WORLD ENERGY COUNCIL | THE NETHERLANDS

HYDROGEN – INDUSTRY AS CATALYST

ACCELERATING THE DECARBONISATION OF OUR ECONOMY TO 2030

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World Energy Perspective

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EXECUTIVE SUMMARY

1.1 ABOUT THIS REPORT

- The World Energy Council believes that hydrogen will be a key ingredient to reaching the European target of a carbon-neutral and eventually a carbon-free economy in 2050. Though hydrogen has many applications, its current role is modest in comparison to fossil fuels. This report presents a case for kick-starting the industrial hydrogen economy and using it as a catalyst for other industries. The analyses in this report are based on literature, case studies, interviews with stakeholders and economic modelling.

- The first section presents key conclusions and recommendations, with the subsequent sections offering background information and substantiation of our findings. Section 2 presents the case for hydrogen within the industry. Section 3 describes our modelling of the economic viability of a number of key hydrogen applications, mainly the transition from grey hydrogen to blue hydrogen and from blue hydrogen to green hydrogen. Section 4 explores barriers to the development of a hydrogen economy, such as market failures, government failures or missing markets. The final recommendations are presented in the last section.

1.2 KEY CONCLUSIONS AND RECOMMENDATIONS

1. KICK-STARTING THE INDUSTRIAL HYDROGEN ECONOMY SHOULD BE A PRIORITY

- The European Union aims to be carbon neutral in 2050. The different energy-intensive functions of our economy consumers in today's society – industry, transport, agriculture, residential applications – are powered either by electrons (electricity) or molecules (thermal energy produced by the burning of different types of fuels). At this point in time, several important steps have been taken in the process of decarbonising the production of pure electricity, but the production of molecules remains stubbornly dependent on fossil fuels. This is problematic, as most modelling shows that molecules will continue to play an important role in providing energy to our economy.

- The candidate technologies to provide carbon free molecule-based energy are limited. Hydrogen is the only molecule based energy carrier that can be made fully carbon free. Green hydrogen can be made through the use of renewable electricity or nuclear power and blue hydrogen can be made from fossil fuels, with the CO_2 by-product captured and stored (carbon-neutral). This allows products such as syngas, bio-methanol, ammonia, and more, to be derived from carbon-neutral hydrogen. In short, hydrogen is likely to play an essential role in realising the ambition of a carbon-free EU by 2050.

- Hydrogen is an energy carrier and has a multitude of potential applications in many different areas of the economy. It can help decarbonise the production of the energy we spend on transport, our residential environment (especially heating) and industrial processes. This report focuses on industrial applications and concludes that the development of an industrial hydrogen economy should be a priority for two reasons:

- Firstly, not all industrial processes can be electrified, and there is a need for a carbon-neutral energy carrier to fully decarbonise industrial production. Hydrogen is simply one of the very few substances that can be used for this purpose. In addition, hydrogen and its derivatives are already a key input in many industries, especially in chemicals and refining. Industrial applications are by far the largest consumer of hydrogen today. Our analysis and case studies (see chapter 2) demonstrate a wide range of further applications, such as using hydrogen to provide energy for industrial processes (like high-temperature heating). In all such examples, hydrogen has the potential to replace carbon-based processes with a carbon-free alternative.

- The second reason is that industrial activities can be a catalyst for hydrogen development in other sectors. Declaring hydrogen to be the most promising molecule-based energy carrier is one thing, achieving scale and consequently lower cost of production is quite another. The volumes of hydrogen needed to reduce the cost of production will be large. In industrial applications, a relatively small number of very large players generate a major share of the volume allowing effective intervention to promote hydrogen use. This is an advantage over transport or residential uses, where the stakeholder landscape is much more fragmented. Finally, a great deal of expertise and infrastructure linked to hydrogen is already available in various industries.

2. MANY INDUSTRIAL HYDROGEN APPLICATIONS CURRENTLY FACE THE 'VALLEY OF DEATH'

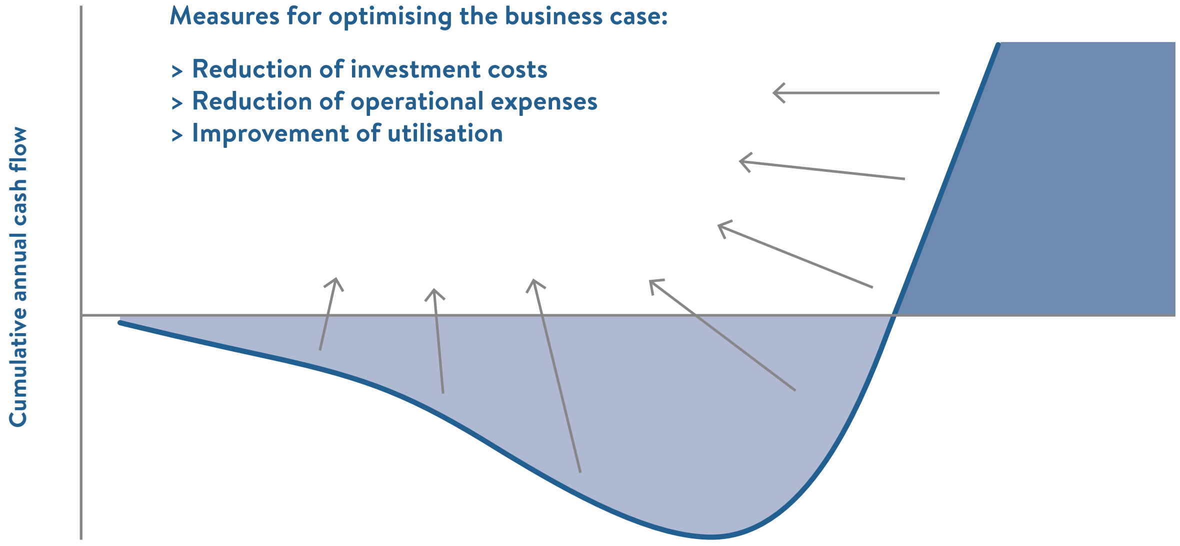
- The hydrogen produced by industrial applications is currently largely carbon based (grey hydrogen), typically generated through steam methane reforming (SMR). Over time, the challenge will be to replace such methods with carbon-free or carbon-neutral alternatives (green or blue hydrogen). Examples of such technologies include producing hydrogen via electrolysis using renewable electricity or re-using carbon to generate syngas for synthetic fuels.

- Many such carbon-free or carbon-neutral technologies are still in the early stages of technological maturity. They have been technically proven and are being demonstrated on a relatively small scale; however, a roll-out on a much larger scale is required for them to operate in a cost-efficient manner. In other words, the technologies are in what economists call the 'valley of death' of the technology curve.

- Our modelling of the economic viability of electrolysis as a carbon-free alternative to SMR (see chapter 3) suggests that electrolysis could become economically viable around 2030. This is based on the assumption of ambitious cost reductions that are very ambitious, but comparable to the spectacular pace of cost reductions observed in offshore wind or solar PV.

- In any case, positive business cases for larger-scale deployment of green hydrogen are currently scarce. Reducing costs and rolling out technologies requires substantial lead time. Backcasting from the desired carbon-neutral economy in 2050, which is likely to still require substantial use of molecule-based energy carriers, we can see that we are not yet on course to reach our goals. To ensure that carbon-neutral hydrogen applications can be rolled out on a large scale from 2030, and to move towards green hydrogen by 2050, we need to take action now.

Figure 1: Hydrogen applications face the valley of death



Source: IEA

3. BLUE HYDROGEN CAN REDUCE EMISSIONS AND HELP BUILD UP THE HYDROGEN ECONOMY

- This report argues that hydrogen-based technologies are very likely to be needed for a carbon-free economy to be achieved by 2050, and that industrial activities are a good place to kick-start the hydrogen economy. However, most of the hydrogen produced by industrial activities is currently not CO_2 neutral as it is based on fossil fuels (grey hydrogen). It could be at least ten more years before green hydrogen can replace grey hydrogen on a sufficiently large scale.

- Blue hydrogen, in which CO_2 emitted in manufacturing processes is captured and stored, offers a way to reduce emissions faster. Our modelling suggests that SMR in combination with carbon capture and storage (CCS) is close to being commercially viable. If the ETS price increases to around €30 per tonne, and the right conditions for transport and storage are put in place, blue hydrogen could become a viable option in a matter of years rather than decades.

- As a consequence, using CCS to make SMR-based hydrogen processes carbon neutral could help significantly reduce industrial emissions in a timely and cost-efficient way. Equally importantly, blue hydrogen can help prepare the ground for a green hydrogen economy. If a transition from grey to blue allows for more hydrogen to be produced and used, then key infrastructure and supply chains for the industrial hydrogen economy can be built. Examples include the development of a network for hydrogen transportation (pipelines, ports, ships and so on). This is particularly important given the complex web of synergetic and symbiotic interlinkages between different industrial parties where one's output is another's input.

- In this sense, blue hydrogen is not an alternative to green hydrogen, but rather a bridge technology which has the added benefit that – if done correctly – could speed up the transition to green hydrogen. However, for blue hydrogen production to become realistic, it is crucial that governments offer clarity on its societal acceptability, develop arrangements for transport and storage prices and, where necessary, include it in financial support schemes for low-carbon technologies.

4. GOVERNMENTS NEED TO GENERATE MARKET PULL AND, FOR A LIMITED TIME, TECHNOLOGY PUSH

- We have analysed the barriers to investment in hydrogen (see chapter 4). The first barrier is that compared to most other forms of energy, both blue and green hydrogen are severely overpriced. In economic terms, the negative externalities of CO_2 are insufficiently valued in the energy market. The fact that the socio-economic gains of CO_2 reduction brought about by the transition to green hydrogen – and the corresponding increase in renewable energy production – are insufficiently monetised in private business cases, which results in insufficient market pull for blue and green hydrogen.

- To take away this barrier, policy makers should ensure that carbon prices fully reflect the negative externality of carbon emissions. It is essential to establish a stable European emissions trading system (ETS) with an upwards price trajectory. National governments are hesitant to introduce forms of carbon pricing due to concerns around distorting the level playing field for their industrial sectors and sending distorted price signals to the international energy markets. In addition, the added value of green, or renewable, hydrogen should be recognised. Policy makers could consider creating markets for green or renewable hydrogen similar to those put in place to stimulate green electricity.

- The second barrier is the fact that green hydrogen technology currently faces the ‘valley of death’. Our view is that hydrogen applications should eventually compete on their merits against alternative technological solutions involving molecule-based energy carriers and pure electricity. However, there are good socio-economic arguments for temporarily helping specific technologies cross the valley, as many examples in history have shown. For one thing, there are large positive externalities associated with learning effects and innovation – the experience with offshore wind has shown that targeted policies aimed at increasing volume and scale can dramatically speed up the pace of cost reductions. Finally, the notorious risk of governments ‘picking a loser’ is relatively small, as the target is clear (carbon neutrality by 2050) and alternatives for industrial hydrogen are scarce.

- Given these observations, it is clear that public financial support will be needed for a limited time, ideally through steady financial support for demonstration projects. Public agencies can also decide to provide co-investment (for example through public-private partnerships). This would demonstrate commitment on the part of the authorities while the risks and rewards are shared with the private sector.

5. AN ACTION PLAN IS NEEDED TO INCREASE COORDINATION AND REDUCE UNCERTAINTIES

- A third barrier to investment in industrial hydrogen is uncertainty around key drivers of the business case. To an important extent, these uncertainties relate to government intervention. An example is uncertainty around regulatory and ownership models for the transport of hydrogen. More generally, there is uncertainty around the commitment to achieving the 2050 carbon target and the pace of decarbonising molecule-based energy carriers.

- A way to reduce such uncertainties is to draft a hydrogen strategy that comprises a clear ambition and action plan, coordinated at the supra-national level. Such a strategy would signal commitment and thereby reduce the risks associated with investment in industrial hydrogen. In addition, the strategy should propose regulatory and ownership models. Transport and storage involve infrastructure that is prone to problems of market power. The strategy should therefore also include guidance on how the authorities intend to cope with such issues.

- A fourth barrier is a lack of coordination. As our case studies make clear, hydrogen projects typically involve several and sometimes very different stakeholders and tend to involve relatively complex supply chains with interlinkages, tailored to the situation. Governments can help coordinate this, for example in spatial planning policies. Another field of coordination required is between EU member states. Differences in policies across member states related to carbon pricing, fiscal treatment or infrastructure usage lead to inefficient and often ineffective outcomes, such as the risk of incentivising a relocation of activities rather than carbon reduction. This is especially important in the fiercely competitive global market in which European industrial activities take place. Energy and industrial policies should be harmonised with the aim of creating a level playing field in which the best technologies are chosen and applied in the region where they make most sense.

If these conditions are met, evidence collected in this report suggests that a prosperous carbon-neutral North-West European economy can be developed by 2050. The energy mix needed to fuel the carbon-neutral economies will eventually consist of molecules and electrons. Hydrogen, while following a path from grey to blue to green – is probably the most fruitful candidate to perform the role of the carbon-neutral molecule

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INDUSTRY AS CATALYST FOR THE HYDROGEN ECONOMY

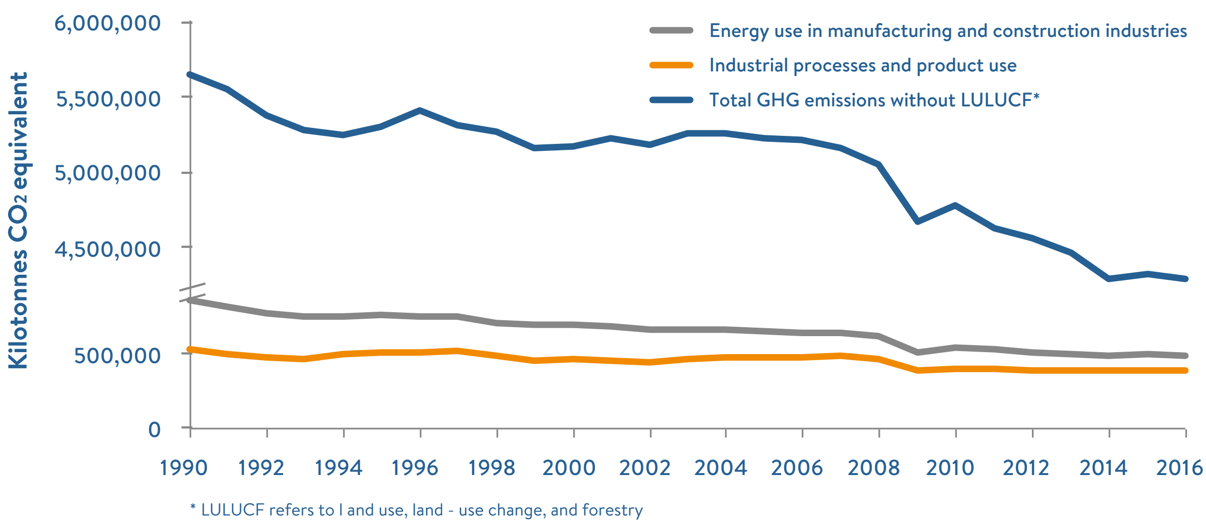
As we battle climate change, the transformation of energy systems is one of the biggest challenges facing the world. Primary energy consumption across the globe is very highly concentrated in coal and oil, which together account for over half of the world's energy consumption. Energy systems need to be rapidly decarbonised with renewables and cleaner energy carriers, making sure we bring greenhouse gas emissions to the lowest possible levels.

While every region might have a different mix of emission sources, nearly 20% of overall emissions in the EU are rooted in industrial applications (energy use in manufacturing and industrial processes). The sheer scale of industrial emissions in the EU makes it imperative that this decarbonisation be handled swiftly.

2.1. THE CHALLENGE OF DECARBONISING INDUSTRIAL EMISSIONS

Decarbonising industrial applications is complicated for a range of reasons other than the scale of the challenge. Industrial emissions have two distinct sources (other than energy production) – 56% comes from energy use in manufacturing and construction and the remaining 44% from industrial processes and product use (EU average). The difference in the two sources and the distinct approaches required to tackle them add further complexity to what is already a huge challenge.

Figure 2: The scale of industrial emissions in the EU



Source: The United Nations Framework Convention on Climate Change (UNFCCC)

1 UNFCCC

DECARBONISING ELECTRONS AND MOLECULES ARE TWO DISTINCT CHALLENGES

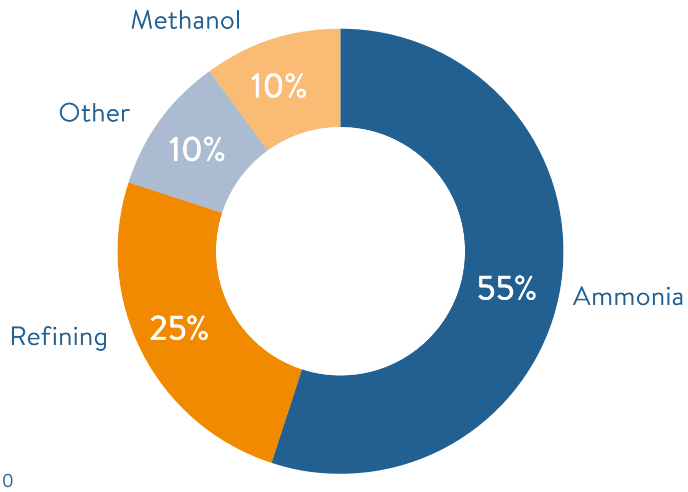
It is estimated that at least 80% of the EU's electricity will be produced using renewable energy sources by 2050. While the greening of electricity will help to a large extent, industrial activities cannot be completely decarbonised by electrification. Green molecules will still be needed, both as feedstock and as an energy source for the industry (particularly for a number of high-temperature processes).

Considering the need for clean molecule-based energy carriers in the industry, it is crucial to rapidly develop the hydrogen route. Hydrogen offers clear advantages over other carriers because it is abundant, can be stored and transported at high energy density in liquid or gaseous form, and produces zero emissions at the point of use. It is particularly useful in medium to high-heat processes where electrification is not an efficient option. Hydrogen is also the only clean alternative for feedstock. Even though most of the hydrogen currently produced is grey, considering the lack of comparable alternatives, hydrogen can be the green fuel that the industry needs to fully decarbonise.

2.2. INDUSTRIAL ACTIVITIES COULD ACT AS A CATALYST FOR THE HYDROGEN ECONOMY

It is estimated that the world produces between 45 and 50 Mt of hydrogen every year, 7.8 Mt of which is made in Europe (2010 estimate).[2] Even though the current scale of hydrogen production is fairly small, industrial applications are already the leaders in hydrogen use. Over 60% of current consumption is focused on chemical product synthesis, especially to form ammonia and methanol. Another 25% is used in refineries to process intermediate oil products.

Figure 3: Global usage of hydrogen



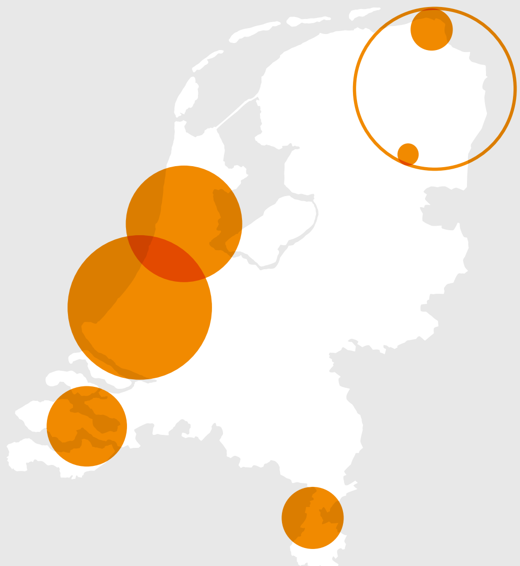
Source: Shell, Zakkour/Cook 2010

2 Shell, Zakkour/Cook 2010.

While industrial activities are currently the largest consumer of hydrogen, other applications like transport and the heating of buildings also have huge potential. Even so, we believe that industry could act as a flywheel for the hydrogen economy, leading to its widespread adoption in the future.
There are several reasons for this optimism. Firstly, the volumes needed to 'green' the industry are vast, which can help the hydrogen economy achieve a larger scale, thus reducing costs. The widespread adoption of hydrogen in the transport and heating sectors is also more difficult because of their more complex stakeholder structure. Industrial activities are generally characterised by a relatively small number of large emitters, leading to a less fragmented stakeholder structure than transport, for instance.

Figure 4: Industrial clusters in the Netherlands

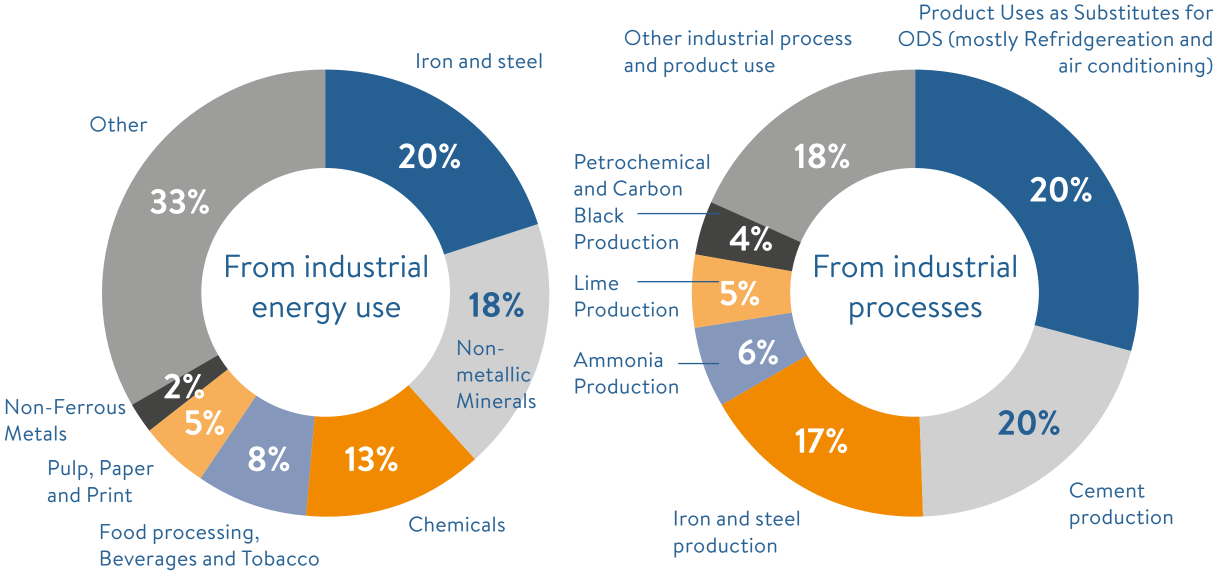
Industries are highly concentrated in clusters with strong interdependence within them. The concentrated stakeholder structure makes it easier to direct investments effectively.



An assessment made at the global level estimated that just 100 producers have accounted for 71% of global industrial GHG emissions since the start of the industrial revolution. In addition to being concentrated in a few companies, industrial emissions are largely rooted in just a few industries, which makes directing investments easier. Looking deeper into industrial emissions, we see that the iron and steel industry generates the highest emissions from industrial energy use, followed by non-metallic minerals and the chemical industry. These three industries alone account for over 50% of all industrial energy emissions. While emissions are a major challenge, the fact that they are concentrated in so few industries makes it possible to effectively channel investments aimed at the adoption of hydrogen.

Interestingly, emissions from industrial processes and product use are also concentrated in just a few sub-sectors, making them conducive to effective transformation with hydrogen. Apart from product use in refrigeration and air-conditioning, most emissions come from just three industries – minerals (largely cement and lime production), metal (mostly from iron and steel production) and chemical (where the largest contribution comes from the production of ammonia).

Figure 5: Industrial emissions in the EU, 2016



Source: UNFCCC

2.3. POTENTIAL FOR INDUSTRIAL HYDROGEN

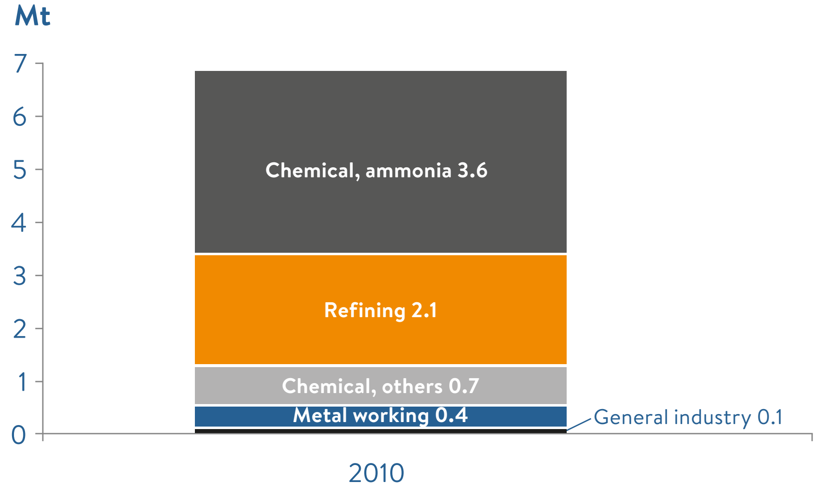
The growth of hydrogen as an energy carrier has been modest at best over the past years. Even though it has been gaining attention, it requires a stronger push to develop proper momentum. In this report, we distinguish three main hydrogen applications that can help decarbonise the industry. This section looks at each of these three applications, their current adoption status and the potential they hold for the future. These same applications form the basis of our economic modelling in the next chapter, demonstrating the feasibility of large-scale hydrogen adoption.

INDUSTRY PRE-COMBUSTION FEEDSTOCK

Industry pre-combustion feedstock is the most popular application of hydrogen in Western Europe, and leverages on technology that has been proven over decades of operations. Currently, Western European industry consumes 6.88 Mt of hydrogen, mainly as a feedstock; this is more than 90% of all hydrogen produced in the region.

More than 50% of the H_2 gas used in industrial activities (3.6 Mt) goes into the production of ammonia, a segment of the chemical subsector. The second most important subsector is refining, which currently accounts for about one third of the industrial demand (2.1 Mt): in this context, hydrogen is used in hydrogenation process to produce lighter crudes. In the future, it is expected that demand for hydrogen from the chemical and refinery subsectors, which together comprise more than 93% of the current demand, will grow at a steady rate (along with the growth in the chemical and refinery industries) of roughly 3.5% to 8 Mt by 2030.

Figure 6: Hydrogen consumption by subsector in Western Europe



Source: CertifHy, Freedonia group

The use of hydrogen as a pre-combustion feedstock has already reached some degree of maturity. While the market for hydrogen is already in place, the main challenge for the feedstock application is 'greening' hydrogen as energy carrier. Only once this challenge has been met will this application have the maximum impact on decarbonising the industry. Currently, more than 95% of hydrogen is produced using steam methane reforming (SMR), which produces CO_2 directly; in other words, this is grey hydrogen. CO_2 reduction targets, however, require the industry to move from grey to blue by adding carbon capture and storage (CCS), and then to green hydrogen by switching to electrolysis of water with green power. While this is technologically feasible, it cannot be massively adopted until it becomes cost-effective.

INDUSTRY PRE-COMBUSTION FEEDSTOCK
Use case: Refhyne, Germany
(Shell, ITM Power, SINTEF, Thinkstep and Element Energy)

This consortium, formed by Shell, ITM Power, SINTEF, Thinkstep and Element Energy, has agreed to install the world's largest PEM electrolyser (10 MW) to produce hydrogen for use at Shell's Wesseling refinery in the Rhineland Refinery Complex, Germany. The gas produced can be integrated into the refinery processes, such as for the desulphurisation of conventional fuels. A unit of this kind can also support the stability of the power grid, facilitating consumption of renewable electricity.

The Rhineland refinery, Germany's largest, currently consumes approximately 180,000 tonnes of hydrogen every year. At the moment, this is produced from natural gas by steam reforming. The newly planned facility, with a capacity of 10 megawatts, will be able to create 1,300 tonnes of hydrogen every year. As such, the project constitutes the first step in a gradual transition from grey to green hydrogen.

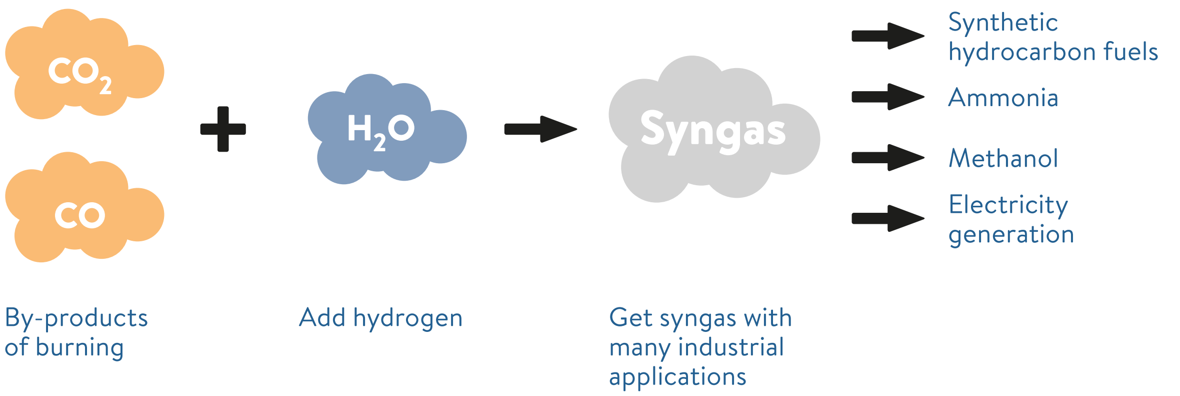
The produced hydrogen will become an input for processing and upgrading products at the refinery's Wesseling site. The plant, the first of its kind, will also test the technology and explore applications in other sectors. The project will help propel companies up the learning curve and provide them with expertise that can be used in the next steps on the road to greening H_2 as energy carrier.

The total investment within the project, including integration into the refinery, will be about €20 million, half of which will come from the European Fuel Cell Hydrogen Joint Undertaking. The detailed technical planning and the approval process started at the beginning of 2018. The plant, named Refhyne, will come into operation in 2020 and be the first industrial-scale test of the PEM technology process.

INDUSTRY POST-COMBUSTION FEEDSTOCK (SYNGAS)

Another promising application of hydrogen lies in its capability to unlock the value of CO and CO_2 that would otherwise be dispersed in the atmosphere. By combining the off-gases from chimneys with hydrogen, one can create synthetic gas (syngas) which can be used to build a broad range of products, from ammonia to synthetic fuels. Adding hydrogen to the off-gases effectively delays emission and allows the carbon molecules to be used at least one more time.

Figure 7: Syngas production



The biggest potential of this technique lies in the industrial sub-sectors that produce chemicals, refined petroleum, and basic and fabricated metals, which are the largest emitters of CO_2 in the EU. A significant part of these emissions could be delayed, and effectively avoided, by using hydrogen to convert them first into syngas and then into valuable products.

The technology can be applied wherever there is direct control over the off-gases produced by the combustion process. For example, capturing CO_2 from transport or household heating is hardly possible, but can technologically be done in industrial processes where CO and CO_2 are emitted as a result of controlled combustions.

Recent activity around this application shows that the technology has evolved from the R&D phase and is now entering the demonstration phase[4]. These technological developments mean that the use of hydrogen as a post-combustion feedstock will be a very promising application in the future.

INDUSTRIAL ENERGY

Industrial activities are the second biggest consumer of energy after the power sector. Hydrogen has the potential to act as a substitute for electricity and carbon-based energy carriers for heating, thereby reducing emissions from industrial energy use. Although hydrogen as an energy carrier is still a relatively new application (with the notable exception of fuel gas used in refineries and petrochemicals industry), it has the potential to eventually replace gas and other fossil fuels. Among other things, hydrogen can gain a lot of ground in high heat processes, for which it is particularly suitable.

4 Store&Go project

INDUSTRY POST-COMBUSTION FEEDSTOCK (SYNGAS)

Use case: Waste-to-Chemistry, Rotterdam

(Nouryon (previously AkzoNobel), Port of Rotterdam, Air Liquide, Enerkem)

A partnership consisting of Air Liquide, Nouryon, Enerkem and the Port of Rotterdam aims to close the waste loop by converting waste back into useful products. The group is in the process of setting up an advanced facility in Rotterdam that will create new raw materials from waste plastics. This business model, which will create biofuels and valuable chemicals from non-recyclable waste, is said to be the first of its kind in Europe.

Essentially, the plant will manufacture synthesis gas (syngas) from domestic and other waste and use it as feedstock for products such as methanol and ammonia. More concretely, the value chain will consist of five steps:

1. Non-recyclable waste will be supplied to the facility as a source of carbon. The project will test various local waste streams, including residual municipal and agricultural waste.
2. Hydrogen and oxygen, key reactants, will be provided by Nouryon and Air Liquide. The Port of Rotterdam will arrange the infrastructure for shipping them.
3. Non-recyclable mixed waste, including plastic, will be processed into syngas using Enerkem's innovative and proprietary thermochemical technology with the use of hydrogen and oxygen.
4. Syngas will then be used to produce clean methanol for the chemical industry and the transport sector. (Currently, methanol is typically produced from natural gas or coal.)

Using methanol, Nouryon will produce DME, chloromethane and other raw materials that are essential to making new products.

The scale of the facility will allow up to 360,000 tonnes of waste to be converted into 220,000 tonnes or 270 million litres of green methanol. This represents more than the total annual waste from 700,000 households and will cut CO_2 emissions by 300,000 tonnes. The economic impact will also include a direct creation of 50 permanent jobs and an indirect generation of a further 200.

The project is supported by the Dutch Ministry of Economic Affairs and Climate, the Municipality of Rotterdam, the Province of South Holland and InnovationQuarter, a regional development agency. The project will also be partly financed by the European Union through the European Regional Development Fund.

With so many stakeholders involved, the Waste-to-Chemistry project is an outstanding example of collaboration both between the private and public bodies and between private parties themselves. The project will capitalise on the benefits of a cluster that represents the whole value chain. Such clusters could become drivers of the hydrogen economy, facilitating the coming energy transition.

When looking at the potential of this application, it is important to consider not only the scale that hydrogen can achieve, but also the extent of emissions that it can help eliminate. As noted earlier, iron and steel production currently accounts for roughly 20% of industrial CO_2 emitted in fuel combustion and 27% in industrial processes. In absolute terms, this is equivalent to 96.15 Mt and 62.64 Mt of CO_2 gas, respectively. This makes iron and steel production one of the biggest industrial emitters, owing to their intensive use of carbon (mostly coal) as fuel and considerable process emissions in the reduction of iron ore.

To gain a better understanding of the emissions-reducing potential of hydrogen, it is important to look at the way steel is currently produced. In Europe, primary crude steel is made from iron ore mostly with the help of two processes. The first uses coke made from coal to melt and reduce iron ore into pig iron in a blast furnace. Next, the hot metal is moved into a basic oxygen furnace, where high-temperature oxygen is blown into it to reduce its carbon content; this is followed by casting and rolling. The second process of direct reduction reduces the iron ore in solid form with a synthetic gas made of carbon monoxide and hydrogen derived from natural gas or from coal gasification. The resulting sponge iron is then melted in an electric arc furnace together with recycled scrap steel.

One way to reduce emissions could be to add a CCS technology to the existing process. However, both processes emit CO_2 at various steps and locations, which would complicate adding a CCS technology and significantly drive up costs. In fact, a study by the Wuppertal Institute (2014) shows that the blast furnace method with CCS business case is always inferior to either the blast furnace-basic oxygen furnace (BF-BOF) method (emitting CO_2 and paying the corresponding price) or the hydrogen-based direct reduction (H-DR) method (an almost emissions-free alternative). Moreover, top-gas recycling associated with CCS would reduce emissions by only 60%, which is not in line with long-term targets.

Looking at the emissions-free alternatives, H-DR appears to be the most competitive. It uses hydrogen (which may be green) to reduce iron ore into sponge iron much like the DR-EAF method, but without the use of syngas. According to the International Energy Agency (IEA), the global production of crude steel is about 1.7 gigatonnes (Gt) and growing. With a potential of 30% from scrap, 1.2 Gt of steel could come from processing 1.7 Gt of iron ore. The volume of hydrogen needed for the H-DR method would thus be 90 Mt, the production of which would require 4320 TWh of renewable energy (assuming 70% electrolysis efficiency).

Another 935 TWh would be needed for the rest of the process with current technologies, adding up to a total of 5255 TWh. In other words, the potential volume of hydrogen demanded for iron and steel production is ten times larger than that required for the production of ammonia (90 Mt versus 9 Mt). This constitutes a huge potential for CO_2 reductions and an opportunity to scale up the hydrogen market.

INDUSTRIAL ENERGY
Use case: HYBRIT, Sweden (SSAB, LKAB and Vattenfall)

A joint venture founded by the Swedish companies SSAB, LKAB and Vattenfall in 2017 has the ambition to design a steelmaking process free of fossil fuels. The idea is to replace coke and coal with hydrogen gas to achieve a production process that releases water instead of carbon dioxide. The work on the HYBRIT project is divided into three phases: a preliminary study (which lasted until the end of 2017), which is being succeeded by research and pilot plant trials that will last until 2024. Thereafter, full-scale demonstration facilities will perform trials up to 2035. The Swedish Energy Agency has supported the project since its inception, including providing the funding for the first four years of research.

In essence, the following stages are proposed for the hydrogen-based metallurgical process:

i) Specially developed iron ore pellets are reduced by hydrogen gas in a so-called direct reduction process. Reduction occurs in a solid state at a lower temperature than in the blast furnace process and results in an intermediate product, sponge iron or direct reduced iron (DRI). The by-product of this process is water vapour.
ii) The sponge iron is used to create crude steel (the same output as the coke-based process).
iii) The crude steel is alloyed and refined before being cast into slabs that are ready for rolling and further heat treatment, a process similar to the blast furnace-based route.
iv) The final product is shipped to customers.

The hydrogen gas required for the process will be produced by electrolysing water through the use of renewable electricity, mainly from wind or hydroelectric power plants. Hydrogen storage will allow a significant number of green power plants to be connected to the process, creating the possibility to balance between intermittent renewable power and the electricity grid.
The two major challenges for the project are: developing an effective process that would use 100% hydrogen on an industrial scale and producing sufficient amounts of hydrogen. Both challenges must be resolved in a commercially viable way.

Sweden is uniquely suited to undertake this initiative. It has a strong, innovative steel industry, access to environmentally friendly electrical power, and the best-quality iron ore in Europe. If it is successful and economically viable, HYBRIT will make a major contribution to decarbonising Swedish industry, while also manifesting the plausibility of a carbon-free steel industry.

Although industrial activities are already the largest hydrogen consumer and have huge potential for the future, wider adoption is limited by a number of factors. One limiting factor is the need for better infrastructure across the entire supply chain, from production to storage and transportation. Another critical impediment to the broader deployment of hydrogen is the poor cost efficiency of the production processes. In order for hydrogen to reach its full potential as an energy carrier, it needs a kick-start that can help it cross the 'valley of death', or the period when costs are so high that they act as in impediment to the uptake of new technology.

INDUSTRIAL ENERGY
Use case: H2FUTURE Steel Project, Austria (Siemens, Voestalpine, VERBUND)

Voestalpine, an Austrian steel company, is looking into ways to replace the coking coal used to reduce iron ore into molten metal with hydrogen in the production of crude steel. As part of these efforts, Voestalpine is partnering with Siemens and Verbund to build one of the world's largest electrolysers for producing green hydrogen in Linz. The electrolyser pilot plant will produce green hydrogen for industrial use at various stages of steel production in the internal gas network.

H2FUTURE will allow key sector coupling questions to be evaluated, among other things through research into the potentials and possibilities for using green hydrogen in various process stages of steel production. In addition, it will investigate the extent to which this technology is transferable to other industrial sectors which use hydrogen in their production processes. Furthermore, the project will focus on integrating the responsive PEM electrolysis plant into the power reserve markets by developing demand-side management solutions, thus compensating for short-term fluctuations in the increasingly volatile power supply by means of load management for bulk consumers.

Siemens will supply the technology for the PEM electrolyser: with an output of 6 MW, this will be very large and modern. VERBUND, the project coordinator, will provide green electricity and develop the grid-relevant services – this means that the hydrogen gas that will be produced at the plant can be classified as green. The other project partners are the Dutch research institution ECN, which will run the scientific analysis of the demonstration operation and transferability to other industrial sectors, and the Austrian transmission system operator APG, which will integrate the plant into the power reserve markets.

Total project financing will amount to around €18 million over the course of 4.5 years. Twelve million euros have been allocated by the EU Horizon 2020 programme under the European Fuel Cells and Hydrogen Joint Undertaking.

Despite the fact that Voestalpine admits that full decarbonisation of steel production is at least two decades away, this project has the potential to fundamentally speed up the evolution toward reduced CO_2 emissions in what remains an industry with one of the highest emission volumes. The prerequisites for the successful execution of this, and, perhaps more importantly, coming, stages are the provision of sufficient energy from renewable sources, as well as favourable political framework conditions which would allow secure long-term planning.

The hydrogen economy will require drastic policy support while the technical and commercial feasibility of the industrial use cases is demonstrated. Since business cases cannot be established spontaneously, policy measures will be crucial to maintaining the competitiveness of hydrogen in industrial applications.

3

THE ECONOMICS OF INDUSTRIAL HYDROGEN

The realisation of a large-scale renewable hydrogen economy is one of the most attractive ways to limit global warming to 2°C or less. As discussed above, hydrogen is currently used mainly for industrial feedstock applications and hydrocracking in refineries, which are powered by grey hydrogen produced via SMR. Conversion of grey hydrogen production today into blue and green hydrogen production tomorrow is a very important step in the roadmap towards a full-scale renewable hydrogen economy. The conversion of existing hydrogen production facilities would allow both significant reductions in direct emissions and scale-based cost reductions for blue and green hydrogen production. An important next step would be to build additional blue and green hydrogen production capacity for the use of hydrogen as an energy carrier. With these developments, industrial activities can act as a catalyst for the renewable hydrogen economy in the period leading up to 2030.

Given the limited availability of renewable energy until 2030 at least, the large-scale development and application of carbon capture and storage (CCS) will also be required to realise the max 2°C scenario. This is another reason why industrial activities are a good focus area. Industrial processes, and hydrogen production especially, produce exhaust fumes with high volumes of concentrated CO_2. The high CO_2 concentration and large volumes of CO_2 involved in hydrogen production based on SMR (or alternative processes to produce hydrogen from natural gas) are therefore a good place to implement CCS projects. The conversion from grey to blue hydrogen production can also be a catalyst for CCS projects in general.

To achieve a renewable hydrogen economy, the hydrogen production process eventually needs to become fully green. This will require the cost of electrolysers to be reduced significantly, which means large-scale green hydrogen production facilities should be developed as soon as possible. However, it is important to note that, until renewable energy is available in abundance, providing sufficient volume will require green hydrogen production to be supplemented by blue hydrogen. Based on the current (predominantly grey) electricity mix and the fact that green hydrogen production often competes with other, more efficient uses of green electricity, converting grey hydrogen production to green hydrogen production could in the current conditions even lead to significant increases in CO_2 emissions.

Hydrogen can have an important role in the realisation of a carbon-neutral economy. For this to happen, there should be a focus on the three industrial hydrogen applications discussed in the previous chapter, so that they can act as a catalyst. In this chapter, we will further explore these applications and consider when they will become economically viable for a given set of assumptions and various sensitivities. Thereafter we will discuss the technological readiness of the individual applications. We will show that, given the right circumstances and incentives – enabled by significant investments in large-scale hydrogen production facilities to realise the envisaged cost savings – these hydrogen applications can already become cost-effective in the foreseeable future, paving the way for the broader hydrogen economy.

3.1. FEEDSTOCK FOR INDUSTRIAL ACTIVITIES: CONVERTING EXISTING GREY HYDROGEN PRODUCTION TO BLUE AND GREEN HYDROGEN PRODUCTION

Currently the price of green hydrogen is not yet cost competitive with grey hydrogen, but can be reduced by large scale rollout of offshore wind, which will lead to lower green electricity prices. Scaling up the production of green hydrogen will also lead to lower prices. In addition, In the development of a green energy market including all technological implications, learning effects will occur, which will lead to efficiency gains, hence lowering hydrogen prices. Finally, an increase of CO_2 allowance emission prices set by the EU will discourage the production of grey hydrogen, and gradually stimulate the production of green hydrogen.

Given the above, at large scale production, a cost price of €2.84/kg - €3.25/kg for green hydrogen can be achieved, but this is compared to a cost price of €1.5/kg for conventional hydrogen production via Steam Methane Reforming (SMR), based on natural gas almost twice as high.[6] This implies that solely based on future and current hydrogen prices, a business case for green hydrogen does not yet exist. For hydrogen producers an additional price incentive such as higher CO_2 emission allowance prices is needed in order to start large scale production of green hydrogen.

FROM GREY TO BLUE HYDROGEN: CO_2 PRICE VS CCS COSTS

The current production costs of grey hydrogen are estimated to be between €1/kg and €1.5/kg, of which 70%-80% is related to the costs of natural gas.[5] The remainder of the price is related mainly to capital costs and CO_2 emission costs. The supply of natural gas usually takes place via existing high-pressure grids, which leads to relatively low transport costs. Natural gas can be supplied from domestic sources, from on or offshore gas fields, or imported via pipelines or LNG terminals. To a lesser extent, the gas – being low-carbon – can also be produced from biomass as biogas.

The costs of producing grey hydrogen are expected to increase in the future due to increasing natural gas prices and higher costs related to CO_2 emissions. Since the natural gas reforming process is already very mature and applied on a large scale, no significant further cost reductions in the production process are expected.

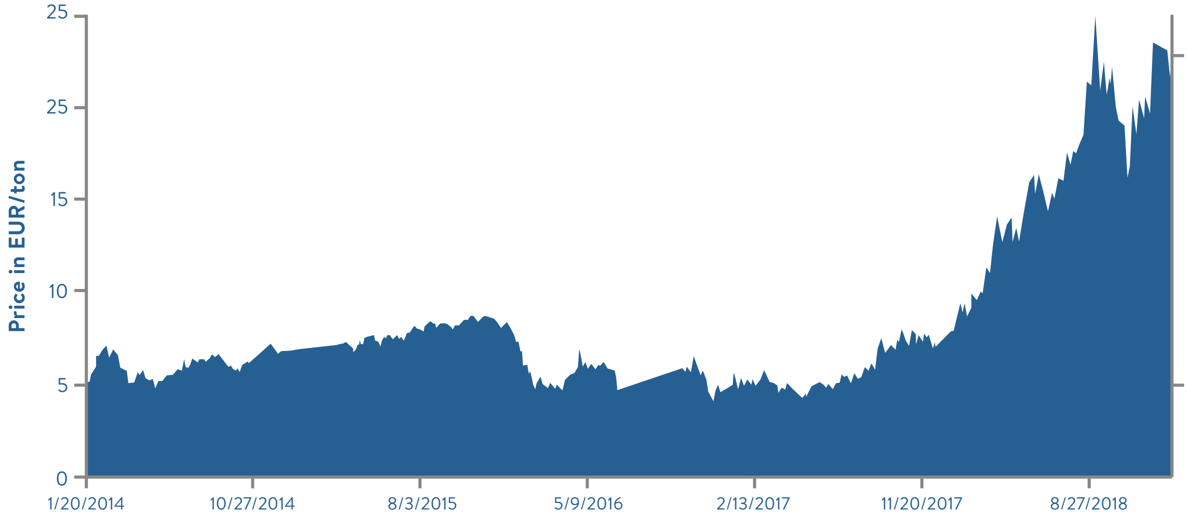
Currently, the CO_2 resulting from the production of natural gas-based hydrogen is mainly emitted into the air. Only a small part is captured and used in the production process of some types of fertilisers or sold commercially for use in beverages or in greenhouses. Since the market for the commercial use of fossil-based CO_2 is limited and will remain so, CO_2 needs to be captured and stored in depleted offshore gas fields in order to convert the grey hydrogen production to blue. The trade-off for grey versus blue hydrogen production is between CO_2 emission costs and CCS costs.

5 Contouren van een routekaart waterstof, TKI Nieuw Gas, 2018.

The estimates for CCS costs vary strongly depending on the costs of capturing CO_2 and the distance for the transport and storage of CO_2. On average, across a range of industries, current total CCS costs are roughly estimated to be around €70/tonne.[6,7] Technological advancements and increases in scale are expected to lead to a decrease to an average cost level of around €45/tonne in 2030.[8,9]

The costs for emitting CO_2 in Europe are determined by the ETS price. This price has significantly increased over the past year, to a current level of around €25/tonne at the end of 2018.

Figure 8: Historical prices of CO_2 (European Emission Allowances)



Source: Markets Insider

The ETS price is expected to increase significantly in the coming years due to annually decreasing emission allowances. As the ETS price will be effectively capped by the costs for alternatives to CO_2 emission (for instance CCS) once there is a sufficient availability of these, the ETS price level is expected to stabilise at around €45/tonne of CO_2 in 2030.

6 Global CCS costs update, Global CCS institute, 2017.
7 Routekaart CCS, CE Delft, 2018.
8 CCS association, http://www.ccsassociation.org/why-ccs/affordability
9 The global status of CCS, Global CCS institute, 2017.

When comparing the cost curves for CO_2 emissions based on forecasted ETS prices and the average CCS cost estimation, price parity is expected in the late 2020s (see graph further in this section). From that point onward, CCS is expected to be commercially viable on average.

The costs of CCS are, however, strongly dependent on the circumstances of the emissions. Capturing CO_2 in the course of natural gas-based hydrogen production is a form of pre-combustion CCS, where the CO_2 stream is relatively pure (between 70 and 90%, depending on the technology). This is a major advantage compared to post-combustion CCS, where the CO_2 is usually mixed with various other gases and may be difficult to separate. CCS costs related to natural gas-based hydrogen production are therefore likely to be lower than average CCS costs.

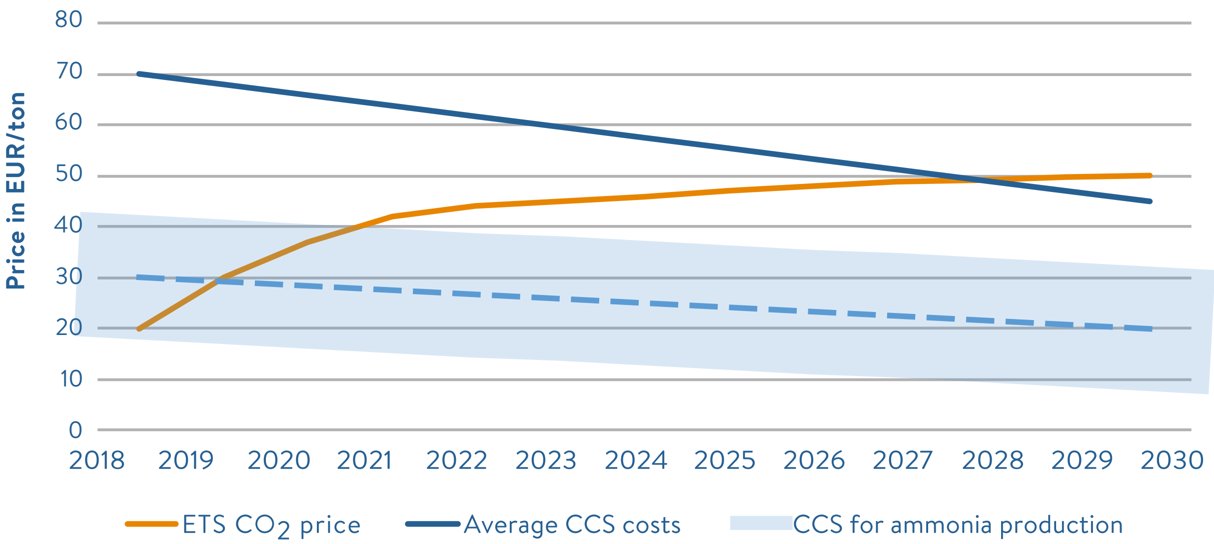
Furthermore, as discussed before, most of the current production of hydrogen is applied as feedstock to produce ammonia. Separation/capturing of CO_2 is already part of the production process for ammonia so the carbon capture-related cost element is already included. This means that CCS costs for ammonia production are generally estimated at the relatively low levels of around €35/tonne of CO_2.[10]

The estimated costs for the transport and storage of CO_2 are also strongly dependent on the required infrastructure. Transport across the sea can take place either by pipeline or by ship. Production locations which are far from the sea require additional transport towards the shore. With respect to CO_2 storage, the use of depleted gas fields onshore is cost-attractive, but is generally not considered an acceptable option due to public resistance. Therefore, storage in depleted offshore oil or gas fields is considered the most viable option for Western Europe. Additionally, deep saline aquifers are considered a viable option for CO_2 storage. In Norway, CO_2 has already been stored in aquifers in the Sleipner gas field for many years. Ammonia production from blue hydrogen with nearby large-scale offshore CO_2 storage could therefore lead to the lowest CCS costs. A project in which these conditions are found is the H21 North of England project. The expected CCS costs for that project range from €25/tonne of CO_2 in case of low volumes to €5/tonne in case of volumes greater than 20 million tonnes per year.[11]

When considering the above, the costs for CO_2 storage and transport in the case of ammonia production might already become competitive at an ETS price between €25 and €35 today, and at even lower levels in the future thanks to scale increases. Based on ETS price forecasts, this would imply cost parity for blue versus grey hydrogen production and use in the very near future for this specific case. If policy makers decide to introduce a national CO_2 pricing mechanism in addition to the ETS scheme, price parity would obviously occur even sooner.

10 Global CCS costs update, Global CCS institute, 2017.
11 H21 North of England report, 2018.

Figure 9: CCS for ammonia production can soon become competitive

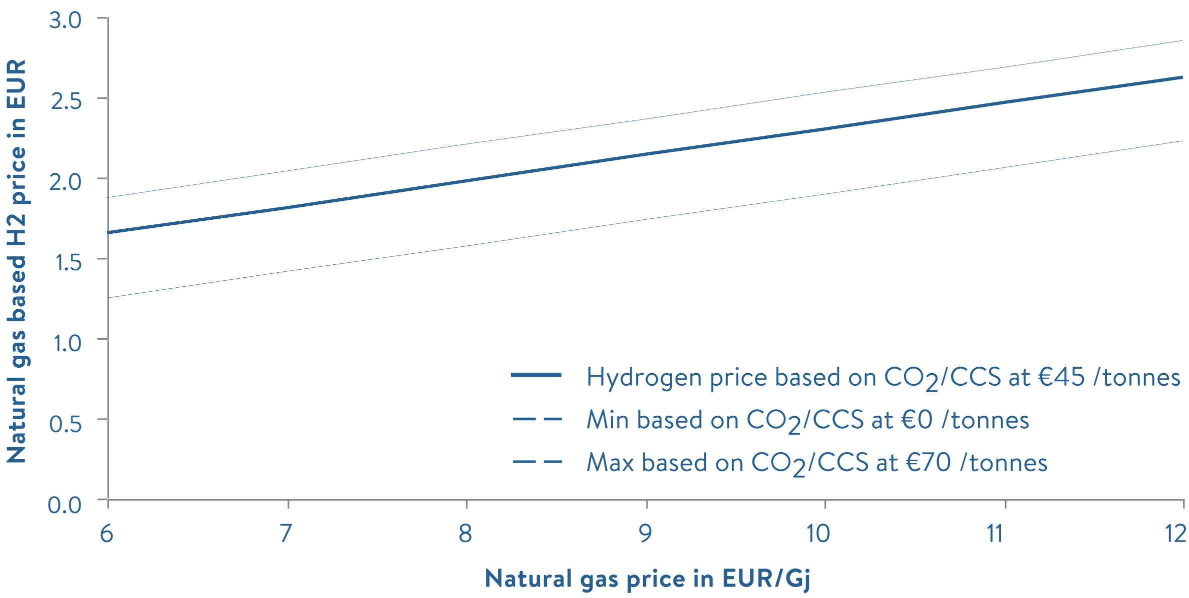


FROM GREY OR BLUE TO GREEN HYDROGEN: SMR VS ELECTROLYSIS COSTS

The cost of producing hydrogen based on SMR is based directly on natural gas prices, which make up 70-80% of the total cost. An increase of the price of natural gas by €6/GJ (roughly a doubling of current industrial prices) would increase the cost of producing hydrogen by €1/kg.

The production of 1 kg of hydrogen through SMR emits around 9 kg of CO_2. As such, an increase in the CO_2 price of €10/tonne would increase the cost of grey hydrogen production by €0.10.

Figure 10: Cost of grey hydrogen and dependence on gas and CO_2 ETS price



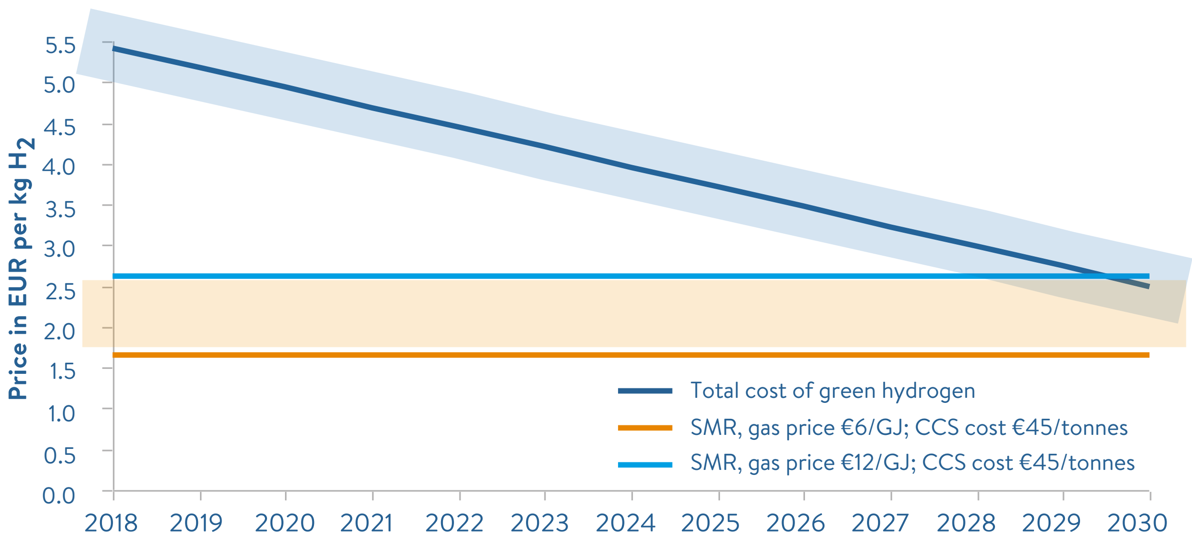
The cost of green hydrogen depends mainly on the prices of electricity, capital and operational costs for the required electrolysers and any transportation costs for the hydrogen. At large industrial production sites, however, hydrogen is produced locally and there are no transportation costs.

Due to the decreasing costs for renewable energy, the general expectation is that electricity prices will decline over time. For our model, we assume the price declining to €30/MWh by 2030, considering the observed and projected cost decreases for offshore wind and solar.

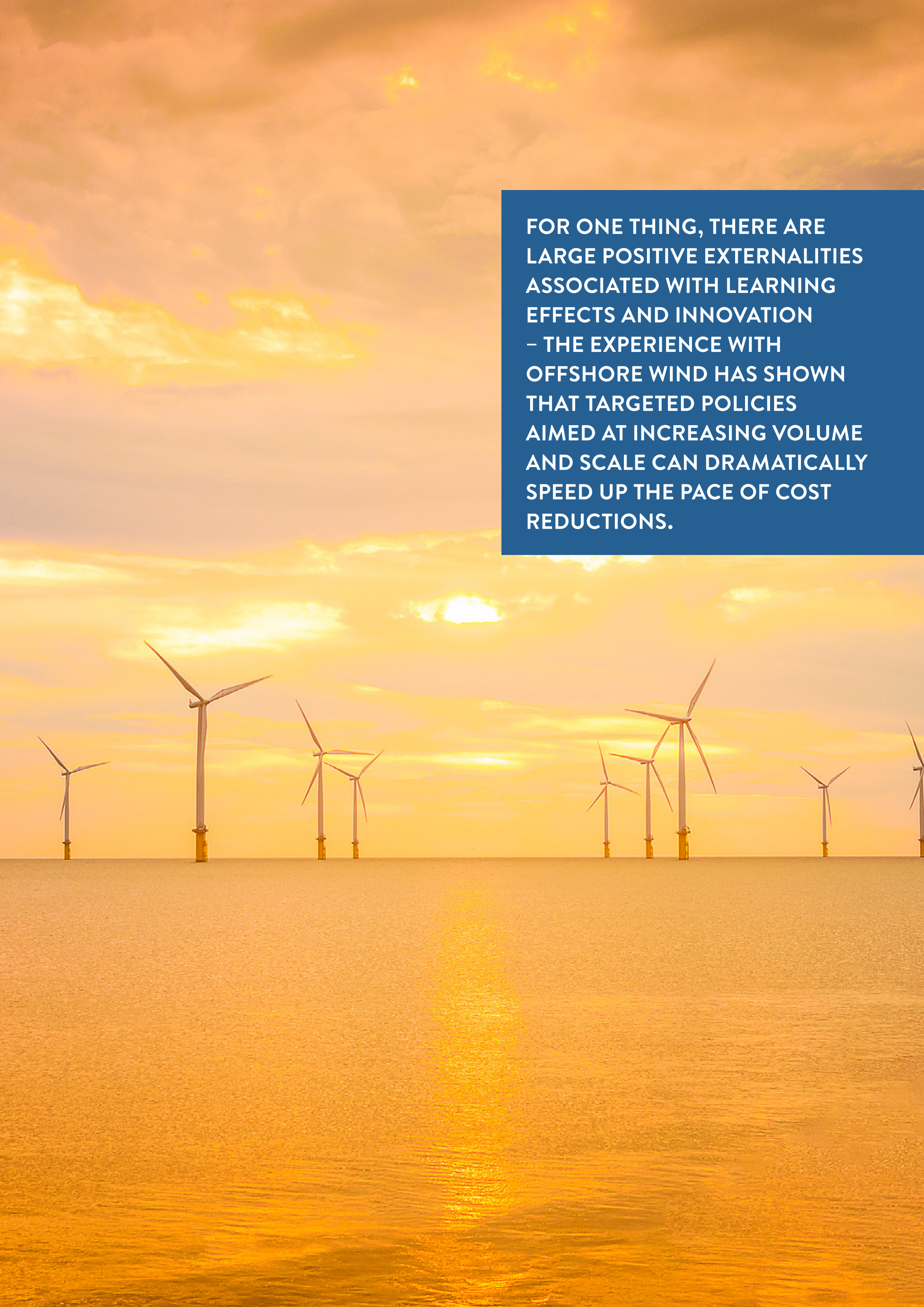
The capex level for electrolysers currently amounts to around €1000/kW of capacity.[12] These costs are expected to decrease significantly towards levels as low as €300/kW of capacity in 2030 thanks to increases in the capacity of the electrolysers and production efficiencies.[13,14] Furthermore, the efficiency of the electrolysers is expected to increase slightly, reducing energy consumption from around 55 kWh/kg of hydrogen produced to 50 kWh or less per kilogram of hydrogen produced.[15]

Based on various other studies, the consensus for the overall cost price for one kilogram of green hydrogen is between €5 and €6 today. This is expected to decrease to €2-3/kg in 2030.[16,17,18,19,20]

Figure 11: Green hydrogen could be competitive by the late 2020s



12 International aspects of a power-to-X roadmap, Frontier Economics & WEC, 2018.
13 International aspects of a power-to-X roadmap, Frontier Economics & WEC, 2018.
14 Contouren van een routekaart waterstof, TKI Nieuw Gas, 2018.
15 Contouren van een routekaart waterstof, TKI Nieuw Gas, 2018.
16 Routekaart CCS, CE Delft, 2018.
17 The green hydrogen economy in the northern Netherlands, NIB, 2017.
18 On the economics of offshore energy conversion: smart combinations, Energy Delta Institute, 2017.
19 Energy of the future?, Shell and Wuppertal Institute, 2017.
20 Renewable energy for industry, IEA and OECD, 2017.

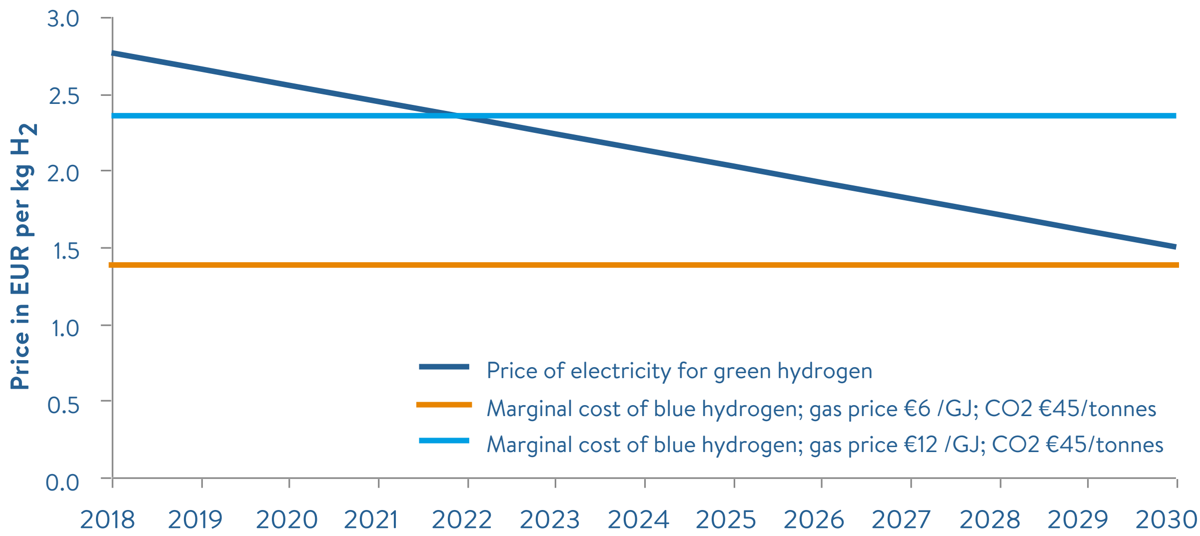


FOR ONE THING, THERE ARE LARGE POSITIVE EXTERNALITIES ASSOCIATED WITH LEARNING EFFECTS AND INNOVATION – THE EXPERIENCE WITH OFFSHORE WIND HAS SHOWN THAT TARGETED POLICIES AIMED AT INCREASING VOLUME AND SCALE CAN DRAMATICALLY SPEED UP THE PACE OF COST REDUCTIONS.

The marginal cost of blue hydrogen is composed of the natural gas price and CO_2 cost, while the marginal cost for green hydrogen depends on the price of electricity. If we take the expected decline in electricity prices over time into account, the marginal cost of green hydrogen can become competitive relatively early on; however, this will only apply if natural gas prices also increase significantly.

Assuming an average power price of €50/MWh and a requirement of 55 kWh to produce one kilogram of hydrogen, the electricity price would be €2.75 for the production of one kilogram of hydrogen. If power prices of €30/MWh and an energy consumption of 50 kWh/kg hydrogen are realised in the future, the price of the electricity required to produce one kilogram of hydrogen would decrease to €1.50.

Figure 12: The marginal cost of green hydrogen could be competitive by the early 2020s



IMPORTANT CONSIDERATIONS FOR GREEN HYDROGEN PRODUCTION

Sufficient renewable energy is an important requirement to reduce CO_2 emissions from green hydrogen production in high volumes. Shifting from grey to green hydrogen production in the current conditions (taking into account the current average European energy mix) would actually lead to an increase in CO_2 emissions per kilogram of hydrogen produced. Shifting towards green hydrogen production only leads to a decrease in CO_2 emissions once sufficient renewable electricity is produced to decrease the overall average level of CO_2/kWh electricity produced to around 1/3 of the current level of around 500 g of CO_2 emitted per kWh of electricity produced.[21,22,23] To decrease CO_2 emissions compared to blue hydrogen production, which has much lower emissions than grey hydrogen, an even greener overall electricity mix is required.

21 Contouren van een routekaart waterstof, TKI Nieuw Gas, 2018.
22 Energy of the future?, Shell and Wuppertal Institute, 2017.
23 Hydrogen as an energy carrier, DNVGL, 2018.

Green hydrogen production is already a preferable option in cases where there is no alternative use for green electricity, for instance on offshore wind farms where hydrogen may be produced locally and (almost) no electricity grid connection is required anymore. Alternatively, green hydrogen production can also be a preferable route for green electricity from solar PV-generated electricity in desert areas, where the efficiency of the solar panels is very high, and the requirement for electricity is low.

CONCLUSION

The conversion of existing hydrogen production from grey to blue depends on the costs of CCS versus CO_2 emission costs. Price parity and therefore an attractive business case for blue hydrogen is expected around 2030. However, for special cases such as ammonia production, and potentially also for hydrocracking in refineries, where CCS costs are relatively low, price parity might already be reached within a couple of years. Since ammonia production facilities are quite concentrated and have very high emissions per plant, a strong emphasis should be placed on converting the production process of these plants from grey to blue.

To achieve price parity between blue and green hydrogen production, it is crucial that the price of renewable electricity be low as this largely determines the marginal price of green hydrogen. Furthermore, the current capex costs for electrolysers need to decrease by around 70%, which can only be realised through significant scale and volume increases. The production costs for blue hydrogen are for the most part determined by natural gas prices, which need to increase significantly to reach price parity with green hydrogen production on marginal costs before 2030.

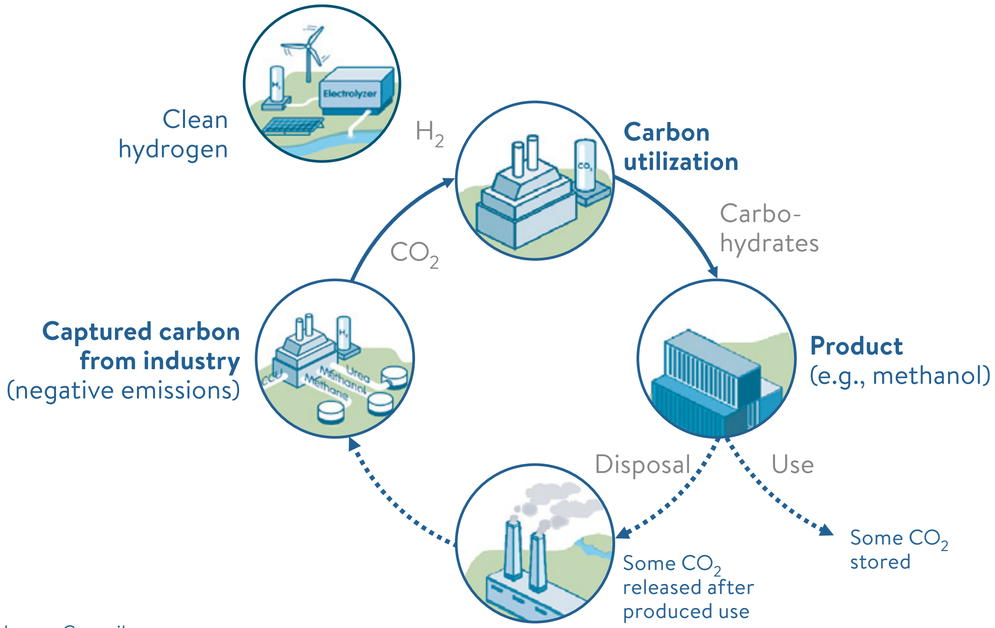
Based on our comparison of costs, a sensible strategy to incentivise the production of green hydrogen is to provide capex (and opex) subsidies in order to kickstart investment in large-scale electrolysis facilities. In periods of low electricity prices, the marginal costs for the production of green hydrogen will then be low enough to make green hydrogen competitive.

3.2. FEEDSTOCK FOR SYNGAS: MULTIPLE USE OF CARBON MOLECULES

In addition to being stored in the subsurface offshore (CCS), CO_2 can also be used as a feedstock (via carbon capture and utilisation, or CCU). With CCU, the CO_2 is directly used (for example in greenhouses) or converted to chemicals with a high value. In this way, CCU can act as a catalyst for the implementation of carbon capture technologies.

Carbon-rich waste gases can be combined with hydrogen to form syngas, a mixture of H_2 and CO/CO_2 which forms the basis of several applications. By combining green hydrogen with carbon from waste gases, CO_2 emissions are postponed as the carbon they contain is reused instead of emitted into the air. Alternatively, the carbon can also be captured from the air, sea or bio-based sources, making the whole process carbon neutral overall.

Figure 13: Hydrogen enables the recycling of captured carbon to chemicals

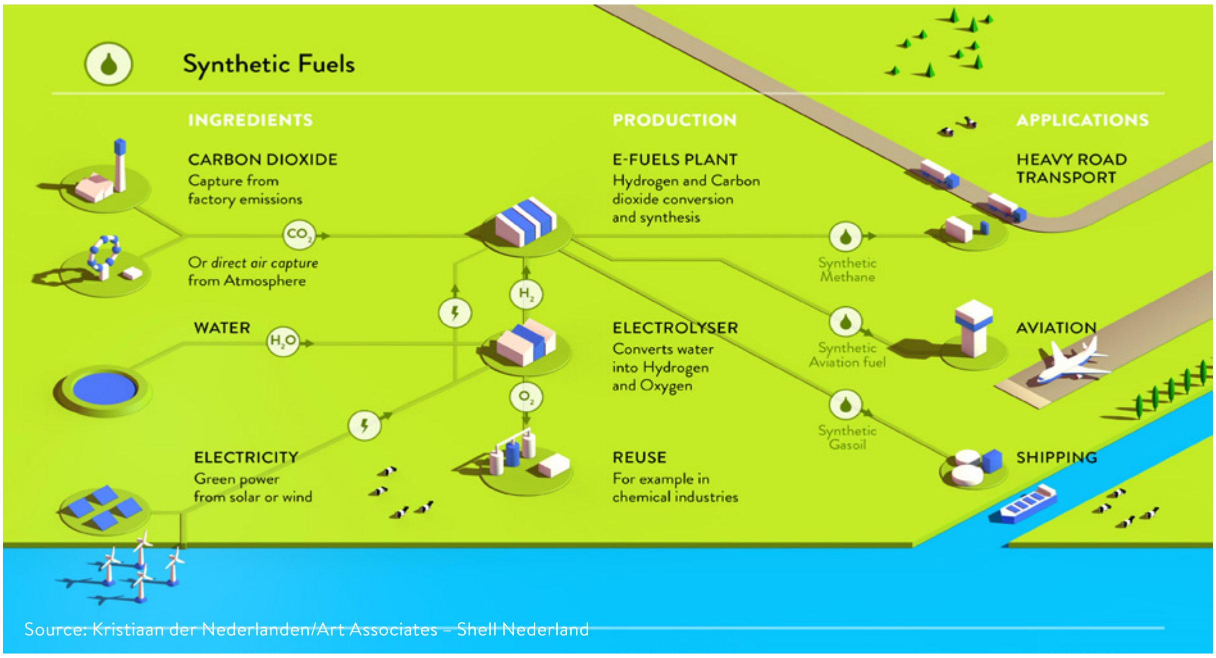


Source: Hydrogen Council

One of the most interesting applications of syngas based on green hydrogen is the creation of synthetic fuels. For light-duty road transport and passenger transport on water, it is perfectly possible to use electric vehicles powered by either batteries or fuel cells (including hydrogen fuel). This option is, however, less attractive for freight shipping and heavy-duty long-distance road transport, and even more so for aviation, due to the high requirements on energy density per weight of fuel for these types of transport. An option for these sectors could be the use of synthetic fuels with a high energy density. The trade-off with the high-energy density is in the efficiency: synthetic fuel has an overall efficiency of only around 10%, compared to roughly 30% for fuel cell electric vehicles (FCEVs) and 60% for battery electric vehicles (BEVs).[24]

24 Carbon neutral aviation with current engine technology, Quintel, 2018.

Figure 14: Syngas: production and uses



Source: Kristiaan der Nederlanden/Art Associates – Shell Nederland

As significant expansion in aviation is expected in the near future, the CO_2 emissions from this sector will increase steeply if the emissions per distance flown is not reduced. One of the few possibilities to decrease CO_2 emissions produced by aeroplanes is to use synthetic kerosene, which can be produced in a CO_2-neutral manner. A study on the use of synthetic kerosene produced with green hydrogen has been performed by Quintel. In its base case scenario for 2030, flights operated with synthetic kerosene would be 20 to 50% higher than flights based on fossil kerosene.[25] This price comparison still excludes CO_2 taxes, however.

An alternative scenario considered whether price parity could be reached with some set of plausible assumptions for all parameters.[26] This showed that price parity between synthetic and fossil fuel-based kerosene could be reached as early as 2030. In this scenario, overall emissions from industrial applications and aviation are effectively 50% lower, as carbon is used twice before being emitted into the air.

IMPORTANT CONSIDERATIONS FOR SYNGAS

While biofuels have in recent years been assumed to be the best choice for the production of biokerosene, they require extreme amounts of land and water. To grow enough biomass to produce biofuel for all aircraft alighting at Schiphol Airport alone, for instance, would require land use equal to 0.5-1.8 times the size of all Dutch farmland and 22-33 times the current water usage of all Dutch households combined.[27]

25 Assumptions: oil price of USD 80/bbl, electricity price of €40/MWh, electrolyser costs of €300/kW and carbon sourced from waste gases.
26 Assumptions: oil price of around USD 100/bbl, electricity costs of around EUR 30/MWh, EUR 20/ton CO_2 taxes and the sale of oxygen at production costs. Other assumptions remaining equal.
27 Carbon neutral aviation with current engine technology, Quintel, 2018.

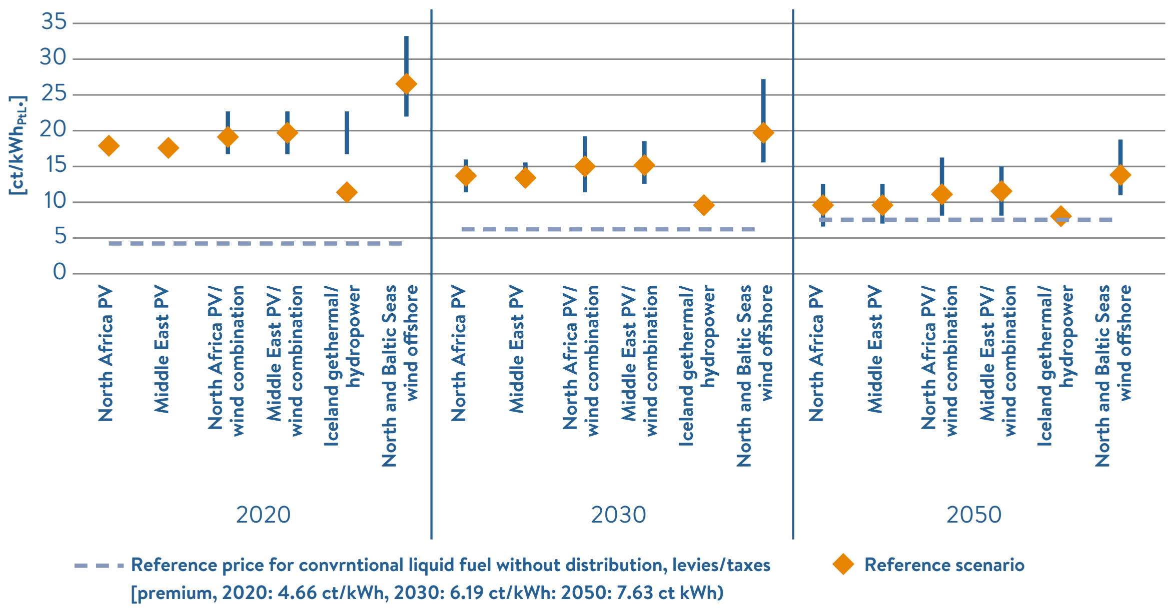
Obviously, this also means that the production of biofuels might end up competing with food production. The use of biofuel for aviation in this way is therefore not considered a viable option. There are still studies into the possible use of algae as a source for biofuels, but this is not yet a viable option from a commercial or environmental perspective.

Since the cost of the electricity used in electrolysis is a main component of the production costs of syngas and synthetic fuels, the local availability of affordable electricity is an important element to consider. In many regions around the world, renewable energy from sun, wind, water or biomass can be produced at much lower costs than in Europe. Locally produced synthetic fuels can then be transported to Europe, mostly making use of existing pipelines, tankers and storage infrastructure. A study by Frontier Economics made a comparison between the costs of (imported) synthetic liquid fuels and fossil fuels. The comparison showed that imported synthetic fuels have a cost advantage over synthetic fuels produced in Europe. Synthetic fuels are, however, expected to remain more expensive than fossil fuels in the foreseeable future.

CONCLUSION

The use of green hydrogen for the production of syngas and synthetic fuels is, in principle, attractive, as fuel is a high-value product. Furthermore, there are limited alternatives to reduce the CO_2 emissions from various transport sectors. From the examples mentioned above, it is demonstrated that the use of synthetic kerosene may become a viable alternative for aviation as early as 2030 under certain assumptions. However, the exemption of this sector from CO_2 taxation and zero fossil fuel taxation is currently still strongly undermining positive business cases for synthetic fuels.

Figure 15: Cost of imported synthetic liquid fuels vs. fossil fuels until 2050



Source: Agora Verkehrswende, Agora Energiewende and Frontier Economics, IEA
Note: Cost of generated synthetic liquid fuels (final energy, without taxes/levies)

IN MANY REGIONS AROUND THE WORLD, RENEWABLE ENERGY FROM SUN, WIND, WATER OR BIOMASS CAN BE PRODUCED AT MUCH LOWER COSTS THAN IN EUROPE.

3.3. ENERGY USE FOR INDUSTRIAL APPLICATIONS: STEEL MAKING BASED ON HYDROGEN

As the crude steel production industry is one of the main industrial emitters of CO_2, substantial effort needs to be directed at finding a way to decarbonise iron and steel production. The vast majority of crude steel production takes place via either the blast furnace-basic oxygen furnace (BF-BOF) or the scrap-electric arc furnace (scrap-EAF) methods, which both lead to high CO_2 emissions. Hydrogen offers a technologically viable and, under the right conditions, economically plausible route to produce crude steel with little to no CO_2 emissions via the direct reduction method (H-DR). Adding CCS to the BF-BOF process is not considered a viable alternative as this drives up the total costs to levels higher than H-DR.[28]

COST COMPARISON BETWEEN BF-BOF AND H-DR

The cost of producing one tonne of crude steel using the BF-BOF method is expected to stay relatively stable in the period between 2018 and 2030.[29] For H-DR, the cost curve is much more dynamic.[30] The cost of producing crude steel via the H-DR route is likely to decrease, with the exact rate mainly depending on the speed of cost reductions in terms of capex and, to a lesser extent, on the electricity price. The electricity needed to produce green hydrogen and to power the electric arc furnace on the steelmaking stage will be assumed to decrease from the current level of around €45/MWh to €30/MWh in 2030.

Decreasing capex costs will call for scale, learning and efficiency improvements. The current level of the capital expenditure required for setting up a direct iron processor, an electrolyser and a hydrogen storage facility is estimated to be €1000 per tonne of crude steel,[31] comprising almost 80% of the total production costs. Applying annual cost reductions of around 3.7% as experienced in the wind energy sector over the last seven years[32] would reduce the total cost of producing a tonne of crude steel by roughly 36% by 2030, from €1200 to €800. While, the cost level is still above the coal-based method, the proximity of the two price tags indicates that H-DR might make a business case by the 2030s. This scenario will be referred to as 'H-DR (3%)' in the rest of this report.

Similarly, assuming a more ambitious scenario with annual cost reductions of around 17%, as experienced in the solar energy sector,[33] the total cost of H-DR will drop sharply to a level that is 66% lower by 2030, and the method will have a competitive business case compared to BF-BOF already in the early 2020s.
This scenario will be referred to as 'H-DR (17%)' below.

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28 Techno-economic evaluation of innovative steel production technologies, Wuppertal Institute, 2014.
29 To quantify the cost of producing a tonne of crude steel with the BF-BOF process, the following cost drivers were analysed: coking coal price, ETS CO_2 price, capex of BF-BOF and operational & maintenance expenses. The sale price of blast furnace slag, a by-product, was added back.
30 When taking the route of direct reduction with hydrogen, it is important to achieve the minimal amount of emissions, so the use of green hydrogen is assumed. The main cost drivers analysed include the electricity price, the capex costs of the direct reduction processor, electric arc furnace, electrolyser, hydrogen storage facility, and operational & maintenance expenses.
31 M. Fischedick, J. Marzinkowski, P. Winzer, M. Weigel (2014), Techno-economic evaluation of innovative steel production technologies. Journal of Cleaner Production, 84, 563–580.
32 Renewable Power Generation Costs in 2017, International Renewable Energy Agency, 2018.
33 M. Fischedick, J. Marzinkowski, P. Winzer, M. Weigel (2014), Techno-economic evaluation of innovative steel production technologies. Journal of Cleaner Production, 84, 563–580.

Strong cost reductions are expected mainly in the cost of electrolysers, for which the production process is expected to be scaled up and automated significantly in the future. As the equipment required for the steel production process itself is produced in much lower volumes, fewer cost reductions are expected on this end. Therefore, the H-DR (17%) scenario is considered much less likely to be realised. To take these limitations with respect to cost reductions into account, we have assumed the high level of cost reductions until 2025, after which we assumed annual cost reductions of only 3%.

SENSITIVITY ANALYSES

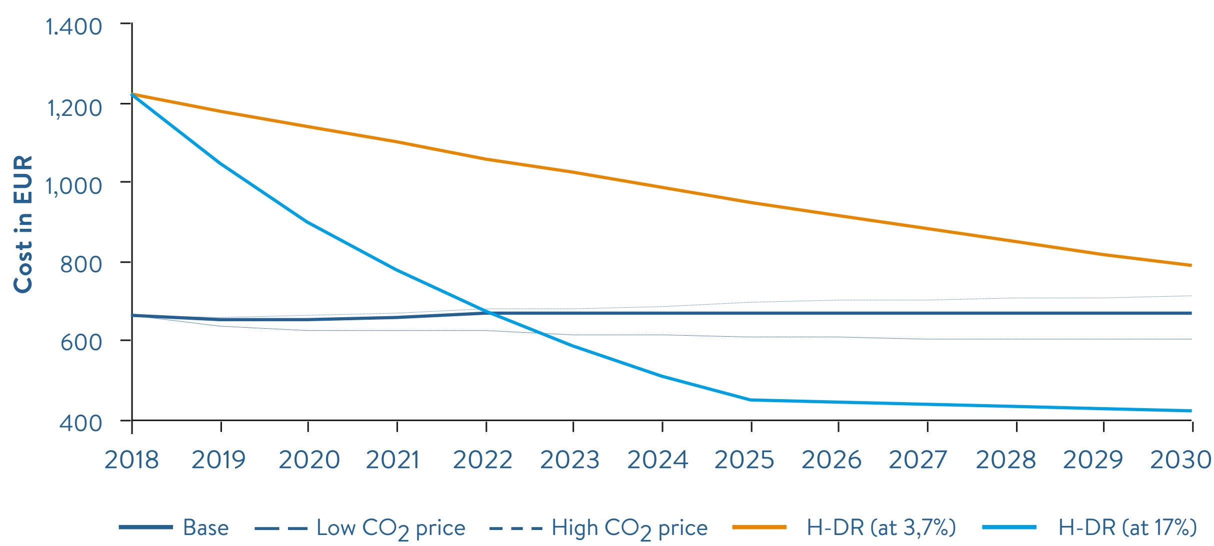
When calculating the ETS CO_2 price, a price increase from €25/tonne of CO_2 in 2018 to around €45/tonne of CO_2 in 2030 is taken into account. A high price of €70 in 2030 or no price increase at all would have only a limited impact on the cost attractiveness of H-DR. Alternatively, introducing a 30% error margin to the price of a tonne of coking coal also only has a limited effect on the total cost, changing it by 3% in both directions (not shown in the graph above).

On top of the uncertainty around the rate of capex cost reduction, the electricity price may also bring changes to the total cost of crude steel. However, assuming a range for the long-term electricity price of between €15/MWh and €45/MWh shows that this does not have a major impact on the overall costs of H-DR either.

CONCLUSION

H-DR cost competitiveness is strongly dependent on the development of the capex curves. Although current H-DR costs are still much higher than those of BF-BOF, the technology may become cost competitive against BF-BOF as early as 2030 in a moderately optimistic scenario. If sufficient scale

Figure 16: Strong cost reductions can make H-DR competitive



is achieved and cost efficiencies in line with historical cost decreases for solar-PV are realised, H-DR technologies may even reach cost parity in the 2020s. In order to realise cost competitiveness, however, it will be critical to accelerate the upscaling process to push the technology down the cost curve.

3.4. TECHNOLOGICAL READINESS OF INDIVIDUAL APPLICATIONS

Hydrogen is currently produced and used mainly for pre-combustion feedstock applications, such as the production of ammonia. The hydrogen production in this case is based on SMR, which is a very mature technology. The conversion of this currently grey production process to a blue production process via CCS is still in a very immature stage. CCS by itself is only applied in a very limited number of places around the globe. In Europe, Norway is the leading example, with two operating CCS installations offshore, Sleipner and Snøhvit, where CO_2 produced during oil and gas production is stored in an offshore deep saline aquifer. The scale is in the order of 1 Mton of CO_2 storage per year.

Other successful CCS installations in the US and Canada are an application of enhanced oil recovery, with CO_2 injection in the oil reservoir. This results in more oil being produced, which is the driver for the business case. Many new initiatives for CCS projects have, however, been either postponed or cancelled altogether for reasons of economics or public resistance. The latest successful implementation of a CCS project is in Canada at the Bounday Dam power plant operated by Sask Power. From a purely technological perspective, the implementation of CCS does not require any breakthroughs.

Hydrogen has been produced via electrolysis for a long time. However, the high costs of electrolysis compared to SMR have made the former less attractive over time, and it is currently only applied on a very limited scale and for specific applications in the chemical industry. As such, large-scale hydrogen production via electrolysis is still immature.

It is important to differentiate the various existing types of electrolysis processes. The most well-known and mature types are alkaline electrolysis (AEL) and proton exchange membrane electrolysis (PEM). Both have operating temperatures of around 60-70 °C. Alkaline exchange membrane electrolysis (AEM) is a third, low-temperature variant, but it remains less developed today. A fourth type is solid oxide electrolysis cell (SOEC), which operates at temperatures between 600 and 800°C. At this moment, it is not yet clear which type has the most potential since each technology has advantages and disadvantages. One of the main technological hurdles is the need for rare earth metals used in the cathodes. Additionally, the efficiency of the electrolysis process needs to be improved further. Significant further scaling is also required in order to realise projected cost reductions.

The use of hydrogen in steel production is still very immature. As described in the various case studies mentioned in this report, there are currently several steel production plants in which the transition from a coal-based process to a hydrogen-based process is being tested and further developed.

4

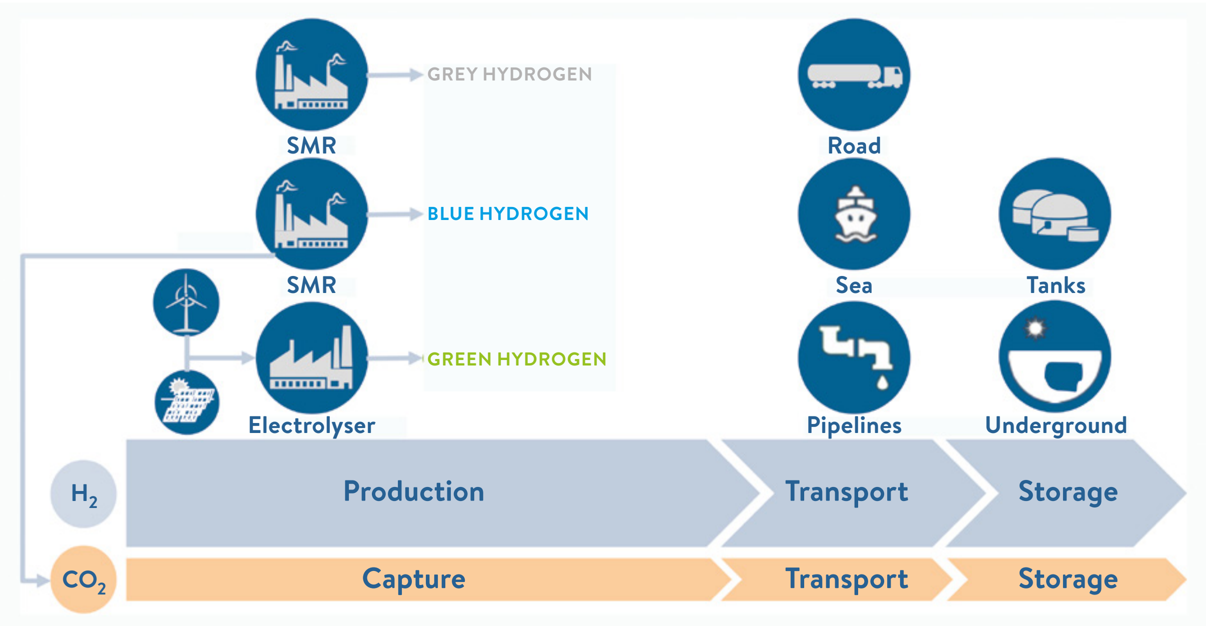
MARKET FAILURES AND OTHER BARRIERS TO THE ADOPTION OF HYDROGEN

In this section, we will identify the market failures and other barriers that stand in the way of large-scale hydrogen adoption. An analysis of these barriers allows us to identify which policy interventions are likely to be the most effective in accelerating the hydrogen economy.

Markets fail when they cannot reach socially optimal outcomes without policy intervention. There are four main types of market failures: 1) **externalities** exist when a third party has benefits or costs from an economic activity in which it does not participate; 2) **public goods** are non-excludable and non-rivalrous, hence their consumption does not affect their availability for others; 3) **information asymmetry** is a situation in which one party is better informed than the other in a transaction; and 4) **market power** (monopoly) is a situation where competition is limited and one party can influence the outcome in a market (market power can be the result of government intervention). Of course, for markets to fail, they first need to exist. The creation of markets that enable socially optimal outcomes can be obstructed by high transaction costs. This is called missing markets and can also require government intervention.

We will consider every stage of the hydrogen value chain in this section. For each stage, we will first give an overview of the relevant characteristics and then analyse the market failures of that stage. Later in this chapter, we will describe the generic barriers and problems that arise along the entire value chain of hydrogen.

Figure 17: The hydrogen value chain



4.1 PRODUCTION OF HYDROGEN

The internal market for gas is mainly governed by the Gas Directive and related regulations. Together with the Electricity Directive, the Gas Directive forms part of the EU's Third Energy Package that entered into force in 2009. The Gas Directive establishes common rules for the transmission, distribution, supply and storage of natural gas. The Gas Directive mandates a structural separation between TSO activities and activities related to generation, trade and supply (unbundling). Furthermore, Storage System Operators (SSO) are also recognised as relevant market players that should also be unbundled from other activities.

The Gas and Electricity Directive includes third party access rights (TPA) for the non-discriminatory access to transmission and distribution systems. Under both Directives, operators have to provide for third party access, either through negotiated or regulated access to their infrastructure. TPA rules in both the Gas and Electricity Directive, may become especially important for (new) hydrogen and energy storage market entrants, in view of the current legislative developments to stimulate power-to-gas in Europe.

Under certain circumstances, major new infrastructures or new interconnectors may be exempt from TPA rules in both the Electricity and Gas Directive.[10] Please refer to the two examples of the BBL pipeline and the BritNed cable below.

MOST HYDROGEN IS PRODUCED VIA SMR

Steam methane reforming (SMR) is the most common method for producing hydrogen. Several types of fossil fuels can serve as an input in this process, with natural gas being the most common. This process yields carbon in addition to hydrogen. If this carbon is released into the atmosphere, the hydrogen produced is considered 'grey hydrogen'. As previously mentioned, the production costs of grey hydrogen are estimated to be between €1/kg and €1.50/kg. This is currently the cheapest method to produce hydrogen.

It is also possible to capture the carbon for other applications or for storage (via carbon capture and storage, or CCS). If CCS is applied, the hydrogen produced is considered 'blue hydrogen'. CCS involves additional costs, however, and its production is expected to become commercially viable in the late 2020s depending on EU ETS carbon prices.

There are substantial economies of scale in the production of hydrogen via SMR. Large-scale hydrogen production – typically around nine tonnes of hydrogen per hour – costs around €1-1.50 per kilogram of hydrogen. Small-scale SMR facilities – producing around 200 to 600 kg of hydrogen per day – make hydrogen at a price per kg of €4-5. This cost level is competitive compared with a combination of large-scale production and transport.[34]

34 Gigler, J. & Weeda, M. (2018) – TKI roadmap

ELECTROLYSIS ALLOWS GREEN HYDROGEN TO BE PRODUCED WITH GREEN ELECTRICITY

A method to produce hydrogen without carbon emissions is to use green electricity for the electrolysis of water. The most common methods used are alkaline electrolysis (AEL) and proton exchange membrane (PEM) electrolysis.

The cost of green hydrogen is mainly related to the price of electricity and capital costs for the required electrolysers. Renewable electricity is more expensive than grey electricity today. Based on our business case calculations mentioned in the previous chapter, green hydrogen is expected to become commercially competitive by the late 2020s. Therefore, today's electrolyser projects need additional public funding to become commercially viable. For example, the electrolyser facility in the REFHYNE refinery project received €20 million by the EU Horizon 2020 programme under the European Fuel Cells and Hydrogen Joint Undertaking.

The current facilities for the production of hydrogen via electrolysis, which are scattered throughout north-western Europe (mainly in Germany and the Netherlands), vary greatly in terms of size. Most production facilities are located at industrial sites where hydrogen is used as feedstock.

MARKET FAILURES IN THE PRODUCTION OF HYDROGEN

The above-mentioned characteristics of hydrogen production lead to the following market failures that hinder the production of hydrogen.

- CO_2 emissions are a negative externality which create costs for third parties. This is why the EU has imposed a price for carbon emission in its ETS. However, the current EU ETS covers heavy industry only and the price of carbon does not completely reflect the social costs of CO_2 emissions, which are estimated to be around €70/tonne of CO_2.[35] The failure to internalise the costs of CO_2 emissions undermines the commercial business case for both blue and green hydrogen production and for research into climate-neutral alternatives. In the case of blue hydrogen, it is not the production itself that is commercially unfeasible, but the CCS process, which involves the capture, transport and storage of carbon. The price of this process is higher than the EU ETS price of carbon. We expect this to change as the future CO_2 price increases on the back of policy driven by the Paris Agreement targets. However, governments need to remain committed to these goals to push the CO_2 price higher.

- When negative externalities are sufficiently priced in, **positive externalities** can also play a role in hindering the production of green hydrogen. Namely, if elements of the information generated by innovation become public goods and firms do not obtain all the gains from this innovation, they might innovate too little. Such innovation might be crucial for pushing hydrogen technologies through the 'valley of death' and reducing the cost of production by reaching economies of scale.

35 RaboResearch, 2018; DNB, 2018

4.2 TRANSPORT INFRASTRUCTURE

HYDROGEN CAN BE TRANSPORTED VIA PIPELINES (REUSE OF OLD PIPELINES OR NEW PRIVATE NETWORKS), BY WATER OR BY ROAD

Ecorys (2018) identifies four potential modes of pure hydrogen transport, including transport via tankers, trucks or pipelines.

- Reuse of the existing natural gas grid for hydrogen: The North Sea countries have an extensive onshore gas network to transport natural gas. These pipelines will gradually fall into disuse as natural gas production in Europe declines, and could be repurposed to transport hydrogen. The Dutch natural gas network is suitable for transporting pure hydrogen gas.[36] Some parts of the infrastructure, such as compressors, may need replacing, however. Furthermore, higher volumes of hydrogen will be needed compared to natural gas to meet the same energy demand.

- New privately owned pipelines: There are already private projects for the transport of hydrogen, such as the 1000 km pipeline between northern France and Rotterdam owned by AirLiquide. These types of investments are linked to private business cases and dependent on the existence of local producers and end users.

- Water and road transport (cooled, under pressure, chemically compounded): This is suitable for small-scale, irregular and geographically dispersed demand and supply.

- Long distance shipping: Comparable to LNG, hydrogen can be transported by tankers over sea.

Although road transport and shipping are good transport options to meet flexible demand, pipelines will be the most efficient option to deliver large amounts of hydrogen at fixed locations in the long run. Private parties such as AirLiquide and Air Products are already building pipelines to transport hydrogen. The existing natural gas pipelines in the Netherlands are owned by the state, so repurposing them would involve a question of ownership. However, if existing gas infrastructure in the North Sea is used for transport of wind energy offshore to the coast, it could lead to massive savings. If this externality is internalised for a conversion unit on a platform or offshore island, the offshore cost price of green hydrogen could reach levels that are competitive with that of grey hydrogen.

DEMAND AND SUPPLY OF HYDROGEN ARE CENTRED ON A FEW INDUSTRIAL HUBS IN NORTH-WESTERN EUROPE

Potential hydrogen pipelines should connect the largest industrial consumers and producers of hydrogen. Currently, hydrogen is mainly produced in the Netherlands and Germany. As we expect the transition towards hydrogen will eventually become a transition to green hydrogen production, these electrolyser facilities will have to be built in proximity to sources of green electricity.

36 DNV GL & GTS, 2017

This will likely be coastal locations where electricity from offshore wind comes ashore. The existing European hydrogen infrastructure developed by AirLiquide connects the ports of Dunkerque and Rotterdam, and includes some side routes in Belgium.

The amount of green electricity in the Netherlands is not expected to be sufficient to produce enough hydrogen to satisfy the total current demand. It is therefore likely that green hydrogen will have to be imported if there is an ambition to only use green hydrogen.[37] An international pipeline connection would then be needed.

THERE IS AN ADDITIONAL NEED FOR CARBON TRANSPORT WITHIN BLUE HYDROGEN PRODUCTION

The carbon captured during the SMR production process for blue hydrogen needs to be transported to a location where it will be stored. The characteristics of such transport are the same that relate to the transport of carbon in general.

MARKET FAILURES IN THE TRANSPORT OF HYDROGEN AND CARBON

- Pipeline infrastructures have a tendency towards a natural monopoly due to the high cost of investments and the importance of economies of scale, meaning that average costs decrease with an increased production volume. Due to economies of scale in transport infrastructure, it is cheapest to let one or very few players operate the transport network. This risk of monopoly power can arise in the transport of hydrogen and carbon and may lead to inefficient market outcomes with higher prices and less innovation than in competitive markets.

  Given these potentially inefficient market outcomes, governments might choose to regulate the monopolistic market player to protect consumers. Regulation could include controls on the price of the usage fees that the owner of the pipeline infrastructure is allowed to charge. Economists often say that, in a state of perfect competition, prices should be equal to marginal costs. Governments therefore tend to impose marginal cost pricing when regulating monopolists.

- In situations where pipeline infrastructure is not yet complete, market players will have to consider whether to invest in the infrastructure. If prices are set at marginal costs, market players may be unable to recoup the high initial investments they made in the infrastructure. Moreover, they might anticipate this and therefore refuse to invest in the infrastructure in the first place. This would lead to an inefficient market outcome. Situations where government intervention leads to inefficient outcomes is known as a government failure.

37 Contouren van een Routekaart Waterstof, TKI Nieuw Gas, 2018, p. 43-44

ALTHOUGH ROAD TRANSPORT AND SHIPPING ARE GOOD TRANSPORT OPTIONS TO MEET FLEXIBLE DEMAND, PIPELINES WILL BE THE MOST EFFICIENT OPTION TO DELIVER LARGE AMOUNTS OF HYDROGEN AT FIXED LOCATIONS IN THE LONG RUN.

4.3 STORAGE OF HYDROGEN

SMALL AMOUNTS OF HYDROGEN CAN BE STORED IN TANKS ON PRIVATE SITES, WHILE LARGE AMOUNTS CAN BE STORED IN UNDERGROUND SALT CAVERNS AND EMPTY OIL/GAS FIELDS

Many hydrogen producing facilities currently also consume the hydrogen produced. This means not much hydrogen needs to be stored and tanks at the facility generally suffice for storage needs. Large-scale hydrogen storage can take place in underground facilities. Salt caverns, already used for storing natural gas, are highly suitable for hydrogen storage as rock salt is one of the best sealing substances available in the subsurface, limiting explosion risks. Salt caverns have a minimum height of 300 metres, and can be up to 1500 metres deep. Given such dimensions, a single salt cavern could store the equivalent of 3 TWh of hydrogen. It is important to remember that there is a difference in the ownership structure between a hydrogen tank on the site of a private facility and a subsea storage facility, which occupies public space.

STORAGE OF CARBON FROM SMR HYDROGEN PRODUCTION IS STILL SUBJECT TO PUBLIC DEBATE

Carbon storage is still subject to public debate. This has led to few locations being designated for CCS in Europe so far, apart from pilot projects. As not many locations are eligible for carbon storage, CCS will likely be organised in a centralised way. Furthermore, it is most efficient to invest in filling few large locations rather than spreading the carbon across many smaller ones.

MARKET FAILURES IN THE STORAGE OF HYDROGEN AND CARBON

- Similar to transport, large-scale hydrogen or carbon storage can be subject to the risk of monopoly power. Storing in public spaces needs coordination. As there are not many underground locations in which hydrogen or carbon can be stored, and it is most efficient for this storage to be centralised, this activity is subject to large economies of scale and thus a tendency towards a natural monopoly. As previously highlighted, this can lead to inefficient market outcomes. Moreover, the government is likely to regulate markets of this kind and, as discussed above, this may result in government failure.

- These government decisions regarding CCS are in large part influenced by public opinion. There is a great deal of opposition to CCS among the public, in part due to the perceived risks of storing carbon underground. These risks have to be dealt with by a responsible party. However, it is nearly impossible to assign responsibility for handling a risk that will last as long as carbon stored in underground locations – that is, potentially forever. This safety risk cannot be captured in a contract between private market operators because it is impossible to put a price on an obligation to handle a risk that may last in perpetuity.

4.4 BARRIERS AND FAILURES ALONG THE ENTIRE VALUE CHAIN

Several barriers or failures in the hydrogen value chain keep the start-up (entry) costs high and therefore lead to missing markets:

- In some parts of the hydrogen value chain, there is a high dependency on government regulation. Regulatory uncertainty can therefore negatively affect the investment decisions of market players. For example, it is unclear whether and how governments will regulate the future pipeline infrastructure. Additionally, potential investors in CCS solutions need clarity on whether the government will allow carbon storage at all and, furthermore, how much carbon will be eligible for storage. This in turn depends on the standards and rules set by governments regarding carbon emissions. In the absence of clarity on future regulation, investors cannot quantify risk and may decide not to invest.

- Even when there is a positive business case for hydrogen technologies, coordination failures may still lead to an insufficient hydrogen production capacity to reach the socially optimal outcome. These failures arise when several steps have to be taken collectively for a process to work, but coordination between them is missing and nothing happens at all. Coordination failures arise in several steps of the hydrogen value chain. Both the transport and storage stages involve economies of scale, so it is cheapest to centralise the transport and storage of hydrogen and carbon. However, this centralisation leads to dependence among the different players in the hydrogen or CCS value chain because hydrogen will only be produced and carbon only be captured if it can also be transported and stored. On the other hand, players facilitating transport and storage of carbon will only start to offer their services when they are assured that there is sufficient supply of hydrogen or carbon. In other words, there is value chain dependence, meaning that players along the value chain are dependent on the actions of others. An example of the importance of value chain dependence can be found in syngas production as processes that combine carbon and hydrogen to produce syngas are circular, meaning that the carbon and hydrogen are the products of other processes. To produce renewable syngas, the hydrogen and carbon used as inputs should also be renewable. A single large coordinated market where hydrogen is traded as a commodity would be most efficient in this context and should therefore be fostered.

- Shifting from grey to blue or green hydrogen may also run into path dependency. This refers to a situation where future innovations that build on the existing stock of knowledge and existing technology are cheaper than a shift to completely different technologies. Imagine a grey hydrogen producing facility that has to stop emitting carbon. It can choose to switch to green hydrogen or to blue hydrogen. As SMR facilities to produce grey hydrogen are already in place, the firm will have an incentive to keep these facilities and therefore add CCS to the production process instead of switching to completely new electrolyser facilities, even though electrolysers may actually be the most profitable option in the long run.

- Governments also need to think about spatial planning when designating a location for hydrogen or carbon storage. There are presumably many stakeholders, such as nature preservation organisations, oil/gas exploiters or local populations that may fear the risks of storing flammable gas close to their homes. Such factors can lead to uncertain outcomes in which investors cannot quantify the risk of storage activities and therefore decide to stay away. Regulatory uncertainty can have a similar effect.

Table 1: Summary of market failures and barriers related to missing markets

Stage	Market failures and barriers	Missing markets
Production	- Negative externalities - Positive externalities (public goods)	
Transport	- Tendency towards natural monopoly - Government failure	
Storage	- Tendency towards natural monopoly - Government failure - Public opinion	
Generic		- Regulatory uncertainty - Coordination failure - Path dependency - Spatial planning

5

POLICY RECOMMENDATIONS

The need for hydrogen is well established. Industry has an important role to play in making sure the hydrogen economy gains the scale it needs. However, there are significant barriers to adoption which will need a clear action plan, particularly on the part of governments and regulators.

1. A CLEAR STRATEGY SHOULD BE DEFINED

Governments need to demonstrate commitment and reduce uncertainty. They should therefore formulate clear strategies designed to bring about a hydrogen economy and specify a regulatory environment that will create clarity amongst investors. Such a strategy should contain a timeline that dictates milestones to be achieved in the coming decade, the roles of the players involved and the budgets available for specific actions to be taken. This strategy would demonstrate the government's commitment. Reducing uncertainty amongst players and investors.

Governments can also play a role in facilitating coordinated action. They can take the lead to remove the wide range of obstacles that arise in the complex process of a market in development. They would not need to do everything, but could, for instance, make investments that are currently unprofitable for private actors. Most importantly, the ambitions and future actions of governments should be clear. A clear government strategy is the first step towards overcoming obstacles such as value chain dependency, lack of public acceptance and positive externalities. A first step can be to publish an official report setting out the path towards a hydrogen economy, including targets, government support programmes such as subsidies or funding and other regulatory changes envisaged to facilitate the implementation of the roadmap. An ambitious plan would also help push the price of CO_2 closer to its real social cost, which is ultimately necessary for the adoption of carbon abatement technologies like blue and green hydrogen production.

2. GREEN AND BLUE ARE NEEDED

To stimulate investments in green hydrogen, governments should announce their plans for parallel adoption of blue and green hydrogen. While the ultimate goal is to green all hydrogen, blue hydrogen is an essential step in a realistic transition towards the adoption of hydrogen in the first place. Adding CCS to existing SMR facilities serves two goals. First, it reduces CO_2 emissions in production processes. Second, blue hydrogen contributes to the development of a hydrogen infrastructure which will ultimately facilitate the adoption of green hydrogen.

Immediate action is required to get CCS organised. We identified many issues that need to be addressed before CCS can be adopted, such as value chain dependence, risk of monopoly power, insecurity of carbon supply and public acceptance. Clear communication and support from governments would help create public acceptance. Furthermore, governments should put a clear framework in place to enable and facilitate CCS. Such a framework would include designating responsible parties for the various steps in the CCS value chain.

It is also important to distinguish CO_2 and green CO_2, which is obtained from biomass or from the air. When green CO_2 is combined with hydrogen, biomethanol or biomethane is generated which is a fully green feedstock. Governments should encourage the use of green feedstock for producing chemical products (such as fertilizers), by providing subsidies or tax incentives.

3. THE ORGANISATION AND COORDINATION OF INFRASTRUCTURE SHOULD BE ENCOURAGED

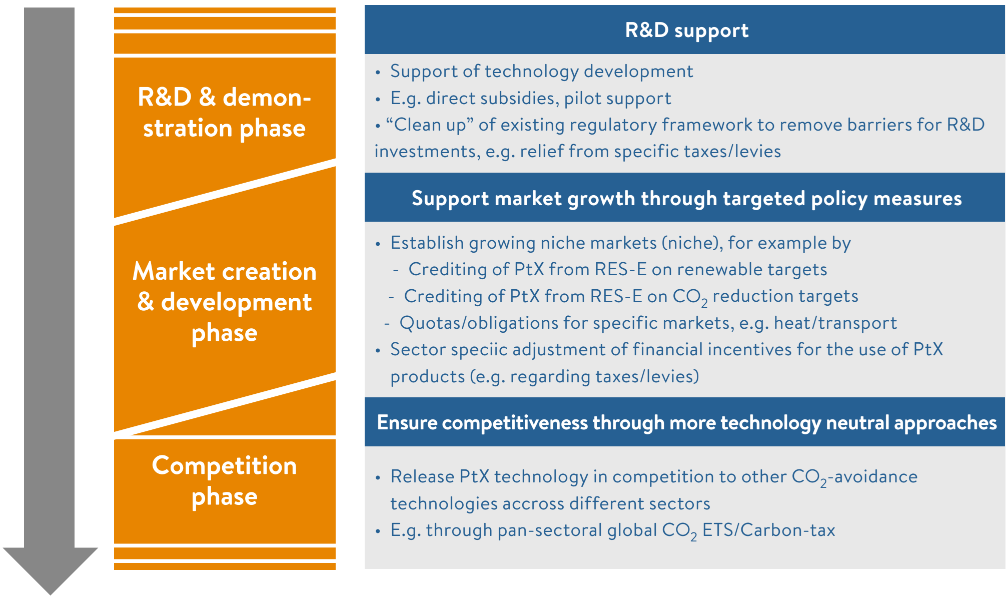
Both the use of hydrogen (transport) and CCS (transport and storage) require large-scale infrastructure, which has many market failures potentially associated with it. Because of the large economies of scale, there is a risk of monopoly power. Governments will want to protect consumer interests and therefore intervene in such a market. However, in doing so, they run the risk of causing inefficient outcomes in the market or hindering the development of new markets because of government failure.

Governments need to start offering clarity on who will be responsible for specific parts of transport and storage. It should be clear whether these will be public or private parties and who will take up which role to achieve which ambitions. For example, how will the hydrogen transport infrastructure be organised, who will be responsible and under which conditions? Governments should research if there is a need for direct investment in infrastructure and put appropriate regulatory frameworks in place.

4. HYDROGEN APPLICATIONS SHOULD BE PUSHED ALONG THE TECHNOLOGY CURVE

Governments should help push technologies through the cost curves. Depending on the technology readiness phase, governments should use the appropriate tools to bring costs down. The various technologies for producing hydrogen are in different technology readiness phases. For example, SMR is an established technology already in the competition phase, whereas CCS and electrolysers are less developed and still need financing via pilot projects or specific R&D financing. Temporary subsidy programmes can also speed up the adoption process. The figure below gives an overview of the technology readiness levels and corresponding policy intervention options.

Figure 18: Potential path of transient policy measures



Source: Frontier Economics

STEP 1 - MARKET FAILURES AND MISSING MARKETS: NEGATIVE EXTERNALITIES, POSITIVE EXTERNALITIES, HIGH DEGREE OF UNCERTAINTY, PATH DEPENDENCY

In the R&D and demonstration phase, governments should subsidise R&D and pilot projects in specific technologies. The EU is already investing in several electrolyser demo plants. These demonstrations reduce the high degree of uncertainty specific to new innovations and stimulate investors to undertake similar projects. Furthermore, governments should reconsider existing regulatory frameworks for the energy sector. For example, in Germany, electricity is subject to high taxes. This is meant for the final consumers of electricity, but when the electricity is used to produce hydrogen – an energy carrier – it is taxed twice, creating an adverse effect on the profitability of green hydrogen production.

STEP 2 - MARKET FAILURES AND MISSING MARKETS: POSITIVE EXTERNALITIES, HIGH DEGREE OF UNCERTAINTY, PATH DEPENDENCY, COORDINATION FAILURES

In the market creation and development phase, governments should clearly state their plans. They can impose quotas and make green hydrogen use compulsory in several end-use applications. For example, governments could set different tax rates for grey and blue/green hydrogen used as feedstock or they could dictate that a certain share of the hydrogen in ammonia production, say, be green. On the other hand, the use of green hydrogen could also be rewarded with tax cuts or other direct financial incentives.

STEP 3 - MARKET FAILURES AND MISSING MARKETS: NEGATIVE EXTERNALITIES

In the competition phase, long-term climate policy should focus on cost efficiency and benefits from a more general climate policy framework where different CO_2 abatement technologies should compete with each other across industries and sectors on a level playing field. A proper CO_2 price that reflects the real social costs of carbon should be part of that policy framework.

Appendix

HYDROGEN 101 (FAQs)

A. WHAT IS HYDROGEN?

Hydrogen is the most abundant element in the universe. At room temperature, hydrogen forms a very light colourless gas with the molecular formula H_2. Hydrogen gas easily forms covalent compounds – most of the Earth's hydrogen therefore exists in molecular compounds such as water, many of which, like methane, are organic. Existing technology that allows hydrogen to be extracted from methane and water has been proven and allows the creation of hydrogen gas that can be transported and used.

The interest in hydrogen as an energy carrier comes from its high energy density per volume – at 120 MJ/kg, this is two to four times higher than coal (~30 MJ/kg) or natural gas (~55 MJ/kg). With no carbon atoms involved in its burning process, hydrogen is a carbon-free energy carrier. Moreover, it can be stored. The combination of the fact that hydrogen can be stored, its high energy density and the absence of CO_2 emissions produced during its combustion is what makes hydrogen so attractive in the energy transition.

B. HOW IS HYDROGEN PRODUCED?

Grey	Blue	Green
Hydrogen is said to be grey if its production results in emission of CO_2 into the air. This is the method used to produce most of the hydrogen available on the market today. The most common grey type of production is steam methane reforming (SMR). Essentially, in the first step methane is separated into hydrogen and carbon monoxide (CO) through the addition of pure water vapour (steam) at high temperatures. $CH_4 + H_2O \rightarrow CO + 3\ H_2$ Next, in a so-called water gas shift reaction, the carbon monoxide is mixed with water again to arrive at carbon dioxide (CO_2) and more hydrogen. $CO + H_2O \rightarrow CO_2 + H_2$ Another grey method for producing hydrogen is gasification. This involves a carbon carrier (e.g. wood, coal or biomass) that is reacted with water without combustion at high temperatures of around 850 °C to get carbon monoxide and hydrogen. The next step, similar to SMR, is water gas shift reaction resulting in CO_2 and additional hydrogen.	The blue type of hydrogen is produced from carbon-containing sources using the exact same steps as for the grey type, but the CO_2 from the reactions is captured and stored using CCS technology in, for example, salt caverns. This production method therefore avoids the release of CO_2 into the air. Given that CO_2 in the air is one of the key drivers of global warming, blue hydrogen can already contribute to realising the 1.5 or 2-degree scenarios.	There is also a way to get hydrogen without adding any CO_2 to the atmosphere. The product of this method is known as green hydrogen. Water is electrolysed to split the H_2O molecule into hydrogen (H_2) and oxygen (O_2) gas. The process can occur at both low and high temperatures and at scales that range from kilowatts to megawatts in size, depending on the type of electrolyser. The most promising technologies using this chemical reaction are alkaline water (AEL) and polymer electrolyte membrane (PEM) electrolysis, both operating at low temperatures. The difference between the two is that PEM electrolysers are more compact and better suited for dynamic load balancing of electricity grids, an important factor if one uses intermittent electricity from renewable sources. On the other hand, alkaline electrolysis is more proven and requires lower capital expenditures, a major cost driver for green hydrogen. To ensure that the hydrogen produced is indeed green, there should be no CO_2 emitted in any of the production steps. Hence, the electricity used must come from renewable sources such as wind or solar.

C. WHAT ARE THE MAJOR APPLICATION AREAS OF HYDROGEN?

Transport	This is perhaps the most sought-after application of hydrogen, since the only by-product of burning hydrogen is clean water – this effectively decarbonises transport. Hydrogen can be used to power fuel cell electric vehicles (FCEVs), which benefit from shorter fuelling time and longer fleet distances than battery electric vehicles (BEVs). The potential is even higher for long-distance fleet transport with vehicles like trains and buses, since the infrastructure needed to fuel these is much more concentrated in hubs like ports, depots or terminals, making infrastructure development easier.
Building heat and power	Another way of using hydrogen is to blend it with natural gas in the existing gas infrastructure for heat and power generation. The biggest advantage of this application is that infrastructure already exists on the demand side. The adjustments necessary to use the pipes that currently transport natural gas are minor and economically insignificant. This makes hydrogen a cost-effective option for decarbonising building heat and power, if the cost of producing hydrogen can be brought down sufficiently.
Power generation, buffering	As the share of renewable electricity in the grid is rising, there is a need to adopt the most cost-efficient way to match demand and supply. The core of the problem is that pure electricity cannot be stored, while energy carriers can – making hydrogen gas a viable solution. Excess electricity supply can be used for the electrolysis of water, to get hydrogen that can be stored. When there is a shortage of energy, hydrogen gas can be burned in fuel cells and converted into electricity. Hydrogen can also be used to transport electricity across distances as an alternative when there is no grid infrastructure or existing infrastructure is operating at full capacity.
Industrial energy and feedstock	The most widespread current applications of hydrogen are in industrial applications. Hydrogen is used as feedstock for chemical reactions to produce ammonia (NH_3) and refine oil into smaller compounds via hydrocracking. The volume of hydrogen demanded in such applications, called **pre-combustion feedstock**, is expected to grow at a moderate but stable annual rate of 2-3% over the coming decades. Hydrogen can also be used in an alternative way to produce steel with zero CO_2 emissions, assuming green hydrogen and green power usage. Specially developed iron ore pellets are reduced by hydrogen gas in a direct reduction (H-DR) process. Reduction occurs in a solid state at a lower temperature than in the blast furnace process and results in an intermediate product, sponge iron or direct reduced iron, while emitting water vapour. Another promising application is the possibility to create synthetic gas from off-gases. As the hydrogen is added to carbon monoxide and dioxide after the combustion process of coking coal, for example, hydrogen can serve here as **post-combustion feedstock**.

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