HYDROGEN FOR A GREEN AND SOCIAL TRANSITION

IMPLICATIONS FOR THE EU HYDROGEN STRATEGY

ISABELL BRAUNGER CAROLIN GRÜTER FABIAN PRÄGER

GUE/NGL THE LEFT IN THE EUROPEAN PARLIAMENT

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B-1047 Brussels, Belgium

+32 (0) 2 283 23 01
guengl-communications@europarl.europa.eu

cornelia.ernst@ep.europa.eu

Authors: Isabell Braunger, Carolin Grüter und Fabian Präger

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EU HYDROGEN STRATEGY UNDER SCRUTINY

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Foreword

Dear Readers,

Since the Paris Convention on Climate Change was signed in 2015, there followed a long period of de facto inaction. It was not until five years later that the European Commission made its proposal for a climate bill according to which the EU should be climate neutral by 2050. Under the pressure to meet their obligations, politics and business are imploringly searching for solutions to decarbonise the economic system based on fossil fuels. For me, renewable energies using the wind and sun are the solution. Their expansion should be paramount for politics and business.

Having said this, hydrogen in particular is currently playing a prominent role as the "oil of the future" in this debate. Just now hydrogen is being negotiated as an attractive alternative for many sectors.

Hydrogen can fulfil many functions of fossil fuels without the need for a systemic rethink. It can be used as a fuel for conventional technologies, such as combustion engines. As with natural gas, it can be conveyed in pipelines and stored in caverns. Unlike fossil fuels, no CO_2 or methane is emitted into the atmosphere when hydrogen is used. The only by-product from its combustion are water molecules.

But are the high hopes placed on the miracle cure of hydrogen justified? We must bear in mind that hydrogen is not a source of energy, but merely an artificially manufactured energy carrier. It can either be generated from water by electrolysis using electric current or via reformation or gasification processes of fossil fuels, such as coal or natural gas. More than 90 per cent of hydrogen is currently extracted from fossil sources. No wonder that the large multinational fossil fuel companies extol it as the solution to climate change. They could still sell "old wine in new bottles" like this and maintain the status quo in the power relations of the production and distribution of energy within a centralised structure.

The Left Group in the European Parliament has therefore commissioned this study in order to give the potentials of hydrogen a root and branch review. The study investigated the areas of application in which hydrogen is appropriate and how it can be classified into the energy system of the future, which will be based on renewable energies. One outcome: Hydrogen can be part of an important, but not the critical, role in the shift in sectors where no direct electrification via renewable energies from the wind and sun is possible. This outcome should deflate the current euphoria surrounding hydrogen. Plans to push forward the development of a hydrogen market full steam ahead must be critically scrutinised. It would be better if hydrogen production can be developed in a demand-driven way and is only used where there are no more effective options for decarbonisation.

Cornelia Ernst
Member of the European Parliament

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This study addresses the question of how the development of the hydrogen sector should be shaped in the course of the socio-ecological transformation in Europe. This is because there is certainly broad agreement on the fact that hydrogen will be part of a climate-neutral energy system. However, there is currently still a lot of discussion about the importance of hydrogen as well as the path towards a climate-neutral energy system. The different manufacturing methods and areas of application are at the heart of the debate.

This study presents the current level of knowledge about hydrogen technologies, highlights the methods regarding energy infrastructure planning and analyses the European Hydrogen Strategy against this backdrop. The objective is to show the risks current strategies and plans hold, identify research needs and see where lock-in effects for fossil infrastructure may emerge. Then, initial recommendations will be outlined.

The key findings of this study in summary:

1. Hydrogen should always be planned with a view to the efficiency and emissions of the overall system and therefore beneficial to the system: As little as possible, as much as necessary.

2. Hydrogen demand may be substantially reduced by exploiting sufficiency and efficiency potentials. These potentials should initially be exploited from economic and ecological points of view.

3. Only hydrogen from additionally installed renewable electricity generation plants has no direct greenhouse gas emissions and can consequently be part of a climate-neutral energy system. The consistent expansion of renewable energies is the first priority. Nuclear energy is not an option here.

4. In order to avoid lock-in effects and stranded assets, the climate impact of natural gas must already be fully taken into account now. Consequently, a consistent exit from the production and combustion of natural gas is necessary. CCTS must not be used as a life-prolonging measure for fossil energy carriers and cannot be part of the solution due to residual emissions as well as unresolved technical and economic challenges.

5. As hydrogen imports from third countries may only be worth considering taking climate-ethical aspects into account and therefore ethical, social, organisational and economic issues must be addressed first, the EU should focus on hydrogen production in Europe, whereby positive impacts on jobs could also be achieved at the same time.

6. Renewable hydrogen in Europe will only be available in a restricted way and thereby constitutes a valuable asset; prioritising areas of application is necessary in order to deploy hydrogen effectively and also to attract investment in innovative, durable technologies.

7. Infrastructure planning of the energy system must be conceived with the target system in mind. The acceptability of the transformation process may be enhanced on the basis of pathways compliant with meeting 1.5°C involving all stakeholder groups and civil society; this in turn will significantly increase the chances of successfully developing a climate-neutral EU.

1. Introduction

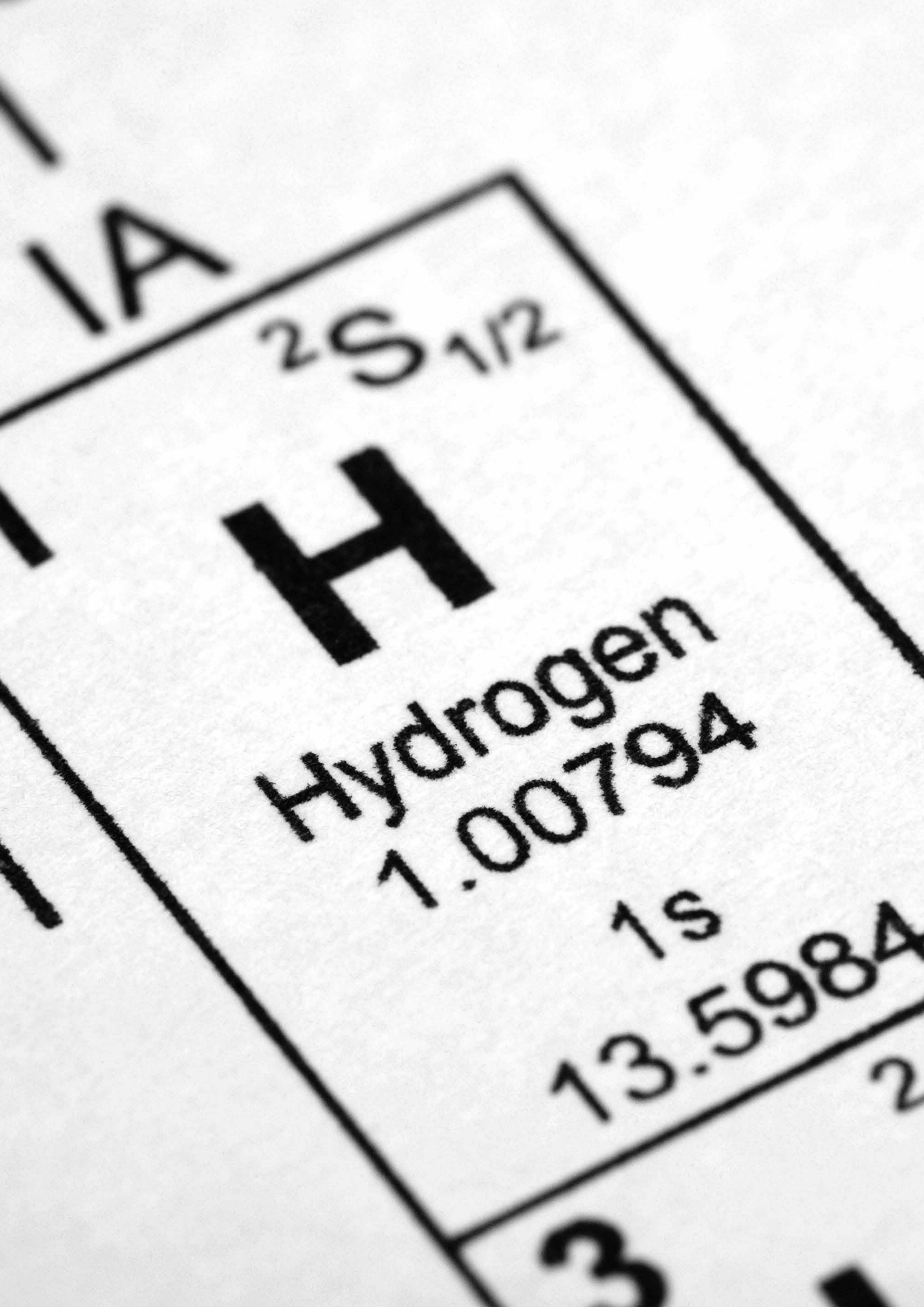
The Paris Agreement was passed on 4 November 2016. All its signatories agreed to keep global warming to significantly below 2°C. This is supposed to minimise the catastrophic effects of climate change, already being suffered by people in countries of the global south today and which are, however, also ever more clearly palpable on the continent of Europe. From a justice perspective, those who are one of the main beneficiaries of industrialisation and the current economy must lead the way. Data from the United Nations Environment Programme (UNEP Emissions Gap Reports), in which all national strategies to attain the Paris climate targets are being investigated and classified, also indicate this. The EU27+UK emit 8.6 % of global greenhouse gas emissions (GHG emissions), whereby the per capita emissions exceed the global average by 25 %. At the same time, the overall emissions only fell by 1.5 % per year in the past decade, with the exception of 2019 when 3 % emission reductions were recorded (UNEP 2020, 6). The faster the EU achieves climate neutrality, the more time countries with less economic power will have to implement the transformation process. The EU, however, still has a long way to go. The present strategy of the Union is not yet consistent with the Paris climate targets and must be further refined (e.g. EEC 2020; Hainsch et al. 2020). Furthermore, nuclear power cannot be part of a sustainable energy mix either due to its high risks to people and the environment and must likewise be replaced by Renewable Energies (RE).

In order to comply with the Paris climate targets, all EU Member States must decarbonise their energy system and switch to Renewable Energies (RE). The transformation process must be based on the latest scientific findings and be jointly designed with the people of the Member States in order to gain acceptance and democratic legitimacy. To achieve this, the European Commission (EC) introduced the Green Deal (GD) in 2019. This should create the framework for a common strategy to transform the European economy sustainably and to spread the costs of the transformation fairly. EU climate protection legislation proposes an increase in the 2030 intermediate goal to 50 % or 55 % GHG emission reduction compared to 1990. In order to realise the GD, a catalogue of measures is being proposed. However, the GD still includes an almost constant percentage of nuclear power in the energy carrier mix (14 %), which must be removed as quickly as possible in the course of the transformation. As part of the strategy for an intelligent sector integration, the European Hydrogen Strategy, which is the reference point for this paper, was developed as well.

The European Hydrogen Strategy outlines the vision of the EC for the importance and role of hydrogen for decarbonisation in Europe (EC 2020). It forecasts that the percentage of hydrogen in the European energy mix will rise from currently 2 % to 13 – 14 % in 2050. The hydrogen strategy along with the entry into a hydrogen economy are currently being met with a great response in political debate and are being hailed as the solution to achieving climate neutrality. There are, however, huge uncertainties in terms of the contribution that hydrogen can make to complying with the Paris climate targets. But it is clear that the majority of current CO_2 emissions cannot be cut through the use of hydrogen in the future and hydrogen will in future have a considerably smaller role than natural gas today. Furthermore, there is the risk that an unsuccessful hydrogen strategy will either result in unnecessary investment in gas infrastructure, which will be badly needed for the transformation elsewhere, or will generate lock-in[1] effects for fossil gas instead of contributing to climate neutrality.

In order to be capable of classifying the EU Hydrogen Strategy in this context, we first of all bring together the information relevant to this in this paper. In chapter 2, we explain the manufacturing methods for hydrogen and contrast regional production with importing the energy carrier. We discuss the potential areas of application for hydrogen in chapter 3 in order then to go into the infrastructure necessary for connecting generation and consumption in the following chapter 4. In addition, we touch upon the planning regime for energy infrastructures hitherto present at European level and subsequently discuss configuration options for planning hydrogen infrastructures. In chapter 5, we consider the hydrogen strategy focusing on the roadmap it includes and point out emerging issues and risks with a view to the previous chapters. Finally, we present our conclusions from the analysis of the role of hydrogen in the socio-ecological transformation for the EU Hydrogen Strategy in chapter 6.

[1] Lock-in effects refer to path dependencies which relate to the emission of CO_2. Lock-in effects may be technological, infrastructural, institutional or human in nature (behaviours) (Seto et al. 2016).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2. Manufacturing methods, production potentials in Europe and import options

In this chapter, we first of all present the different manufacturing methods for hydrogen in section 2.2. We take into consideration both methods based on fossil energy carriers and those based on electricity. In section 2.3, we discuss the conditions for hydrogen production in Europe and for imports. Furthermore, we describe the potential positive impacts on jobs of regional hydrogen production in Europe.

2.1 Key messages

- The electrolysis of water with electricity from RE is the sole method for hydrogen production without GHG emissions. The production of hydrogen is consequently directly associated with the consistent expansion of RE.
- Supplementing fossil hydrogen production with Carbon Capture, Transport and Storage (CCTS) does not result in GHG-free production, as the rate of capture will likely remain below 100 %, the CO_2 storage facilities in Europe are limited and methane emissions from extracting and transporting natural gas remain. In the course of using CCTS, the objective of enabling the further use of fossil natural gas is being pursued in particular.
- The development of fossil hydrogen production with CCTS in the initial phase threatens lock-in effects, as infrastructure which cannot contribute to the long-term objective of climate neutrality will continue operating and, where appropriate, even be expanded.
- The production of hydrogen by means of electrolysis and nuclear energy is dangerous and is uninsurable anywhere in the world. It is expensive and not sustainable, as the problem of final storage is still unresolved today and there are high risks to health and the environment.
- Importing from third countries must consider aspects of climate ethics, such as the competition for water and land.
- Producing hydrogen within Europe means that the European added value and positive effects on jobs will be significantly greater than from importing hydrogen or hydrogen-based products.
- • Manufacturing hydrogen-based products is highly inefficient due to conversion losses and should therefore only be treated as a niche product.

2.2. Manufacturing methods within the EU

Hydrogen can be manufactured in a number of ways. The only option of producing hydrogen without emitting CO_2 constitutes electrolysis of water using electricity from RE (IRENA, 2019a). However, currently in Europe fossil energy sources, in particular natural gas, are being used to produce hydrogen in more than 92 % of production facilities (Hydrogen Europe 2020). The most important and thereby also an already proven technology is steam reformation during which hydrogen and CO_2 are formed from natural gas by adding water vapour. The European Hydrogen Strategy indicates that 70 – 100 million tonnes of CO_2 are currently emitted each year through the production of hydrogen (EC 2020). The volume of hydrogen produced in 2018 was approximately 11.5 million tonnes[2] (Hydrogen Europe 2020).

2.2.1 Manufacture using fossil energy carriers

In order to reduce GHG emissions in the future despite the increasing need for hydrogen, various methods which continue to be based on the use of fossil energies are being discussed alongside the use of electrolysers operated using renewable electricity.

Carbon Capture, Transport and Storage (CCTS) is being discussed as an option to reduce CO_2 emissions. Approx. 0.4 tonnes of CO_2/MWh of hydrogen is released during steam reformation today (Greenpeace Energy eG 2020). By using separation systems, these CO_2 emissions could theoretically be reduced to a level of 0.14 tonnes in 2025 and 0.06 tonnes of CO_2/MWh of hydrogen in 2040 (Greenpeace Energy eG 2020). As there have so far only been very few CCTS

[2] The energy content of hydrogen (lower heating value) is 33.3 kWh/kg. 11.5 million tonnes of hydrogen consequently has an energy content of approximately 383 TWh. Any cost information (€/MWh) relates to the lower heating value.

projects in the context of hydrogen production, the rates of capture are associated with a high level of uncertainty. In Canada, a maximum rate of capture of 80 % was achieved in the first operating year of a steam reforming plant with carbon capture, which, however, fell significantly short at times (IRENA 2019a). In the future, a maximum carbon capture rate of 85 – 95 % may be expected (IRENA 2020). All things considered, the option of CCTS cannot consequently contribute to the objective of the CO_2-free production of hydrogen.

Furthermore, it is debatable whether CCTS will be available in a technically and economically viable way in the future (Hainsch et al. 2020). According to cost projections, which assume the availability of CCTS, the costs for the production of hydrogen by means of steam reformation combined with CCTS are between €50/MWh and €80/MWh (Greenpeace Energy eG 2020; Matthes et al. 2020).

A further prerequisite for the use of CCTS in hydrogen production would be the coordination of upgrading or constructing steam reforming plants with separation systems, the approval and development of storage facilities as well as the approval, planning and creation of transport infrastructure between steam reforming plants and storage facilities within a very short time. For only if hydrogen became available from fossil sources significantly earlier than renewable hydrogen would this contribute to decarbonisation.

This is set against the fact that CCTS has been discussed in the context of climate protection for two decades now (IPCC 2005), but so far only numerous planned yet not completed CCTS projects exist. Successfully implemented large-scale demonstration projects are completely absent. CCTS is therefore primarily the attempt of the fossil energy industry to secure its long-term survival and to show fossil energy carriers as sustainable (von Hirschhausen, Herold, and Oei 2012; von Hirschhausen, Praeger, and Kemfert 2020).

It should also be noted that the storage capacities available for CO_2 in Europe are limited and involve a high level of uncertainty. The limited storage capacities should consequently not be planned and blocked recklessly. This is why CCTS does not constitute an option for hydrogen production for which an alternative electricity-based CO_2-free production is possible.

The separation of methane, which requires very high temperatures between 500 °C and 1000 °C, is being considered as another alternative for hydrogen production. Hydrogen and fixed carbon (graphite) are formed during what is known as pyrolysis. So far, only small demonstration and pilot plants are in operation, which means that there is a high level of uncertainty in terms of the scalability of the technology (Matthes et al. 2020). The production costs are therefore also associated with high levels of uncertainty. On the premise of technological progress and the realisation of scale effects, the productions costs of hydrogen using pyrolysis could be €100/MWh in 2030 and €87/MWh in 2050 (Agora Energiewende and AFRY Management Consulting 2021). Pyrolysis itself does not produce any CO_2 emissions; GHG are however emitted in the upstream chain when sourcing natural gas.

It should as a matter of principle be noted that, with all hydrogen production methods via the use of natural gas, methane emissions are released when extracting, transporting and storing natural gas. The Global Warming Potential (GWP) of methane is significantly stronger than that of CO_2 (up to 86 times in the first 20 years, up to 34 times GWP in the first 100 years (Myhre et al. 2013, table 8.7, p. 714)). A technology based on the supply of natural gas for the production of hydrogen is consequently also associated with the output of GHG emissions in the long term.

The use of electricity from nuclear energy during electrolysis does not provide an alternative for the manufacture of hydrogen either. Nuclear energy is associated with high accident risks to people and the environment, which means that there is no possibility of insurance for this in the world (Diekmann 2011; Wealer et al. 2019). Even if disregarding upstream chain emissions, dismantling and final storage, nuclear power is therefore not economically competitive. The current construction of new nuclear power stations (e.g. Olkiluoto-3 in Finland and Vogtle in the USA) demonstrate significant cost increases and losses as well as extensive delays (Wealer et al. 2019). SMR ("Small Modular Reactors") pilot projects and Generation IV currently being developed will not resolve the safety problem, which means that nuclear power remains uninsurable and economically unviable (Pistner and Englert 2017; Pistner et al. 2021; Ramana 2021; Frieß et al. 2021). The issue of the suitable final storage of highly radioactive waste and the associated search for sites has continued to be unsolved for decades. The costs of final storage are incalculable to this day and not fully included in the costs of nuclear energy (Besnard et al. 2019).

2.2.2 Manufacture by means of electrolysis and renewable electricity

Solely electrolysis which uses electricity from RE is therefore available as a technology for GHG-free hydrogen production according to the current level of knowledge. As yet, approximately 4 % of the volume of hydrogen in the EU is produced by means of electrolysis (Greenpeace Energy eG 2020). Here, the application of alkaline electrolysis has primarily been used for over 100 years. In recent decades, PEM (proton exchange membrane) electrolysis has, amongst other things due to its suitability for rapid load changes, become more important and is used in niche applications today (Fraunhofer 2019). Alkaline and PEM electrolysis at operating temperatures between 50 – 80 °C rank among low-temperature electrolysis. Efficiency for low-temperature electrolysers related to the amount of electricity used is approximately 65 % today. Current studies assume an increase of up to 75 % (Matthes et al. 2020).

High-temperature electrolysis (operating temperatures between 700 °C – 850 °C) is characterised by higher efficiencies of up to 82 – 91 % with regard to the amount of electricity used in the long term. However, the high levels of efficiency require the availability of superheated steam. If this is not available via waste heat from external (industrial) plants, the demand for energy will increase due to the additionally required generation of superheated steam. High-temperature electrolysis is currently still at an early stage of development and is only available on a small scale. Initial demonstration projects exceed a plant size of 1 MW (IRENA 2020).

The production costs of renewable hydrogen by means of electrolysis are largely dependent on the electricity costs. Efficiency, investment costs, other operating costs (in addition to electricity costs), operating time and full load hours as well as the capital costs of the electrolysers also affect the production costs. In the course of the further development and cost reductions of electrolysers and electricity generation plants, hydrogen production costs of less than €50/MWh could be achieved at sites with RE potential, such as Germany, in the long term, while the costs are currently more than €80/MWh (Matthes et al. 2020). At sites with a high potential for renewable electricity production, costs of between €30 and €40/MWh could be achieved by 2050. These cost projections require low or no network and system costs. In general, the costs may strongly diverge, as they depend on various factors.[3]

As Europe's electricity system is currently not only based on RE, the CO_2 emissions from hydrogen production via network electrolysers depend firstly on the decarbonisation of the electricity system and secondly on the operation of electrolysers and the specifications of the volumes to be produced[4]. Due to the extensive interdependencies with the electricity system, the production of hydrogen cannot and should not be viewed in isolation. As a consequence, the costs and CO_2 emissions of hydrogen production should not be analysed separately, but the impacts of hydrogen production on the costs and CO_2 emissions of the whole energy system need to be analysed (cf. section 4.2.1).

2.2.3 SIDE NOTE: Hydrogen-based products

In addition to hydrogen, hydrogen-based products are also being discussed as a means of achieving climate neutrality. This refers to synthetic methane as a natural gas substitute, synthetic fuels in particular for the transport sector as well as other hydrocarbons in particular for the industrial sector. These products are only mentioned briefly here. Nevertheless, it should be pointed out that the production processes are associated with conversion losses.

The efficiency of the Sabatier process for the manufacture of synthetic methane from hydrogen and CO_2 is just below 80 %, while the efficiency for the manufacture of liquid hydrocarbons based on hydrogen by means of the Fischer-Tropsch or methanol synthesis is around 70 % (Matthes et al. 2020). If no further technologies available on a large scale are developed or no huge efficiency improvements are achieved, more than a fifth of the energy content of the hydrogen will consequently be lost during the conversion into hydrogen-based products. This loss of efficiency is added to the loss already caused by electrolysis. There are further losses during transport and, ultimately, combustion. This, for example, produces an overall efficiency of 13 % for the electricity from the combustion of synthetic fuels in combustion engines (Agora Verkehrswende, Agora Energiewende, and Frontier Economics 2018, 12).

[3] The site and the connection (either to the electricity grid or directly to individual electricity generation plants) of the electrolysers as well as operational decisions (e.g. use of excess electricity) are relevant.

[4] Projections for Germany assume CO_2 emissions between 0.3 and 0.36 tonnes of CO_2/MWh hydrogen in 2025, which may be reduced to up to 0-0.07 tonnes of CO_2/MWhH2 by 2040 (Greenpeace Energy eG 2020). These are below the GHG emissions from hydrogen production by steam reformation.

A source of CO_2 is also required for the production. CO_2 captured in processes – from biogenic or fossil energy carriers – or CO_2 extracted from the air ("direct air capture"), which has so far been at an early stage of development, is in principle worth considering for this. As explained in section 2.2.1, CO_2 capture will probably not be available on a large scale and does not consequently constitute an option for sustainable decarbonisation. Furthermore, both processes need electricity and a low temperature, which means that the efficiency of using hydrogen-based fuels decreases further.

2.3 Production in Europe versus imports

Apart from the issue of the manufacturing method, the issue of the manufacturing sites also matters. The following sections first of all outline the prerequisites for production in Europe. Then, aspects to be considered for importing hydrogen will be discussed. In the third section, there follows a description of the development of jobs in the course of developing a hydrogen economy. The development of jobs in Europe might, in particular, also be dependent on the selection of production sites for hydrogen.

2.3.1 Production in Europe

As electrolysis using renewable electricity is the only option for CO_2-free hydrogen production, cost cuts for RE and its expansion are vital for the production of hydrogen. A study by the Öko-Institut (Matthes et al. 2020) shows that, assuming average full-load hours in Germany, there is an additional need to expand onshore wind depending on an efficiency of the electrolysis between 59 and 79 GW in order to produce 100 TWh of hydrogen each year. The need to expand offshore wind additionally required for hydrogen production is, under the same set of assumptions, between 28 and 38 GW and for PV between 127 and 170 GW.

As the need to expand RE demanded by hydrogen production depends on the full-load hours of electrolysers, both the different potentials of wind and solar energy within the EU and the potential of electrolysers as a flexibility option for the electricity system must be taken into account for a detailed consideration. Lux and Pfluger (2020), under the assumption of a decarbonised European energy system in 2050, show that the volumes of hydrogen outlined in the 1.5°C EC scenarios (1536–1953 TWh)[5] can only be produced with a huge expansion of RE in Europe[6]. The additional need to expand wind energy is 766 GW and solar energy is 865 GW, although electrolysis is being integrated into the electricity system as a flexibility and part of the otherwise limited energy is consequently being used for the production of hydrogen (Lux and Pfluger 2020). In total, wind turbines with an output of up to 1700 GW, PV systems with an output of up to 1500 GW and other exogenously specified electricity generation plants[7] with an output of 193 GW are being installed to cover the demand for electricity using the stated hydrogen volumes in the decarbonised energy system contemplated in 2050. For comparison: In 2017, altogether wind turbines with an output of 169 GW and PV systems with an output of 107 GW were installed in the EU (Lux and Pfluger 2020). A huge expansion in RE is therefore required.

2.3.2 Importing from third countries

If hydrogen imports from third countries are considered, a lot of factors must be taken into account. These, apart from preferably favourable climatic conditions, include infrastructure conditions as well as additional site-specific resource potentials and restrictions (e.g. space/water). Schimke et al. (2021) indicate that "soft" factors should also be considered. By this, they mean factors, "which go beyond the natural resource potential, such as the political stability of a country or its energy policy framework" (Schimke et al. 2021, 100). These include the national rates of green electricity, the degree of public electricity supply and also the expertise to expand production capacities, training structures and training capacities, etc. These factors are more uncertain, as they may be developed unpredictably (over a considerable period of time).

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[5] Lux and Pfluger (2020) determine the demand for hydrogen for the 1.5TECH and 1.5LIFE scenario of the European long-term vision "Clean Planet for All – A European Strategic Long-Term Vision for a Prosperous, Modern, Competitive and Climate Neutral Economy" (EC 2018a) (EC 2018b).

[6] The following countries are being considered: EU-27 excl. Cyprus and Malta and also the UK, Norway, Switzerland, Bosnia and Herzegovina, Serbia, Kosovo, Montenegro, Albania, North Macedonia.

[7] The exogenously specified generating capacities include facilities for electricity generation with further renewables, such as hydrogen and biomass (130 GW) and nuclear energy and waste (63 GW).

With regard to infrastructure-related factors, there is the problem that studies often only take into account the infrastructure necessary for the production of hydrogen on site (PV or wind turbines, desalination plants (depending on the circumstances on site), connection of the RE generation park to the generating plant for hydrogen as well as the generating plants themselves) (Heuser et al. 2020). To be capable ultimately of exporting these as well, domestic pipelines which convey the hydrogen to the next port/export pipelines, liquefaction and compression facilities or other facilities which process the hydrogen for transport, storage capacities as well as vessels or pipelines for long-distance transport are, however, also needed.

In their study, Brändle et al. (2020) calculate the costs of hydrogen in 2050 from several regions and via different transport routes to Germany. As a result, they come to a similar conclusion as the Wuppertal Institute and DIW Econ (2020) in their meta-analysis of different scenarios for importing hydrogen to Germany compared to domestic production. The production costs of electricity from RE are cheaper in some regions of the world due to better weather conditions; if the costs of transport are included in the calculation, the difference both for maritime and pipeline transport levels out.
Furthermore, it is worth bearing in mind that on their own the costs for the production and transport of hydrogen still do not provide any information about the actual price which will have to be paid for hydrogen in perspective. There are also surcharges for taxes, profits, risk surcharges, marketing, warranty, expenses for research and development, etc. (Wuppertal Institute and DIW Econ 2020). Another factor will be the relationship of supply and demand. Most studies do not reflect this factor either, but consider the potential import from specific countries and regions. There has not yet been a global overview of the potential demand (Wietschel et al. 2020). In addition, the transaction costs of negotiation, contracts as well as monitoring invoices are ignored.

To be capable of assessing the social and ecological impacts of the production of hydrogen, besides the influence on climate change, other criteria and causal chains must be considered. One of these criteria is water consumption. The level of water consumption for the entire hydrogen life cycle depends on many different factors, including the chosen technology and its level of efficiency. Added to this is the indirect water consumption, which arises during production from solar plants and wind turbines. This is appreciably higher with solar than with wind (Shi, Liao, and Li 2020). Studies show that the water consumption for the production of hydrogen from wind and solar power is substantially lower than from gas reformation or the use of electricity from other sources (Mehmeti et al. 2018; Shi, Liao, and Li 2020). Apart from the amount of water consumption for the production of hydrogen, whether water in the corresponding region is scarce plays a considerable role for assessing sustainability. So, Shi, Liao and Li (2020) emphasise that scarcity of water could be a big limiting factor when establishing hydrogen production facilities in regions suffering from water shortages: The use of water for electrolysis may be competing with the water supply of the local population and local agriculture. Even if desalination plants are used for the hydrogen production, from ethical points of view it should first of all be ensured that the people themselves have been provided with adequate water before desalination plants produce drinking water which will be used for the production of the energy carrier hydrogen and consequently for energy export.

Besides water consumption, there are also other criteria which must be considered when importing hydrogen to Europe from third countries. For example, the transformation of the energy sector to RE in the country of production must be ensured. As conversion losses result from the production of hydrogen (cf. section 2.2.2), direct use of electricity on site should be prioritised from ecological points of view with respect to the export of hydrogen. In general, the power supply of the local population should also be prioritised. Exporting is only justifiable from ethical points of view with a very high rate of electrification. Furthermore, this must not result in competition for land with, for example, agriculture on site. The aspects mentioned show that a socially and ecologically sustainable global hydrogen economy needs binding rules.

2.3.3 Job effects of hydrogen production

Hydrogen production in general offers great potential for employment, whereby the majority of jobs would arise in renewable electricity generation. This is the top priority in the value-added chain for renewable hydrogen. Related to this are the manufacture, installation, operation and maintenance of solar power plants and wind turbines. In second place comes the actual production of hydrogen. Here too, the manufacture, installation, operation and maintenance of electrolysers as well as the transport of hydrogen are the key aspects for added value. Further economic effects arise from the expansion and operation of hydrogen storage. To this are added indirect effects for the hydrogen regions.

With the production of hydrogen within Europe, the added value, as well as positive job effects, is significantly greater than from importing. This is true, in particular, for the first stage of the value-added chain, renewable electricity production, but also for the installation and operation of electrolysers (Wuppertal Institute and DIW Econ 2020).

In a study by Ludwig-Bölkow-Systemtechnik GmbH (LBST) for the German state of North Rhine-Westphalia, the potential job effects are evaluated as follows (Michalski et al. 2019):

- operating wind onshore plants: 559 jobs/GW_{el}
- operating wind offshore plants: 1839 jobs/GW_{el}
- operating PV systems: 270 jobs/GW_{el}
- operating electrolysers: 280 jobs/GW_{el} in 2030 / 120 jobs/GW_{el} in 2050

For comparison, the employment figures in German brown coal power stations (Öko-Institut 2017):
operating a modern brown coal power station: 250 jobs/GW_{el}

As already mentioned, further jobs would emerge in the planning/engineering as well as in the construction of the facilities. Production by the facilities also creates jobs; these might, admittedly, arise from exporting the systems, for example, and are not tied to the production of hydrogen within the EU. Having said that, these jobs would only arise in the short to medium term because it can be expected that facilities will be manufactured in the hydrogen-producing countries in the long term due to the experience and increased knowledge from the operation itself. In principle, high percentages of imports would raise the question of whether developing electrolyser manufacturers or market leadership in Europe is possible at all, as economies of scale will hardly be generated and knowledge can hardly be expanded (Wuppertal Institute and DIW Econ 2020; Greenpeace Energy eG 2020). It is consequently also debatable in the short term whether innovations and consequently also new jobs may emerge in Europe when close contact between manufacturers and operators of electrolysers is not possible on site.

In general, neither renewable electricity nor hydrogen will be produced and used in addition to fossil energy carriers, but instead this is why there will be displacement effects. This means not only new jobs will emerge, but also existing jobs in the conventional energy industry will be lost. When designing processes of structural change, the question then arises to what extent the jobs emerging in the renewable industry can be located where jobs will, for example, be lost in coal or natural gas extraction. If, due to local circumstances, the expansion of renewable facilities is possible, it should be determined to what extent the skills and competences necessary for the new jobs overlap with those in the conventional energy industry. If other or advanced knowledge is necessary, offers of retraining and advanced training will have to be devised. In order to be able to use the full transformation potential of the regions, these should not only address (former) employees from coal, natural gas and oil production, but in addition reach out to other target groups. For example, predominantly men work in both the conventional and in the renewable energy industry. How can women also be recruited into the regions affected by structural change for jobs in the renewable energy industry and if necessary be trained (IRENA 2019b)? Furthermore, it is worth counteracting brain drain and making the region attractive for those who want to stay, for example, with a very good training programme on site (Oei, Brauers, and Herpich 2019).

3. Areas of application

The development of a hydrogen infrastructure must be designed over the long term. This is why forward planning is necessary. Renewable hydrogen will only be available in a very limited way in the short and medium term. It is difficult to project in what quantities and at what cost renewable hydrogen will be available over the long term. In order, firstly, not to over-dimension the infrastructure and, secondly, to be capable of operating and fully utilising the established hydrogen infrastructure with renewable hydrogen, it is advisable to prioritise according to individual fields of application. Fields of application which have no possibility of electrification or other decarbonisation and will also be necessary in a sustainable economic system in the long term should be given priority. This needs targeted support. Below, we outline in which sectors hydrogen can be expected to be used according to these principles.

3.1 Key messages

- Hydrogen and hydrogen-based synthetic fuels should only be used on grounds of efficiency where electrification is not possible.
- Projections regarding hydrogen demand should not be oriented in isolation to the status quo, but take into account the objectives of society as a whole and thereby also fundamental modification options.
- Various technologies for direct electrification as well as heat storage are available to provide building heat. Hydrogen should therefore only play a marginal role.
- Hydrogen should be available in industry in a targeted way for applications (in particular, steel production, the chemical industry). The use of hydrogen for process heat generation is debatable, as more efficient electricity-based methods are already available or are being developed for the high-temperature range.
- As a consequence of long lifetimes, in industry investment should only be made in technologies which are compatible with the long-term objective of GHG neutrality.
- Comprehensive developments, such as changes in lifestyle (sufficiency), expansion of the circular economy as well as a more sustainable orientation in agriculture must be taken into account regarding projections of the future hydrogen demand in the industrial sector.
- The use of hydrogen in passenger cars is not advisable due to their poorer efficiency compared with battery electric vehicles (BEV). Infrastructure planning should therefore focus on the charging infrastructure for BEV and not on a hydrogen filling station infrastructure.
- Hydrogen and hydrogen-based fuels should be used in the transport sector primarily in aviation and in parts of shipping and heavy-load traffic.
- In addition to hydrogen production by means of electrolysis, storage and reconversion, other more efficient flexibility options are available in the electricity sector. Future demands for flexibility options in general as well as the need for hydrogen as a flexibility in particular must be established integrated with the planning of the entire energy system.

3.2 Homes

In 2015, natural gas at 1297 TWh covered most (44 %) of the heating supply in the EU-28. Thereby, 14 % fell to district heating; the rest was incinerated in boilers. Biomass was the second-most used (570 TWh), followed by oil (427 TWh). Coal covered 333 TWh of the heating supply, two thirds of which was used in the district heating supply. Nuclear energy for the heating of residential buildings using electric heating or heat pumps amounted to 200 TWh. RE (excluding biomass) covered the lowest amount of the heating supply at only 85 TWh (Bertelsen and Vad Mathiesen 2020).

Altogether, the overview shows that the heating supply to buildings is to a large extent still based on the use of fossil energy carriers. At the same time, there are a lot of renewable technologies which can be used to supply heat to buildings. These include near-surface and deep geothermics as well as the use of other forms of ambient heat and solar thermal energy.

3.2.1 Deep geothermics

Deep geothermics exploits the heat stored in the interior of the earth and is continuously and controllably available. It can be differentiated between high-temperature storage sites (linked to volcanic or tectonic activities and used worldwide for over 100 years) and low-temperature storage sites (< 100°C). Geothermal energy can be deployed in situ as well as in local and remote district heating. In addition to heat, electricity can also be generated. The seasonal storage of heat and cold (in what are known as aquifer storage facilities) is another application option of geothermal systems. For example, industrial waste heat could be stored in the summer to provide heat in the winter. The Netherlands have already implemented over 2,000 of these storage facilities (Heumann and Huenges 2018).

The successful realisation of geothermal systems needs, alongside appropriate geological conditions, a predictable and adequate heating sales market and the connection to corresponding distribution networks, project financing (high initial investment, long implementation periods, long project duration), as well as local acceptance (seismic activity through the construction and operation of plants) (Heumann and Huenges 2018). Dalla Longa et al. (2020) calculated a potential for deep geothermics of approximately 880 to 1050 TWh/a for the EU-28 in 2050.

3.2.2 Near-surface geothermics and other ambient heat

Ambient heat includes natural sources of heat, such as near-surface geothermics and waste heat from bodies of water and air as well as waste heat from industrial processes. Air is an easily accessible and cheap source with a lot of potential. Having said that, it is characterised by a seasonal temperature profile. Near-surface geothermal energy (depending on the depth) follows the soil temperature over the course of the year in a delayed and moderated way. From a depth of ~3 m, the temperatures are seasonally relatively stable. The efficiency of the waste heat from industrial processes depends on its continuous availability and temperature level and must initially be captured in situ and incorporated into the thermal design (Herkel, Miara, and Schossig 2018).

As a rule, the temperature level available due to ambient heat is not sufficient for the heating supply and must be raised by means of electrically-driven heat pumps. In the meantime, it is also possible to use the heat pump technology in existing unrenovated buildings (Greenpeace Energy eG 2020). The higher the percentage of RE in the electricity mix, the better its environmental balance and the greater the importance of heat pump technology to sector coupling (Herkel, Miara, and Schossig 2018; Fraunhofer IEE 2020; Yilmaz et al. 2018). In addition to supplying the building, heat pumps can also be integrated into local and district heating networks. The lower the flow temperature in the networks, the higher the efficiency of the systems.

3.2.3 Solar thermal energy

Solar thermal energy is another technology for the renewable heating supply. Admittedly, a large part of the solar yield falls in the summer months. With the aid of short-term storage systems, coverage of 10 – 30 % of the space and drinking water required can now be met. With the aid of enhanced storage capacities, up to 50% can actually be reached ("solar houses"). Having said that, solar thermal energy requires additional sources of heat depending on the region. Like the heat pump, solar thermal energy can be used both in situ and in local and district heating. The level of efficiency rises the lower the flow temperatures. Austria and Denmark, for example, have a lot of experience in using solar thermal support in district heating (Giovannetti et al. 2018).

3.2.4 Thermal storage facilities

Compared with electricity, heat can be stored relatively easily. Large underground storage facilities can contribute to adjusting seasonal variations and to increasing the renewable percentages of the provision of heat to supply buildings. Thermochemical storage facilities in particular have huge potential with regard to increasing storage density and minimising thermal losses in the case of seasonal storage. However, its exploration is still in its infancy. Pit stores, geothermal probes and aquifer storage facilities have the lowest specific costs compared with other technologies (Puchta and Dabrowski 2018).

3.2.5 Reduction in energy consumption to heat buildings

Building insulation is another important contribution to decarbonising the heating supply. 35 % of buildings in the EU are older than 50 years and 75 % of buildings were built before energy standards in the building sector were established. In order to meet the objective of climate neutrality, up to 97 % of buildings would have to be renovated and the current renovation rate doubled. In the process, the buildings with the worst insulation should be given priority (EC 2018a, 90). In the "Clean Planet for All Baseline" scenario (this only considers policy actions which had already been proposed by the EC), energy consumption in homes will fall by 38 % by 2050 compared with 2005; in the "1.5 LIVE" scenario, 57 % reduction will actually be achieved (EC 2018a, 99).

3.2.6 Hydrogen

One option of using hydrogen to heat buildings would be adding it into the natural gas network (cf. 4.1.2). This could not address homes as yet heated by coal or oil at all, however, as they are not connected to the gas network. Only homes connected to the gas network could be decarbonised to a small extent in this way. However, even with an addition rate of 20 %, only an approx. 7 – 8 % reduction in CO_2 can be achieved, as hydrogen has a lower energy density than natural gas and a larger gas volume is necessary to provide the gas consumption with the same amount of energy (Fraunhofer IEE 2020). In order to achieve a significant emission reduction in the heating sector, the percentage of hydrogen would have to be considerably higher. Having said that, all connected gas terminals would then have to be replaced and the gas distribution networks converted to hydrogen, which means that the use of hydrogen in heating buildings would then be associated with a lot of effort and high costs. There is, consequently, no infrastructural benefit from using hydrogen in the heating supply compared with electrification. At the same time, especially in the case of low-temperature heat, the fact that the heat pump (efficiency of approx. 285 %) is always far more efficient than fuel cell heating (efficiency of 45 %) must never be forgotten either (Agora Verkehrswende, Agora Energiewende, and Frontier Economics 2018).

In district heating, the use of hydrogen in gas-fired power plants would be an option. There is, however, no direct benefit over the direct electrification and use of waste heat for supplying the base load with hydrogen in district heating. By contrast: Local and district heating networks provide the opportunity of integrating different technologies as well as heat sources. This benefit should also be used for the heating transition. In the case of hydrogen, the waste heat arising from the reconversion could be fed into local and district heating networks. The combined heat and power plants (CHP plants) used for this complement renewable energy systems if, due to the weather, little electricity can be produced, but the demand is high. Despite the higher investment, it may be advisable to use (electrically-driven) CHP plants for the reconversion instead of gas turbines, as reconversion capacities are then likely to be used even if the demand for heat is high. Assuming an integrated European energy system, these periods may be limited. In order to avoid the need to develop considerable back-up capacities, these periods should be increasingly bridged by load management. Reconversion plants will only be needed if the percentage of renewable energies in the whole energy mix is very high (section 3.5).

3.2.7 Conclusion

Various direct electrification options are available for the provision of heat to buildings. Direct electrification will always be more efficient than the use of hydrogen and its derivatives, primarily due to the transformation losses incurred in production. The waste heat from the hydrogen reconversion may be fed into local and district heating networks. Currently, it is, however, still unclear to what extent hydrogen will be used as a storage medium in the electricity sector.

3.3 Industry

The future demand for hydrogen from industry is associated with huge uncertainties. Present estimates of the demand from industry in the EU in 2050 are assuming a reduction in GHG of at least 95 % between 160 and 630 TWh (Agora Energiewende and AFRY Management Consulting 2021).

Three factors are of particular importance to the level of demand.

- Firstly, the demand trend forecast in the studies of the raw materials produced using hydrogen and consequently also outlooks for economic growth and the development of the circular economy are critical.
- Secondly, it should be noted that the demand for hydrogen in the EU also depends on the choice of location of the individual value creation stages for hydrogen-based products. Importing products manufactured using hydrogen will result in a decrease in the demand for hydrogen within the EU.
- Thirdly, the application of hydrogen in the industrial sector may be subdivided into two categories. On the one hand, hydrogen can be used as a raw material, for example, in the chemical industry as well as the steel industry. On the other hand, the energy use of hydrogen as a fuel to generate process heat, for example in the glass industry, is being discussed. The demand for hydrogen differs in existing studies depending on the consideration of heat generation from hydrogen.

The use of hydrogen is consequently debatable in particular in the context of generating process heat. The reason for this is that increasingly electric and consequently more efficient technologies for covering the demand for heat – also in the field of high-temperature heat – are being developed (Agora Energiewende and AFRY Management Consulting 2021). Furthermore, a reduction in the final energy demand for process heat in Europe is possible in the wake of the circular economy (Fuel Cells and Hydrogen Joint Undertaking 2019).

The use of hydrogen as a material is also characterised by uncertainties. Industrial processes in the EU currently use between 257 and 325 TWh of hydrogen each year, which is to a large extent generated in steam reforming plants (Agora Energiewende and AFRY Management Consulting 2021; Fuel Cells and Hydrogen Joint Undertaking 2019). The highest demand is in refinery technology processes and the chemical industry. In the future, the demand for hydrogen from the refinery technology sector will fall, while, primarily, steel production will be added as a new source of demand. These three important fields of application for hydrogen in industry will be briefly examined in more detail below.

3.3.1 Refineries

Hydrogen is currently used in refinery processes to derive fuels from mineral oil for the transport sector as well as hydrocarbons as a raw material for the chemical industry. As the use of mineral oil is not compatible with the GHG objective, synthetic fuels are used for some applications in decarbonisation scenarios in the transport sector and synthetically manufactured base products in the chemical industry.[8] Assuming that the products will be produced outside the EU and subsequently imported, the demand for hydrogen in refinery operations in the EU will disappear (Agora Energiewende and AFRY Management Consulting 2021). If the production of synthetic fuels and base products using hydrogen does, however, take place in the EU, the demand for hydrogen for the corresponding production processes will grow (cf. section 2.2.3).

3.3.2 Chemical industry

Hydrogen is, amongst other things, used for the production of ammonia and methanol, two important raw materials for industry. Ammonia plays a role in the production of fertiliser in particular, while methanol represents one of the most manufactured organic chemicals (Fraunhofer 2019). In principle, the GHG emissions resulting from its production today may be reduced by replacing hydrogen based on fossil energy carriers with hydrogen produced by means of electrolysis using electricity from RE. However, in particular with regard to ammonia, it should be pointed out that the demand for ammonia and consequently also for hydrogen will fall sharply if the use of mineral fertilisers manufactured on a large industrial scale declines in line with sustainable agriculture.

In addition to the trend in the production of ammonia and methanol, an increase in plastic recycling processes may result in changes to the demand for hydrogen in the EU. In the course of the objective of a circular economy as well as restrictions in the export of plastic waste, plastic recycling could become more important in the future. Hydrogen is necessary for recycling processes (Fraunhofer 2019).

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[8] The forecast volume of electric fuel and raw materials depends on several factors. Firstly, the trend in the final demand, for example the demand for mobility in motorised private transport, will be pivotal. Furthermore, the volume will be determined by projected efficiency improvements. In addition, the extent of electrification will be of particular importance.

3.3.3 Steel production

71 % of steel produced in the EU is currently created using the blast furnace route. By reducing iron ores to form pig iron with coke, this method produces 1.8 tonnes of CO_2 per tonne of steel (Fuel Cells and Hydrogen Joint Undertaking 2019). Apart from this method, direct reduction (DR) using natural gas and/or hydrogen with subsequent further processing of the sponge iron forming in the DR plants in an electric-arc furnace is also one of the primary steel production routes. This method is associated with significantly lower emissions. However, it is debatable whether a complete reduction in CO_2 emissions is possible using this method, as the production of high-grade steel in particular anticipates the use of a hydrogen/natural gas mixture[9] for DR (Agora Energiewende and AFRY Management Consulting 2021).

In the secondary route, steel scrap is melted down in the electric-arc furnace so that, assuming a decarbonised electricity mix, this method does not produce any CO_2 emissions. The percentage of scrap-iron based electrical steel is, however, limited by the availability of steel scrap and by the quality requirements of the steel to be produced. More recycled steel could be produced by improving the sorting of steel scrap as well as establishing standards for steel (Agora Energiewende and Wuppertal Institute 2019). Potential estimates consequently assume an increase in the EU-wide percentage of scrap-iron based electrical steel from approximately 40 % in 2015 up to 77 % in 2050 (Fleiter et al. 2019). Furthermore, the electricity demand for the secondary route is only a quarter of the electricity demand of steel production in DR plants (Agora Energiewende and Wuppertal Institute 2019). The holistic approach consequently strongly suggests increasing the percentage of scrap-iron based electrical steel as far as possible.

3.3.4 Conclusion

The huge uncertainties with regard to the applications for hydrogen in industry are becoming a present-day challenge due to the capital intensity and long technical lifetimes of 50 up to 70 years of customary large plants in the industrial sectors relevant to the demand for hydrogen (Agora Energiewende and Wuppertal Institute 2019). The long lifetimes mean that investments should only be made in technologies which are compatible with the objective of decarbonisation. Furthermore, large specific investments give rise to a long-term demand for the energy carriers established within the technology selection. Uncertainties with regard to the availability and cost of the energy carrier used may result in investment not being arranged, but deferred. Equally, the investment may give rise to what are known as “stranded assets” if the demand for the energy carrier cannot be covered in the long term (from a business perspective). It is therefore of importance to industrial sectors, such as steel production and the chemical industry, to create planning certainty with regard to the availability of hydrogen. At the same time, more efficient solutions, such as scrap-iron based electrical steel production, should, however, be developed and be the focus. Equally, the present final demand in industry should not be perpetuated in isolation, but comprehensive interdependent developments and objectives, for example in agriculture or mobility behaviour, should always be taken into account.

3.4 Transport

The transport sector is responsible for approximately a quarter of all GHG emissions in the EU and is the only sector in the EU in which emissions have actually risen since 1990. As a result, the sector is, however, also demonstrating a huge potential for GHG reductions at the same time (EC 2018a) for which appropriate measures are already available today.

Hydrogen has hardly played a role in transport in Europe to date. So, the percentage of hydrogen consumption in the transport sector is not recorded separately at all (Statista GmbH 2021). Hydrogen-based synthetic fuels have hardly been in use to date either. Biofuels can only be produced in small amounts according to environmental, justice and sustainability criteria and should, therefore, not play any significantly greater role in the future and the manufacturing process will essentially be limited to “Second Generation” biofuels[10] (Emmrich et al. 2020; CAN Europe and EEB 2020).

[9] High-grade steel in particular requires a specific carbon content which must be provided by the methane in the gas mixture.

[10] These include fuels not produced on the basis of organic sources, which may serve as food at the same time (e.g. sugar cane, maize, rapeseed and soya).

In order to be capable of achieving the objective of “climate neutrality” in the EU by 2050, the EC is planning for a greenhouse gas reduction in the transport sector of 90 % by 2050, which is ambitious, but is at the same time contingent on another compensatory measure and negative emissions and cannot therefore be deemed sufficient. As a result, different scenarios were developed, which demonstrate decarbonisation of the transport sector by 2040 (Emmrich et al. 2020; CAN Europe and EEB 2020).

3.4.1 Passenger cars

The combustion of diesel and petrol in internal combustion engines gives rise to climate-damaging CO_2 as well as other air pollutants, such as soot and nitrogen oxides, which are extremely harmful to the environment and human health and result in additional deaths and diseases (Umwelt Bundesamt 2021; Lozzi and Monachino 2021; EEA 2020). The percentage of emissions from passenger cars of overall emissions in the transport sector is at 45 % the largest area and calls for a rapid decarbonisation of the fleet of approximately 260 million cars with internal combustion engines in the EU (EEA 2020). In principle, 3 options are available for this: battery-electric vehicles (BEV), fuel cell electric vehicles (FCEV) and combustion of hydrogen-based synthetic fuels (e-fuels) (Transport & Environment 2018).

When selecting the strategy for decarbonising passenger cars in Europe, which is the most efficient and most sustainable type of drive should, however, always be verified. Different scenarios and analyses (Emmrich et al. 2020; CAN Europe and EEB 2020; Transport & Environment 2018) view the battery-electric drive as beneficial in the private passenger car sector on grounds of efficiency and cost. Direct electrification in the passenger car sector and any other sectors where possible should also be considered as a priority in the EGD strategy (EC 2018a, 10). At the same time, an extensive battery-electric fleet of passenger cars also provides the opportunity to make a big contribution to grid stability and security of supply via integration which serves the grid (vehicle-to-grid).

3.4.2 Transport, air traffic and shipping

Hydrogen and its derived products should, due to their energy efficiency and for economic reasons, only operate those types of drive which from today’s perspective cannot be electrified directly or where battery storage cannot be used due to limited capacities (Transport & Environment 2018; Emmrich et al. 2020). According to today’s level of development, these areas of application are, chiefly, air traffic as well as elements of shipping and long-distance haulage (Emmrich et al. 2020; EEA 2020). A filling station system which is geared towards long-distance haulage will turn out significantly more loose-knit than the existing filling station system. For example, 140 filling stations would be enough for Germany (Rose, Wietschel, and Gnann 2020). More recent studies show that battery-driven and overhead line HGVs may also have an advantage in the field of long-distance heavy goods vehicles regarding greenhouse gas intensity compared with HGVs run on fuel cells and synthetic fuels (Aleksandar Lozanovski et al. 2020). Even in air traffic, in which the combustion of kerosene in jet engines was considered as without alternative for a long time, there are new developments that could, in future, forego the combustion of kerosene, hydrogen or e-fuels in battery-electric aircraft (Gnadt et al. 2019; Schäfer et al. 2019), which are, however, still in the design phase. In general, we find that the transport of goods will increasingly have to be shifted from the road onto rail and in some instances onto inland waters in order to reduce the overall traffic volume in this area and consequently also the emissions (Emmrich et al. 2020).

3.4.3 Modal shift, sufficiency and sustainable urban development

Despite technological progress, a climate-neutral transport sector will not be achievable without an absolute reduction in traffic volume (sufficiency) as well as a change in the mode of transport selected towards walking and cycling, which goes hand in hand with improvements in health and quality of life (Sandberg 2021; Waygood, Sun, and Schmöcker 2019). Implementing these measures is encapsulated in the concept of what is known as modal shift. This means the transition from emissions-intensive transport options (motorised private transport) to low-emission or emission-free options (local public transport, cycling and walking) and the related short-term and long-term infrastructure planning (Meinherz and Binder 2020; Strömgren et al. 2020). European strategies will also address these measures. At the end of 2020, as part of the Green Deal, the EC published a “Strategy for sustainable and intelligent mobility” in which it presents a roadmap towards achieving the CO_2 reduction targets in the transport sector by developing 10 flagship initiatives and 82 measures (EC 2020). The strategy particularly highlights intelligent networking and digitalisation as well as sustainable urban development to reduce the volume of traffic.

3.4.4 Conclusion

In addition to exploiting all the potentials to reduce the traffic volume and the shifting of traffic towards local public transport as well as walking and cycling, infrastructure and measures for direct electrification should be created. Only the remaining traffic volume not directly electrifiable should be converted to hydrogen options. The measures available, such as widespread electrification of the traffic volume, modal shift and sufficiency measures, require long-term planning and investment in infrastructure. These must therefore be integrated into urban planning as a key element now and, for reasons of acceptance, be developed together with European citizens.

3.5 Electricity

In a future electricity system based on RE, the demand is growing for flexibilities which can offset the volatile electricity feed-in from wind turbines and PV systems. The generation of hydrogen by means of electrolysis, its storage and subsequent reconversion is one of several flexibility options. At times of high electricity feed-ins from RE, hydrogen may be generated cheaply by means of electrolysis. With low electricity feed-ins, this can be used in gas turbines, gas-fired power plants and steam power plants or fuel cells to generate electricity (D. Caglayan et al. 2020). Today, hydrogen is only used on a small scale for heat or combined heat and power generation in hydrogen boilers or CHP plants. This largely takes place on industrial sites where hydrogen is generated as a by-product (Hydrogen Europe 2020).

3.5.1 Other flexibility options

Another flexibility option is battery storage, which is particularly suitable as short-term storage (in a period from hours to days) (Child et al. 2019). Pumped-storage power plants also present an alternative, whereby the capacities for this technology are limited in Europe and are largely already being used (Hainsch et al. 2020). To compare storage solutions, it is relevant that the transformation losses are considerably smaller in battery storage than the transformation losses from hydrogen generation and reconversion (Robinius et al. 2020). Having said that, other technical and economic characteristics of storage facilities as well as the requirements resulting from the generating plants must also be taken into account. Integrated analyses of the overall energy system are therefore required for the selection of the storage options.

In addition to storage solutions, the European electricity market, heating networks and demand-side adjustments also offer flexibility. The expansion of interconnectors (cross-border electricity transmission networks) enables regional differences to be equalised. In order to establish this flexibility option reliably, supranational, integrated dimensioning of the energy system as well as long-term agreements on the use of the capacities are a prerequisite. Heating networks with electric feed-in of heat can also make a contribution to the temporal flexibilisation of the electricity system, as the heating network itself constitutes a heat store and its capacity may be increased by additional heat stores. Likewise, demand-side flexibility options are conceivable due to the targeted adjustment of the demand for electricity ("demand side management") in particular in the industrial sector. These flexibility options are, however, difficult to calculate in the long term compared to the storage solutions, as long-term agreements with numerous private sector companies would be required to make adjustments to the operation of heating networks or the demand for electricity.

3.5.2 Conclusion

In general, hydrogen could be used in an electricity system based on volatile RE to balance the electricity supply and demand. However, other flexibility options with different technical characteristics and varying organisational effort are also available. The options must be assessed with a view to the entire energy system. Hydrogen will probably be relevant as a flexibility option for the electricity system only with a very high percentage of RE due to transformation losses and limited availability.

4. Infrastructure (planning)

Planning the energy infrastructure is crucial for shaping the energy system of the future. This is because long-term investment decisions are made for infrastructures (the lifetime for gas transport infrastructure is 80 years on average), which means that today's plans and investments in infrastructures create options and consequently decide which decarbonisation pathways can be taken in the future and what costs these entail (Heilmann, De Pous, and Fischer 2019). Normally, in many energy system studies, decarbonisation scenarios, which either continue to be based traditionally on the transport and trading of large volumes of gases (i.e. natural gas, hydrogen and their derivatives) or envisage extensive electrification, are diametrically opposed. There has, consequently, not yet been any unified view on the role of hydrogen and there are huge uncertainties with regard to the size of the hydrogen system required in the EU. Assumptions regarding this are, however, of great importance to infrastructure planning. In order to meet this challenge, this chapter firstly presents the technical/systemic characteristics of hydrogen infrastructure and then, based on this and in the context of the uncertainties mentioned, expresses initial findings and recommendations for the infrastructure planning of the entire energy system as well as for hydrogen infrastructure planning.

4.1 Key messages

- From a technical point of view, a lot of questions with regard to the future transport infrastructure as well as the storage potentials of hydrogen are still unresolved.
- Hydrogen imports from third countries are, from a technical point of view, complex and associated with high transport costs.
- Salt cavern stores probably offer the greatest potentials for storing hydrogen cheaply. However, their suitability has not yet been definitively confirmed. Innovative storage, which can flexibly inject, withdraw and store large volumes of hydrogen in solid or liquid carriers (LOHC, metal hydride or cryogenic storage), still requires considerable research and development (R&D requirement) for economical use on a larger scale. Overall, hydrogen stores will, from today's perspective, be more expensive than natural gas stores.
- In principle, the costs of hydrogen networks could be reduced significantly by reassigning natural gas networks to hydrogen networks. In so doing, it must however be noted that the future demand for and source of hydrogen differs significantly from today's demand for and source of natural gas. Only reassignments which are appropriate from the long-term perspective should be realised.
- Expanding the natural gas infrastructure in the course of reassigning natural gas pipelines is counterproductive, in particular due to the exit from natural gas necessary for the objective of climate neutrality.
- The addition of hydrogen into the natural gas network (blending) must, due to its low potential for CO_2 savings, only be considered to balance the speed of the development of hydrogen production and a hydrogen transport infrastructure alongside hydrogen applications. However, the risk of lock-in effects must be taken into account here.
- The hydrogen system, as part of the overall energy system, is closely related to the electricity and also the natural gas system. An integrated planning of the energy system aimed at the objective of climate neutrality is therefore essential for an efficient development of the entire energy system.
- For energy infrastructure planning, it is highly relevant to incorporate knowledge of various stakeholders, including independent experts and NGOs, and consequently take favourable transformative pathways from a macrosocial perspective.
- Groundbreaking decisions must be made with regard to the development of the hydrogen system in order, firstly, to ensure focus on complying with the 1.5°C target and, secondly, to facilitate targeted efficient development.

4.2. Technical/systemic aspects

This section focuses on the technical/systemic characteristics of the hydrogen system. Firstly, the interdependencies of the hydrogen system with the electricity and gas system are outlined. Then, there follow overviews of the transport and storage options for hydrogen.

4.2.1 Hydrogen as part of the energy system

The hydrogen system, as part of the entire energy system[11], is associated with the electricity and gas system and consists of several components itself. Coordination between the interdependent components is necessary so that customers can use hydrogen.

The hydrogen system includes production facilities, user facilities, transport infrastructure and storage. Electrolysers as production facilities are in turn integrated into the electricity system. Consequently, site selection and operational concepts for electrolysers have impacts both on the hydrogen system and on the electricity system. If, for example, electrolysers are established near the demand for hydrogen in what are known as “hydrogen valleys”, this reduces the transport requirement for hydrogen, while the need to expand the electricity network may grow and vice versa.

The impacts of the operational concept of electrolysers on the electricity and hydrogen infrastructure are shown below: If the operation of the electrolysers conforms to the availability of electricity from RE, a higher storage capacity for hydrogen will be needed compared to demand-oriented operational management. However, demand-oriented operational management of electrolysers may also have impacts on the dimensioning of the electricity system (for example, higher generating capacities or more extensive flexibility options could be necessary).

Furthermore, there are also coordination needs between the natural gas and hydrogen system. Firstly, a reassignment of natural gas pipelines to hydrogen pipelines is being discussed, which would give rise to coordination needs. Secondly, on the production side, natural gas is required as a raw material in steam reforming plants. Transport infrastructures for natural gas and also for hydrogen will therefore be required at steam reforming plant sites, if the hydrogen is not fully used on site. In addition to this, coordination needs would arise with a CO_2 infrastructure if upgrading steam reforming plants with CCTS facilities took place. Thirdly, there are interdependencies on the user side between the hydrogen and natural gas system. For example, when switching users from natural gas to hydrogen, the infrastructures required must also be adjusted. Steel production in DR plants gives rise to the possibility that, as described in section 3.3.3, hydrogen and methane will be in demand at the same time.

Furthermore, taking into account the waste heat potentials of industry and electrolysers may result in greater efficiency, which means that coordinating electrolysers and the waste heat from industry as well as local heat demand could also be worthwhile here. High-temperature electrolysers achieve a high level of efficiency if waste heat from industrial plants can be used (cf. section 2.2.2). Also, the use of waste heat from electrolysers in heating networks is perspectively intended in some projects, such as Westküste 100[12] in northern Germany.

In general, it is clear that there are extensive coordination needs due to the numerous interdependencies and the hydrogen system cannot be viewed in isolation. Only with an integrated view of the energy systems can the most efficient solutions be identified. When developing a hydrogen system, the electricity and gas system as well as sources of and demands for heat alongside the ramifications for these energy systems[13] must, consequently, also be taken into account (cf. section 4.3).

4.2.2 Transport infrastructures

Depending on where hydrogen will ultimately be produced, and is to be used, appropriate transport infrastructure is necessary. Generally, when transporting hydrogen, the distinction must be made between short distances and long distances. For the use of hydrogen in the transport sector, a filling station network would also have to be established[14]. For short distances, hydrogen networks seem to be particularly suitable. Their construction, however, requires time for planning and coordination (cf. section 4.2.1). The reassignment of natural gas pipelines is likely to involve a particularly extensive

[11] The entire energy system includes all the components instrumental to the energy supply. All energy carriers (e.g. electricity, gas, biomass) are, consequently, also taken into account. A systemic, integrated approach becomes more important in the course of the growing interconnection of sectors, as demand in the transport, heating and industrial sector can be covered directly by using electricity or electricity-based energy carriers (e.g. hydrogen) and, consequently, all sectors are connected to each other.

[12] https://www.westkueste100.de/en/

[13] The development of an extensive gas system for carbon-based energy carriers (e.g. synthetic methane) will not be considered further here, as this is regarded as unlikely due to transformation losses during the production of carbon-based energy carriers from hydrogen (cf. section 2.2.3).

[14] These filling stations cannot only be realised by reassigning existing natural gas filling stations, but require specific storage and refuelling technologies, which are in general designed in a more expensive and more complex way than the refuelling of diesel or natural gas. A filling station network designed for heavy-load traffic may turn out very much more loose-knit than the existing filling station network.

coordination need, which could however significantly reduce the costs of hydrogen pipelines. Initial investigations demonstrate reduced costs of more than 60 % for long-distance pipelines. However, these investigations assume that the conventional pipelines are suitable despite the risk of certain metals becoming brittle due to hydrogen. No larger hydrogen pipelines made of steel operated at high pressures are currently in operation, which means that there is still an extensive need for research in order to be able to gauge the potential for reassignments (Cerniauskas et al. 2020).

The long-distance transport of hydrogen is challenging due to its low volumetric energy density. It will remain uneconomical in the long term to transport gaseous hydrogen across long distances by ship. There are alternative approaches for this. For example, the hydrogen could be 1) liquefied, 2) converted to ammonia or 3) inserted in carrier molecules with a higher energy density. All the methods mentioned involve their specific advantages and disadvantages, which Brändle, Schönfisch, and Schulte (2020) illustrate as follows:

1. Liquid Hydrogen (LH2) has a higher volumetric density than gaseous hydrogen and is therefore better suited to maritime transport. However, the hydrogen must be cooled down to temperatures below -240° C for liquefaction, which requires substantial amounts of energy. Besides this, the low temperatures required constitute a challenge for the materials used, which increases the costs of the transport (and storage) infrastructure. Boil-off is also a problem. LH2 transport is not yet well developed on a large scale, as there are currently no commercially available LH2 ships, but only smaller test vessels.
2. Ammonia (NH_3) is a compound of nitrogen and hydrogen and is gaseous at standard temperature and pressure. It can be liquefied at temperatures below -33° C and has a volumetric energy density which is 50 % higher than that of liquid hydrogen. The transport networks and infrastructure for ammonia are well established; maritime transport takes place in commercial liquefied gas tankers (LPG). The primary cost drivers of ammonia transport are its transformation and reconversion processes; transformation requires 7 – 16 % (Bartels 2008) and reconversion approximately 16 % (T-Raissi 2002) of the energy contained in the hydrogen.
3. Liquid Organic Hydrogen Carriers (LOHCs) are molecules which can absorb and release hydrogen through a chemical reaction. Examples of potential liquid organic hydrogen carriers are methanol, toluene and phenazine (Aakko-Saksa et al. 2018; Matthias Niermann et al. 2019). Their properties are similar to those of oil. They can therefore be transported in the existing infrastructure for liquid fuels (Aakko-Saksa et al. 2018). As with ammonia, however, high costs are associated with transformation and reconversion, which would require up to 40 % of the equivalent energy contained in the hydrogen (Wulf and Zapp 2018). In addition to this, the LOHC molecules currently being considered are often expensive and have to be transported back to their place of origin for reuse (IEA 2019b).

In summary, it can be said that hydrogen liquefaction or transformation is very energy-intensive and expensive and therefore increases the costs of hydrogen supply by 50 – 150 %, depending on the transport technology and distance (IEA 2019a, 608). Furthermore, all three options are not yet available on a large scale (Wijayanta et al. 2019).

Another option for the long-distance transport of hydrogen would be mixing it with natural gas in natural gas pipelines. Timmerberg and Kaltschmitt (2019) assume that the operating pipelines are potentially capable of transporting 10 % hydrogen by volume in the natural gas with negligible adjustments to the infrastructure. To be capable of using the hydrogen in its pure form, it should, however, be recovered again in appropriate systems. Otherwise, only a hydrogen/natural gas mixture is available for further use, which enables the high-grade hydrogen to flow into any (also inefficient) applications, contrary to the logic of prioritising applications. A blend of natural gas and hydrogen would also result in the heating value of the natural gas falling, while the price for it rises. Furthermore, in the long term, the natural gas users of today will not be the hydrogen consumers of tomorrow. In the event of mixing hydrogen, the costs of converting the natural gas network and the development of a hydrogen infrastructure would be borne by all consumers. In addition, the expensively produced hydrogen would no longer be available for applications reliant on it and the high quality standards for natural gas, which are of prime importance to industrial consumers, could no longer be guaranteed.

4.2.3 Storage options

Its low density (0.09 kg/m^3) and resulting tendency to diffusion, further reinforced by high pressures and temperatures prevailing in container tanks, means that hydrogen storage is associated with a lot of technical effort (Klell 2010). With regard to its mass, hydrogen has the highest energy density of all conventional fuels with, at the same time, a low volumetric energy content under standard conditions, which requires larger tanks or higher pressure to store it.

Hydrogen can be stored seasonally as an energy reservoir in large quantities – i.e. over several months. If this hydrogen is manufactured from RE electricity, there is the option of storing large quantities of RE electricity over longer periods and, if required, reconverting it into electricity again or supplying it to other applications. To achieve energy self-sufficiency, it is possible to connect hydrogen to intermediate energy storage in pressurised tanks using power-to-X plants. This type of storage is, however, less efficient than, for example, battery or compressed air storage due to the losses which arise during electrolysis, storage and reconversion (in fuel cells or combustion in hydrogen turbines) (Robinius et al. 2020 tables C.3 and C.7).

Intermediate storage of hydrogen is often necessary also to present a continuous, secure and application-oriented hydrogen supply to processes reliant on hydrogen (e.g. industrial processes or refuelling of FCEVs). Conventional storage tanks and underground storage are not always functional for flexible production and the flexible injection and withdrawal of hydrogen or easy handling (for example, to refuel vehicles). This still requires substantial research regarding innovative storage concepts (e.g. cryogenic liquid gas storage and LOHC storage) (Fraunhofer 2019).

The easiest and most cost-efficient way of storing large quantities of hydrogen is injection into underground salt caverns. As a result, salt caverns constitute a substantially cheaper alternative to storage tanks (Agora Energiewende and AFRY Management Consulting 2021). Europe has a theoretical potential of 84.8 PWh_{H2} available for this (D. G. Caglayan et al. 2020). If, however, the capacities of salt caverns which are further than 50 km away from the shore are excluded[15], the technical potential will fall to 7.3 PWh_{H2}.

Strong compression of hydrogen (up to 800 bar) enables this to be stored in special storage tanks in a compressed and, consequently, space-saving form. The compression and high pressure also reduce or prevent diffusion in the storage tank. These high-pressure storage tanks are used for small quantities of hydrogen primarily in mobile applications (passenger cars and HGVs) due to their convenient design.

Another option is the liquefaction of hydrogen. For this, the hydrogen must be cooled to below -240° C and compressed in an energy-intensive process. It can then be stored in liquid form in special, heat-insulated tanks. This type of storage is particularly suitable for the transport of larger quantities over long distances. Warming up during transport can, however, result in hydrogen being evaporated, unlike with compressed gas storage.

Liquid hydrogen can also be stored in cryogenic tanks. A cryogen is a liquid that boils at a temperature below approximately -150° C, which applies to liquid hydrogen (Li, Chen, and Ding 2010). If high pressure and low temperatures are combined, it is possible to store hydrogen in a transcritical state in a thermally insulated pressure tank, which enables a form of liquid hydrogen with a high energy density. However, there is still a significant need for research and development regarding the storage of liquid hydrogen in a transcritical state, which is currently being increasingly explored in the context of aerospace (Zuo et al. 2020).

Innovative storage options are chemical metal hydride storage, in which the hydrogen molecules decompose upon contact with the surface of the metal into molecular hydrogen and are stored in the lattice structures of the material or are adsorbed on the surface of certain materials (Bhattacharyya and Mohan 2015; Müller and Arlt 2013). The materials and metal hydrides currently available are still tremendously expensive and heavy. Novel materials are, however, being explored (Tarasov et al. 2021; Yartys et al. 2021).

Other innovative storage concepts are LOHCs ("liquid organic hydrogen carriers") (cf. section 4.2.3). Their advantage is that the existing infrastructure for petroleum products in the mobility sector and energy transport and storage could continue to be used (Matthias Niermann et al. 2019). However, there is still a significant need for research and development in the entire process chain and regarding the different carrier molecules (especially in their application in the mobility sector). At the same time, these types of hydrogen storage and hydrogen transport will be competing with other methods, which means that their technical and economic use must still be proven. The most promising LOHC is methanol, which could in future have an economic and process-related advantage over compressed or liquefied hydrogen for transport over long distances (M. Niermann et al. 2021).

[15] This restriction describes economic and environmental protection requirements originating from the disposal problem of the brine solution in the cavern construction, as saline brine solution cannot be disposed of in rivers and lakes.

The costs of hydrogen storage are difficult to quantify and vary depending on the size and type of application. Matthes et al. (2020, 71 tables 2 – 7, 2 – 8) assume a flat rate of €5/MWh for storage, whereby it is not evident what specific type of storage is being used. M. Reuß et al. (2017) assume that no pressure tank storage is used for the seasonal storage of hydrogen, as the costs of other types of storage (cavern storage, liquid storage and LOHCs) are in the range of €8 – €10/kg, while compressed gas storage is approximately €10/kg. The cheapest way of storing large quantities of hydrogen will, in all likelihood, constitute reassigned storage caverns (Agora Energiewende and AFRY Management Consulting 2021).

4.3 Energy infrastructure planning

Today, ENTSO-E (the European Network of Transmission System Operators for Electricity) and ENTSOG (the European Network of Transmission System Operators for Gas) are responsible for the planning of the electricity and gas infrastructure at European level, i.e. across borders. Both are a merger of the transmission system operators and long-distance pipeline system operators (hereinafter referred to as ÜNB and FNB), which are establishing a European network development plan on the basis of the respective national network development plans. This Ten Year Network Development Plan (TYNDP) will be published every 2 years, brings together the respective network expansion measures of the Member States and so forms the basis of the future expansion of the European energy infrastructure (e.g. LNG terminals, pipelines, electricity grids and electricity and gas storage). The objective is to ensure the interconnectivity of the European electricity and gas markets. The planning is based on three scenarios, which take into account the current policy measures and climate objectives of the European Union (ENTSOG and ENTSO-E 2019).

- “National Trends” (NT) are based on the national energy and climate plans (NECPs) as well as on other national policies and climate objectives and are (by their own account) compatible with the “2030 Climate and Energy Framework” and the “EC 2050 Long-Term Strategy”
- “Global Ambition” (GA) is based on economies of scale in centralised generation, such as offshore wind farms and power-to-X, and does (by its own account) conform to the 1.5°C target of the Paris climate agreement
- “Distributed Energy” (DE) is based on a more decentralised development of electricity generation, a sharp uptake of PV and does (by its own account) conform to the 1.5°C target of the Paris climate agreement

As energy infrastructure planning faces the challenge of the transformation towards a climate-neutral energy supply, it is questionable whether the existing planning processes are up to this task. The TYNDPs, in contrast with, for example, Germany’s network development plans (NDPs), are taking a more holistic approach by carrying out gas and electricity network planning in an integrated way. Nevertheless, the spectrum of scenarios underlying network planning does not seem sufficient and comprehensive enough. A fully RE scenario which manages without CO_2 capture, negative emissions and nuclear power is not being considered and is, consequently, not being taken into account in network planning either. In this context, it should be questioned whether ÜNB and FNB include innovations and social trends in the planning beyond their field of activity to the same extent as potential options[16] (e.g. the implementation of CCTS infrastructure, the expansion of nuclear power and the widespread use of hydrogen), which do not require any fundamental changes to the structures of the status quo. This is because, for this purpose, ÜNB and FNB would have to have the knowledge needed[17] and integrate this consistently into their planning. Ultimately, the various personal interests of ÜNB and FNB, depending on the ownership and regulatory regime, in maintaining the value of the existing infrastructures should also matter for the development of the scenarios (Heilmann, De Pous, and Fischer 2019; Giannelli and Fischer 2020; Weber 2017).

In order to rise to the great challenge of transforming the energy system, integrated planning processes for the entire energy system are needed with a view to the considerable complexity of the energy system, which goes beyond the current network development planning (cf. section 4.2.1). Of particular importance here is to incorporate the knowledge of different stakeholders in the energy sector and civil society and, consequently, take beneficial socio-ecological transformation pathways from a macroscoial perspective.

[16] The development of a fully RE energy system, electrified, decentralised and close to its citizens as far as possible, will if anything be prevented by the implementation of CCTS technology, a further expansion of nuclear power and the widespread introduction of hydrogen (CAN Europe and EEB 2020).

[17] E.g. knowledge of new technologies, which can be used as a flexibility option or may result in high efficiency gains, but also of social trends and the potential of sufficiency measures.

4.4 Hydrogen infrastructure planning

The development of hydrogen supply and demand as well as the transport and storage capacities required for this needs comprehensive hydrogen infrastructure planning. This is why, in the context of the publication of the European Hydrogen Strategy, the "European Clean Hydrogen Alliance" (ECH2A) was established. This alliance brings together industry, national, regional and local authorities as well as civil society. In general, the ECH2A should serve to take and support the measures of the hydrogen strategy and increase the production of "renewable" and what are known as "low-carbon" hydrogen as well as its demand (EC 2020). Against this backdrop, the name of ECH2A seems misleading, as solely "renewable" hydrogen is designated as "clean" in the European Hydrogen Strategy. One focus for the work of the ECH2A is the development of an "investment pipeline"[18]. However, it should be questioned whether and to what extent interdependencies with other energy systems are taken into account in the development of the investment pipeline. Integrated holistic planning is necessary in order to identify beneficial transformation pathways from the perspective of citizens and to derive appropriate measures (cf. sections 4.2.1 and 4.3). This must specify the settings of the course for planning hydrogen infrastructure, as only in this way can all the potential options for the transformation be adequately taken into account.

At the start of hydrogen infrastructure planning, in addition to organisational issues, the demand side has several groundbreaking decisions pending in relation to transport infrastructure and also to production installations and facilities, which should be made at an early stage:

- As electrolysis using renewable electricity is the only option for CO_2-free hydrogen manufacture, an exit from fossil hydrogen is necessary (cf. section 2.2). The exit pathway is, however, yet to be defined. This is because the current electricity mix in the EU is not CO_2-free and, furthermore, includes a lot of nuclear energy, which means that even the production of hydrogen by means of electrolysis gives rise to CO_2 emissions if the electrolysers do not have a direct and exclusive connection to renewable generating facilities (cf. section 2.2.2). It should be noted that the direct relationship of renewable electricity to electrolysis may also have a negative effect for the renewable share of electricity in the electricity grid, as the electricity produced and used in this way would be "absent" in the electricity grid if renewable facilities are not additionally built. Especially in the light of the fact that GHG savings from grid electricity can only be realised for electrolysis from a very high share of renewable electricity (Matthes et al. 2020; Greenpeace Energy eG 2020), this additionality must be strictly enforced.
- In the context of establishing CCTS facilities, there is the risk of a fossil lock-in, as the costs must be regenerated by the plant. In addition to the amortisation of the costs, there is also the risk that the volumes of renewable hydrogen will not be enough in the long term to replace the hydrogen from steam reformation. Possible reasons for this could be that the potentials for the production of renewable hydrogen are inadequate or the expansion of wind turbines and PV systems is not moving forwards fast enough due to a lack of investment. It is also likely that CCTS, as in recent years, cannot be technically and commercially implemented in large-scale sectors (Jacobson 2019; von Hirschhausen, Herold, and Oei 2012). These threatening lock-in effects, which originate both from the existing installations and from new production facilities for fossil hydrogen, result in CCTS being incapable of contributing to the reduction in emissions from hydrogen production in either the short or medium term.
- Systems and components designated, planned and, where applicable, even promoted as "h2-ready" also harbour the risk of resulting in a lock-in effect. This is because "H_2-ready" means that the infrastructures so named (pipelines, storage) and consumers (in most cases, CHP plants) are technically no longer designed just for natural gas, but also for a natural gas/hydrogen mix and for up to 100% hydrogen as well (Wahl and Kallo 2020). A precise definition of H_2-ready is lacking however. This harbours the risk that an operation with 100 % hydrogen is not possible in the long term either and, consequently, the term is used to enable the promotion and marketing of another natural gas due to blending (Gondal 2019).
- The addition of hydrogen into the natural gas network also harbours the risk of a fossil lock-in, as this stimulates a market start-up for hydrogen, but this only contributes to a constant utilisation of the natural gas network and, however, neither stimulates the construction and upgrading of hydrogen networks nor the conversion of gas customers. In the short term, the admixture could encourage investment in electrolysers at sites with high RE potential, although there is still no hydrogen infrastructure there (cf. EC 2020). Nevertheless, it is highly doubtful whether the admixture may be beneficial due to additive quotas limited by customers with a view to the costs of adapting the facilities, customers or storage required compared with other transport options. According to these initial considerations, increasing the limits for the admixture is inadvisable and, as hydrogen loses value due to its addition into the natural gas network, as shown in the European strategy, the long-term addition of hydrogen into the natural gas network is not appropriate either.

[18] See: https://www.ech2a.eu/missionandvision

- The reassignment of natural gas pipelines into hydrogen pipelines could be an option to reduce the costs of developing H_2 infrastructure and, at the same time, to avoid “stranded assets” in the area of natural gas networks. However, the major challenge is to identify the natural gas pipelines, which from a technical point of view are worth considering for reassignment and are also required as hydrogen pipelines in the long term because a hydrogen network will turn out to be considerably smaller than today’s natural gas network (Cerniauskas et al. 2020). Natural gas networks being expanded elsewhere in the course of reassigning natural gas pipelines into hydrogen pipelines must also be avoided. Further research is therefore required as to which pipelines are suitable for reassignment and with what measures and, thereby also, costs the reassignment is associated. In addition to this, a transparent procedure should be developed in order also to put other stakeholders in a position to assess the suitability of natural gas pipeline for the reassignment.
- In the development phase, the question also arises as to whether the electrolysers should be established in what are known as hydrogen valleys or close to the generation and serviceable for the network. Integrated analyses of the energy system must be carried out in order to make the site selection for the electrolysers and, thereby also, decisions on the electricity and hydrogen infrastructure (cf. section 4.3). An assessment of the scientific findings currently available is not possible within this framework. It is at this time, however, advisable only to push forward and develop absolutely necessary applications and infrastructures, so-called “no regret” infrastructure, to prevent path dependencies and stranded assets (Agora Energiewende and AFRY Management Consulting 2021).

In general, it appears that the development of a hydrogen infrastructure is subject to a number of risks of generating lock-in effects. Groundbreaking political decisions must be made in order to take these risks into account. The basis for the decisions should be hydrogen infrastructure planning, which includes the knowledge of various stakeholders, including NGOs as well as independent experts, and is based on the integrated planning of the entire energy system with 100 % RE. The processes should be transparent, as well as focusing on climate protection and thereby also the interests of citizens, taking a cost-effective and efficient decarbonisation pathway.

5. Political level: The European Hydrogen Strategy

The European Hydrogen Strategy illustrates the vision of the EC for the importance and role of hydrogen for decarbonisation in Europe. Challenges are identified and potential instruments and measures to overcome them are briefly outlined. Furthermore, the hydrogen strategy contains a roadmap (cf. figure 1) until 2050. In the following, the focus is on this roadmap presented by the EC and resulting questions and points for discussion. The roadmap includes details on the manufacture and sourcing of hydrogen, the potential applications of hydrogen as well as the necessary infrastructure. Three chronological timeframes are considered here: 2020 – 2024, 2025 – 2030 and 2030 – 2050.

We divide the analysis of the hydrogen strategy into 5 aspects: 1) manufacturing method, 2) expansion and volume targets, 3) infrastructure and cost summary, 4) prioritisation of applications/ sectors and 5) imports.

5.1 Manufacturing methods

In general, the EC attaches great importance to hydrogen for the realisation of the GD. The EC declares it is prioritising "renewable hydrogen", which is manufactured using RE-operated electrolysers. Furthermore, the EC sees a need for "low-carbon hydrogen", which can be manufactured using various methods. As an essential feature of "low-carbon hydrogen", the EC states that the GHG emissions arising throughout its life cycle must be considerably lower than from current hydrogen manufacture. A limit is not indicated here however. Production based on fossil energy carriers with CCTS as well as by means of electrolysis using electricity from nuclear energy is consequently included, which runs counter to the objective of sustainable decarbonisation.

The following key questions remain unresolved with regard to the manufacture of hydrogen in the hydrogen strategy:

- What volumes of "low carbon hydrogen" are envisaged? What methods are behind these?
- What role will nuclear energy play in the generation of hydrogen?
- Besides the upgrading of steam reforming plants with CCTS facilities, are new steam reforming plants for the generation of hydrogen using fossil energies also being planned?
- What service lives are envisaged for the CCTS facilities installed in the transition period?
- Is there an intention to dismantle the CO_2 infrastructure or will this continue to be used for industrial companies?
- What interfaces are there for the natural gas exit and for the reassignment of gas infrastructure?
- How much CO2 will be stored in the transition period? What CO_2 storage will be developed for this?
- What time frames have been considered for the approvals and construction processes of CCTS facilities?

5.2 Expansion and volume targets

In order to produce the required volumes of hydrogen, the EC stipulates, amongst other things, that by 2024 and 2030 electrolysers with a cumulative output of 6 GW and 40 GW respectively should be installed. Under the optimistic assumption of an efficiency for the electrolysis of 87.5 %, approximately 1.4 million tonnes and 9.3 million tonnes of hydrogen respectively can be produced with continuous operation at full load. These volumes cannot be reached however, as no maintenance or fault-related downtimes are taken into account and continuous operation is not compatible with the volatile generation of RE. In addition to the development of electrolysis capacities, the upgrading of production capacities based on fossil fuels using carbon capture and storage technologies is envisaged.

Furthermore, the development of hydrogen and CO_2 infrastructures is an integral part of the roadmap. As "low-carbon hydrogen", from the EC's perspective, is needed for the transition period, the development of CO_2 transport infrastructure as well as the opening up of carbon storage will already be necessary before 2024. The planning of a pan-European hydrogen network should also start right away, even if the electrolysers will initially be built in the demand centres. In the long term, a pan-European hydrogen infrastructure and a hydrogen filling station infrastructure are anticipated.

		2020 – 2024	2025 – 2030	2030 – 2050
Manufacture & sourcing	RE uptake	• No information on renewable expansion	• 80 – 120 GW RE should be directly connected to electrolysers (investment of 220 – 340 billion €) • Faster implementation of large wind turbines and solar systems for H_2	• RE capacities will have to be massively increased • Assumption for investment projections: 500 GW using RE-operated electrolysers
	Renewable hydrogen	• Installation of electrolysers with output of at least 6 GW • Up to 1 million tonnes of RE hydrogen	• Installation of electrolysers with output of at least 40 GW • Up to 10 million tonnes of RE hydrogen	• No indication of volumes "The objective of the EU is clear: an integrated climate-neutral energy system in which hydrogen and electricity from renewable sources play a key role"
	Low-carbon hydrogen	• Upgrading of generating plants with technologies for CO_2 capture and storage • Assumption for investment projections: 5 million tonnes of low-carbon hydrogen „In the short and medium term, other types of low-carbon hydrogen will, however, also be required, primarily to rapidly reduce the emissions from existing hydrogen generation and to assist the distribution of renewable hydrogen at the same time and for the future"		• No explicit exclusion • But direct reference to low-emission hydrogen only in the transition period
	Imported hydrogen		• Reference to EU industry plan (40 GW in the EU, 40 GW from neighbouring states)	
Applications	Leading markets: Industry	• Existing H_2 demand (e.g. chemical sector) • Initial other industrial applications	• Supporting measures for H_2 in steel production	• All sectors in which alternative solutions for decarbonisation cannot be implemented or are associated with higher costs should be reached – from aviation and shipping through to industrial and commercial buildings which are difficult to decarbonise
	Leading markets: Transport	• Where applicable, heavy-load traffic	• Supporting measures for H_2 for heavy goods vehicles, rail transport, parts of maritime transport and other modes of transport (specific support of fuel cells)	
	Electricity system		• Daily and seasonal storage	
	Buildings	• Feed-in of H_2 into natural gas network conceivable	• Heating supply with H_2 in hydrogen valleys possible	
EU infrastructures	H_2 network	• Low demand for infrastructure, as electrolysers are in demand centres • Planning for EU network should start	• Creation of "hydrogen valleys" • Establishment of the backbone of a pan-European network and network of hydrogen filling stations • Establishment of hydrogen storage facilities „The objective of the EU by 2030 is the realisation of an open and competitive EU hydrogen market with unhindered cross-border trade and an efficient distribution of the hydrogen generated to the individual sectors."	
	CO_2 infrastructure	• Some forms of low-carbon hydrogen require infrastructures for CO_2 capture and use • No information on storage and transport		

Figure 1: Own illustration of the European hydrogen roadmap.

The following key questions remain unresolved with regard to the expansion targets in the hydrogen strategy:

- On what are the volume targets for 2024 and 2030 based? Are these limited by the forecast demand or by the production side?
- Why shouldn't the further expansion of RE start immediately rather than only after 2030?
- Which sector in Europe could have the long-term demand for hydrogen? What minimum volumes are anticipated in the long term?
- How many facilities based on fossil fuels will have to be upgraded and how high is the related investment?

5.3 Infrastructure and cost summary

The estimates in the hydrogen strategy for the necessary investments in the production of "renewable hydrogen" in the EU by 2050 are between €180 billion and €470 billion and those for the production of "low-carbon hydrogen" between €3 billion and €18 billion. In addition, investment in the transport, distribution and storage as well as in the hydrogen filling station infrastructure is reported to amount to €65 billion by 2030. Amongst other things, a cross-border refuelling network for pure hydrogen (and also alternative fuels) is required. Hydrogen should, at the same time, help to decarbonise private transport and also be used in HGVs in heavy-load traffic through FCEVs (Fuel Cell Electric Vehicles) as well as synthetic hydrogen-based fuels. Trains can be run on fuel cells and hydrogen-based ammonia could be used in fuel cells for ship propulsion engines. Air traffic can be decarbonised using hydrogen-based synthetic kerosene and cut significant amounts of GHG emissions.

Even within the demand sectors, the hydrogen strategy reflects much-needed investment. Retrofitting a steelworks is associated with investment of between €160 million and €200 million. A comprehensive overview of the necessary investments for the production and demand side as well as infrastructure is not shown. This can, however, presumably also be attributed to the huge uncertainty with regard to the long-term demand.

The following key questions remain unresolved with regard to the costs of a hydrogen infrastructure in the hydrogen strategy:

- What are the costs associated with the development of a pan-European hydrogen network that facilitates unhindered cross-border trade?
- To what extent do transport costs reduce the cost benefits of sites with greater production potentials for RE?
- What role can the cheaper transport of derivatives play in the future if these are used by the final consumer?
- Why is it expected that the expansion of RE can be implemented more quickly in connection with hydrogen production? Should RE be established and used resolutely for hydrogen generation?

5.4 Prioritisation of applications/sectors

In general, it is clear in the roadmap shown in figure 1 that at no time is a sector excluded as a hydrogen client. The demand for "renewable hydrogen" is, according to the roadmap, initially evolving in the industrial sector in particular where there is already a demand for hydrogen. Equally, heavy goods transport could already play a role early on. In the medium and long term, hydrogen will evolve as a storage option for the electricity sector. The EC also sees options for the use of hydrogen in the building sector. Initially, hydrogen could find its way into the building sector by being fed into the natural gas network. As the admixture, however, reduces the value of hydrogen, the EC only envisages this option if hydrogen infrastructure is not yet available and, consequently, decentralised facilities could be associated with high costs for storage. In the medium and long term, hydrogen will be conceivable in "hydrogen valleys" as well as in industrial and commercial buildings difficult to decarbonise.

The following key questions remain unresolved with regard to the prioritisation of sectors for the use of hydrogen in the hydrogen strategy:

- How will planning security be created for individual application sectors and/or individual hydrogen clients so that investment is stimulated?
- Will electrolysers be operated in a way serviceable to the system so that they are available as a flexibility for the electricity system?

5.5 Importing

Both the GD and the hydrogen strategy emphasise energy partnerships with third countries and regions as key to the European energy market. The hydrogen strategy even has a separate chapter entitled “international dimension”. This highlights the fact that the international dimension is an integral part of the EU strategy. Southern and eastern neighbouring regions should, however, be treated as a priority due to their geographical proximity.

Neither sustainability criteria (cf. section 2.3.2) nor other conditions are specified under which hydrogen or its derivatives can be imported to Europe. It is only mentioned that trade should be designed to be “fair”. What exactly is meant by this is not elaborated.

Also lacking are details on the extent of potential imports from third countries. However, it is disclosed that industry estimates approximately 40 GW of electrolysis capacities could be developed in the eastern and southern neighbouring regions by 2030 in order to safeguard trade with the EU. Further sources for classification are not specified nor is information given on what basis the estimates were made.

The following questions remain unresolved with regard to hydrogen imports in the hydrogen strategy:

- In what quantities should imports take place?
- What requirements will be placed on the imports?


SYSTEM
CHANGE
NOT
CLIMATE
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6. Conclusions and initial recommendations

Firstly, this paper presented current knowledge regarding the potential production and origin, possible application areas of hydrogen as well as the infrastructure required for using hydrogen. The opportunities and risks arising from the further expansion of the hydrogen system and individual components of the system were also illustrated (chapters 2 – 4). Sections 4.3 and 4.4 also discussed to what extent targeted use can be made of opportunities and risks can be reduced as part of infrastructure planning. Chapter 5 illustrates the roadmap of the European Hydrogen Strategy and points out emerging questions and risks with a view to the previous chapters. This chapter lastly brings together the findings and presents key ideas and initial recommendations for the development of the hydrogen system in the EU.

Plan hydrogen appropriately for the system: As little as possible, as much as necessary

Hydrogen generated from renewable energy will play a certain role in a fully renewable and climate-neutral energy system and so is relevant to compliance with the Paris climate protection agreement. Nevertheless, the direct use of electricity is possible in many sectors and is then clearly more efficient than the use of electricity-based hydrogen. The focus should therefore be on the expansion of RE. Under no circumstances should the development of the hydrogen system reduce the speed of decarbonising the electricity system and further electrification (via, for example, heat pumps and BEVs). Establishing off-grid RE generating plants for the production of hydrogen must consequently be examined extremely critically. Hydrogen generation should be integrated appropriately for the grid as a matter of priority and its use be restricted to non-electrifiable processes and as energy storage.

Reduce demands through sufficiency in consumer behaviour and efficiency improvements

At the same time, potentials for cutting GHG due to an agricultural turnaround, changes in mobility and consumer behaviour as well as production processes (efficiency and sufficiency) towards a circular economy in planning processes should be given greater consideration and, consequently, also be exhausted. Focussing solely on technological solutions will not be enough to resolve the social and ecological problems of our age. An open discussion about changes in values and behaviour must be initiated.

Facilitate RE expansion, nuclear energy is not an option

Hydrogen should, from ecological and sustainable standpoints, only be produced by means of electrolysis using renewable electricity. Hydrogen production must therefore always be combined with an additional expansion of RE. In no way should the continued operation and even the construction of new nuclear power plants, nor SMR or Generation IV19, be made possible in the course of the electricity demand required for hydrogen production, as these involve high safety risks and the issue of final disposal remains unclear. In addition, nuclear power is not viable from a private sector perspective.

Exit from fossil natural gas industry urgent, CCTS makes no contribution to a sustainable hydrogen economy

As hydrogen production today is mostly based on the use of fossil energy carriers (primarily natural gas), an exit from fossil hydrogen production is required. An exit pathway should be developed for fossil natural gas and hydrogen as quickly as possible, which will create planning security for investors and prevent potential compensation payments for plant operators. CCTS makes no contribution to a sustainable hydrogen economy. This also applies to pyrolysis, which enables a reduction in GHG emissions but not a total avoidance.

Hydrogen imports critical, local hydrogen manufacture to be prioritised

Hydrogen imports from third countries involve geopolitical uncertainties. To what extent climate-ethical aspects, such as the competition for water and land with local agriculture as well as competition between energy exports and achieving domestic climate neutrality, are adequately taken into account and decisions concerning this can also be reviewed and implemented must also be scrutinised. As a matter of principle, regional hydrogen generation should therefore be priori-

[19] These reactor and power plant concepts are often portrayed as innovations to solve nuclear power problems, but on closer inspection exhibit the same safety-related, economic and environmental risks and concern as conventional nuclear power plants. See: (Pistner et al. 2021).

tised. Whether imports should play a role in the long term depends on the extent to which systems can be created to take climate-ethical aspects into account with a high degree of reliability (e.g. such as certificates and sustainability criteria currently being discussed). At this stage, these developments are not yet foreseeable and there is a danger of repeating the mistakes of the past ("Desertec" and "Food and Fuel"), which is why imports from third countries must be regarded extremely critically. Finally, above all, the development of energy systems in the exporting countries towards renewables as well as the development of transport costs are, however, of great importance.

Need to prioritise applications in order to use limited hydrogen available from RE electricity effectively

Prioritising applications is necessary for the effective and targeted use of hydrogen as well as the efficient development of its infrastructure. This is because knowledge of the origin and demand side is of importance to the targeted development of a hydrogen infrastructure. Furthermore, planning security with regard to the availability and affordability of hydrogen is relevant to investment in new facilities. The limited availability of renewable hydrogen means that planning security cannot be created for many applications at the same time. It must be prevented that fossil hydrogen is used for applications which were planned with the prospect of renewable hydrogen, but, due to scarcity, a plant can only be supplied with fossil hydrogen instead of renewable hydrogen. Renewable hydrogen should therefore initially be available where structural changes and high levels of investment in new facilities are necessary (e.g. DR plants for steel production, later also reconversion plants). This could prevent new investment in facilities which are not compatible with the objective of climate neutrality (e.g. blast furnaces for steel production). Replacing fossil with renewable hydrogen must not be overlooked either, but can gradually take place in line with the exit pathway.

Align infrastructure planning with 1.5°C target, ensure civil society involvement

In general, due to the strong interdependencies of the hydrogen system with other parts of the energy system (electricity and natural gas system), it is clear that only comprehensive planning can do justice to this complexity. It is of particular importance that knowledge is extensively included in the plans and the planning is always aimed at the 1.5°C target and the remaining carbon budget. For this purpose, the involvement of numerous stakeholders in the energy sector, civil society organisations as well as independent experts should take place so that the transformation is carried out in the interests of citizens.

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„Hydrogen is not a silver bullet against climate change, but in certain areas green hydrogen can make an important contribution to the energy system of the future." Dr. Cornelia Ernst

The Left in the European Parliament
Rue Wietz 43
B-1047 Brussels
www.left.eu