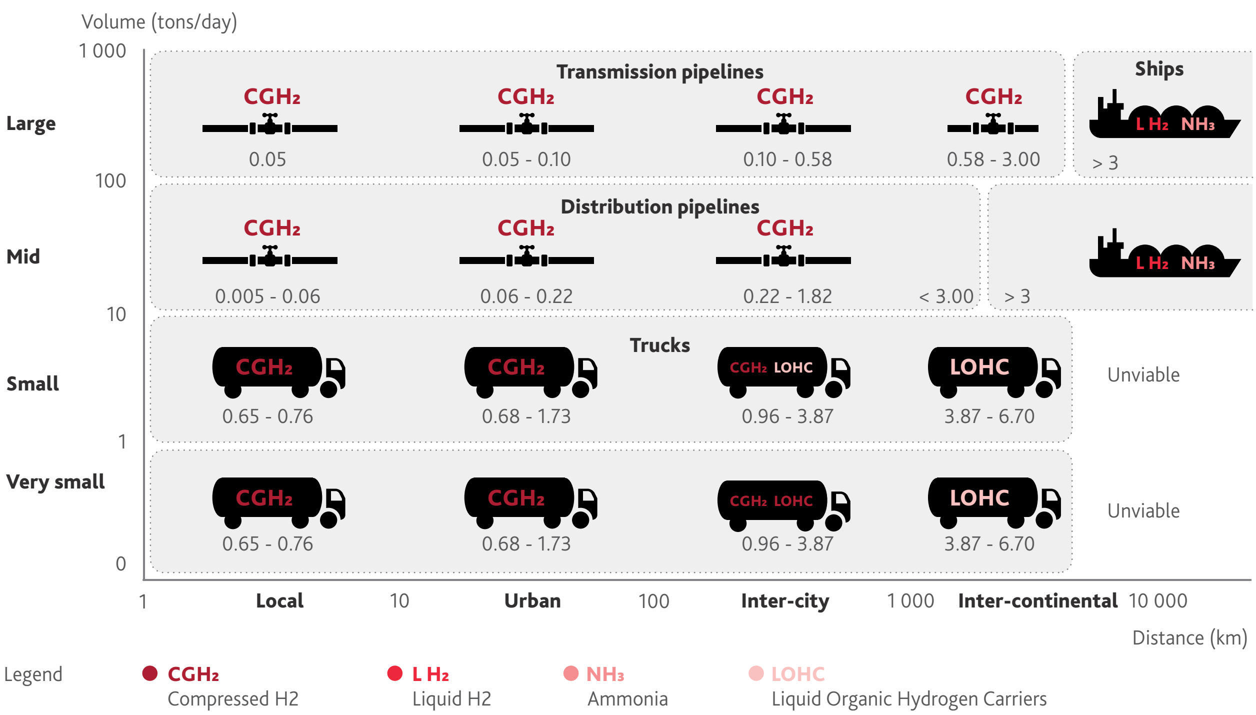
If so, the heavy transport sector could be a "swing" segment of the hydrogen transport infrastructure. The appropriateness of deploying hydrogen in the road transport sector should therefore be considered in light of the costs of extending the hydrogen network, as well as the importance of path dependencies in the transport sector.

4.4. Imports could justify cross-border connections

Whether or not hydrogen imports and exports are developed is a fundamental issue in assessing infrastructure needs.

Establishing cross-border connections would require the construction of long-distance hydrogen transport routes, i.e., a more extensive infrastructure than clusters alone. Hydrogen supply outside demand clusters could make more diffuse hydrogen uses competitive beyond industrial clusters, typically for road transport, or even motivate hydrogen deployment in sectors where it is not the best decarbonization solution with the amortization of infrastructure investments. The cost of such connections should be included in the opportunity studies of importing hydrogen-based carriers.

FIGURE 9. Cost of transporting hydrogen by volume transported, distance transported and means of transport



Note: figures include the cost of movement, compression and associated storage (20% assumes for pipelines in a salt cavern). Ammonia assumed unsuitable at small scale due to its toxicity. While LOHC is cheaper than LH_2 for long-distance trucking, it is less likely to be used than the more commercially developed LH_2.

Source: Bloomberg NEF (2020).

In addition, hydrogen import and export policies between European countries and with third countries should be subject to enhanced European cooperation to ensure security of supply and cost minimization.

Despite major uncertainties in terms of hydrogen demand, it is possible to identify key parameters for infrastructure development which can already be analyzed and discussed. In particular, the issue of hydrogen imports to the European continent, already explored by some political and industrial actors, raises important issues of economic optimization and environmental criteria.

5. IMPORTING HYDROGEN: ECONOMIC, INDUSTRIAL AND SUSTAINABILITY ISSUES

Increased availability of resources for low-carbon hydrogen production (renewable or nuclear energy resources, fossil methane and carbon sequestration) may make it attractive for European actors to import hydrogen or derived fuels produced outside the continent. Developing cross-border hydrogen trade with third countries would increase the available volumes of hydrogen or derived fuels and possibly lower their cost. In countries that could become exporters, the sale of hydrogen or derived fuels would be the means to develop an economic activity based on their comparative advantage in terms of resource availability. Thus, some countries would be able to export hydrogen due to surplus renewable energies (Chile, Australia, Maghreb, Namibia) or fossil methane (Norway, Algeria, Saudi Arabia, Qatar, Russia). Many of these countries are currently fossil fuel exporters, for which the development of a low-carbon hydrogen industry could replace an economic activity that will be greatly reduced in a world adhering to the Paris Agreement.

Today, there is a divergence of approaches between European countries on this issue. While France does not mention cross-border hydrogen trade in its strategy, Germany plans to import the majority of its consumption from within and outside Europe, while Spain and Portugal mention the possibility of exporting hydrogen to the rest of Europe (BMWi, 2020; DGEG, 2020; MITECO, 2020; MTE, 2020). The European hydrogen industry has set a target of building 40 GW of electrolysers in countries bordering the EU (North Africa and Ukraine) in addition to the 40 GW built in the EU (van Wijk & Chatzimarkakis, 2020).

For the EU, opening up to hydrogen imports raises the question of the impact of this measure on its degree of energy autonomy. Today, the majority of fossil fuels used in Europe are imported: in 2019 83% of fossil methane and 89% of petroleum products available in the European Union (EU28) were imported (Eurostat, 2021). According to the European Commission's scenarios compatible with a 1.5°C warming, a carbon-neutral energy system in 2050 would import almost zero fossil fuels, and the majority of molecules for end uses would be derived from hydrogen: nearly 20% of final energy demand, i.e., around 1,500 TWh (129 Mtoe) in 2050, compared with less than 10% for their fossil counterparts, i.e. around 600 TWh (52 Mtoe) (European Commission, 2018b).

As a result, today's climate-neutral scenarios describe a decrease in energy imports by 2050: the share of imports decreases from 60% of primary energy consumption to around 25% in 2050 according to the European Commission's 1.5TECH and 1.5LIFE scenarios – which assume that all hydrogen or derived fuel is produced in the EU (see **Figure 10**). In the extreme hypothesis that hydrogen-derived molecules would be totally imported, then the share of primary energy consumed from imports would still decrease to around 35%. These figures could of course change as the use of hydrogen develops: some scenarios foresee consumption of around 3,000 TWh of hydrogen and its derivatives, almost double the estimate in the scenarios produced in 2018 by the European Commission (European Commission, 2018b; IFP Energies nouvelles *et al.*, 2021). However, it seems that the manufacture of hydrogen and possibly its processing in the EU would not be of sufficient magnitude to reverse the downward trend in the proportion of imports in the energy supply compared to the current situation.

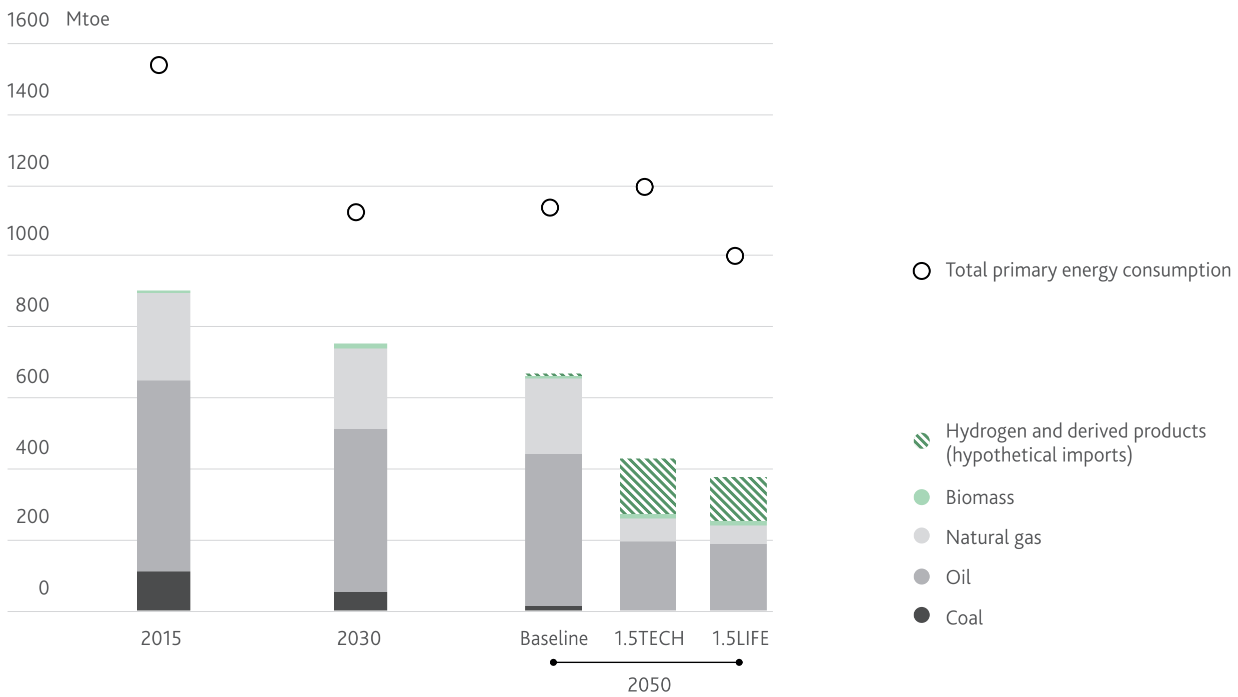
Moreover, supply security does not only depend on imports: the level of risk, reflected in part by the political and economic situation and the substitutability of the countries of origin, but also the trust relationships between countries, are also important parameters (Escribano, 2021; Wietschel *et al.*, 2020). Importing significant volumes of hydrogen and derived fuels requires enhanced cooperation between the countries involved, both to structure significant initial investments in production, transport and storage technologies, and to build trust. International standards for sustainability and traceability of hydrogen will also be needed. All of these dimensions must be examined in import opportunity studies and assessed from different perspectives (economic, industrial strategy and environmental impact) to make certain that they are the subject of political choices to ensure the commitment of EU countries.

5.1. Economic challenges of imported hydrogen and hydrogen derivatives

The decision to import hydrogen or other associated carriers is partly an economic one: in theory, it is a matter of taking advantage of situations where hydrogen production costs in an exporting country are sufficiently low compared to the importing country to offset transport costs.

Hydrogen can be transported over long distances, either in gaseous form through a pipeline, or liquefied in the form of ammonia and carried by ship, similarly to liquefied fossil methane (LNG) today, or bound to other molecules known as liquid organic hydrogen carriers (LOHC). While pipeline transport is cheaper over shorter distances as it does not require hydrogen processing, this option can become prohibitive on an intercontinental scale, as illustrated in **Figure 9**, and even more so if fossil methane pipelines are not already present (Bloomberg NEF, 2020). The capacity for ammonia transport and synthesis from hydrogen already exists, but conversion back to hydrogen is underdeveloped and could be costly. Ammonia can be used

FIGURE 10. Energy imports into the EU in 2015, 2030 and 2050 according to different scenarios



Adapted from the European Commission (2018). Note: imports of hydrogen and derivatives are assumed in this study and do not correspond to the European Commission's scenarios, which assume that all these fuels are produced in the EU.

directly in certain "priority" hydrogen applications, such as fertilizer manufacture or as maritime fuel (see Section 5.2), but also in other energy applications. Liquefied hydrogen can partly rely on liquefaction, regasification and transport capacities that are currently used for fossil methane, with some adaptations. The LOHC option is currently at an early stage of development. The economic trade-off between these options depends on the distance travelled and the volume transported, along with the presence or absence of LNG or ammonia industries and the end use of the hydrogen.

Regarding electrolytic hydrogen, the potential of a country's exportable hydrogen or derived carriers is subject to the availability of renewable or nuclear electricity resources, as is the case for domestic hydrogen, which calls for a significant development of electricity production capacities (see Section 3.3). Thus, taking renewable resources into account, a study by Fraunhofer IEE quantifies the total potential for exporting pure hydrogen by pipeline from Morocco and Tunisia by 2050 at 400 TWh/year (Gerhardt *et al.*, 2020), which could cover only a fraction of European needs depending on the level of demand (see Table 1). Economically, several studies suggest that there are situations in which import routes would be economically viable, provided that large-scale electrolysers and/or CCS infrastructure for blue hydrogen are deployed in exporting countries, as well as relatively long-distance hydrogen supply lines (Agora Energiewende & AFRY Management Consulting, 2021; Escribano, 2021; Hampp *et al.*, 2021; Wietschel *et al.*, 2020; World Energy Council, 2021). This can represent an important industrial and sectoral acceleration for potential exporting countries, especially those with relatively low electricity consumption, poorly developed electricity infrastructure and predominantly thermal power generation, but raises questions about the prioritization of sustainable energy sources in these countries (see Section 5.2).

The economics of importing blue hydrogen in a transitional phase are different. Producing blue hydrogen in north-western Europe (UK, Norway, Netherlands), or outside the continent (Russia, Algeria), and exporting it elsewhere in Europe would require long-distance hydrogen transport infrastructure. The EU is currently a major importer of fossil methane, and it is easy to imagine that some of the pipelines used for fossil methane could be converted to hydrogen, given that current fossil methane producers are well positioned to manufacture blue hydrogen. However, to comply with the Paris Agreement (see Section 2.1), blue hydrogen consumption in the EU can only be temporary, which questions the economic viability of investing in these import routes.

5.2. Industrial value chain issues and hydrogen imports

The issue of hydrogen imports needs to be considered in the broader context of industrial value chains. In a low-GHG emissions system, it is possible that the geography of these value chains will evolve from production located close to demand, to production located close to low-carbon energy sources and underground CO_2 storage sites. Supply chains could then be separated into intermediate feedstocks. For example, for steel, international trade could shift from trade in iron ore to trade in metallic elemental iron derived from direct reduction with hydrogen (Bataille *et al.,* 2021; Gielen *et al.,* 2020; Philibert, 2017). This also applies to the supply of hydrogen: the desirability of importing blue or electrolytic hydrogen for steelmaking in Europe should be weighed against the import of steel intermediates produced near low-carbon energy sources and ore production sites. For the chemical industry, it could also be relevant to import ammonia produced with hydrogen by low-cost electrolysis elsewhere in the world. Finally, for synthetic fuels derived from hydrogen that can be used in transport, the comparative transport costs could lead to the installation of the production of these fuels in countries with excess capacities, allowing these countries to produce the hydrogen necessary for their manufacture rather than sourcing them from Europe (Philibert, 2021).

Ultimately, some priority applications for hydrogen could be satisfied not by importing hydrogen, but by trading intermediate products. The choices of specialization and geographical reorganization for the involved industries could strongly influence the outlets for European hydrogen production. Such reorganizations of industrial sectors will not only depend on economic criteria: securing access to certain industrial products and maintaining expertise and employment in industrial areas should also be considered.

5.3. Environmental aspects of imports of hydrogen or hydrogen products

In the event that EU countries decide to source some of their hydrogen or intermediate products from outside the EU, it is essential that the life-cycle emissions of the hydrogen used are reported and controlled (Escribano, 2021; Wietschel *et al.,* 2020). It would be counterproductive to import carbon-intensive hydrogen, grey or blue hydrogen with low capture rates or with methane with high upstream emissions, or electrolytic hydrogen from high carbon electricity (mostly non-nuclear or renewable). Hydrogen imports should therefore be subject to criteria that take into account the full environmental consequences of hydrogen production. These criteria should be defined in the framework of cooperation between hydrogen-producing and importing countries and, ideally, lead to the definition of international standards in terms of hydrogen production for climate neutrality.

These standards should at least take carbon content into account, as highlighted by several stakeholders (BMWi, 2020; European Commission, 2020; Hydrogen Europe, 2021). Imported hydrogen could be subject to the same standards as hydrogen produced in Europe, also accounting for the transport footprint if relevant, i.e., mostly renewable or nuclear electricity used, while blue hydrogen installations must have very high capture rates and low gas leakage (see Section 2.1). The applicability of these standards in terms of hydrogen GHG emissions data collection and monitoring should also be addressed.

Finally, the systemic effects of the development of hydrogen export industries in producing countries should be examined as they raise important environmental and social issues of energy resource distribution. In some countries envisaged for electrolytic hydrogen production that have very carbon-intensive electrical systems, such as Morocco or Algeria, a proportion of the populations may have limited access to energy. In this context, it is important to ensure that exports of hydrogen and its derivatives do not divert the renewable or nuclear electricity resources needed to decarbonize the energy system and to provide access to energy for all in these countries, in line with the Sustainable Development Goals defined by the United Nations.

6. CONCLUSION

This study was conducted in the context of accelerated hydrogen support policies in Europe and France, and provides keys to understanding the challenges of hydrogen development by 2030 and 2050.

Hydrogen technologies are at an early development stage and there are competing proposals from industrial and public actors as to the applications to be developed for decarbonization. The level and sectors of hydrogen demand are structural factors for the establishment of production, storage and transport infrastructure and for calculating the level of public support for sectors. However, the differences between the envisaged uses lead to very different estimates of demand volumes and consequently to different strategies for industrial sectors and infrastructure requirements. It is therefore necessary to identify the criteria and conditions underlying these visions. In addition, the political objectives for the emergence of hydrogen industries in France and in the European Union call for a reflection on the governance of this development.

Which hydrogen applications should be developed? We show that despite the technical and economic uncertainties surrounding the evolution of hydrogen production, it is possible to prioritize applications in order to target the segments where it is most needed. Thus, some uses of hydrogen are "unavoidable" to achieve climate neutrality (uses as industrial feedstocks, air and sea transport), while others are not critical to decarbonization because there are sufficiently abundant alternatives. In addition to its role as a chemical reagent and energy carrier, hydrogen could contribute to balancing the electricity system, especially as the proportion of variable renewables is high. The volume of hydrogen demand is extremely variable, depending on the underlying envisaged uses: for example, the inclusion of road transport corresponds to a doubling of demand in France compared to a situation where hydrogen is only used as a feedstock in the industrial sector where there are few alternatives (chemical industry, refineries, steel), according to RTE's most optimistic pathway for hydrogen, see Table 2.

The development of electrolytic and possibly blue hydrogen applications is partly guided by a fall in production costs, but this does not guarantee that hydrogen is directed towards priority uses, given the necessary industrial reconfigurations. This underlines the importance of policies to support innovation and the development of industrial sectors.

Public strategies for choosing applications are defined at European, national and local levels.

- At the EU level, the revision of the rules on state aid for environmental protection and energy proposed at the end of 2021 and discussed during 2022, which will provide a framework for national-level aid, as well as the green hydrogen quotas set in several passages of the Fit for 55 package (ReFuel EU for aviation, FuelEU for maritime), are important steps.
- In France, the revision of the SNBC and the PPE during 2022 is also an opportunity to discuss these choices. The selection of projects for the hydrogen PIEEC by the Member States and the European Commission, which should take place during 2022, can accelerate the deployment of certain uses by pooling support for innovation and the first commercial projects.
- At the local level, local authorities have a role to play in the industrial dynamics through the formation of hydrogen ecosystems, as underlined by the 2018 French hydrogen plan (MTES, 2018).

Policy choices regarding uses should be subject to review clauses to reassess the capacity of support to target priority applications and to adapt to technological advances in less mature uses, particularly technology demonstration initiatives and the first experiments in manufacturing and transporting hydrogen.

While part of the hydrogen demand could be supplied by electricity surpluses resulting from balancing the electricity grid, the volumes produced would not be sufficient to supply essential hydrogen applications. This justifies the development of a dedicated hydrogen supply, which raises several issues.

Under what conditions would blue hydrogen play a role in the transition to climate neutrality in 2050? The industrial scale-up required for hydrogen produced from steam methane reforming coupled with CO_2 capture and storage (CCS) to become very low-emission (high rate of CO_2 capture during production, control of fossil methane leakage and development of CO_2 transport and geological storage) is a challenge. Even so, emissions from blue hydrogen would not be zero, indicating that its role can only be transitory and casting doubt on the economic viability of potential installations.

The solution to the question about the role of blue hydrogen must be discussed in part at the European level because geological storage resources for CO_2 and fossil methane are concentrated on the continent, and due to the integrated nature of the fossil methane market (and possibly CO_2) (European Commission, 2021f). This is part of the discussion on the revision of the "gas package" (proposed by the Commission in mid-December 2021), which addresses, among other things, infrastructure and the hydrogen market (European Commission, 2021b). The delegated act on European taxonomy, which proposes a limit of 3 kg CO_2e/kg H2 for "sustainable" blue hydrogen, and the directive on energy taxation, which is part of the Fit for 55 package, also address this issue. The 3 kg CO_2e/kg H2 limit can only be transitory in a vision of climate neutrality, which raises the question of whether and how quickly this limit will be lowered in the longer term.

What are the prospects for a long-term electrolytic hydrogen supply? Electrolysis could provide sustainable low-emission hydrogen, but its cost would be relatively high compared to fossil alternatives, even in the long term. Moreover, the cost of this hydrogen varies greatly depending on the volume of demand and therefore the uses that are chosen to be deployed. The extra cost compared to fossil fuels would probably be manageable for applications without alternatives, but it will be essential to direct the least expensive hydrogen (made from marginal or cheap renewable electricity) towards these applications. This raises the issue of the economic relevance of deploying hydrogen for applications for which there are alternatives, i.e. low-temperature heat, light transport, blending into gas networks, possibly heavy goods vehicles, high-temperature heat and balancing of the electricity grid.

Hydrogen supply policies are partly decided at the European level in the context of the revision of state aid rules and the Fit for 55 package (revision of the Renewable Energy Directive, revision of the carbon market). The national level is also important as it defines the support mechanisms for hydrogen production and determines pilot projects.

Under what conditions and why should hydrogen or its derivatives be imported? An international hydrogen and derived products trading system would theoretically optimize hydrogen resources and supply costs. The question of whether such a system should be developed is part of broader reflections on the geographical distribution of industrial value chains and their possible reconfiguration as energy sources evolve, while there may be advantages for industries to organize trade at other production stages. Furthermore, trade in hydrogen and its derivatives will only contribute to the Paris Agreement if it complies with strict and enforceable sustainability standards, notably in terms of life-cycle greenhouse gas emissions, but also in terms of distribution between exports and domestic production of energy resources in the producing countries. Finally, it should be noted that imports of significant volumes of hydrogen and its derivatives contradict the argument that hydrogen helps to achieve energy independence.

The modalities of trading hydrogen and its derivatives between countries are partly decided at the bilateral level, as in the case of Belgium's alliances with Namibia, or Germany's H2Global programme. Hydrogen standardization initiatives could be carried out within the framework of international organizations, at least within the European Union. Finally, such trade relations are partly based on national choices regarding the use of energy imports.

What hydrogen transport infrastructure can be implemented to ensure that hydrogen is provided to applications that require urgent decarbonization? It is difficult to answer this question definitively since the long-term vision for hydrogen usage remains unclear. In the meantime, it seems important to focus infrastructure development efforts towards "unavoidable" hydrogen applications in order to avoid stranded costs, which primarily concerns existing users whose production would be maintained in a carbon-neutral system. The long-term vision of hydrogen infrastructure must be built at both European and national levels. The planning of hydrogen infrastructure by national electricity and gas network operators is one of the problems identified by the gas package (European Commission, 2021b) and will therefore be a subject for European discussion, in particular on the establishment of cross-border connections, which are important for some industrial consumers, and possibly import routes for hydrogen and hydrogen carriers, but also strongly involving Member State actors. In addition, several sectoral texts of the Fit for 55 package (notably the regulation on alternative fuels infrastructure) aim to set relevant technological guidelines for hydrogen, notably in transport with measures concerning electricity charging infrastructure or hydrogen/biomethane refuelling infrastructure, an important parameter for the adoption of long-distance heavy goods vehicles.

Our analysis highlights the extent of the challenges posed by the establishment of the hydrogen sector to achieve climate neutrality and provides insights. This work must be complemented by sectoral analyses to estimate the potential volumes of hydrogen consumption, the associated costs and the prerequisites for the energy networks to enable its deployment. To start with, more detailed analyses are required regarding hydrogen use by heavy goods vehicles, which is particularly important for defining the size of hydrogen infrastructure and the level of consumption, while the issue of hydrogen imports is also a subject that requires further examination.

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Hydrogen for climate neutrality: conditions for deployment in France and Europe

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Citation: Bouacida, I., Berghmans, N., (2022). Hydrogen for climate neutrality: conditions for deployment in France and Europe. *Study* N°02/22, Iddri, Paris, France, 30 p.

ISSN 2258-7071

This study has received financial support from the European Climate Foundation as well as from the French government in the framework of the programme "Investissements d'avenir", managed by ANR (the French National Research Agency) under the reference ANR-10-LABX-01.

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