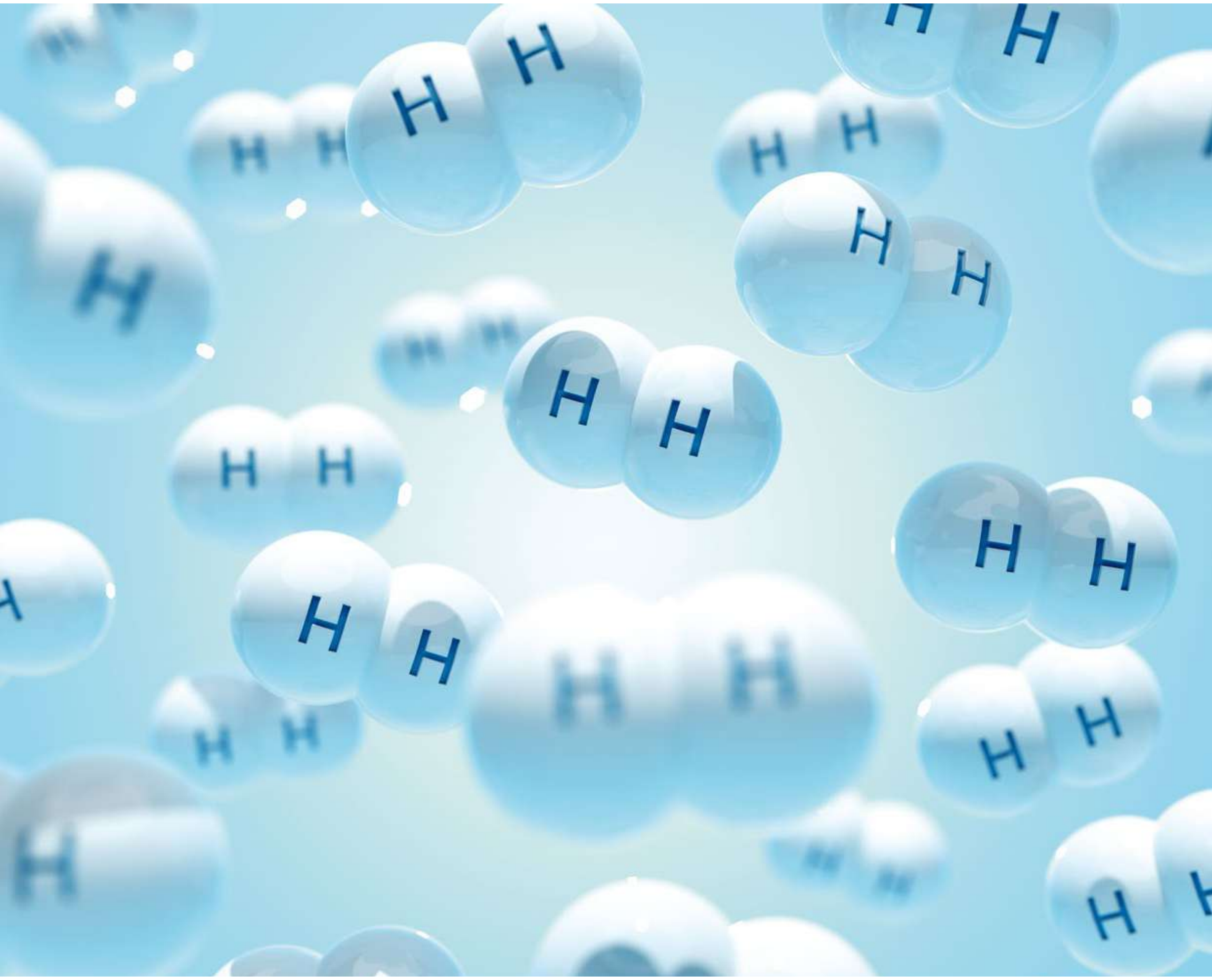
GREEN H_2 INVESTMENTS FROM BUZZ TO BOOM

SEPTEMBER 2022

A MACROECONOMIC, TECHNOLOGICAL, REGULATORY AND MARKET OVERVIEW OF HYDROGEN OPPORTUNITIES



AURORA ENERGY RESEARCH Fraunhofer ISE KGAL REAL INVESTMENTS Roland Berger WATSON FARLEY & WILLIAMS

WELCOME

It has been seven years since more than 190 nations committed to limiting global warming to 1.5 degree in the Paris Agreement. The UN Climate Change Conference of 2015 is still considered a landmark for global climate protection, but doubts are increasing among scientists as to whether this target is still achievable at all.

Green H_2 plays a key role in decarbonising the portfolios of institutional investors

In its latest report, "State of the Global Climate", the World Meteorological Organization warns that there is a 50% probability that the average annual temperature could already exceed pre-industrial levels by more than 1.5 degrees at least once by 2026. When politicians and experts met in Paris, this was still considered virtually impossible. Thus, the remaining time for decarbonising the economy is running out much faster than expected. We are already experiencing the effects of man-made global warming, for example in heat waves, storms, heavy rain or periods of drought with alarming frequency. Every year, the consequences of climate change threaten people's livelihoods and destroy assets worth billions.

As a result, there is also increasing pressure on institutional investors to decarbonise their portfolios in line with the Sustainable Finance Disclosure Regulation (SFDR) and EU Taxonomy rules. KGAL believes that green hydrogen will play a key role in this regard and we explain our reasoning in detail in this white paper. Furthermore, green hydrogen helps to establish a secure and independent energy supply in Europe – a goal that is gaining even greater importance following the invasion of Ukraine.

However, green hydrogen for climate protection is a very dynamic field of research, with rapid progress in every respect. It takes bright minds from different disciplines to explore the framework and unlock its full potential. That is why we have collaborated on this white paper with high-ranking experts from Roland Berger, Fraunhofer ISE, Aurora, and Watson Farley & Williams, whose judgement supports KGAL's assessment of the hydrogen market.

The time to act is now!

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EXECUTIVE SUMMARY

Decarbonising our societies and economies is arguably the biggest challenge of this century. However, large parts of industry, agriculture or sea transport cannot be decarbonised directly with green electricity. Green hydrogen is therefore key to bringing their CO_2 emissions to net zero. As this view becomes increasingly established, green H_2 project announcements are skyrocketing. Consequently, green hydrogen is also gaining in importance for investors.

In this white paper, we take a comprehensive look at the current state of green hydrogen from all perspectives relevant to investors. Given the complexity of the topic, KGAL has invited leading experts from various disciplines to share their view of the market. Some of their key findings are summarised below:

ECONOMIC CONDITIONS

Although green H_2 is a key building block of climate neutrality, the installed base of electrolysis capacity is still very limited, at about 0.5 GW globally. By 2030, 850 GW of capacity would need to be installed to meet the net-zero emissions scenario. A massive green H_2 build-out is required – and imminent. As the industrial supply chain scales up and projects are maturing, Roland Berger sees commercial de-risking via secured offtake, access to competitive renewables, and a viable transport set-up as key success factors for projects.

TECHNICAL FRAMEWORK

Hydrogen is the crucial ingredient in producing sustainable and storable synthetic energy carriers or chemicals via the so-called Power-to-X pathway. A whole palette of colours, from yellow to blue to pink, is used to classify the different approaches, but only green hydrogen is truly sustainable, Fraunhofer ISE emphasises. The necessary production and transport pathways for green hydrogen are technically feasible and ready for large-scale industrial application. In the coming years, production volumes and system efficiencies will be increased through innovative reactor, process and catalyst concepts, an increasing share of renewable energy, as well as new pipeline logistics and storage options.

COST OF GREEN HYDROGEN

Green hydrogen is produced by way of electrolysis using renewable electricity. Aurora speaks of four main electrolyser business models: inflexible grid electrolyser, flexible grid electrolyser, renewables co-located electrolyser (island mode), renewables co-located electrolyser with grid connection. The economics of green hydrogen production depends greatly on the project set-up and market, but in general, costs are forecast to fall below that of blue hydrogen; in countries such as Spain and Norway it will likely be in the 2030s. To bridge the time gap, governments need to implement supportive measures and subsidies.

REGULATORY FRAMEWORK

The German greenhouse gas (GHG) quota system and the EU RED II directive provide good examples as to how the demand for green hydrogen is stimulated by the regulatory framework: create an obligation for certain market participants (e.g. fuel producers, steel producers, airlines) to reduce their CO_2 emissions, and allow the use of green hydrogen to count towards that amount. Watson Farley & Williams predict that once these first steps to develop a regulatory framework for green hydrogen have been taken, a positive domino effect will occur. More countries will start or continue to develop their own hydrogen frameworks.

INVESTMENT OPTIONS

The rapid maturing of green hydrogen markets now increasingly attracts the interest of institutional investors. KGAL expects illiquid investments to significantly gain importance, as they will be vital for financing the transition to a low-carbon economy. First, green hydrogen projects offer attractive return potential, and second they are an ideal hedge for an existing renewables portfolio, as they procure and consume renewable electricity. At present, Opportunistic and Value-add investments are primarily available; Core plus assets will follow in two-to-five years. In light of the insecure energy supply and the risks of climate change, the time to enter the green hydrogen market appears to be just right.

CONTRIBUTORS

CHAPTER 1

ROLAND BERGER

Roland Berger is the only management consultancy of European heritage with a strong international footprint. As an independent firm, solely owned by its partners, Roland Berger operates 50 offices in all major markets. Its 2,400 employees offer a unique combination of an analytical approach and an empathic attitude. Driven by values of entrepreneurship, excellence and empathy, Roland Berger is convinced that the world needs a new sustainable paradigm that takes the entire value cycle into account. Working in cross-competence teams across all relevant industries and business functions, Roland Berger provides the best expertise to meet the profound challenges of today and tomorrow.

CHAPTER 2

FRAUNHOFER INSTITUTE FOR SOLAR ENERGY SYSTEMS ISE

With almost 1,400 employees, the Fraunhofer Institute for Solar Energy Systems ISE is the largest solar research institute in Europe. It creates the technical prerequisites for an efficient and environmentally friendly energy supply, both in industry and in emerging and developing countries. In the main research areas of energy provision, energy utilisation, energy distribution and energy storage, Fraunhofer ISE contributes to the broad application of new technologies. In the area of hydrogen technologies, research is conducted into the production, conversion and thermochemical processing of hydrogen. Technology development in the Thermochemical Processes department helps to reduce emissions in the synthesis, transport and use of sustainably produced fuels, energy carriers and chemicals along the entire value chain. With innovative solutions in the fields of process engineering and catalyst developments, economic and sustainability assessment and process simulation, a significant contribution is made to the success of the global energy transition.

CHAPTER 3

AURORA ENERGY RESEARCH

Founded by University of Oxford professors and economists who saw the need for a deeper focus on quality analysis, Aurora has grown to become the largest dedicated power analytics provider in Europe. Aurora is a diverse team of around 250 experts with vast energy, financial and consulting backgrounds, working towards the common goal to help market participants make sensible long-term strategic decisions. Aurora's large team of power market experts produce critical analytics to almost all major market participants in Europe and Australia, and in the last 5 years Aurora has been commercial/market advisor for more than 200 transactions, totalling over €30bn. More than 550 companies subscribe to Aurora's regular forecasts and analysis.

CHAPTER 4

WATSON FARLEY & WILLIAMS

WATSON FARLEY & WILLIAMS

Watson Farley & Williams is an international law firm advising on complex transactions and disputes through local knowledge and an integrated international network. Watson Farley & Williams was founded in 1982, it has more than 170 partners and 550 lawyers in 17 offices around the world. It has a strong sector focus, combining technical excellence with deep industry knowledge across energy, transport and real estate. Watson Farley & Williams LLP has a dedicated hydrogen group acting for clients on hydrogen related matters in Europe, Asia and the MENA region.

CHAPTER 5

KGAL

KGAL REAL INVESTMENTS

KGAL is a leading independent investment and asset manager with a managed investment volume of more than €16.5 billion. The group sources, executes and manages long-term real asset investments for institutional and private investors in sustainable infrastructure, real estate and aviation. KGAL started investing in the renewable energies sector in 2003 and currently holds assets of around €3.2 billion. The company operates 74 solar parks, 51 wind farms and four hydroelectric power plants in ten countries across Europe. Half of KGAL's 60-strong renewables team are asset management specialists. Part of the team with many years of experience is dedicated exclusively to investment opportunities in the green hydrogen sector.

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GREEN H_2 INVESTMENTS – ENABLING CLEAN ENERGY AND INDUSTRY

1.1 GREEN HYDROGEN: A KEY BUILDING BLOCK OF CLIMATE NEUTRALITY

Decarbonising our societies and economies is the transformational challenge of this century. The European Union (EU) is accelerating its path towards carbon neutrality with the Green Deal, setting the target of turning Europe into the first climate-neutral continent by 2050, and pledged to reduce emissions by at least 55% by 2030, compared to 1990 levels.

To achieve this profound transformation towards a climate-friendly economy, the energy system will have to be reshaped in ways that go significantly beyond greening the power grid. While green energy is now a vital part of the electricity mix, the share of electricity used in overall energy consumption is still limited. For example, renewable energy sources contributed 38% to the overall European electricity mix in 2020, overtaking fossil fuels. But looking at the share of renewable energy in the overall economy, taking into account the transport sector, as well as heating and cooling, the share of renewables was substantially lower, around 22%. This is due to a number of structural challenges. Sectors such as heavy industry, with huge energy needs to process heat from burning fossil fuels, are notoriously difficult to electrify. The same holds true for heavy duty transportation. Moreover, there is a lack of grid infrastructure to transport green power from areas of production to centres of demand.

This is where green hydrogen has a key role to play. It can be used as a renewable fuel or feedstock in all major CO_2-emitting sectors, including those where direct electrification is not possible. By producing hydrogen using electrolysis powered by renewable sources, green power becomes easier to store and transport as an energy carrier, enabling sector coupling. Besides green hydrogen that is produced from renewable energy sources, alternative technologies exist to produce hydrogen with low carbon content (so-called clean hydrogen). These include blue hydrogen, which is

FIGURE 1: THE ROLE AND NEED FOR HYDROGEN IN DECARBONISATION

WITHOUT CLEAN HYDROGEN, NO FULL DECARBONISATION OF ...

INDUSTRY

Clean feedstock for ...

- Green fertilisers
- Green steel
- Green plastics

MOBILITY

Clean fuel for ...

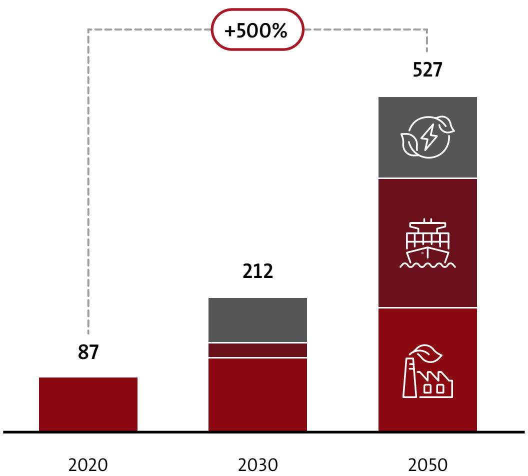
- Zero-emission shipping
- Sustainable aviation
- Clean trucking

ENERGY

Clean fuel and energy storage for ...

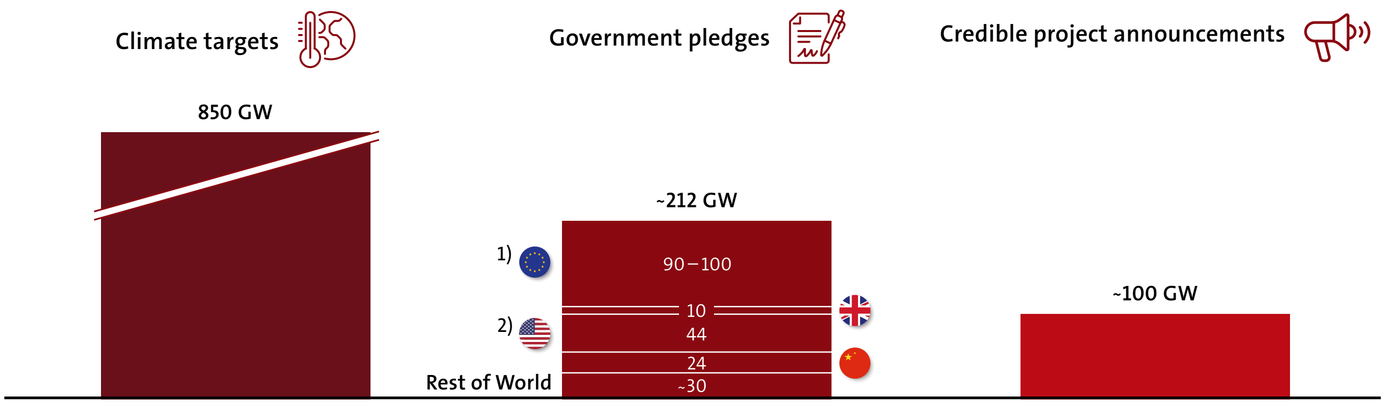
- 100% green electricity mix
- 100% decarbonised heating

H_2 CONSUMPTION IN THE IEA'S NET ZERO EMISSION (NZE) SCENARIO [MT]



Source: IEA, Roland Berger

FIGURE 2: ELECTROLYSIS CAPACITY BY 2030 (GW)



- According to the IEA, **ca 850 GW total installed electrolyser** capacity is required by 2030 to stay on a path to meet the **1.5°C target** set out in the Paris Agreement
- **Governments** have committed to ramp up electrolyser build-up to a total of **ca 200+ GW** this decade – EU as frontrunner with 90–100 GW
- Currently, announced projects **total ca 250 GW**, many of which are still at **press announcement stages only – ca 100 GW are credible** and provide concept in more detail

1) European Commission's REPowerEU Communication proposed a Hydrogen Accelerator: 10 million tons of annual domestic production by 2030 – requires ca 90-100 GW electrolyser capacity; 2) Based on IEA's scenario calculation, without clear commitment from the US government; Source: IEA, National Hydrogen Strategies, desk research, Roland Berger

produced from fossil sources but with carbon capture, and pink hydrogen, which is produced from nuclear power using electrolysis (the technology of an electrolyser will be explained in more detail in Chapter 2). Clean hydrogen can be used as a combustion fuel in industrial or mobility applications, or be reconverted to electricity in a fuel cell. As a feedstock, clean hydrogen can replace grey hydrogen in industrial processes, such as refining. Taking things one step further, clean hydrogen-based derivative products, such as ammonia, methanol, or Fischer-Tropsch-based e-fuels, can serve as sustainable feedstocks and fuels. For example, green ammonia can be used for fertiliser production while synthetic jet fuel produced from green H_2 can replace fossil-based kerosene in aviation.

Massive green H_2 build-out will be required

Tackling climate change will require a substantial build-out of electrolysis capacity for industrial-scale green H_2 production, as well as a corresponding ramp-up of renewable electricity generation capacity mostly from solar PV, onshore wind and offshore wind to feed the electrolysis plants. Despite the buzz around green H_2, the installed base of electrolysis capacity today is still very limited at around 0.5 GW globally. Contrasting this with the green H_2 capacity required to achieve climate neutrality clearly shows the magnitude of the challenge ahead. According to the International Energy Agency (IEA), 850 GW of electrolysis capacity would need to be in operation by 2030 to meet the net-zero emission scenario. Given the crucial role of green hydrogen for achieving a clean energy transition, policymakers across the world have been stepping up their efforts to facilitate the market ramp-up by committing to ambitious electrolysis capacity build-out targets, amounting to about 200 GW of pledged build-out by 2030. Europe is positioning as a front-runner, with ambitious targets set both by national governments, and at the EU-level. This momentum has been accelerated with the recent RePowerEU package put forth by the European Commission to achieve independence from fossil energy imports from Russia in light of the Ukraine war. The package foresees doubling the previous target for green H_2 use in the EU, both from domestic production and from imports, to a total of 20 million tons by 2030. At the same time, credible project announcements currently stand in the order of about 100 GW of electrolysis capacity by 2030. On the one hand, this snapshot shows that the origination and development of viable projects is a key challenge. On the other hand, it illustrates the substantial opportunity and growth potential for real asset investors to drive new projects to meet the build-out targets.

1.2 INVESTMENTS IN H_2 TECHNOLOGY AND REAL ASSETS ON THE RISE

Looking at the financial investment perspective, the emerging green hydrogen economy is actually following a rather typical pattern for early-stage industries. In recent years, the strategic focus of investors has been largely on technology companies with strong IP and engineering capabilities required to produce industrial-scale green H_2 equipment. These technology-focused investments covered the entire value chain. On the upstream side, electrolyser manufacturers have clearly been the focal point of investors' attention. Midstream, investment activities were focused on technology players active in H_2 conversion, storage, and transport technologies. Downstream, investors were targeting technology companies for various end-use applications, from mobility to stationary fuel cell applications. The industry has seen significant investment in a variety of forms, ranging from private series funding rounds, to IPOs in the start-up space, to spin-outs of the H_2 business from established technology companies and conglomerates. Fuelled by the business prospects of the green energy transformation, valuations of publicly listed H_2 technology companies have soared through 2020. After temporary setbacks in 2021, and general volatility from macroeconomic uncertainty, valuations have bounced back and H_2 companies are currently trading around 65% above early 2020 levels.

As a result, the industrial supply chain is now capitalised for a massive scale-up of its production capacities, moving from small-batch manufacturing to mass-production. The electrolyser industry illustrates this point, with global capacity set to increase more than six-fold from around 7 GW annual production capacity in 2022 to around 47 GW by 2025, based on the announcements of factory scale-ups by OEMs worldwide.

Large-scale project investments breaking through

The next step of scaling up the green H_2 economy will now require putting the equipment to use in large-scale green H_2 production projects. Consequently, the attention of financial investors is shifting towards the real assets space. While this includes first and foremost large-scale integrated renewables and green H_2 production projects, adjacent investment areas are also in scope. Often, green H_2 is not actually the final product to be consumed, putting the focus on subsequent steps of derivatives production, such as green ammonia or methanol. Additionally, there are no established, ready-to-use transport chains for green H_2. As a result, investing in transport infrastructure, such as conversion/reconversion terminals and even ships, may be worthwhile, as well as a prerequisite for getting production projects off the ground and connecting supply and demand.

Green H_2 project announcements are skyrocketing, following a distinct geographical pattern. While Europe leads the pack in terms of number of projects, the announced projects are relatively small on average. Conversely, we see large-scale project announcements, mostly with a clear medium-term export orientation, in

FIGURE 3: STOCK MARKET PERFORMANCE OF H_2 TECHNOLOGY COMPANIES

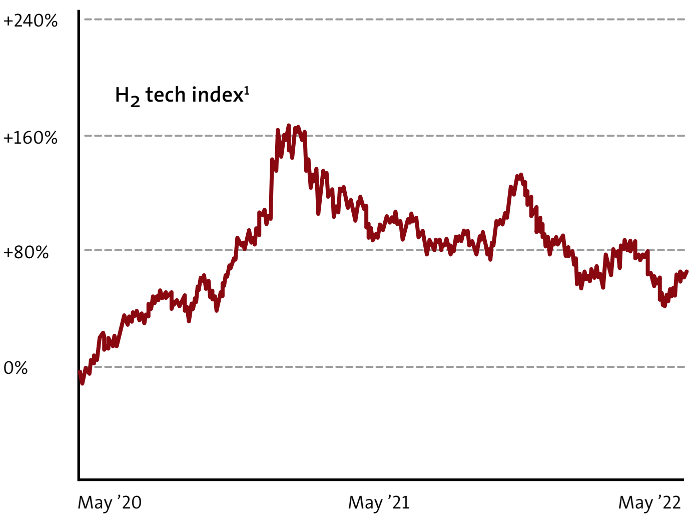
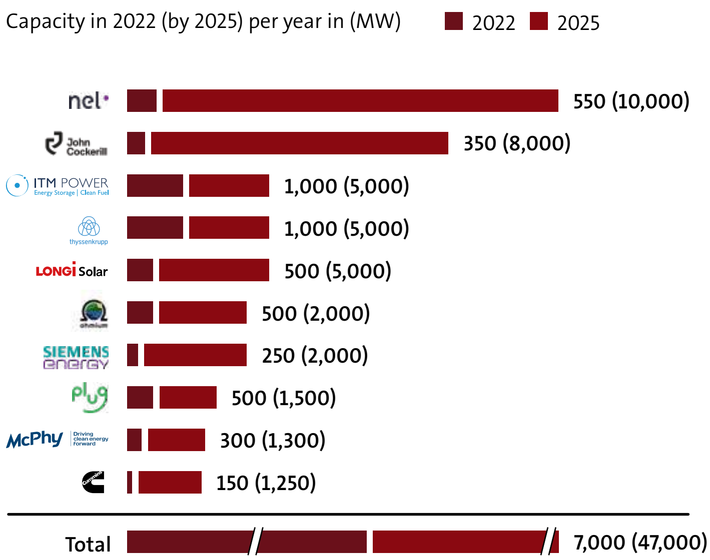
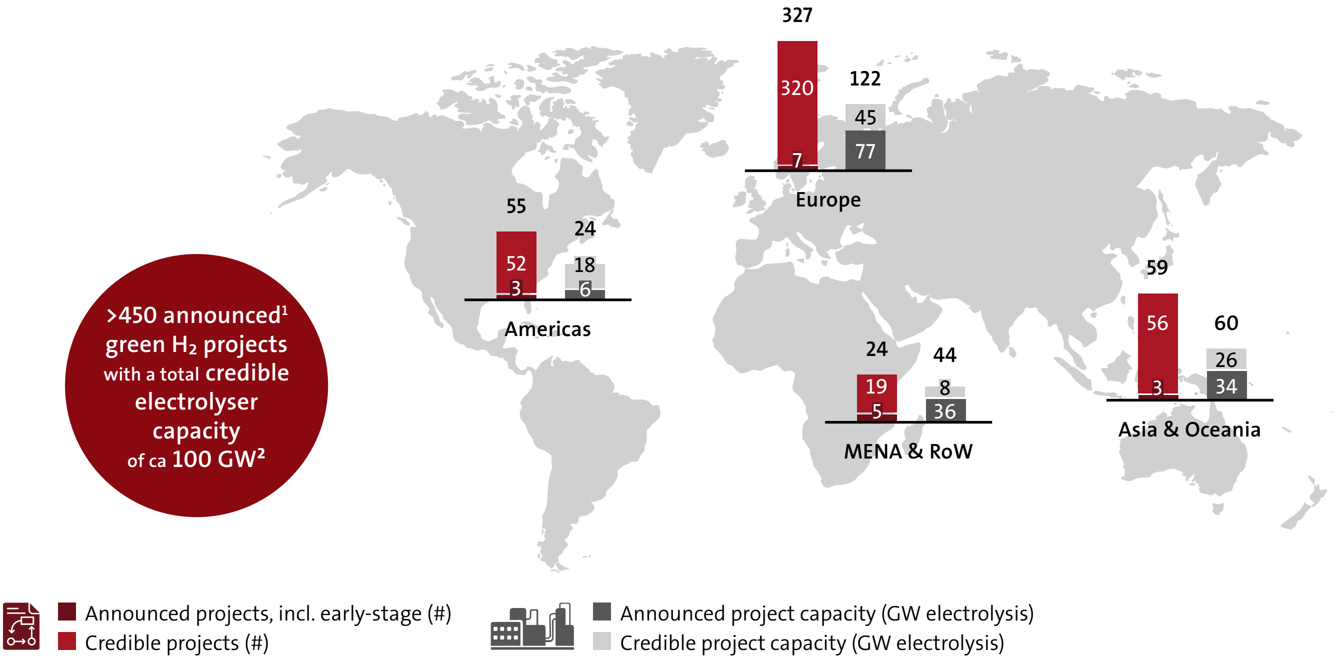


FIGURE 4: EXPECTED ELECTROLYSER MANUFACTURING CAPACITY FOR SELECTED PLAYERS



1) Vontobel certificate on Solactive Hydrogen Top Selection Index, comprising 15 companies from industrialized countries that are active in the hydrogen sector; Source: Company announcements, Vontobel, Press research, Roland Berger

FIGURE 5: ANNOUNCED GREEN H_2 PROJECTS



1) As of June 2022, incl. early-stage projects (e.g. press announcement); 2) Some announced green H_2 projects have not yet specified electrolyser capacity; Source: IEA, desk research, press announcements

global regions with a very low levelised cost of electricity (LCOE), namely in South America, Africa, the Middle East, and Oceania.

1.3 TAPPING INTO THE REAL ASSET OPPORTUNITY FOR GREEN H_2

In the current, early stage of the green H_2 market development, green H_2 is not a liquid, globally traded product in the sense of a green commodity. Rather, the current market is driven by captive projects. These are integrated supply chains that de-risk both the required upstream large-scale investments in renewables and electrolysers as well as midstream transportation by obtaining captive, long-term offtake agreements, typically with a certain component of public funding support. Often, strategic investors, such as oil and gas companies or industrial offtakers of green H_2 are the driving forces behind these projects, both as developers and equity investors in wider consortia. As a result of this captive, project-centered market structure, we see three archetypes of projects in the emerging green H_2 economy:

1. Local, small-scale & mobility-focused
2. Local, medium-scale & industry-focused
3. Larger-scale, international & export-focused

While local, mobility, centered projects are fairly advanced throughout Europe, with sizeable H_2 fuel cell bus fleets operational in municipalities across the continent, the limited size of these projects makes them less relevant for financial investors.

Archetypes 2 and 3, however, should be the focus of investors for a number of reasons:

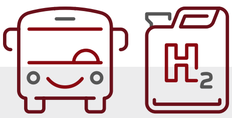
- Given the scale of these projects, meaningful investment ticket sizes can be achieved.
- As projects mature, moving from the drawing board towards final investment decision (FID), strategic investors move their H_2 activities from on-balance-sheet innovation budgets to project financing, and are increasingly open to bringing additional institutional investors on board to mobilise the capital required for capital investments.
- These projects are typically designed around large-scale industrial offtakers with strong balance sheets, enabling offtake de-risking and improving the prospects for bankability of projects.
- Captive projects typically follow a step-wise approach, with a medium-sized first stage and substantial scale-ups in later years, in line with the market ramp-up. Taking an investment stake in the first stage can be crucial to securing favourable positioning when expansion stages need to be financed a few years down the road.

Three success factors are key for project investments

The real asset investment opportunity in green H_2 is unfolding, as the world is moving towards a decarbonised energy and industry system. But much of the project landscape is still uncharted territory for institutional investors. Just like in any early-stage industry, being mindful of the underlying challenges and taking a highly selective approach is crucial to investing successfully. Given the captive nature of the market, prospective investors need to gain a deep and thorough understanding of individual project investment opportunities to gauge their commercial prospects and risks. Specifically, three main success factors need to be in place for projects to yield meaningful investment opportunities:

- Secured offtake: Projects need to have binding, multi-annual offtake commitments as a starting point and should be structured based on viable underlying commercial models, to enable commercial de-risking and, ultimately, bankability. In the early stages of the market, this will in many cases include a public funding component to cover the cost premium of green H_2 vs grey H_2 from legacy technologies.
- **Access to low-cost, high-load renewables:** The cost of renewable electricity is the key make-or-break factor of the business case for green H_2 production. Achieving a high load factor for the electrolyser is crucial to optimise the utilisation of electrolysis plants. In practice, this can typically best be achieved by combining different renewables sources, such as wind and solar PV, with complementary power profiles, as well as storage solutions. Choosing strategic project locations with access to low-cost renewables and high load factors is thus a key determinant for achieving competitive H_2 production costs.
- **Viable transport set-up:** Connecting supply and demand via transport is the "missing link" for the new H_2 economy – and in fact one of the most critical practical barriers for the market ramp-up [ROL].* Four main technology routes are conceivable today: pipeline transport, green ammonia conversion and re-conversion, liquid organic hydrogen carriers (LOHC), as well as liquid H_2. There is no one-size-fits-all carrier that outperforms the other technologies across use-cases. For example, regardless of the considerable costs of liquefaction and cooling, liquid H_2 might still be a better option if high-purity liquid hydrogen is required at the point of use. The most economical option for any given scenario will ultimately have to be determined on a concrete use-case basis for each project.

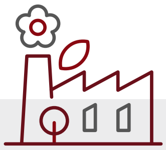
FIGURE 6: HYDROGREN PROJECT ARCHETYPES



ARCHETYPE 1
Small-scale & mobility-focused green hydrogen projects

- **1–10+ MW**
- **Local** green H_2 production **serving mobility applications,** thus coupled with hydrogen refuelling stations, fleet decarbonisation efforts, increasingly (semi-)captive
- Typically grid power supply (green certificates)
- Mostly **led by public-private initiatives**
- **Established and growing** (EU, JP, US)

Examples: Hydrospider (CH), Zero Emission Valley Auvergne-Rhone-Alpes (FR), Hydrogen Valley South Tyrol (IT)



ARCHETYPE 2
On-site industrial green hydrogen production projects

- **10–300+ MW**
- **Local/regional** green H_2 production on the site of **large industrial consumers** (refining, steel, fertiliser) as "anchor-load", smaller mobility off-takers as add-on
- Typically grid power supply (green power purchase agreement (PPA))
- Mostly **led by private developers**
- **Growing** in number and size, first projects up to 20 MW operational (EU, US)

Examples: Pernis Refinery (NL), Basque H_2 Corridor (ES), Refhyne (DE), HyNet North West England (UK)

ARCHETYPE 3
Centralised large-scale green hydrogen export "gigaprojects"

- **250+ MW to multi-GW**
- **Regional/international projects** with low-cost green H_2, NH_3, MeOH, etc. production for **export** (often multi-phased). Connecting supply and demand globally
- Typically co-located, additional renewables capacity
- Mostly **led by private or sovereign developers**
- **Emerging**, first FID in 2022/23 (EU, MENA, AU)

Examples: Project NEOM (KSA), AquaVentus (DE), HyPort Duqm (OM), H_2 Magallanes (CL), Pilbara Hydrogen Hub (AU)

** Please refer to the Roland Berger Hydrogen Transport Study to find out more: www.rolandberger.com/en/Insights/Publications/Transporting-the-fuel-of-the-future.html*

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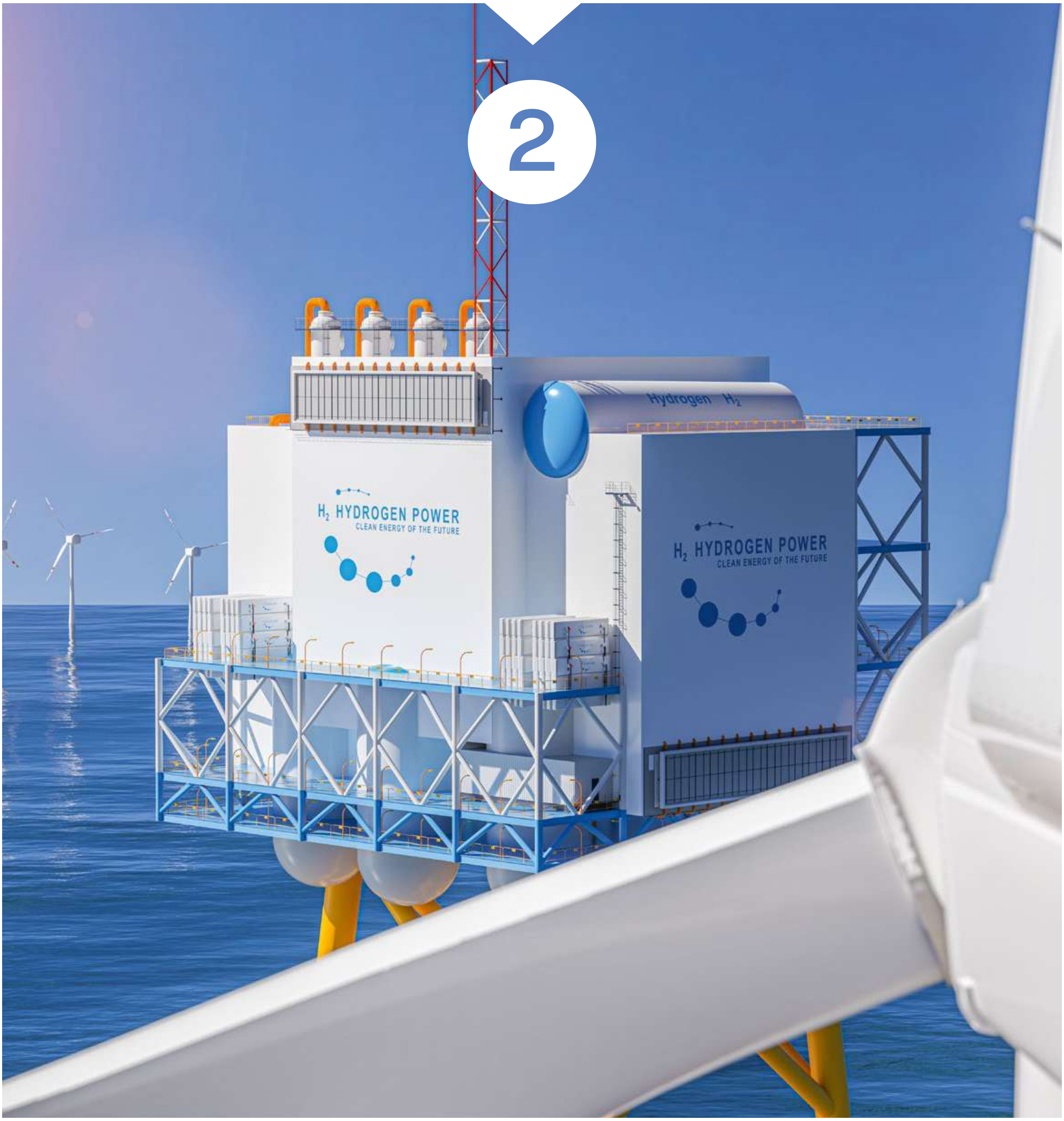

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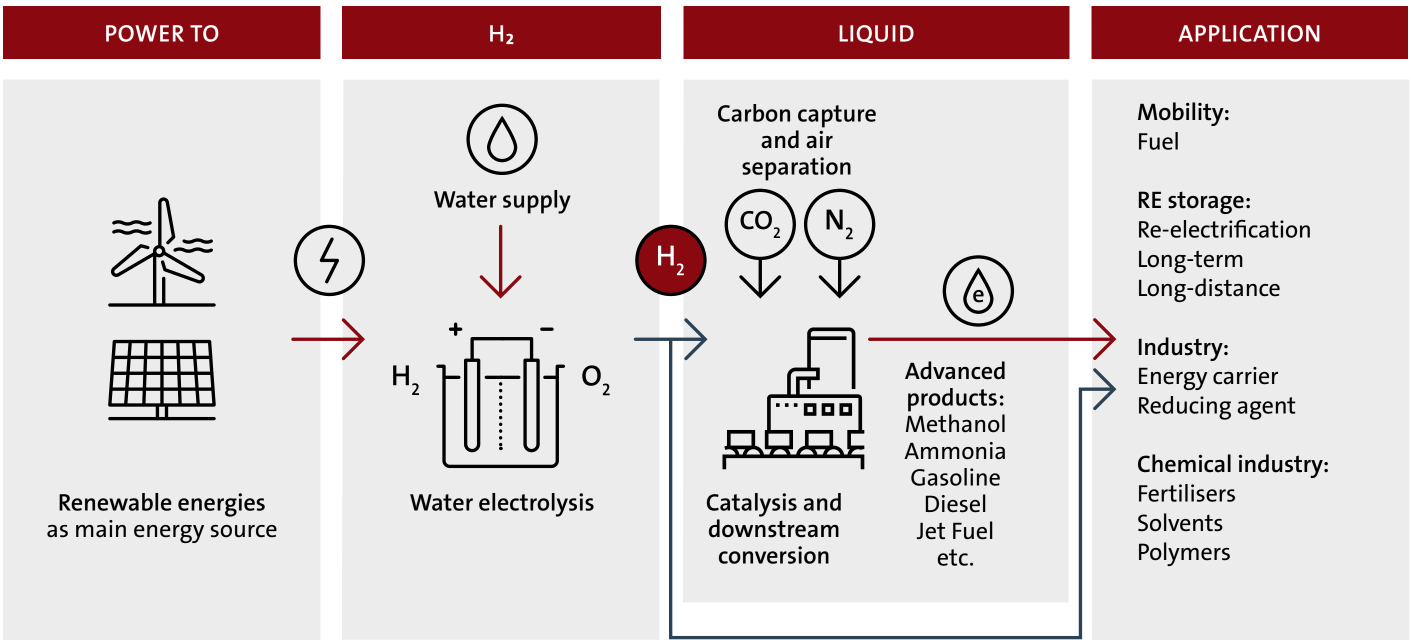
THE TECHNOLOGICAL FRAMEWORK FOR THE PRODUCTION OF GREEN HYDROGEN AND DERIVED PRODUCTS

2.1 PTX AND POTENTIAL PATHWAYS FOR LARGE-SCALE HYDROGEN PRODUCTION

Future economies will depend on significant amounts of sustainably produced hydrogen to achieve high defossilisation* rates. Hydrogen will be the crucial ingredient in delivering sustainable and storable synthetic energy carriers or chemicals. This can be done via several Power-to-X (PtX) pathways, where "P" refers to electrical power and "X" refers either to a final product (e.g. methanol, ammonia) or application of the product (e.g. mobility, heat, power, chemicals).

The basic PtX pathway entails the use of electricity to produce hydrogen via water electrolysis. Hydrogen can then be used directly, for example in fuel cells or gas turbines for electricity generation (power-to-power), or it can substitute for fossil products, such as coke in steel production. Alternatively, hydrogen is complemented with nitrogen (N_2) or captured CO_2, forming the feedstock for downstream conversion into gaseous or liquid synthetic energy carriers and chemicals. Further conversion and purification steps are necessary depending on the target product and application. The resulting energy carriers and chemicals can then be utilised in various sectors: methanol can be used in chemical industries, synthetic diesel and jet fuel in the mobility

FIGURE 7: THE GENERAL LAYOUT OF THE POWER-TO-X PATHWAY



** In contrast to decarbonisation, defossilisation describes the replacement of fossil energy sources and production processes by renewable ones, of which a relevant part continues to be carbon-based. Future carbon sources use carbon from the atmosphere or biogenic sources to ensure a closed carbon cycle.*

TABLE 1: TECHNOLOGY READINESS LEVEL (TRL)

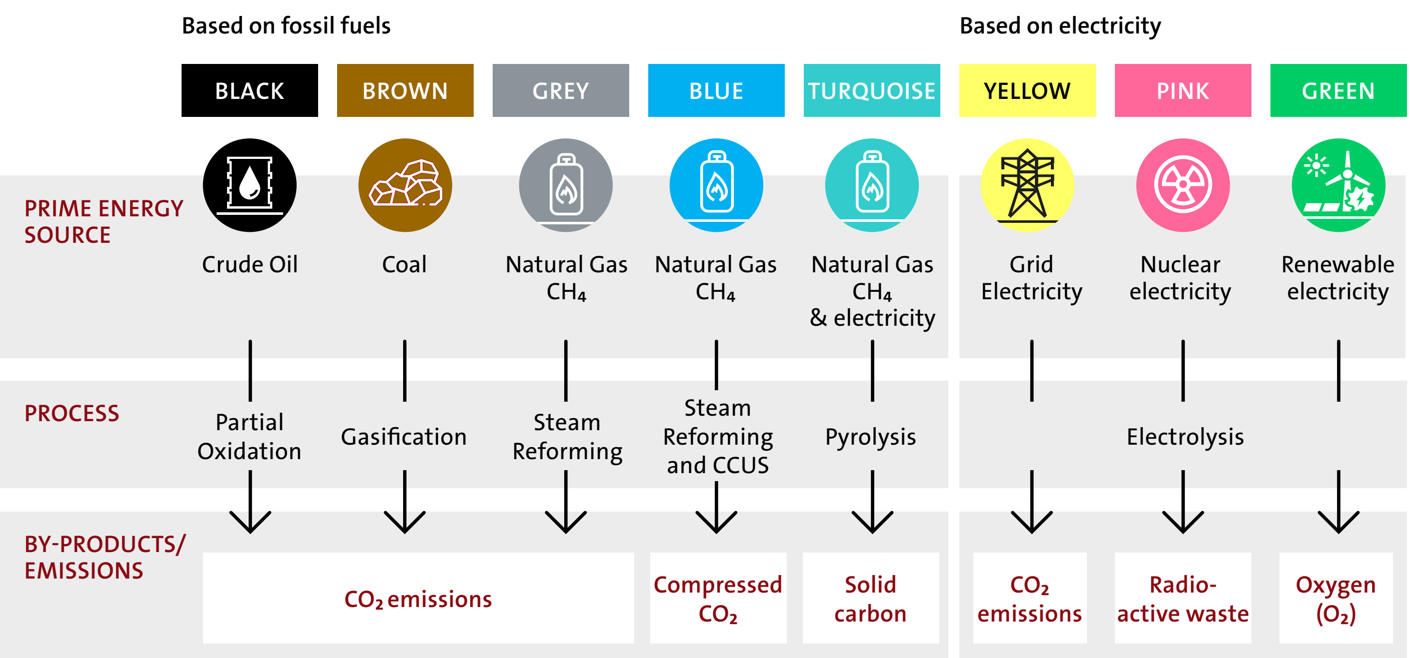
The TRL is an established indicator to assess the state of development of a technology from invention to large-scale commercial availability. Thereby, nine classes from a basic technology concept (TRL 1) to a proven system in its intended operational environment (TRL 9) are utilised.

Research		
TRL 1	TRL 2	TRL 3
Basic principles observed	Technology concept formulated	Experimental proof of concept
Development		
TRL 4	TRL 5	TRL 6
Technology validated in laboratory	Technology validated in relevant environment	Technology demonstrated in relevant environment
Deployment		
TRL 7	TRL 8	TRL 9
System prototype demonstration in operational environment	System complete and qualified	Actual system proven in operational environment

sector, and ammonia in the agricultural and shipping sector. The appeal of the PtX pathway is that fluctuating and difficult-to-store renewable electricity can be converted into hydrogen – and subsequently to other energy carriers – that can be stored over the long term. In addition, these synthetic renewable energy carriers can be fed into the existing infrastructure and are therefore essential for the entire defossilisation of the global economy. Today, the EU's annual hydrogen consumption of 380 terawatt hours (TWh), or 9.7 megatonnes (Mt), is almost entirely supplied by so-called grey, brown and black hydrogen, which are produced using hydrocarbons [KAK]. These production pathways are therefore inherently linked to high emissions of CO_2 and other greenhouse gases (GHGs). Future demand must be met by "low-carbon" or "renewable" hydrogen.

Future large-scale supply of sustainable hydrogen will instead come in a palette of "colours", representing different hydrogen production technologies according to their primary energy source, technology readiness level (TRL > see Table 1), production costs and environmental impacts. While green, yellow and pink hydrogen use electricity as the primary energy source, the other colours displayed in Figure 8 are based on fossil fuels. Blue hydrogen is based on fossil-based production but includes an additional carbon-capture process. Capture rates of up to 90% are envisioned and reported for the first pilot plants, but the

FIGURE 8: COLOURS OF HYDROGEN



feasibility of these rates are questionable. Furthermore, they can only be achieved with significant efficiency losses and thus increased costs [GOR, GLO]. To be classified as "low-carbon", these blue hydrogen production pathways also need to be able to permanently store the captured CO_2. The most discussed technically feasible option is geological storage by underground sequestration of CO_2 in depleted fossil hydrocarbon reservoirs and saline aquifers. However, geological sites for sequestration are limited and subject to leakage risks [CAM].

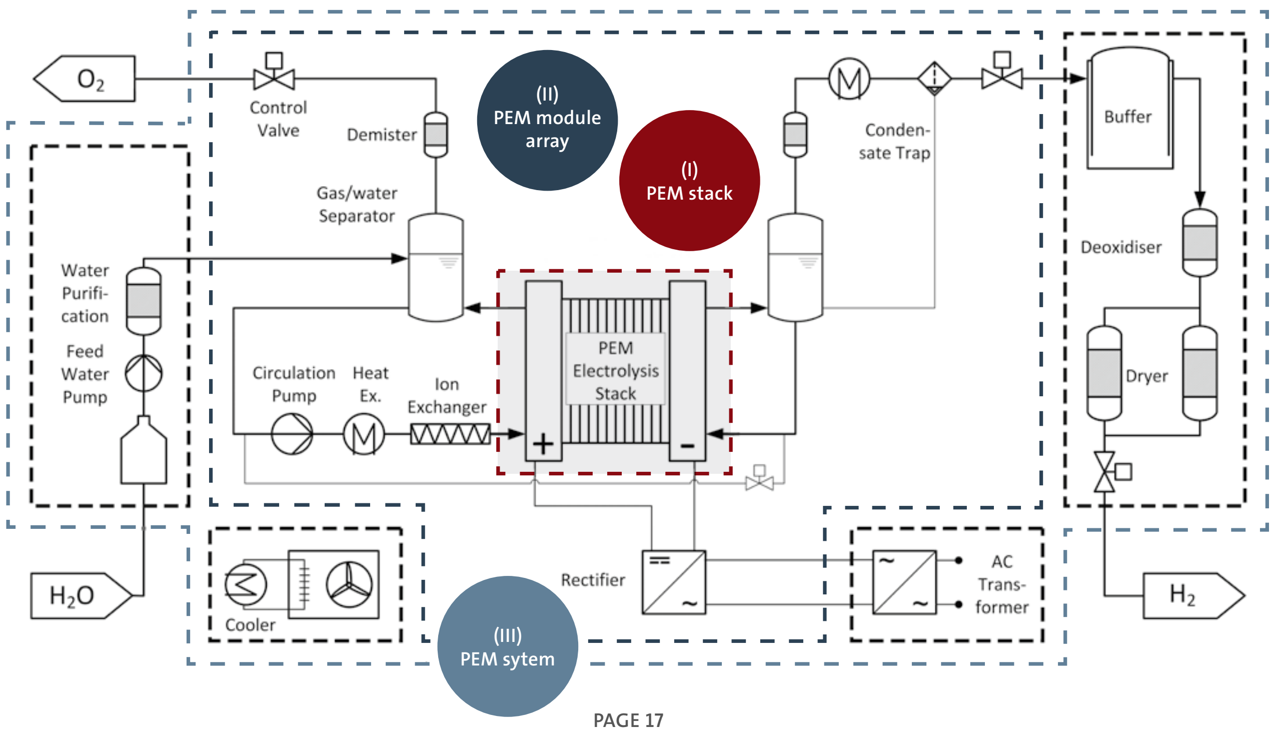
The production pathway for turquoise hydrogen directly targets the production of solid carbon, rather than gaseous, CO_2. This is possible by pyrolysis of a hydrocarbon feedstock (primarily natural gas) at high temperatures in the absence of oxygen. The obtained carbon can then be used in steel, tyre and construction industries. Since the required processes are currently under development and still at low TLR (ca 4–5), their ability to meet technical challenges has yet to be thoroughly evaluated. Although blue and turquoise hydrogen pathways are often seen as potential bridging technologies towards fully renewable hydrogen, they are still based on fossil natural gas and other feedstocks, and are thus dependent on the respective world market prices and exporting nations. In addition, even if complete carbon capture could be achieved during the process, the pathways for blue and turquoise hydrogen continue to emit significant amounts of upstream GHGs through natural gas extraction and supply chains, which would be unacceptable as alternatives are available.

Green hydrogen production pathways offer massive potential for GHG emissions savings and numerous other sustainability advantages. While biomass is a potential feedstock for green hydrogen production, this chapter will focus on pathways for the electrolytic splitting of water powered by renewable electricity. Nuclear power and electricity from the grid are also possible for water electrolysis, but these so-called pink and yellow production pathways, while offering higher electrolyser full-load hours, can produce radioactive waste or substantial CO_2 emissions (depending on the electricity source).

2.2 GREEN HYDROGEN PRODUCTION

As the price of fossil fuels (coal, gas, crude oil) has generally been much lower than electricity, water electrolysis still only constitutes a small share of overall hydrogen production. The increasing demand for low-carbon hydrogen, however, is driving a rise in global interest. Water electrolysis is a well-known electrochemical method that decomposes water under a direct electric current. The electricity induces a redox reaction, splitting the water molecules (H_2O) into hydrogen (H_2) and oxygen (O_2). The

FIGURE 9: LAYOUT AND SYSTEM COMPONENTS OF A PEM ELECTROLYZER



Source: Fraunhofer ISE

TABLE 2: THREE MAJOR ELECTROLYSIS TYPES PEM, AEL, AND SOE COMPARED [ELE, HOL, SMO]

	PEM	AEL	SOE
Anode Reaction	$2\ H_2O \rightarrow 0{,}5\ O_2 + 2\ H^+ + 2e^-$	$2\ OH^- \rightarrow H_2O + 0.5\ O_2 + 2e^-$	$O_2^- \rightarrow 0.5\ O_2 + 2e^-$
Cathode Reaction	$2\ H^+ + 2\ e^- \rightarrow H_2$	$2\ H_2O + 2e^- \rightarrow H_2 + 2\ OH^-$	$H_2O + 2e^- \rightarrow H_2 + O_2^-$
Operating Conditions	30–50 bar 50–90°C	2–30 bar 60–90°C	< 30 bar 500–1,000°C
Stack Lifetime	< 70,000 h	< 80,000 h	< 40,000 h
TRL	8–9	9	6–7
Advantages	• Dynamic operation • Simple and compact design • High current densities	• Mature and proven • Large stack sizes available • Reduced capital cost • Non-noble and abundant materials	• High energy efficiency (in case of available waste heat) • Reduced capital cost • Non-noble materials
Disadvantages	• Noble materials • Acidic environment • High membrane cost	• Limited dynamics • Low current densities • Corrosive electrolyte • Gas permeation	• Heat source availability • Mechanically fragile design • Sealing issues • Unstable electrodes

required energy to split the molecule is supplied by electrical energy and additional thermal energy (in the case of solid oxide electrolysis (SOE)). Water electrolyser layouts can be divided into three levels: (I) stacks, with several electrolysis cells connected in series, (II) the module array, comprising several stacks plus auxiliary equipment such as gas separatorion and rectifier technologies, and (III) the complete electrolysis system including the balance of plant (BoP) equipment such as transformers, water deionisation unit, cooling system and gas treatment. This layout is shown in Figure 9, using the example of a polymer electrolyte membrane electrolyser (PEM).

Generally speaking, there are three types of water electrolysis depending on the nature of the electrolyte. Alkaline electrolyte electrolysers (AEL) and PEM are low-temperature concepts and SOE is a high-temperature concept. The main characteristics of these three electrolysis types are displayed in Table 2. Ideally, an electrolysis system coupled with renewable electricity generation has a high load change rate, a short start-up time, and a large operating window with a low minimum partial load to follow the volatile electricity supply. The optimal electrolysis type and layout size will depend on these and many other parameters. In the short term, the choice will be between cost-efficient, mature AEL and flexible PEM electrolysis, but PEM electrolysis will become more attractive in the longer term due to rapid technology improvements and cost reductions. The future development of electrolysers at the gigawatt scale involves larger stack sizes, increased operating temperature and pressure, higher current densities and a compact system design. Additionally, membrane and catalyst development will significantly reduce the demand for scarce materials, such as the corrosion-resistant metal iridium [SMO].

2.3 SUPPLY OF WATER VIA DESALINATION OF SEAWATER

The feed and cooling water demand for hydrogen and PtX production should not be underestimated. This is especially relevant in arid countries and regions with high renewable energy potential but limited freshwater resources. To avoid exacerbating water stress, the water for PtX production in these countries should be supplied by the desalination of seawater. Seawater desalination is a proven technology with over 15,000 facilities worldwide, producing around 95 million m³/day of desalinated water globally [JON]. Around 70% of the desalination plants in operation use reverse osmosis (RO) technology with a TRL of 9. In an RO desalination system, pre-treated seawater is pushed through a partially permeable membrane under high pressure to overcome osmotic equilibrium.

Salts, ions and other impurities are retained on the side of the seawater supply. Depending on the temperature and salinity of the seawater, the plant capacity and the membrane utilised, the electrical energy demand for seawater desalination via RO can be less than 1% of the energy consumption of a typical PtX plant [VOU]. In addition, pumping the desalinated water via a pipeline consumes further electricity, depending on the distance and altitude difference. Brine, a by-product of seawater desalination, is discharged back into the sea. In addition, to elevated temperatures and the high salt content, brine can also contain substances such as biocides, additives and metals.

To minimise the adverse effects of brine discharge on local marine ecosystems, mitigation strategies must be applied. For example, brine discharge should be located on coastlines with large currents and sufficient water circulation to ensure its rapid dilution and distribution. In addition, current research is targeting potential use cases for the resulting brine, which could include the production of sodium hydroxide or hydrochloric acid, for example [KHA]. The water quality of desalinated seawater, or regular tap water for that matter, is not however sufficient for most electrolyser systems. Most electrolyser systems therefore include equipment for water deionisation.

While the stoichiometric water demand to produce 1 tonne of hydrogen amounts to 8.9 tonnes of deionised water, the overall water demand considering treatment losses and equipment cleaning, is in the range of 10–20 tonnes, depending on the water source [SIM].

2.4 SYNTHESIS OF DERIVED FUELS AND CHEMICALS

Apart from hydrogen, there is demand for other liquid energy sources in various sectors, with methanol, Fischer-Tropsch (FT) fuels and ammonia being among the most promising. Although synthetic methane is also a derivative of green hydrogen, it will not be analysed in this paper due to its drawbacks compared with direct use of gaseous hydrogen and carbon-containing liquid methanol.

Methanol and methanol-to-x

Methanol is a widely used base chemical and ideal platform molecule with numerous applications in the chemical, industrial and transport sectors. It is liquid at atmospheric conditions and can utilise existing infrastructure. Conventionally, methanol is produced from synthesis gas (syngas), which is obtained from the reforming or partial oxidation of fossil carbon sources, such as natural gas or coal, according to the following reaction equation:

$$(1) \quad CO + 2\,H_2 \rightarrow CH_3OH \qquad \Delta H = -90.8\ kJ/mol$$

Whenever electricity is stored in the form of methanol, the process is also known as power-to-methanol (PtM). The simplest and most mature renewable methanol production method is the CO_2-based production pathway via direct CO_2 hydrogenation, which follows the reaction equation:

$$(2) \quad CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O \qquad \Delta H = -49.2\ kJ/mol$$

CO_2 and hydrogen are converted into methanol by a catalytic exothermic process in the presence of a copper, zinc oxide and aluminium oxide catalyst (Cu-ZnO-Al_2O_3) under suitable reaction conditions at moderate temperatures (ca. 220–270°C) and elevated pressure (ca. 50–80 bar). To produce 1 tonne of methanol, around 1.4 tonnes of CO_2 and 0.19 tonnes of hydrogen are needed as feedstock. The co-produced water of approximately 0.56 tonnes is separated from the methanol by distillation [SCH]. No external heat supply is required, as waste heat from the exothermic reaction can be recovered for this purpose. This CO_2-based PtM pathway is technically mature and industrially available, with a TRL of 7–9. Mitsui Chemicals Inc. and Carbon Recycling International already have PtM plants, and many more projects have been announced worldwide [ZEL]. Besides significant GHG emission reduction potential, the major benefits of the CO_2-based production pathway are lower exothermy, resulting in easier heat removal, and the potentially higher catalyst selectivity towards methanol, simplifying product purification. These advantages can translate into reduced capital and operating costs due to milder process conditions, simpler reactor design and process step savings. On the other hand, the CO_2-based production pathway increases water formation, which is a challenge for the long-term stability of existing catalysts. Current research has therefore developed catalysts designed for higher CO_2 feed concentrations. Methanol is an ideal platform molecule that enables numerous subsequent processing options. The methanol-to-gasoline (MtG) pathway is industrially mature, with a TRL of 9, and has been implemented in fixed-bed or innovative fluidised-bed reactors, depending on the technology provider [ZEL]. The MtG pathway utilises approximately 0.4

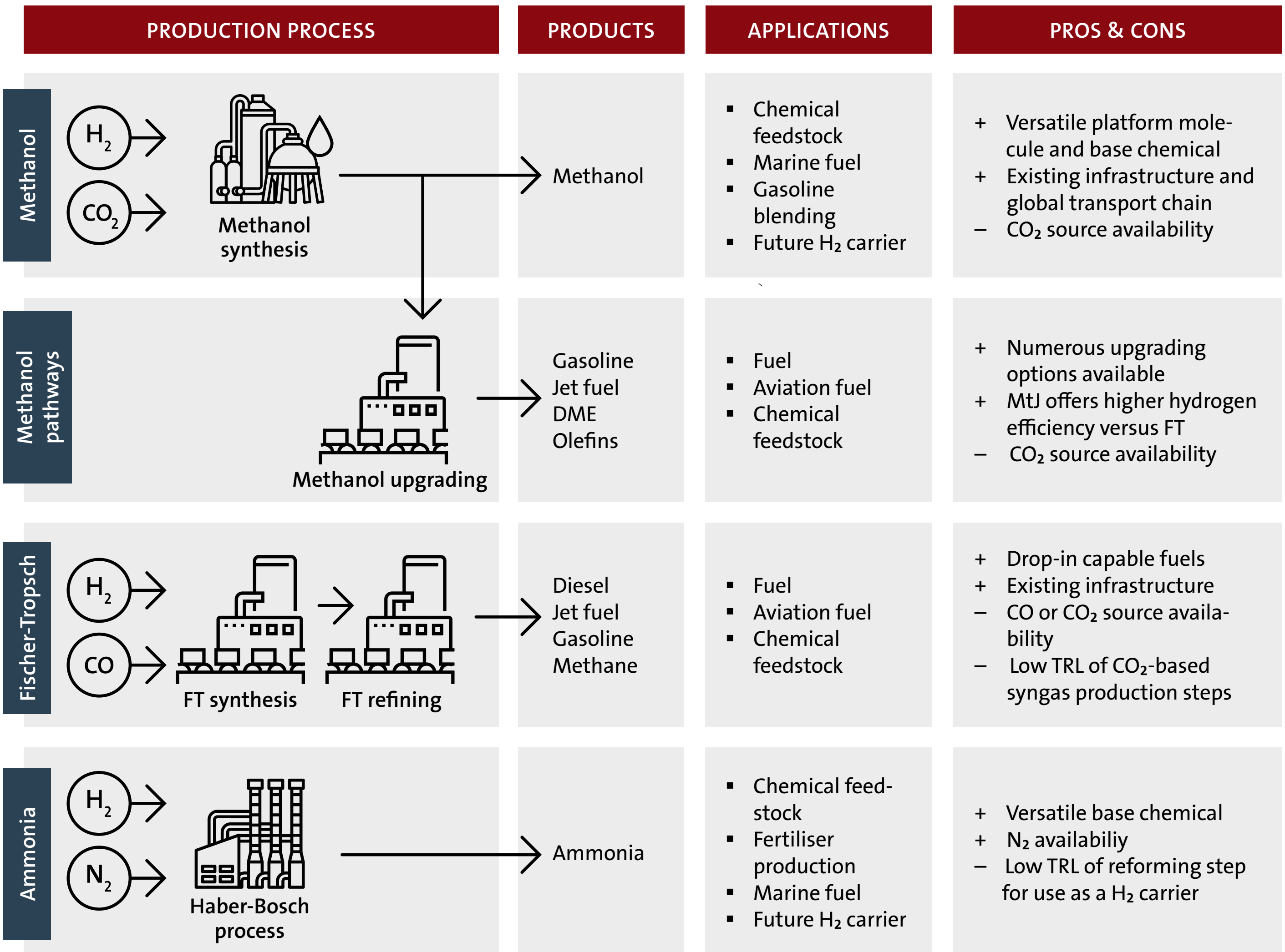
Apart from hydrogen, methanol, FT fuels and ammonia are among the most promising PtX products

tonnes of hydrogen, 2.87 tonnes of CO_2, 0.13 tonnes of oxygen and 0.37 MWhel to produce 1 tonne of gasoline [SCH]. The methanol-to-jet fuel (MtJ) pathway consists of three process steps – olefin synthesis, oligomerisation and hydrogenation – to produce jet fuel, gasoline and light gas. This production pathway yields a high proportion of jet fuel in the final product compared to the FT pathway, resulting in a higher hydrogen efficiency for methanol [BAT]. The process conditions and choice of catalyst can adjust the selectivity towards certain products. No complete MtJ demonstration plant is currently in operation, but the production of a drop-in capable jet fuel produced via MtJ is expected as the individual steps of this pathway are already commercially available (although they do not yet have ASTM (American Society for Testing and Materials) certification).

Fischer–Tropsch (FT) fuels

The FT synthesis is of great political and economic interest. It can supply a variety of drop-in capable products, such as synthetic diesel or jet fuel, to existing infrastructure and applications that will depend on energy-dense liquid fuels in the future. Conventionally, the syngas educts carbon monoxide and hydrogen are produced from coal, natural gas or biomass in a process known as gasification or reforming. As direct FT synthesis from CO_2 is at very early laboratory stages, the renewable process is based on syngas, either produced via a combination of water electrolysis and the reverse water gas shift (RWGS) reaction, or by high-temperature co-electrolysis [DIE]. In the RWGS, CO_2 is reduced to CO by hydrogen according to the following equation:

FIGURE 10: SCHEMATIC OVERVIEW OF THE MAIN PTX CONVERSION STEPS



(4) $CO_2 + H_2 \leftrightarrow CO + H_2O$ $\Delta H = +42.1$ kJ/mol

In co-electrolysis, water and CO_2 are converted to hydrogen, carbon monoxide and oxygen with the aid of electric power within the SOE. The reaction equation below displays the two reduction processes on the cathode side.

(5) $CO_2 + 2\,e^- \rightarrow CO + O_2^-$ and $H_2O + 2\,e^- \rightarrow H_2 + O_2^-$

The FT synthesis converts the resulting syngas into various long-chain hydrocarbons via CO hydrogenation and polymerisation, as follows:

(6) $n\,CO + 2n\,H_2 \leftrightarrow (CH_2)n + n\,H_2O$ $\Delta H = -158$ kJ/mol

Thereby, hydrogen and CO in a stoichiometric ratio of 2–2.2 reacts with water and CH_2 building blocks, which form increasingly longer hydrocarbon chains in the reactor. This produces a broad spectrum of hydrocarbons, collectively known as syncrude, with increasing numbers of carbon atoms, from gases (C1–C3) to solid waxes (C35+). The resulting chain length window of the syncrude can be controlled to a certain degree by the choice of catalyst, temperature and pressure. Cobalt catalysts and low temperatures (200–250°C) enable the synthesis of long-chain hydrocarbons, such as diesel components and waxes, which are subsequently processed via traditional petrochemical refining processes like hydrocracking or distillation to produce gasoline (C4–C12) or jet fuel (C7–C18) for example. Iron catalysts and high temperatures (300–350°C) lead to the production of mainly short-chain hydrocarbons. Along the RWGS pathway, around 3.1 tonnes of CO_2 and 0.48 tonnes of hydrogen are needed as feedstock to produce 1 tonne of FT product and approximately 3 tonnes of water [SCH]. While the FT synthesis and subsequent processing steps are industrially mature with several large-scale plants already in operation, the two syngas production steps (RWGS, co-electrolysis) based on CO_2 still have a comparably low TRL of 6, and further research is required [ZEL]. The production of syngas via biomass gasification can be utilised directly in a conventional FT synthesis reactor, but there is a limited quantity of sustainable biomass.

Ammonia

Ammonia is one of the most widely produced chemicals and is the basis for producing all other nitrogen compounds. Over 80% of ammonia is processed into fertilisers, especially urea and ammonium salts. Conventional ammonia is produced from nitrogen and hydrogen via the Haber–Bosch process, according to the following equation:

(3) $N_2 + 3\,H_2 \leftrightarrow 2\,NH_3$ $\Delta H = -46{,}1$ kJ/mol

In the most common conventional process, hydrogen is produced from steam methane reforming (SMR) and nitrogen provision comes from air separation. Storage of electricity in the form of ammonia is known as power-to-ammonia (PtA). The synthesis could be carried out according to the conventional Haber-Bosch process or using innovative production concepts currently under development. In contrast to the conventional process, an electrolyser provides the educt hydrogen. As stated by reaction equation above, hydrogen and nitrogen in a stoichiometric ratio of 3:1 are converted into ammonia via an exothermic process in the presence of an iron catalyst under suitable reaction conditions at high temperatures (400–450°C) and high pressure (120–220 bar). Subsequently, the synthesised gaseous ammonia is cooled to enable liquefaction at a temperature of –33°C. To produce 1 tonne of ammonia, around 0.83 tonnes of nitrogen and 0.18 tonnes of hydrogen are needed as feedstock [AUS]. The purification step to remove ammonia from unconverted hydrogen and nitrogen is straightforward. The individual system components of the renewable ammonia synthesis are industrially available. The integration of the overall process within a large industrial environment offers potential for optimisation in terms of dynamic operation and process intensification, leading to a TRL ≥8 [ZEL].

2.5 SUPPLY OF CARBON AND NITROGEN

In addition to hydrogen, other precursors such as carbon dioxide and nitrogen are required to produce the synthesis products.

Supply of carbon

There are several possible carbon sources available, classified according to their origin. The available carbon sources show substantial differences in their (future) availability, capture costs and sustainability.

One option, which is especially relevant as it enables a closed carbon cycle, is the separation of CO_2 from ambient air via direct air capture (DAC). The operating principles of available DAC technologies can be distinguished according to their regeneration temperature, adsorbent type and physical separation technology. In low-temperature solid sorbent DAC (LT-DAC) plants, CO_2 from the air is bound to a sorbent via adsorption and subsequently regenerated using low-temperature heat or moisture [DEU]. High-temperature aqueous solution DAC (HT-DAC) is based on the principle of

TABLE 3: OVERVIEW AND CATEGORISATION OF AVAILABLE CARBON SOURCES

DIRECT AIR CAPTURE	▪ LT-DAC ▪ HT-DAC	
BIOGENIC SOURCES	▪ Biomethane production ▪ Bioethanol production	▪ Biogas combustion ▪ Biomass combustion
INDUSTRIAL SOURCES	**Process-related emissions** ▪ Pulp and paper ▪ Glass and ceramics	▪ Waste incineration ▪ Cement ▪ Lime
	Energy-related emissions or mitigation concepts under development ▪ Steel and iron ▪ Non-ferrous metals	▪ Refineries ▪ Chemicals

absorption and desorption, where CO_2 chemically binds with a capture solution, which is then subject to several chemical conversion steps before it is finally decomposed via calcination at around 900°C [KEI, FAS].

Announced projects reveal substantial differences in terms of project sizes. While small-to-medium LT-DAC plants are commercially available from companies such as Climeworks and Global Thermostat, large-scale HT-DAC with an annual capture capacity of 1 million tonnes are provided by Carbon Engineering. But LT-DAC modules show clear environmental advantages and outperform HT-DAC modules by a factor of 1.3–10 in relevant environmental impact categories [MAD]. Besides the possibility of closing the carbon cycle, DAC technologies are location-independent and offer almost unlimited availability. The major drawbacks of DAC technologies are the comparably high energy demand and capture costs, although substantial reductions are expected.

> **Industrial point sources of carbon, where CO_2 is captured from the CO_2-rich gas streams of industrial processes, are especially relevant for the upcoming decades**

Biogenic carbon sources permit the closing of the carbon cycle together with low capture costs. For example, the production of biomethane from biogas or bioethanol fermentation generates almost pure CO_2 streams, which can be easily captured. However, it is essential to evaluate the substrate class of the biogenic point sources. Some substrates, like agricultural residues or municipal solid waste, can be classified as sustainable, unlike other substrates like energy crops. Therefore, the potential for sustainable biomass utilisation is limited.

Industrial point sources of carbon, where CO_2 is captured from the CO_2-rich gas streams of industrial processes, are especially relevant for the upcoming decades. > see Figure 11, next page It is important to distinguish (a) sources with a significant share of unavoidable process-related emissions from (b) sources with other appropriate emissions reduction strategies or insignificant process-related emissions. Sectors in category (a), such as cement and glass, have limited CO_2 reduction potential through direct electrification, or the use of hydrogen and its derivatives, as a substantial fraction of their emissions are process-related. On the other hand, sectors in category (b), such as iron and steel, or aluminium, either have other appropriate emissions reduction strategies in place, for example through the direct reduction of iron ore with green hydrogen, or their emissions are mainly energy-related. In principle, the various processes available to separate CO_2 from industrial processes can be grouped into three main categories: (1) pre-combustion, (2) post-combustion and (3) oxy-fuel combustion. Pre-combustion technologies are based on upstream decarbonisation of the fuel by gasification. This method is therefore unsuitable for sectors with significant process-related emissions. Post-combustion, of which carbon scrubbing with amines is currently the most mature and utilised technology, involves capturing CO_2 from flue gas and is thus suitable for all industrial point sources [ZEL]. The third category, oxy-fuel combustion, is not yet industrially mature but has excellent potential for the future. In oxy-fuel combustion processes, oxygen (e.g. from electrolysis) is utilised rather than air for fuel combustion. Excluding inert air components leads to a high CO_2 fraction in the flue gas. A synergistic integration within a PtX value chain is possible, as oxygen is produced as a by-product of water electrolysis, and thus energy-intensive air separation can be omitted.

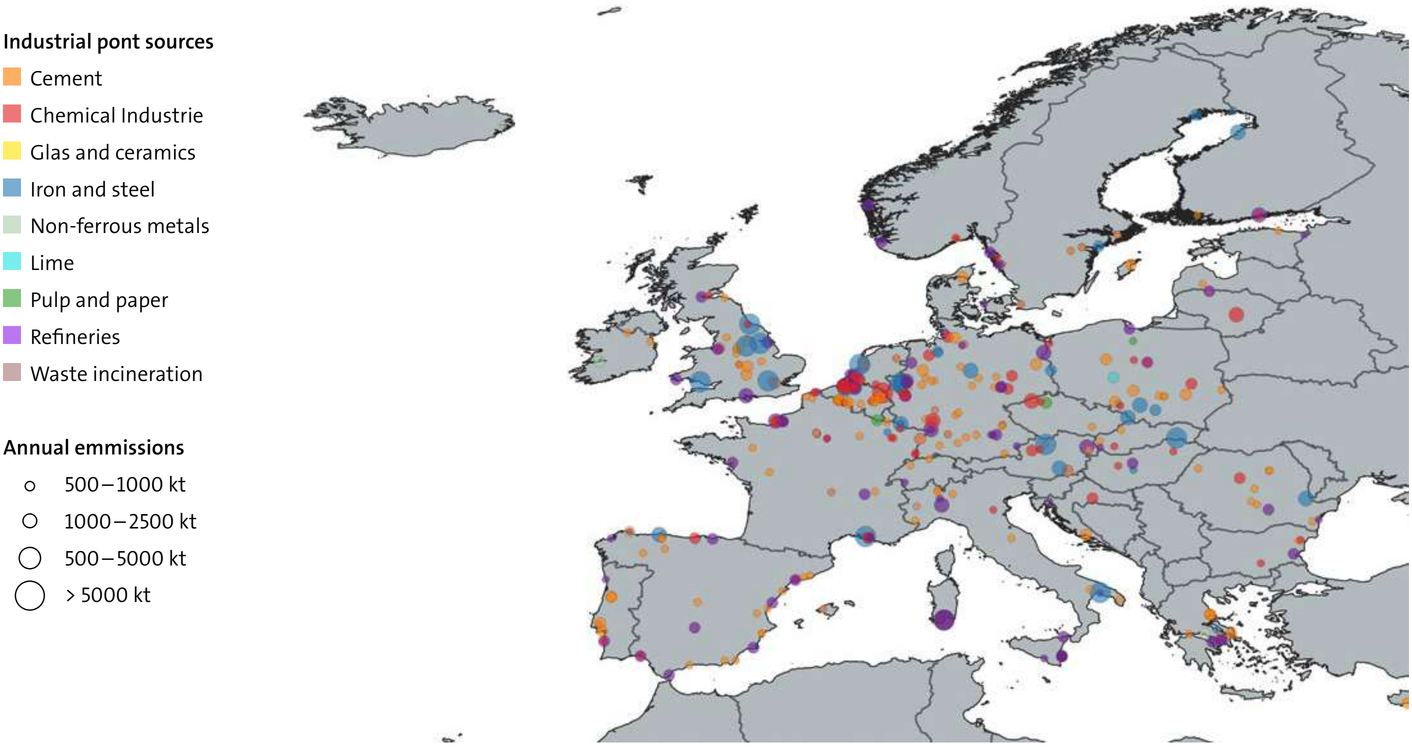
Supply of nitrogen

Nitrogen can be obtained from air through three technologies: cryogenic distillation, pressure-swing adsorption and membrane separation. Cryogenic distillation plants, also known as air separation units (ASUs), are the most common method for nitrogen production in medium-to-large-scale plants. With this method, atmospheric air is purified by filtration, compression and cooling, before the purified air is cooled to the cryogenic temperature of –185°C via heat exchangers. The components of air (nitrogen, oxygen and argon) can then be separated due to different boiling points [AUS]. The total electricity demand of an ASU is in the range of 0.5–0.8 MWhel per tonne of ammonia, depending on the plant size and the degree of refrigeration recovery [HAN] and does not contribute signifcantly to the overall production cost of green ammonia pathways.

2.6 INTERMEDIATE H_2 STORAGE AND FLEXIBLE SYNTHESIS OPERATION

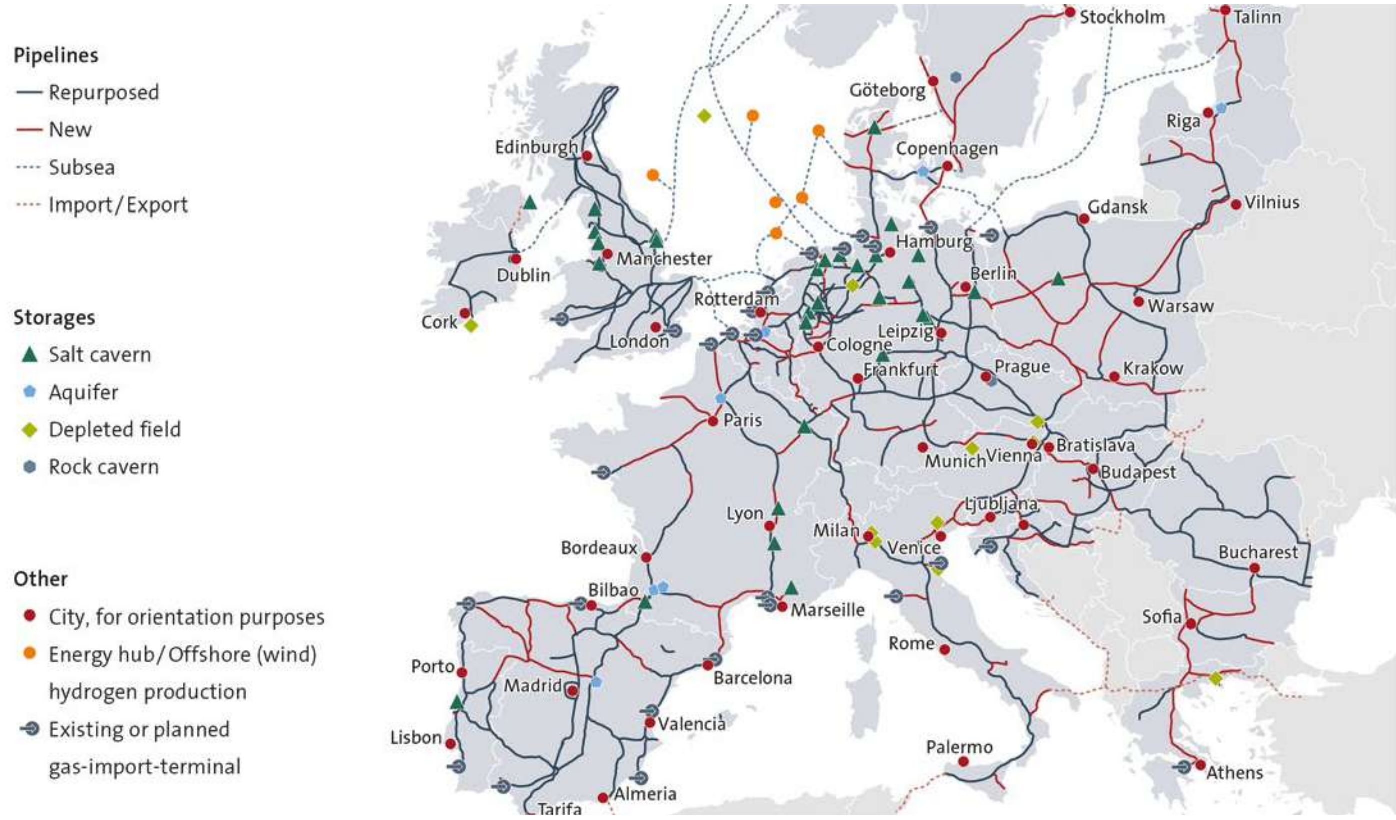
Although high electrolyser full-load hours are achievable through a combination of renewable energy sources, there is a need to compensate for the volatility of renewable energy, and thus hydrogen supply for the (so-far) steady-state operation of PtX synthesis plants. Consequently, it is necessary to develop an optimised intermediate storage and operation concept considering (a) the short-term storage of surplus renewable electricity in battery systems, (b) intermediate hydrogen storage and (c) the operation management of the PtX value chain. The technologies for intermediate hydrogen storage can be divided into physical, chemical and adsorption options. Adsorption and chemical storage options, including metal and chemical hydrides, do not yet have the TRL for large-scale industrial applications. On the other hand, physical storage technologies are industrially mature processes and can be grouped into liquified hydrogen (LH_2) and compressed gaseous hydrogen (CGH_2). LH_2 is a well-established technology, requiring cooling below –253°C and offering a high volumetric storage density, but it has a significant energy demand for the liquefaction of 24–36% of the hydrogen energy content (8–12 MWh/tH_2) [HAN]. Thus, LH_2 is not an appropriate intermediate storage option for subsequent synthesis processes, but it is suitable for long transport distances

FIGURE 11: AVAILABLE INDUSTRIAL CO_2 POINT SOURCES WITHOUT FOSSIL POWER PRODUCTION IN EU 28 AND NORWAY WITH ANNUAL EMISSIONS ABOVE 500 KT IN 2014 AND 2017 [PEZ]



Source: D2.3 WP2 Report – Open Data Set for the EU28

FIGURE 12: ENVISIONED MATURE HYDROGEN PIPELINE NETWORK IN EUROPE BY 2040 [ROS]



Source: European Hydrogen Backbone initiative 2022, supported by Guidehouse

(see next section). CGH_2 can be grouped into large-scale geological storage options and small-to-medium-scale tank or tube storage. Geological storage options, such as salt caverns, aquifers, and depleted oil or gas fields, are geographically limited but offer a cost-competitive way to temporarily store large quantities of hydrogen.

Salt caverns play a decisive role in this regard, as aquifers and depleted oil or gas fields show problems with permeability [LAB]. Pressurised tubes or tank storages can be located underground, and typically operate in a pressure range of up to 100 bar. Due to the high investment costs, optimised storage size and system integration are material to the competitiveness of PtX products. Besides increasing electrolyser full-load hours, there is the potential to increase the operating window of synthesis processes and reduce the size of the intermediate hydrogen storage. Currently, state-of-the-art synthesis processes are operated full-load with minimal part-load operation. Current research activities on operation management, reactor designs, and catalyst performance under dynamic and flexible conditions enable an expansion of the operating window that would offer reduction potential for intermediate hydrogen storage. Overall, future PtX plants are developing away from syngas-based, steady-state, large-scale plants towards more flexible systems with direct CO_2 utilisation. Further efficiency increases, by developing new reactor and innovative heat integration concepts, will be feasible in the near future.

2.7 PRODUCT STORAGE, TRANSPORT AND RECONVERSION

In addition to the intermediate storage of hydrogen, various technology options are available for the long-distance transport of H_2. In the long term, pipelines for gaseous hydrogen transport represent a promising option for large-scale transport over several hundred to several thousand kilometres. As envisioned by the European Hydrogen Backbone > see Figure 12, a mixture of existing repurposed natural gas pipelines and new pipelines can be used for a pipeline-based transport of pure hydrogen across Europe to connect producers, import terminals, consumers and storages. Another option is to transport LH_2 at low temperatures with significantly increased energy density in suitably insulated tanks. Soon, in largescale liquefaction plants the liquefaction energy demand could realistically be as low as 18-24% of the hydrogen energy content. The first ship-based storage systems, with several thousand tonnes of capacity, have already been approved for ocean transport, and their commercial deployment is targeted before 2030. The boil-off rate of less than 0.2 percent per day, that is evaporating from the stored LH_2, can be utilised as marine fuel. Furthermore, hydrogen can be bound to a liquid organic hydrogen carrier (LOHC) for storage and transport. The storage within LOHC is based on a reversible chemical reaction where the LOHC is loaded with gaseous H_2 at elevated pressures and temperatures, enabling storage in liquid form. Subsequent long-distance ship transportation of the hydrogenated LOHC is straightforward and possible without any boil-off losses. However, the additional costs for the LOHC medium and the comparably lower energy density have to be considered [HAN].

The storage of liquid products, such as methanol or ammonia, is handled via storage tank farms of varying sizes. For ammonia, this is realised at a low but non-cryogenic temperature of –33°C. The transportation of these products via vessels is proven and mature, similar to conventional liquid energy carriers. It is possible to use the transported energy carrier directly as a marine fuel, which is already implemented in the case of methanol, for example. Retrofitting existing diesel engines is also viable for methanol. If ammonia is used as a hydrogen carrier, it can be decomposed into its constituent nitrogen and hydrogen by an endothermic reforming process at the destination point. However, over 20% of the available hydrogen energy content is used up as heat input during the reforming step [GID]. Highly active non-noble metal catalysts for ammonia reforming are under development to reduce cost and energy intensity. The resulting nitrogen is reused or released back into the atmosphere. As with ammonia, the transport of LOHC requires an endothermal dehydrogenation step to release the stored hydrogen. The required heat can be supplied by waste heat or through the oxidation of a share of the released hydrogen. Unlike ammonia, LOHC also requires a return transport of the dehydrogenated carrier to the port of origin or hydrogen production site. The hydrogen storage capacity of LOHC is limited to approximately 6.2% of its mass, which is substantially lower compared to the storage capacity of ammonia, for example, at

> **The production and transport pathways for H_2 are technically feasible and ready for large-scale industrial application**

17.8 wt%. In the case of LH_2, a regasification step is necessary. Regasification is less energy-intensive, consuming less than 1% of the hydrogen energy content, with heat supplied by water or air.

To conclude, the production and global trade of renewable energy via hydrogen and its derivatives are essential for deep defossilisation. The necessary production and transport pathways are technically feasible and ready for large-scale industrial application. In the coming years, production volumes and system efficiencies will be increased through innovative reactor, process and catalyst concepts, an increasing share of renewable energy, as well as new pipeline and shipping options. The identification of an optimal PtX production and transport pathway can be accomplished through a comprehensive evaluation of site-specific prerequisites, such as existing power, gas, water, transport and industrial infrastructures, and surrounding economic, ecological, political and technical factors.

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THE ECONOMICS OF (GREEN) HYDROGEN

3.1 THE DEMAND FOR (GREEN) HYDROGEN

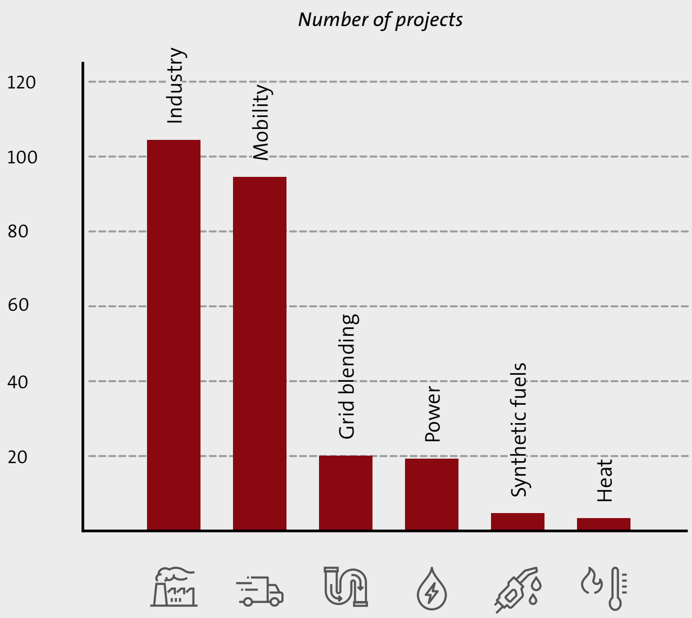
The existing demand for hydrogen, which has so far been almost entirely produced from fossil fuels, comes mainly from the fertiliser industry, refineries and some other industrial applications. In these sectors, a speedy switch from fossil (mainly grey) hydrogen to green hydrogen will be possible with small-to-no additional upfront investments on behalf of the offtaker. These sectors represent an obvious entry point for green hydrogen, and price competitiveness with grey hydrogen will be key. However, the market for green (and other low-carbon forms of) hydrogen is expected to be substantially larger than the existing fossil hydrogen market because it can decarbonise so-called hard-to-abate sectors by replacing various other (primary) fossil fuels like coal, natural gas and crude oil, or processed derivatives thereof. This is particularly relevant for applications in heavy industries (like steel) and certain mobility and transport uses (mainly shipping, aviation, and heavy goods vehicles), where hydrogen and its derivatives are often the most efficient – and sometimes the only technically feasible – decarbonisation option. Using green hydrogen for those new applications usually requires some additional capital expenditure by the offtaker for refurbishments or retrofitting. In addition to these offtake applications, with the further expansion of renewable electricity generation, green hydrogen may also play an import role in grid stabilisation and electricity storage in the

AURORA'S GLOBAL ELECTROLYSER DATABASE

The market analysis for green hydrogen is based on Aurora's global electrolyser database, which tracks existing and planned electrolyser projects around the world. The majority, but not all, of these projects are based on renewables. By collecting information on the technical, project and financial details, Aurora identifies trends that are emerging in the green hydrogen market. The database also tracks the offtakers for these projects.

Aurora identifies 45 GW of "non-early-stage" electrolyser projects across Europe, meaning that these projects have reached certain milestones such as planning permission, environmental impact assessment approval or FID. "Early-stage" projects, which are still in planning or discussion stages, and which have not reached FID, add an additional 97 GW to the pipeline. Aurora defines early-stage projects as installations and programs still in planning or discussion stages, and which have not reached FID. In Europe, industry is the most named offtaker, followed by mobility.

FIGURE 13: OFFTAKE INDUSTRIES OF ANNOUNCED ELECTROLYSER PROJECTS



Source: Aurora Energy Research [AER1]

medium to long term. Consequently, green hydrogen is not only competing with grey hydrogen, but may in many cases replace other fossil fuels – a fact that heavily influences the competitiveness of green hydrogen depending on the sector in question.

In many projects there is some overlap between offtaker types, meaning that an electrolyser has more than one named end-user type. The data in Figure 13 indicate the sectors in which demand for green hydrogen is already relevant, and where it will likely gain further momentum in the upcoming years.

3.2 THE SUPPLY AND PRODUCTION COSTS OF (GREEN) HYDROGEN

On the supply side, hydrogen production has so far been almost completely based on fossil fuels – especially gas (grey hydrogen, see Chapter 2) by way of Steam Methane Reforming (SMR) or Autothermal Reforming (ATR) – whereas production from (renewable) electricity by way of electrolysis is expected to be crucial in decarbonising the economy. Not surprisingly, the cost drivers of electricity-based hydrogen are very different from those of fossil-based hydrogen. > See Table 4 While other forms of fossil hydrogen and electricity-based hydrogen exist (see Chapter 2), grey and green hydrogen are the most relevant and will hence be the focus of our cost analysis. Hydrogen production costs are generally expressed as the levelised cost of hydrogen (LCOH). LCOH is calculated by dividing the net present value (NPV) of the total lifetime costs of the asset by the NPV of total hydrogen production over the asset's lifetime. For example, an LCOH of €5/kg H_2 in 2023 is the discounted lifetime average production costs for a plant that becomes operational in 2025. The actual production costs within a year can vary significantly. An electrolyser connected to the grid without hedging is exposed to hourly power prices, whereas an SMR plant may be subject to natural gas price fluctuations.

The cost drivers of electricity-based hydrogen are very different from those of fossil-based hydrogen.

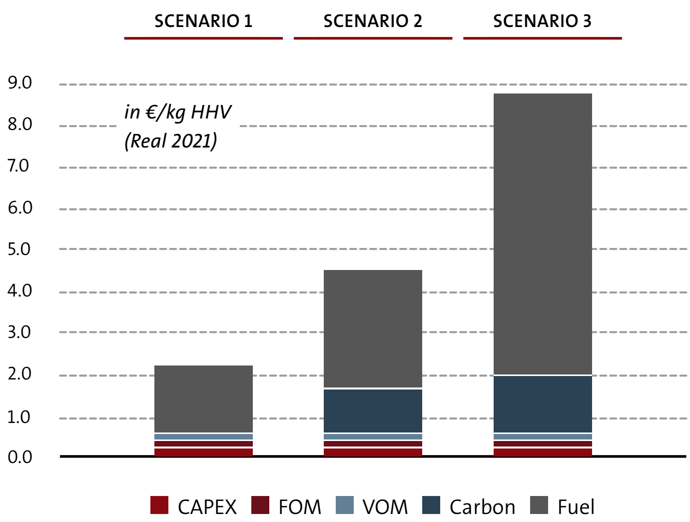
The LCOH can generally be split into two segments: capital costs and operating costs. The capital cost largely comprises the cost of the technology itself. The running costs will be driven by how the electrolyser system (for green hydrogen) or steam methane reformer (for grey hydrogen) is set up, taking into

TABLE 4: ASSUMPTIONS AND OUTPUT OF GREY HYDROGEN COST FORECASTS

PARAMETERS USED FOR LCOH	SCENARIO 1	SCENARIO 2	SCENARIO 3
Cost for SMR (€/kW)		500–550	
Lifetime in years		30	
Load factor (%)		95	
Efficiency (%)		80	
Wholesale gas price input levelised over lifetime (€/MWh)	30	70	150
CO_2 price or tax levelised over lifetime (€/t CO_2)	0	100	150
LCOH of grey hydrogen (€/kg)[1]	2	5	9

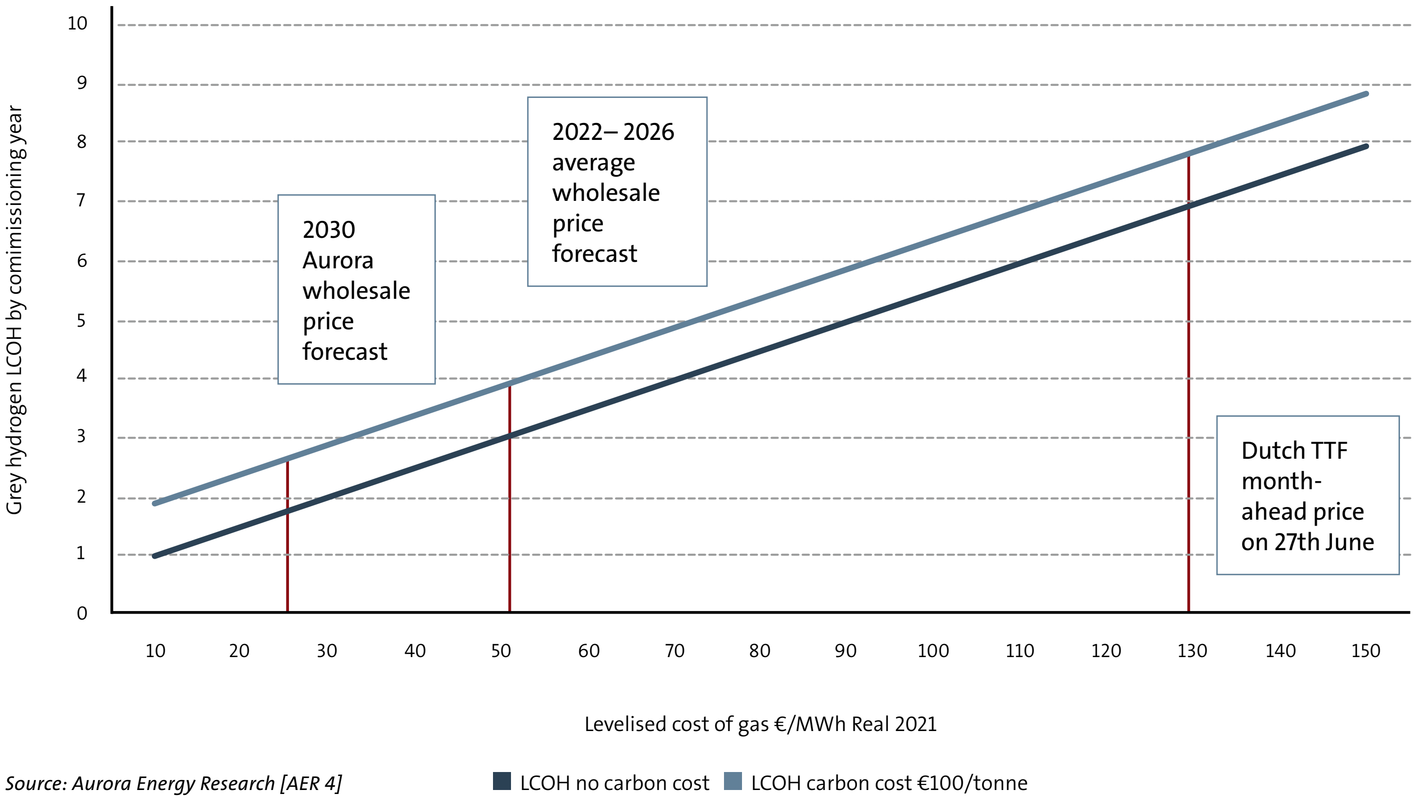
1) Aurora Energy Research assumes in its central view that grey hydrogen producers do not pay for carbon emissions, meaning the LCOH of grey hydrogen commissioned in Europe today is €2/kg

FIGURE 14: THREE SCENARIOS FOR LCOH OF GREY HYDROGEN



Source: Aurora Energy Research [AER 2] [AER 3]

FIGURE 15: SENSITIVITY OF THE LCOH OF GREY HYDROGEN TO NATURAL GAS PRICES



Source: Aurora Energy Research [AER 4]

account the efficiency and load factor, as well as procurement costs of electricity (for green hydrogen) or natural gas (for grey hydrogen). Levelised cost analysis does not account for revenue components, such as subsidies and revenue from selling the hydrogen, but does consider cost exemptions such as tax relief for electrolysis or carbon taxes on fossil fuels.

Grey hydrogen

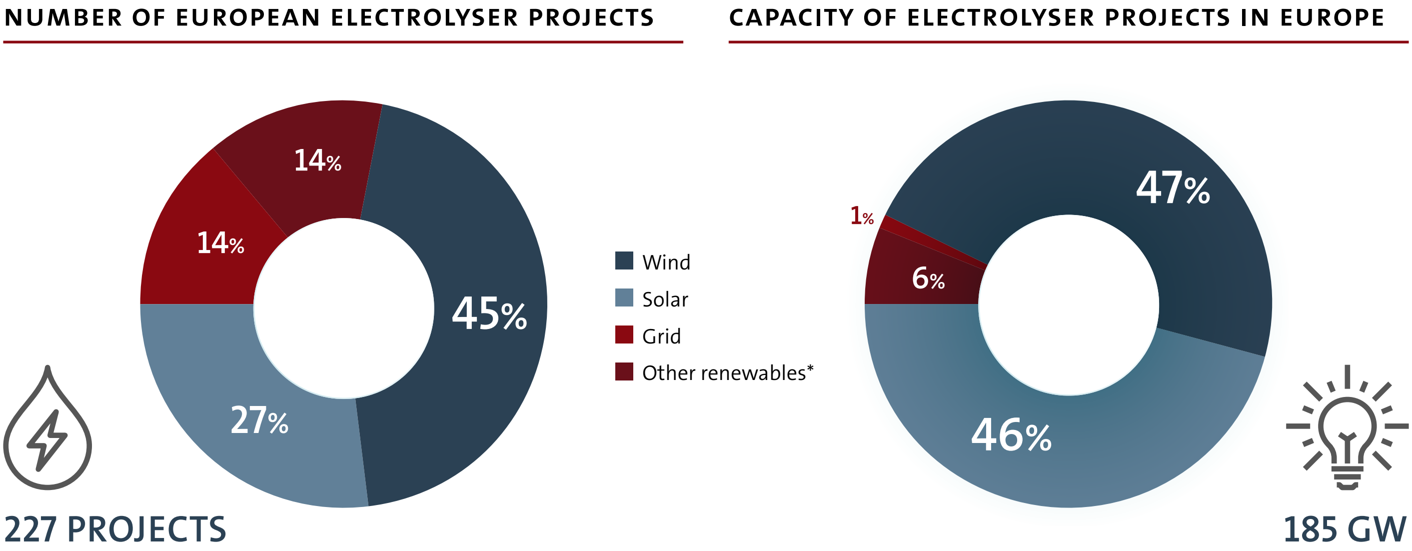
The cost of grey hydrogen comprises:

- the capital cost or expenditure (CapEx) of the steam methane reformer, or autothermal reformer
- fixed operations and maintenance costs (FOM), which do not vary with fuel input or generation
- variable operations and maintenance costs (VOM), which do vary with input or generation
- the fuel input costs of natural gas
- the cost of taxes on greenhouse gas emissions if applicable

Grey hydrogen production is a mature technology. Capital expenditures are quite stable, and Aurora does not assume declines in capital costs or economies of scale over time. Fuel input costs (i.e. the cost of natural gas and, if relevant, the penalty applied to greenhouse gas emissions) are by far the most relevant cost drivers. Given the current fluctuations in the natural gas market, we have calculated how the LCOH of grey hydrogen changes with the gas price.

Figure 15 shows the sensitivity of grey hydrogen LCOH to the input gas price. When the levelised cost of natural gas increased above €100/MWh in the first half-year of 2022, the resulting LCOH exceeded €5/kg hydrogen higher heating value (HHV) in Real 2021 prices. To demonstrate the impact of a potential carbon price, the chart shows one LCOH assuming no carbon price and one LCOH assuming a cost of €100/tonne CO_2. An often-discussed approach to reducing the carbon intensity of grey hydrogen is carbon capture use and storage (CCUS); the resulting product is called “blue hydrogen”. Additional CapEx and FOM for CCUS vary quite significantly and result in an additional LCOH in the range of €0.4–€0.8/kg of blue hydrogen compared to grey hydrogen.

FIGURE 16: NUMBER AND CAPACITY OF EUROPEAN ELECTROLYSER PROJECTS BY POWER SOURCE



**Other renewables: Where the source of renewable power is not defined by the project; Source: Aurora Energy Research [AER5] [AER6]*

Green hydrogen

As outlined in Chapter 2, hydrogen may be produced by way of electrolysis using electricity. In principle, the electricity may come from different sources, including fossil fuels like gas. However, using renewable electricity for electrolysis will result in the lowest carbon intensity of the hydrogen produced and will hence be the focus of our analysis. According to Aurora's global electrolyser database, most electrolyser projects planned within Europe will be powered by solar, wind, or a combination of both. By number of projects, wind is the most popular source of power, numbering over 100 projects.

By capacity, wind and solar are nearly tied at around 87 GW each. A smaller number of projects is designed to procure electricity from the grid or from a combination of other renewable sources such as hydropower. > See Figure 16 Aurora compares the cost of green hydrogen on a levelised basis, making it possible to compare the costs of different options even when they have different cost structures.

The costs for green hydrogen are made up of:

- CapEx, which comprise the electrolyser and balance of plant (BoP)
- FOM
- VOM
- stack replacement cost: Aurora assumes a full stack replacement after a fixed number of running hours
- cost of power input – this is the most important variable running cost and will change significantly depending on the electrolyser setup
- additional charges – additional fees (such as taxes) associated with being connected to the power grid

TABLE 5: AURORA COMMON ASSUMPTIONS FOR GREEN HYDROGEN COST FORECASTS

PARAMETERS USED FOR LCOH	2022	2030
Cost of PEM electrolyser incl. BoP (€/kW)	1,400	1,000
Economic lifetime (years)	25	25
Stack lifetime (hours)	70,000–75,000	75,000–80,000
Stack replacement cost (% of CapEx)	15	15
Efficiency (%)	65–70	70–80

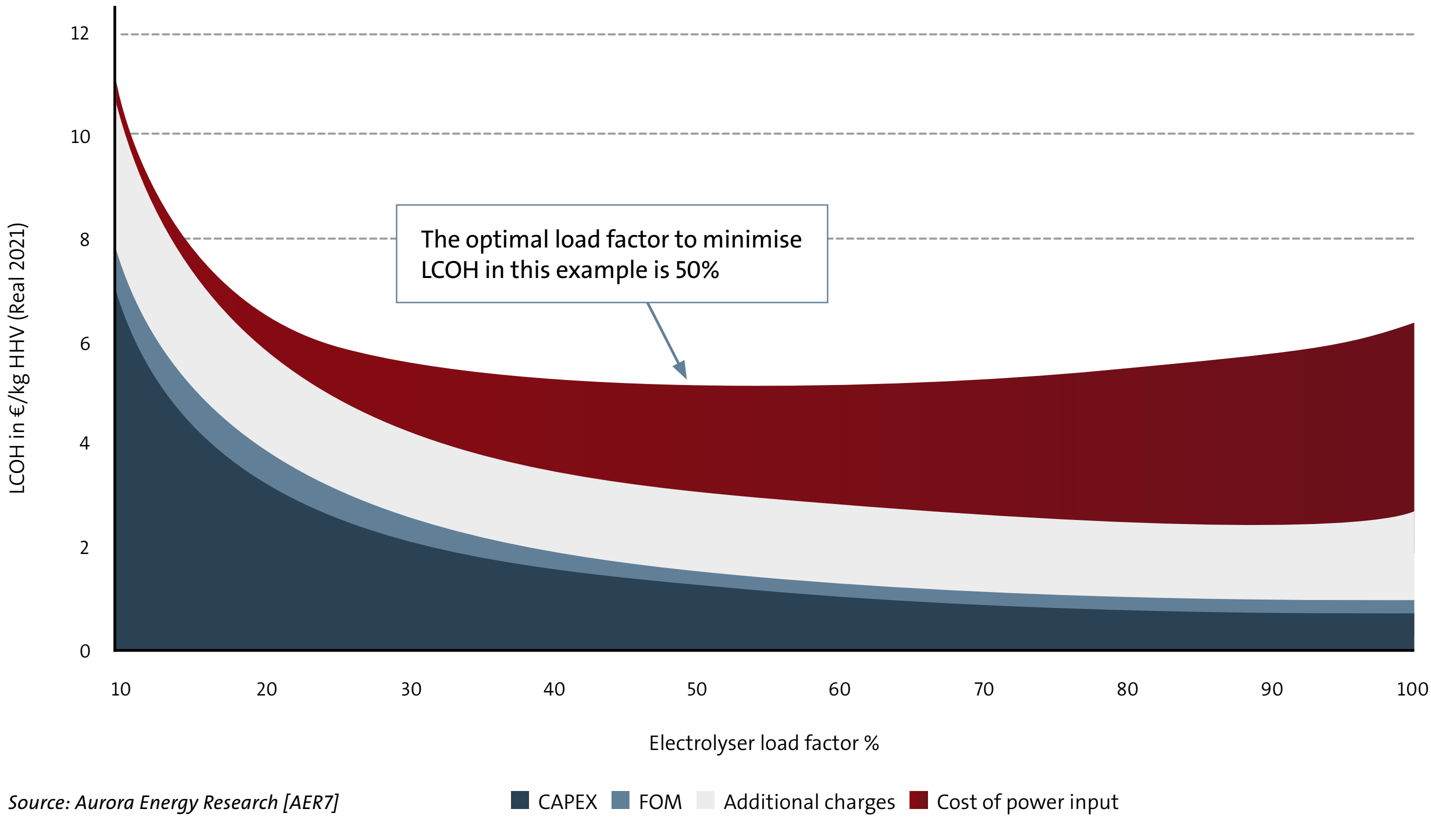
Source: Aurora Energy Research [AER7]

The CapEx for an electrolyser today is assumed to be around €1,400/kW of power input capacity. These are expected to fall in the upcoming years due to technology improvements and economies of scale. Costs could however increase with the cost of materials, such as the catalysts used. Between now and 2030, Aurora assumes the CapEx for a PEM electrolyser, including the BoP, will fall by 40% to around €1,000/kW. The load factor and the procurement cost for electricity are correlated with each other. In Aurora's modelling, only operating an electrolyser during periods of low electricity prices results in low power costs, but will also mean a lower load factor. In contrast, increasing the load factor by also operating an electrolyser during periods of high electricity prices will mean higher average electricity procurement costs. In turn, the load factor affects the LCOH. Running at a low load factor of around 10–30% will mean that the CapEx component of the LCOH is relatively high, whereas the share of electricity costs is relatively low. On the opposite end, running at a high load factor of 90–100% means the electrolyser is exposed to the highest power prices. Figure 5 shows an example for a flexible grid-powered electrolyser (as explained below) located in the north of Great Britain and comissioned in 2030, the optimum load factor to minimise the LCOH is 50%. >See Figure 17

Between now and 2030, Aurora assumes the CapEx for a PEM electrolyser, including the Balance of Plant, will fall 40% to around €1,000/kw

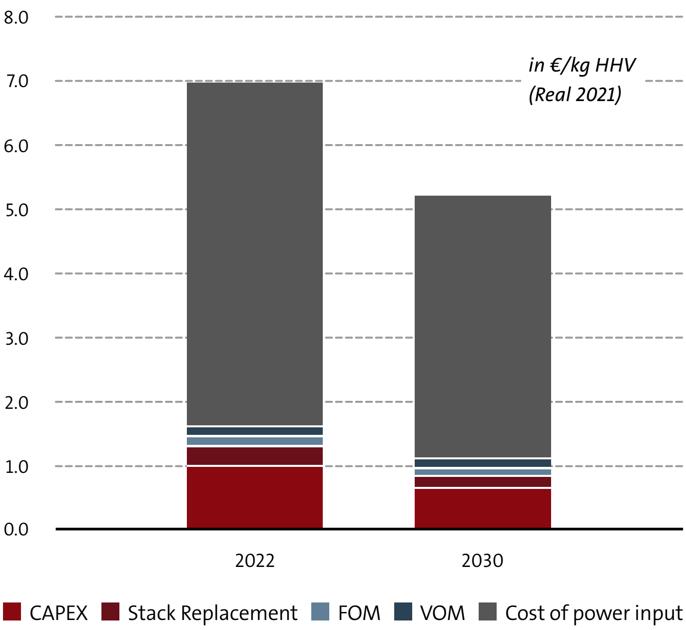
If the electrolyser is using power from the grid, the carbon intensity of the hydrogen produced will be determined by the carbon intensity of the grid during those hours. The grid's carbon intensity, in turn, is determined by the electricity production mix and the storage capacities of the electricity grid. Usually, power prices and the carbon intensity of the grid are correlated. Solar and wind power have no direct carbon

FIGURE 17: LCOH FOR A GRID-CONNECTED ELECTROLYSER COMMISSIONED IN 2030 IN EUROPE



Source: Aurora Energy Research [AER7]

FIGURE 18: LCOH FOR A GRID-CONNECTED INFLEXIBLE ELECTROLYSER IN NORTHWEST EUROPE BY COMMISSIONING YEAR



Excludes grid charges and levies, which increases LCOH further; Source: Aurora Energy Research [AER9]

emissions, and high solar and wind generation dampen power prices. During times of low renewable electricity availability, and in the absence of sufficient storage capacities, fossil-based electricity will likely be covering baseload electricity demand. As a result, high load factors of grid-connected electrolysers usually involve a higher carbon intensity of the electricity procured, and hence of the hydrogen produced. Due to their expansion, renewables will likely become an even more important determinant of spot electricity prices as well as the grid carbon intensity in the future.

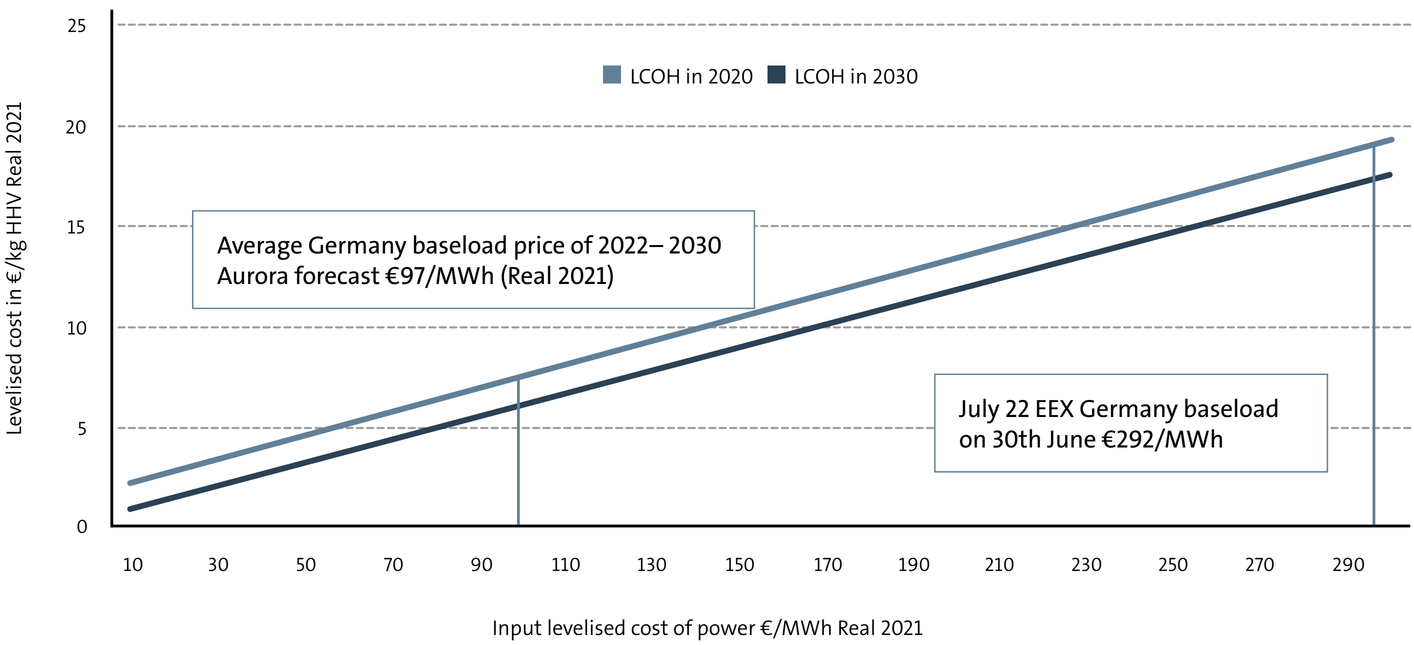
3.3 GREEN HYDROGEN BUSINESS MODELS

Aurora Energy Research has investigated the LCOH of several types of electrolyser setups, which are known as “electrolyser business models”. These models are based on projects in the electrolyser database. The main models Aurora examined are:

a) Inflexible grid electrolyser

Around 30 projects in Europe indicate that the main source of power will be grid imports. This first electrolyser business model runs on grid electricity only. It does not have to be

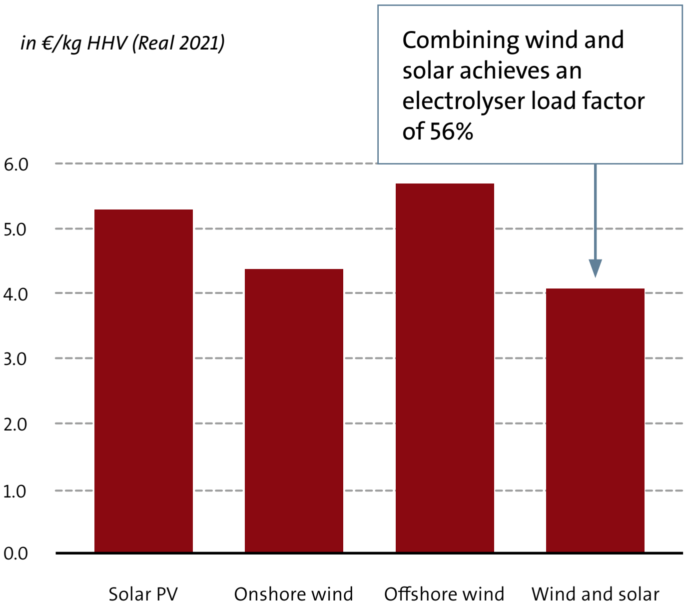
FIGURE 19: LCOH FOR A GRID-CONNECTED INFLEXIBLE ELECTROLYSER IN NORTHWEST EUROPE BY INPUT COST OF POWER



Source: Aurora Energy Research [AER 4] physically co-located with renewables, nor does it need a physical PPA, although the power could be greened by purchasing guarantees of origin or by signing a PPA. Because it is connected to the grid, the electrolyser could run at a high load factor and thereby produce hydrogen at a stable rate. The constraints include the need to be close to the power grid, the capital cost of grid connection, and exposure to grid charges. Assuming the electrolyser runs at a high and constant load factor, the majority of the LCOH for this business model is the cost of power, as the CapEx and other components are expected to be relatively stable. In the example in Figure 18, the average electrolyser located in northwest Europe (Great Britain, Germany, Netherlands, France) will see its LCOH fall from nearly €7/kg in 2022 to just over €5/kg by 2030 due to the expected drop in wholesale power prices in Europe. As the cost of power is the largest variable, Figure 19 demonstrates the relationship between the assumed input cost of power and LCOH.

The carbon intensity of the hydrogen can be calculated as the weighted average carbon intensity of the electricity procured from the power grid. Under the current draft of the RED II delegated act (as further explained in Chapter 4), hydrogen produced under this business model would likely qualify as green in very few countries, if any, where the renewable share of total electricity production is already very high. This business model may however play an important enabling role in the transition to a hydrogen-based economy.

FIGURE 20: LCOH FOR A RENEWABLES-POWERED ELECTROLYSER CO-LOCATED (ISLAND) IN FRANCE, COMMISSIONED IN 2025



Source: Aurora Energy Research [AER11]

b) Flexible grid electrolyser

This electrolyser also imports all its power from the grid, but unlike the inflexible grid electrolyser, it varies its operating hours to minimise LCOH. This optimisation avoids importing power during periods of high power prices and high grid charges, allowing it to achieve a lower LCOH. As a result, its load factor is variable and it will not produce a regular output of hydrogen.

Some factors to consider are:

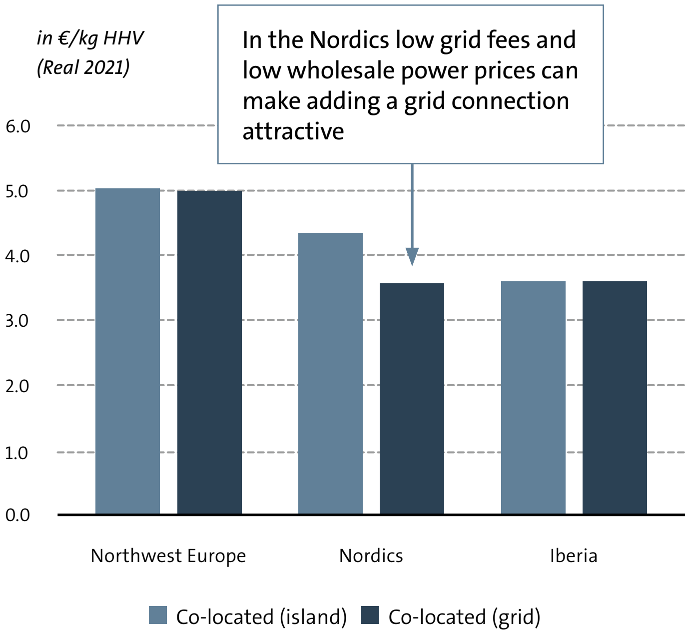
- Variable hydrogen output: Imposing a minimum load factor, such as a daily floor, to the electrolyser would mean the hydrogen production profile will smooth production throughout the year and avoid long periods without hydrogen production. This would increase the LCOH given that the electrolyser will have to operate in higher price hours.
- Storage infrastructure: Adding on-site or system-level storage to the electrolyser can help to smooth the production and adjust it to the consumer offtake profile. However, adding storage also adds to the delivered cost of the hydrogen.
- Hydrogen market liquidity: Certain use cases do not require a smooth generation profile, so the fully flexible electrolyser can still be a good option here. For instance, if there is a sufficiently liquid market, an electrolyser could sell its production by injecting it into the grid.

The carbon intensity of the hydrogen can be calculated as the weighted average carbon intensity of the electricity procured from the grid. As outlined above, electricity prices are mainly impacted by demand cycles and the availability of renewable electricity. Since the electrolyser under this business model mostly runs when electricity prices are low, it is likely to procure a large portion of its electricity from renewables. For the hydrogen to qualify as green under RED II (see Chapter 4), for instance, an appropriate PPA or guarantees of origin as well as compliance with temporal and geographical requirements will however be a prerequisite.

c) Renewables co-located electrolyser, island mode (no grid connection)

In Aurora's electrolyser database, most projects indicate that the main source of power will be solar or wind. Within this group, one business model is to co-locate the electrolyser

FIGURE 21: LCOH FOR OPTIMALLY SIZED RENEWABLES CO-LOCATED ELECTROLYSER ISLAND VS GRID-CONNECTED, COMMISSIONED IN 2025



Source: Aurora Energy Research [AER12]

with a solar and/or wind farm and forgo the grid connection altogether. It therefore has access to zero carbon, low marginal cost renewable energy. Aurora assumes the levelised cost of electricity from renewables will decrease over time with economies of scale, thereby reducing the fuel cost component for this business model. In this case, the electrolyser can be sized to an optimum ratio with the renewable asset to maximise the electrolyser load factor, but also to minimise renewable power spill. Without a grid connection, it can be in a location with good renewable output but no grid access, and does not pay grid fees. The disadvantages are that its hydrogen production is dependent on the power generation profile of the renewable asset. Like the flexible grid electrolyser, the hydrogen output and load factor will be variable. Figure 20 compares the LCOH for electrolysers connected to solar, onshore wind, offshore wind, and a combination of wind and solar. Aurora's modelling suggests that combining the generation profiles of wind and solar with the same electro-lyser allows you to achieve both a higher electrolyser load factor and lower LCOH due to the complementary generation profiles of solar and wind.

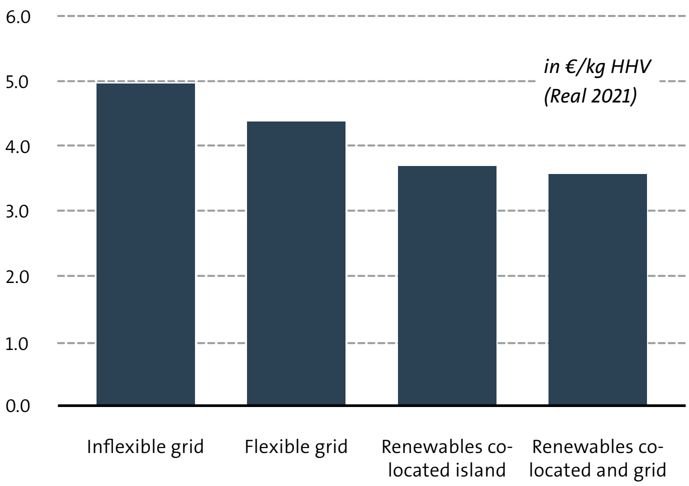
Projects developed according to this business model will procure 100% of their electricity from renewable sources and likely qualify as green under the current draft of the RED II delegated act (as further explained in Chapter 4).

d) Renewables co-located electrolyser with grid connection

This electrolyser imports power from a renewable asset but also has a grid connection from which it can top up power when the renewable asset is not generating. In this case, the renewable asset can also export power to the grid, thereby diversifying the entire project's revenue stream and reducing power spill. The electrolyser will be optimised to top up electricity from the grid only when the revenue from producing hydrogen is high enough to justify the associated power and grid charges. Figure 21 shows the expected LCOH for the renewables co-located island model and renewables co-located grid model for three different European regions. It illustrates that in the Nordics, the relatively low grid charges means that adding a grid connection actually lowers your LCOH.

The carbon intensity of hydrogen produced under this model, and hence its qualification under RED II, primarily depends on the relative share of the electricity procured from the grid compared to the co-located renewable electricity source, as well as the carbon intensity of the grid electricity procured.

FIGURE 22: LCOH FOR ELECTROLYSER BUSINESS MODEL COMMISSIONED IN 2025, EUR. AVERAGES



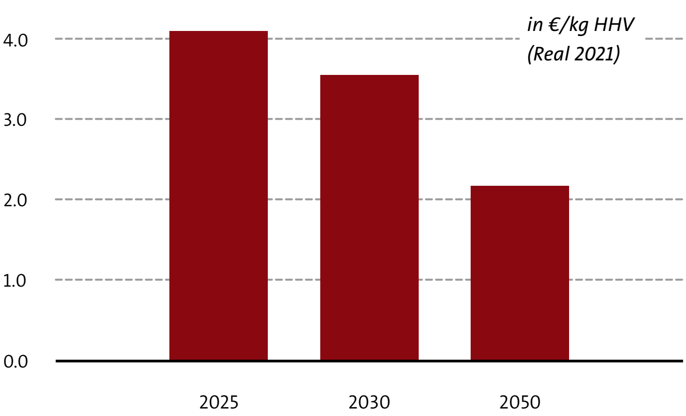
Source: Aurora Energy Research [AER13]

The average European levelised cost of green hydrogen will fall below that of blue hydrogen in the 2040s, assuming no subsidies.

Comparing all four business models

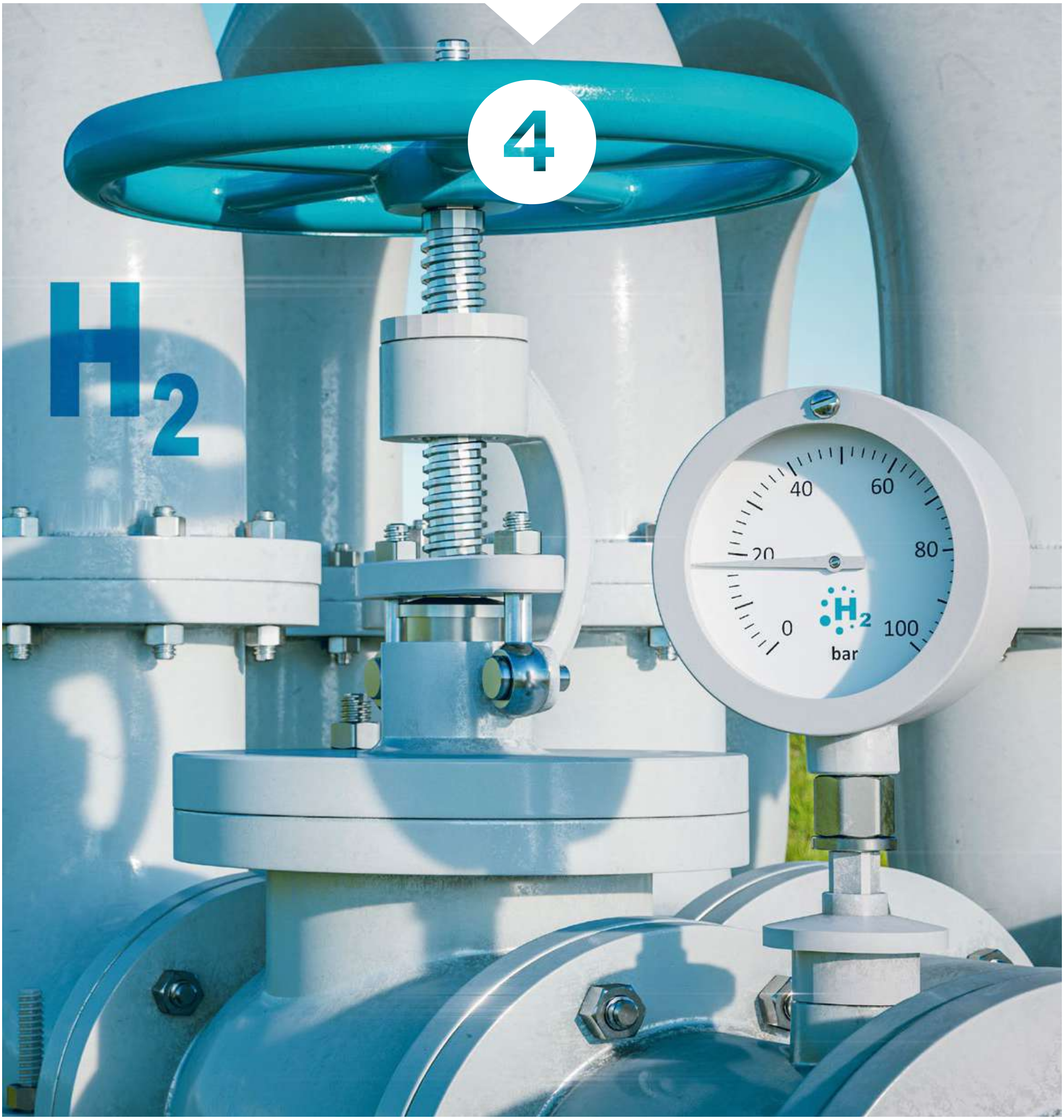
In Aurora's electrolyser database, solar and wind-powered electrolysers are the most popular type, but it is still unclear whether these projects will operate in island mode or with a grid connection. On a European average basis, connecting with renewables helps to achieve a lower LCOH and carbon intensity than grid power alone. Depending on the region, adding a grid connection to a renewables setup can lower the LCOH, but this will increase the carbon intensity of the hydrogen. Over time, the total green hydrogen production cost is expected to fall. In individual countries such as Spain, the UK and Norway, green hydrogen costs are forecast to fall below blue in the 2030s.

FIGURE 23: LCOH FOR AN ELECTROLYSER UNDER OPTIMAL CONDITIONS



Electrolyser that is optimally sized for the connected renewables asset, and with optimal grid connection, by commissioning year over an average of eight selected European countries; Source: Aurora Energy Research [AER14]

In summary, the economics of green hydrogen production depends greatly on the project setup and market, but costs are forecasted to come down over time. Irrespective of the business model selected, the levelised cost of green hydrogen is currently still above the cost of grey hydrogen. To help bridge the gap, governments have announced several policies and subsidies, as further outlined in Chapter 4.



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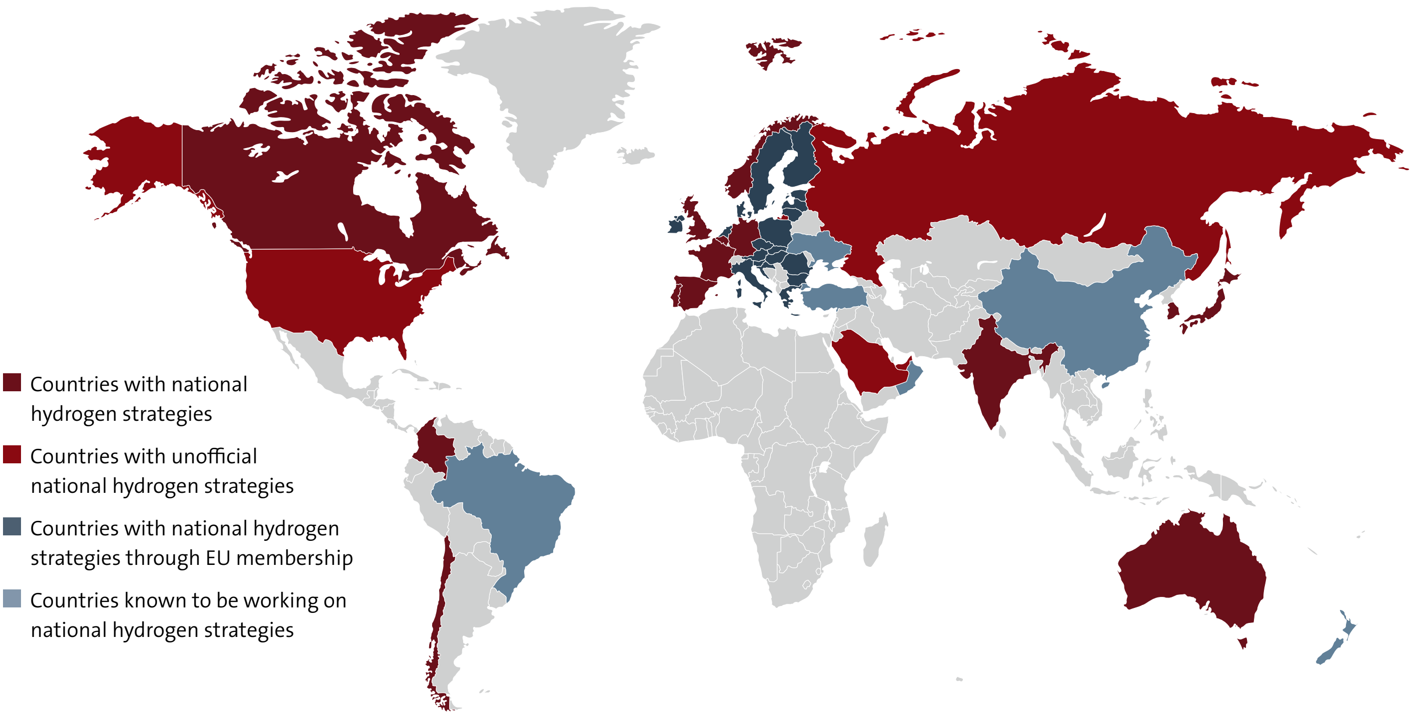
SHORT OVERVIEW OF THE REGULATORY SITUATION

Green hydrogen is certain to play a key role in an era of renewable energy, but with climate change becoming ever more apparent, we cannot wait for market forces alone to help green hydrogen achieve a breakthrough. As explained in Chapter 3, regulatory incentives are needed to give green hydrogen the key role it deserves.

More than 20 countries worldwide have already drafted a hydrogen strategy, or are actively working on one. These strategies provide a good overview of what plans and goals individual countries are pursuing with regard to (green) hydrogen. They also contain statements on the timeframe for the development of a hydrogen economy as well as discussions of regulatory instruments such as Carbon Contracts for Difference (CCfDs) or Important Projects of Common European Interest (IPCEI) funding.

These strategies are important political declarations of intent, but they are not legally binding. Claims (e.g. for a certain type of subsidy or the implementation of a subsidy system by a certain date) cannot be derived from them. Legislative implementation acts are therefore required in order to develop a reliable regulatory framework for hydrogen or, more generally, a hydrogen market environment. The following outlines regulatory incentives and the currently existing regulatory framework for green hydrogen.

FIGURE 24: HYDROGEN STRATEGIES WORLDWIDE



Source: Recharge analysis

4.1 REGULATORY INSTRUMENTS TO PROMOTE GREEN HYDROGEN

There are several instruments available to promote the expansion of green hydrogen production and consumption. On the supply side, these instruments may aim at reducing the production costs of green hydrogen (LCOH) and thus the price gap between green hydrogen and competing fossil fuels.

On the demand side, regulatory instruments may increase the price of using fossil fuels or may oblige market participants to switch to low-carbon energy carriers like green hydrogen.

Supply-side support regimes

One effective regulatory approach is to address the supply side of green hydrogen. Such measures include non-refundable subsidies, grants or preferential loans to finance the upfront CapEx. Another approach would be to offer accelerated tax depreciation regimes for all or parts of the CapEx, thereby alleviating the tax burden of project companies in the first years of operation. These instruments have in common that they aim to increase the competitiveness of green hydrogen by reducing what is still a relatively high LCOH. The EU's IPCEI regime is an example of this policy approach.

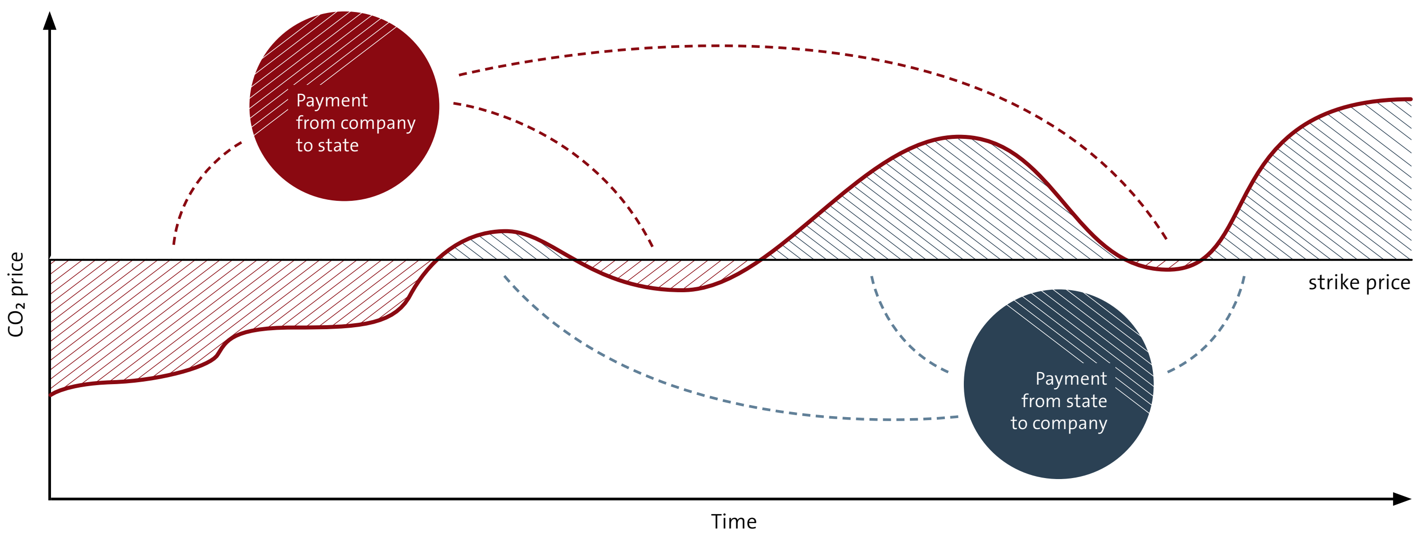
Carbon prices and taxes

Carbon prices or taxes address the demand side and give a financial cost to GHG emissions by way of charging a carbon price or tax to the emitters. Since the use of any fossil fuel generally involves some degree of carbon emissions, a carbon price or tax would increase the cost of using fossil fuels for the offtaker, making the use of green hydrogen relatively more financially attractive. A common way is to trade emission rights over carbon markets like the EU ETS, whereby emitters need to purchase emission rights for each ton of CO_2 emission.

Carbon Contracts for Difference (CCfDs)

CCfDs also target the demand side for green hydrogen and aim at bridging the price gap between green hydrogen and fossil fuels. Even if carbon prices apply, they are often not high enough in order to make green hydrogen competitive. The central idea of CCfDs is that the state (or another public body) concludes a contract with the offtaker procuring green hydrogen, who would otherwise need to purchase CO_2 certificates for the emissions that are now being avoided by the use of green hydrogen. Under the CCfD, the parties agree to pay the difference between the price for CO_2 certificates and the price for the use of green hydrogen. Under the CCfD, the price for using green hydrogen is set at the beginning (strike price). If the price for emission certificates falls below the strike price, the state will pay the difference to the company. If the price for CO_2 emissions is higher than the price

FIGURE 25: SIMPLIFIED ILLUSTRATION OF CCFDs



Source: WFW

for the use of green hydrogen the company will pay the difference to the state. Naturally, this example is highly simplified, and any legal framework will need to consider various issues before CCfDs can be implemented in practice. A CCfD system will definitely support the offtake price of green hydrogen and hence diminish the market risk of green hydrogen production.

The current regulatory framework for green hydrogen does not yet contain any regulations for CCfDs. However, it is safe to assume that such provisions will be provided by European and national legislators in the foreseeable future.

Legal obligations and bans

Finally, the most rigorous approach to promoting green hydrogen is to impose legal obligations or bans on certain market participants, especially in carbon-intensive sectors such as fuel, steel and chemical producers. These mechanisms may target the carbon footprint of their products or prescribe certain percentage obligations for the use of low-carbon (or carbon-free) fuels, like green hydrogen, thereby directly increasing the demand for these fuels. This approach can be seen in the RED II directive for the transport sector, as outlined in the next section.

4.2 THE EU FIT FOR 55 LEGISLATION FRAMEWORK

The European Union's overall hydrogen strategy will be implemented by the so-called Fit for 55 legislative package, which includes the RED II. Figure 26 illustrates the EU regulations that are important for the hydrogen economy. This shows that the regulatory framework for hydrogen will not consist of a single EU directive or regulation. Rather, there will be a multitude of legal regulations that will set the regulatory framework. Which of these regulations apply to a specific case depends largely on the use of green hydrogen.

For example, a different set of framework conditions will apply depending on whether the green hydrogen is to be used as a ship fuel or in steel production. However, many fundamental questions will be decided in the context of the EU recast of the RED II. The current version already contains relevant regulations for hydrogen applications in the transport sector.

In short, RED II sets the overall EU target for renewable energy sources consumption by 2030 to 32%, whereby a sub-target of 14% applies to the transport sector. This means that member states must ensure that at least 14% of fuel consumed in road and rail transport is derived from renewable sources by 2030. In addition, RED II defines a series of sustainability and GHG

FIGURE 26: FIT FOR 55 LEGISLATIVE PACKAGE

Source: European Union

emissions criteria that bioliquids used in transport must comply with to be counted towards the overall 14% target. While most of RED II deals with biofuels produced from certain feedstock, it also stipulates certain usage cases which allow fuel suppliers to use renewable fuels of non-biological origin (RFNBOs), such as green hydrogen, to count towards their 14% target. See also Chapter 2 for a further explanation of RFNBOs, like methanol, FT-derivatives and ammonia.

RED II recast

On 14 July 2021 the European Commission presented a draft of an amendment to RED II. Under the revised directive, the overall target for renewables increases to 40% and the renewables share of the transport sector is set to 26% by 2030. The directive also stipulates that 2.6% of this share will need to be fulfilled by RFNBOs, including hydrogen, with a GHG emissions savings threshold of at least 70%. Furthermore, the EU will remove certain beneficial provisions of RED II that currently allow advanced biofuels to benefit from certain multipliers when calculating their energy reduction goals. This will set an even bigger incentive for investment in RFNBOs. Finally, green hydrogen, ammonia, advanced sustainable biofuels and bio-LNG may benefit from a 10-year tax break under the proposed legislation. The Commission suggests that increased tax rates based on energy content should target fossil fuels. The RED II Recast draft is currently undergoing the legislative procedure. It is expected to enter into force in the second half of 2022.

The RED II draft delegated act

As outlined above, RED II stipulates the regulatory framework under which the use of hydrogen may be counted towards the transport sector's reduction criteria. However, if using renewable power is the only criterion for classifying hydrogen production as "green", this can create unwanted effects such as intensifying grid capacity issues, in particular if the renewable facility that produces electricity and the electrolyser that consumes it are connected through a grid bottleneck. Another possibility is that the demand for renewable energy becomes so great that it creates cannibalising effects between usage cases (e.g. e-mobility and green hydrogen). To counteract these undesirable effects, a RED II draft delegated act [DEL2] gives the European Commission the option of specifying additional renewable energy requirements that renewable electricity must meet in order for hydrogen to be considered "green". The first official draft of this delegated act, published on 20 May 2022, contains detailed provisions which can be divided into four major points:

- **Additionality:** A limit (up to 36 months under the current draft) applies to the length of time allowed between the renewable energy plant and the electrolyser coming into operation.
- **No public funding:** The renewable plant must not have received support in the form of operating or investment aid (feed-in tariff systems).
- **Temporal correlation:** In principle, production of renewable electricity and the use of that electricity in the electrolyser must occur within the same hour (with certain exemptions if a storage facility is used).
- **Geographic correlation:** In principle, the renewable plant and the electrolyser must be located in the same, or in neighbouring, bidding zones. Member states may introduce additional criteria concerning geographic correlation.

The draft delegated act stipulates a transitional phase, expiring on 31 December 2026, which will have a major impact on the requirements above.

If the PPA was concluded, and electricity was supplied under this PPA, on or before 31 December 2026, the additionality requirement and the limitation on public funding do not apply. This means that early projects will benefit from far cheaper PPAs and will have access to a much larger pool of potential PPA suppliers. In addition, the rules on temporal correlation will be less strict (a 1-month period instead of a 1-hour period, as foreseen in the current draft).

> **Too many important global players have already made a move towards hydrogen and there is no alternative visible**

All these requirements are still under discussion. Some stakeholders express concern that these requirements will substantially delay the development of a hydrogen market [IWR]. This is understandable from a lobbying perspective, but Watson Farley & Williams believe that overall, these requirements are conducive to long-term, sustainable market development. It is true that some of these requirements will present challenges to early hydrogen projects.

However, these challenges are substantially lowered for first movers which can take advantage of the transitional provisions – which in our view act as a first mover bonus. The European Commission has learned some lessons regarding the development of a market for renewable energies. If the aim is to provide a market environment that requires fewer changes in the long run, and which avoids cannibalising renewable energy sources, the price may be a somewhat slower development than some market participants had hoped for. Nevertheless, "the die is cast". Too many important global players have already made a move towards hydrogen and there is no alternative visible. Therefore, the hydrogen market will come.

4.3 CASE EXAMPLE: GERMANY' S FEDERAL IMMISSION CONTROL ACT

European directives need to be transposed into the national laws of EU member state. In Germany, §37a–§37h of the Federal Immission Control Act (Bundesimmissionsschutzgesetz – BImSchG) contain the relevant provisions for implementing RED II. Further details have been included in certain ordinances under BImSchG (Bundesimmissionsschutzverordnung – BImSchV), namely the 36th BImSchV, the 37th BImSchV, the 38th BImSchV and the upstream emissions reduction ordinance (UERV) [THG]. As part of this legal framework, the German government has implemented a GHG quota system that requires fuel distributors (so-called obligated parties) to monitor and gradually reduce the GHG emissions of the fuels they put on the market (e.g. by blending fossil fuels with biofuels that have a low GHG balance). However, the BImSchG now provides alternative methods for reducing the GHG balance, which include inter alia the use of green hydrogen in refinery processes or as an intermediate when producing conventional fuels. Again, green hydrogen derivatives, as explained in Chapter 2, will play an important role in fulfilling the GHG quota and reducing GHG emissions.

4.4 SUMMARY AND OUTLOOK

The German GHG quota system and the EU RED II provide good examples of how the demand for green hydrogen can be stimulated by regulatory frameworks. The two key levers are:

- Obliging certain market participants (e.g. fuel, steel and chemical producers, airlines and vessel operators) to reduce their CO_2 emissions by a certain amount.
- Allowing the use of green hydrogen to count towards the reduction obligation (especially where grey hydrogen is already used in industrial processes).

This summary reflects what is already being contemplated in the various hydrogen strategies. However, as explained in Chapter 3, it is quite clear that this system will only work if the cost of CO_2 emissions is higher than the cost of using green hydrogen. Otherwise, market participants will be incentivised to continue using grey hydrogen and other fossil fuels. The price of CO_2 emissions cannot be predicted with any certainty, the investment case for installing green hydrogen electrolysers cannot be calculated with sufficient reliability. This issue can be overcome by using CCfDs.

Once the first steps are taken to develop a regulatory framework for green hydrogen, a positive domino effect will occur. More countries will begin or continue to develop their own hydrogen frameworks, leading to a European hydrogen directive comparable to the power and gas market directives. This will then lead to a European hydrogen market. The regulatory framework from national and international bodies are clearly looking for ways and incentives to help reducing GHG emissions.

Financial investors have the opportunities to act as impact financiers in this market, but will need to consider the regulatory environment as well as the market risks of green hydrogen investments. Chapter 5 will further investigate the current investment environment.

More countries will begin or continue to develop their own hydrogen frameworks, leading to a European hydrogen directive comparable to the power and gas market directives.

5

KGAL INVESTMENT MANAGEMENT

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GREEN HYDROGEN OPPORTUNITIES FOR (IMPACT) INVESTORS

The previous chapters have outlined that green hydrogen offers a technically mature and strongly growing market. While early-stage investments in pilot projects are generally being carried out by strategic investors, the rapid maturing of the green hydrogen markets now increasingly attracts the interest of institutional investors – a situation that is very similar to the market for renewable energies in the mid-2000's. In addition, an increasing number of institutional investors worldwide have the desire – and the need – to gradually decarbonise their portfolios. Hence green hydrogen, being a zero/low carbon energy carrier, is gaining particular attention from impact investors.

5.1 OVERVIEW OF GREEN HYDROGEN INVESTMENT PRODUCTS

Generally speaking, institutional investors can participate in the green hydrogen market by way of liquid investments into listed securities or by investments in illiquid assets, such as private equity and infrastructure assets.

Listed securities

As explained in Chapter 1, in recent years a growing number of investments have been channelled into stocks and bonds of companies whose business activities are directly or indirectly connected to green hydrogen, especially manufacturers of electrolysers and fuel cells. While the valuation of such listed products is heavily linked to overall financial market risks and volatility, the general upward trend in green hydrogen company stock prices has mainly been boosted by positive green hydrogen market fundamentals, implying an overall growth expectation of this market and ultimately the expected roll-out of large-scale green hydrogen projects in the upcoming decades. The next wave of green hydrogen investments is expected on the asset level.

Illiquid investment products

Illiquid investments in the green hydrogen market are expected to significantly gain importance in line with the overall growth of the green market, as they will be vital for financing the transition to a low-carbon economy. Illiquidity is usually compensated by a premium over comparable liquid market products.

Venture capital/private equity and private debt

Investments in non-listed equity and debt instruments of companies in the green hydrogen market offer a higher risk–return profile, limited liquidity and lower exposure to financial market volatility when compared to listed securities, but share with them a valuation focused on the underlying market's fundamentals and individual company growth expectations. Private equity investments are carried out by strategic but also financial investors. Typical investee companies include technology-focused start-ups and project developers. A recent example is the participation of Copenhagen Infrastructure Partners and Blue Earth Capital in the German electrolyser manufacturer Sunfire.

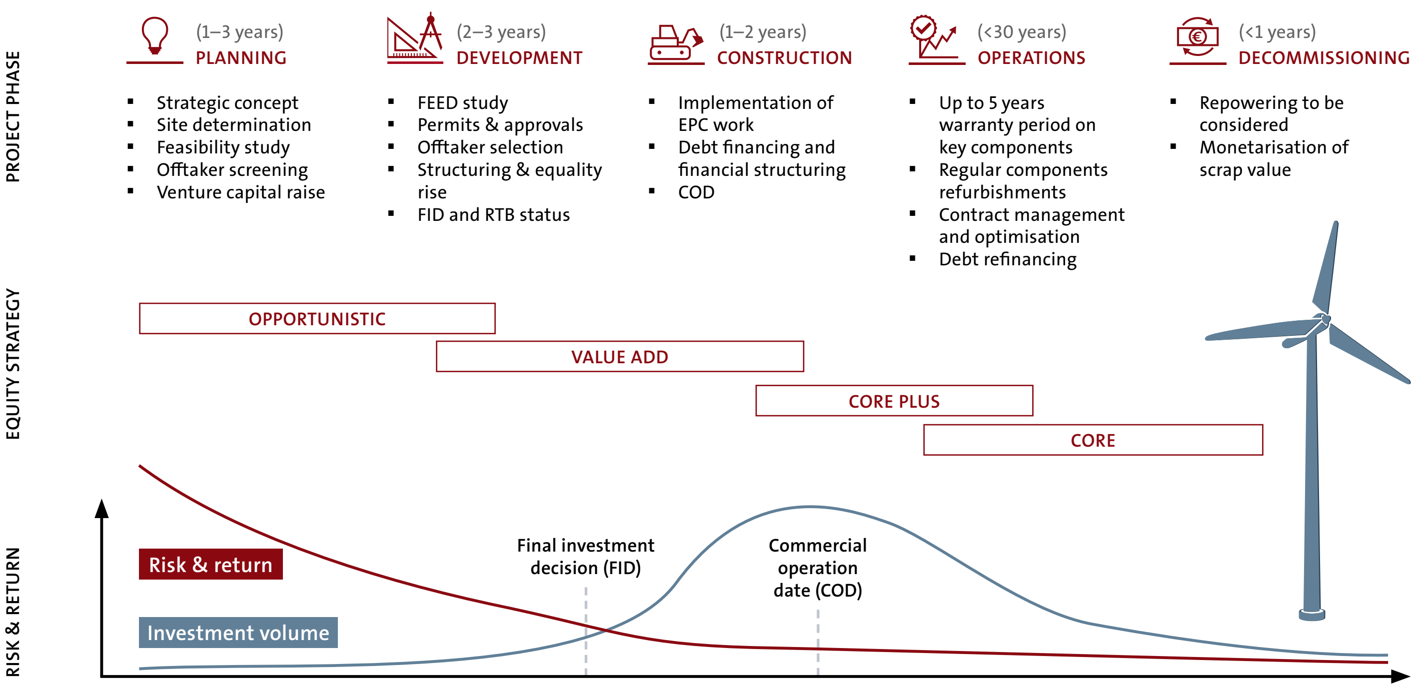
Infrastructure equity and debt

Infrastructure equity and debt investments, just like real asset investments in general, solely rely on the cash profile of a single project, housed in a special purpose company (SPC), and generally have no recourse to the parent company or project developer. The cash flows of the project company are generally contracted on a long-term basis and usually have limited exposure to financial market risk. In a young and emerging market, like that of green hydrogen, investment opportunities will first be available in equity financing, and will be followed by an increasing number of project finance and infrastructure debt finance once the market in general has matured, and projects enter the ready-to-build status. Since debt investments in the green hydrogen market are not expected to be available in the next two to three years, they will not be in focus here. Infrastructure equity strategies differ according to their risk appetite and return expectations, generally target different infrastructure assets in different development phases and may be applied to the green hydrogen market:

> **Illiquid investments will be vital for financing the transition to a low carbon econonomy**

- **Core:** These are long-term (>10 years) investments into already operating (secondary market) project companies receiving stable, long-term cash flows that are often highly regulated and contractually secured with a highly creditworthy offtaker. The asset usually has a monopolistic position and is located in a developed, stable market. Project risks are low and so are capital gain and return expectations (<8%) in current market conditions. Given the early nature of the green hydrogen market, there are currently no Core investment opportunities available.
- **Core Plus:** Core Plus investments are similar to core investments, but the project company's cash flows are subject to a certain degree of variability, such as demand fluctuations, but also offer some optimisation potential. They usually take place during the construction phase or shortly after commissioning (brownfield) of the infrastructure project, and holding periods generally range from 6–10 years or longer. The risk and return expectations are low to moderate (8–10%, based on current market conditions). Considering the number of green hydrogen project announcements, a relevant number of Core Plus investment opportunities are expected to become available in the next 2–5 years.
- **Value Add:** Value Add investments pursue a mid-to-high risk strategy and generally target assets in the development or early construction phase (greenfield) that still require significant development, optimisation and de-risking efforts ("value add"). Return expectations are primarily based on capital appreciation rather than ongoing cash flows and range between 10–15% in current market conditions. Holding periods are generally 5–7 years. In the green hydrogen market, an increasing number of Value Add investments opportunities have become available in recent months.
- **Opportunistic:** Opportunistic investments are characterised by a high risk–return profile and target projects in the planning and early development phase. Such projects still require fundamental planning and development efforts and usually have not yet secured full permitting and offtake agreements. The high return expectations of Opportunistic investments (>15%) rely almost entirely on capital growth during a relatively short holding period of generally 3–5 years. There are a number of Opportunistic investments in the green hydrogen market, with some overlap with private equity or even venture capital, given the nascent nature of the market.

FIGURE 27: PHASES OF A GREEN HYDROGEN PROJECT AND THE RELATED INFRASTRUCTURE EQUITY STRATEGY



Source: KGAL

TABLE 6: CHARACTERISTICS OF INFRASTRUCTURE EQUITY INVESTMENT STRATEGIES IN THE GREEN HYDROGEN MARKET

INFRA EQUITY STRATEGIES	OPPORTUNISTIC	VALUE ADD	CORE PLUS	CORE
Investment timing	Planning phase, early development phase	Development phase	Construction phase, early operations phase	Operations phase
Tenure in years	3–5	5–7	6–10	>10
Investment volume (in Mio. €), bankability	Low–Medium (3–20), often all equity	High (>10), bankability possible	High (>50), bankability likely	High (>50), bankability likely
Risk exposure	High–Very high	Medium–High	Medium	Medium–Low
IRR expectations	>15 %	10–15%	8–10%	<8 %
Cash flow profile	Terminal value	Mainly terminal value	Mainly cash yield	Cash yield
Sustainability impact	Medium–High	Very high	Low–Medium	Low–Medium
Availability of green hydrogen assets	Available	Available	Expected to be available in 2–5 years	Currently not yet available

Source: KGAL

With a need to diversify their risk exposure and to attain attractive returns in a low-interest market environment, institutional investors have increased their allocation to infrastructure investments in the last decade. Infrastructure investment risks are generally less dependent on financial market volatility and hence offer an obvious hedge and require individual, project-specific mitigation approaches to optimise returns.

5.2 RISK–RETURN PROFILE

Depending on the type of equity investment strategy, the occurrence and relevance of a risk – and hence the need to undertake mitigation measures – may vary significantly, thereby justifying the relatively broad range of return expectations. In general, green hydrogen projects share the same types of risks with infrastructure projects.

Approaches to mitigating and optimising project returns

While the investment strategy and risk appetite of each investor may be different, there are some general approaches to mitigating risks in a dynamic and growing market, like that of green hydrogen, in addition to usual due-diligence processes.

- **Value chain investing:** In order to avoid a cluster of technologic, regulatory and price risks, green hydrogen production projects (upstream) may be combined with the processing of hydrogen derivatives (see Chapter 2) as well as with mid-stream (logistics and storage) and down-stream assets (such as hydrogen fuelling stations).
- **Partnership strategy:** With the aim of addressing development, technology and offtake risks, it is often beneficial for a financial investor to enter partnerships and invest alongside one or more strategic investors (such as utilities, offtakers, OEM providers and developers), thereby ensuring an alignment of interest among all key project partners involved, and justifying the contractual disadvantages implied by a minority stake in a project company.
- **Geography and diversification:** A very important driver of green hydrogen costs is green electricity. An investment strategy may be diversified across local, national, international and potentially intercontinental investments. Euro-denominated assets in stable jurisdictions are generally preferred by European investors and benefit from lower transport costs due to their geographic proximity to large offtake markets. For diversification purposes, such European assets may be complemented by investments in countries with more favourable meteorologic conditions and lower electricity prices (such as Chile and Australia), but higher transport costs.
- **Offtaker selection:** A diligent selection of the offtaker and the design of the offtake agreement are essential, since a change in the offtaker may involve high costs. The offtaker should be characterised by a high creditworthiness and a high incentive to decarbonise its value chain. The transport sector and a number of other industries are under increasing regulatory and public pressure to reduce their carbon footprint. As for the terms of the offtake agreement, a linkage between the electricity procurement price and the hydrogen (or hydrogen

TABLE 7: OVERVIEW OF TYPICAL RISKS IN GREEN HYDROGEN PROJECTS

RISK TYPE	RISK DESCRIPTION	GREEN HYDROGEN SPECIFICS	MITIGATION APPROACHES
Regulatory & political risk	▪ **Subsidies:** Ramp-up subsidies/contracted offtakes generally need to be secured over prolongated periods – retroactive changes may seriously erode returns ▪ **Legal stability:** Legal stability is crucial to maintaining project rights, permits, etc.	▪ **Subsidies:** The majority of early green hydrogen projects will require subsidies like IPCEI or CCfDs ▪ **Legal stability:** Generally high project complexity and need for stable legislation	▪ **Subsidies:** Focus on reliable jurisdictions and upfront subsidies if possible ▪ **Legal stability:** Diversification across countries; focus on stable jurisdictions
Macroeconomic risks	▪ **Inflation:** Changes in inflation may have a detrimental impact on operating cash flow ▪ **Interest:** Varying interest may affect (re-)financing conditions and divestment value due to changing refinancing costs/discount rates of follow-on investor ▪ **FX:** Cash flows denominated in FX may experience volatility in case of FX fluctuations	▪ **Inflation:** Particularly relevant for electricity procurement and electrolyser costs ▪ **Interest:** No specificities ▪ **FX:** Particularly relevant for potential H_2 exporters like Australia, Chile, North Africa and the Middle East	▪ **Inflation:** Execution of long-term, inflation-adjusted procurement, service and offtake agreements ▪ **Interest:** Execution of long-term financing agreements with fixed interest rates; diligent timing of divestments to achieve optimal divestment terms ▪ **FX:** Limit exposure to FX; focus on hard currencies; diversification across different currencies
Offtake risks	▪ **Price risk:** Declining and lower-than-expected offtake prices may jeopardise cash flow forecasts ▪ **Counterparty risk:** Insolvency of, or legal disputes by, a counterparty may lead to legal costs and/or revenues losses	▪ **Price risk:** Linkage with electricity procurement costs is key; high price volatility of competing fossil fuel prices; LCOH ist expected to decline in upcoming years ▪ **Counterparty risk:** Particularly relevant as a change in offtaker is often difficult due to high H_2 transport costs and tailor-made products (liquefaction and compression, H_2 derivatives)	▪ **Price risk:** Execution of long-term hydrogen purchase agreements (HPAs) with fixed offtake prices; Focus on CapEx-subsidised assets or assets supported by CCfDs to bridge price gap; ▪ **Counterparty risk:** Focus on offtakers with a sufficiently high rating and/or parent/government guarantees; diversification of offtakers across the portfolio
Technology risks	▪ **Key components:** Failure and wear & tear of key components may lead to substantial production losses and replacement costs ▪ **Operations:** Production or transport losses, additional costs for repairs, etc. due to poor component or engineering quality, etc.	▪ **Key components:** Electrolyser stacks efficiency decreases over time; replacements are expected to be required after 8-15 years ▪ **Operations:** Electrolysis and BoP efficiency is critical; additional losses expected in case of processing into H_2 derivatives	▪ **Key components:** Procurement from reputable OEMs; long-term warranty and service agreements; cost provisions for component replacements ▪ **Operations:** Risk transfer to component manufactures and service (O&M) providers; diligent risk management to minimise operational losses
Development & construction risks	▪ **Development:** Key risks include permitting and construction delays, change in financing terms, negotiations for offtake, procurement and services, etc. ▪ **Construction:** Delays due to delivery problems, shortage of qualified staff	▪ **Development:** Young nature of H_2 market may lead to increased development risks and delays ▪ **Construction:** No specificities	▪ **Development:** Focus on stable regulatory environment ▪ **Construction:** Co-operation with reliable and creditworthy market partners (developers, OEMs, offtakers, etc.)
HSE risks	▪ **Health & safety:** Risks include toxic emissions due to leakages, fire, explosion, accidents ▪ **Environmental:** Risks include emissions, leakage of toxic substances, conflicts with nature and biodiversity protection efforts, etc. during construction and operations	▪ **Health & safety:** Some H_2 derivatives, in particular ammonia, have higher safety requirements ▪ **Environmental:** No specificities	▪ **Health & safety:** Assessment as part of legal and technical due diligence; insurance coverage ▪ **Environmental:** Upfront due diligence and exclusion of/refraining from controversial projects; diligent ongoing monitoring

Source: KGAL

derivative) offtake price will be crucial to ensuring the long-term financial stability and bankability of a project.

- **Sector selection:** The competitiveness of green hydrogen and its derivatives may vary for different offtakers and sectors.

From an investor perspective, it may be beneficial to diversify their green hydrogen portfolio across different sectors, with a focus on markets with the highest price competitiveness.

5.3 CLIENT NEEDS AND OUTLOOK

Beyond the aim of achieving an attractive, risk-adjusted return, a number of other factors play an increasingly important role for the investment decision-making process of financial investors. These include, in particular, asset allocation restrictions under Solvency II as well as impact and sustainability considerations. For infrastructure equity investors, some explanation.

Solvency II

Insurance companies subject to Solvency II may purchase shares in illiquid infrastructure equity investments in accordance with their internal investment guidelines.

When calculating the solvency capital requirement – taking into account the look-through approach – the equity risk submodule (qualified infrastructure equity or equity type 1) is expected to be applicable. Where fixed-interest shareholder loans are being granted, the interest rate risk and the spread risk submodules are expected to be applicable with regard to such loans; as the case may be, the currency risk submodule may have to be applied additionally.

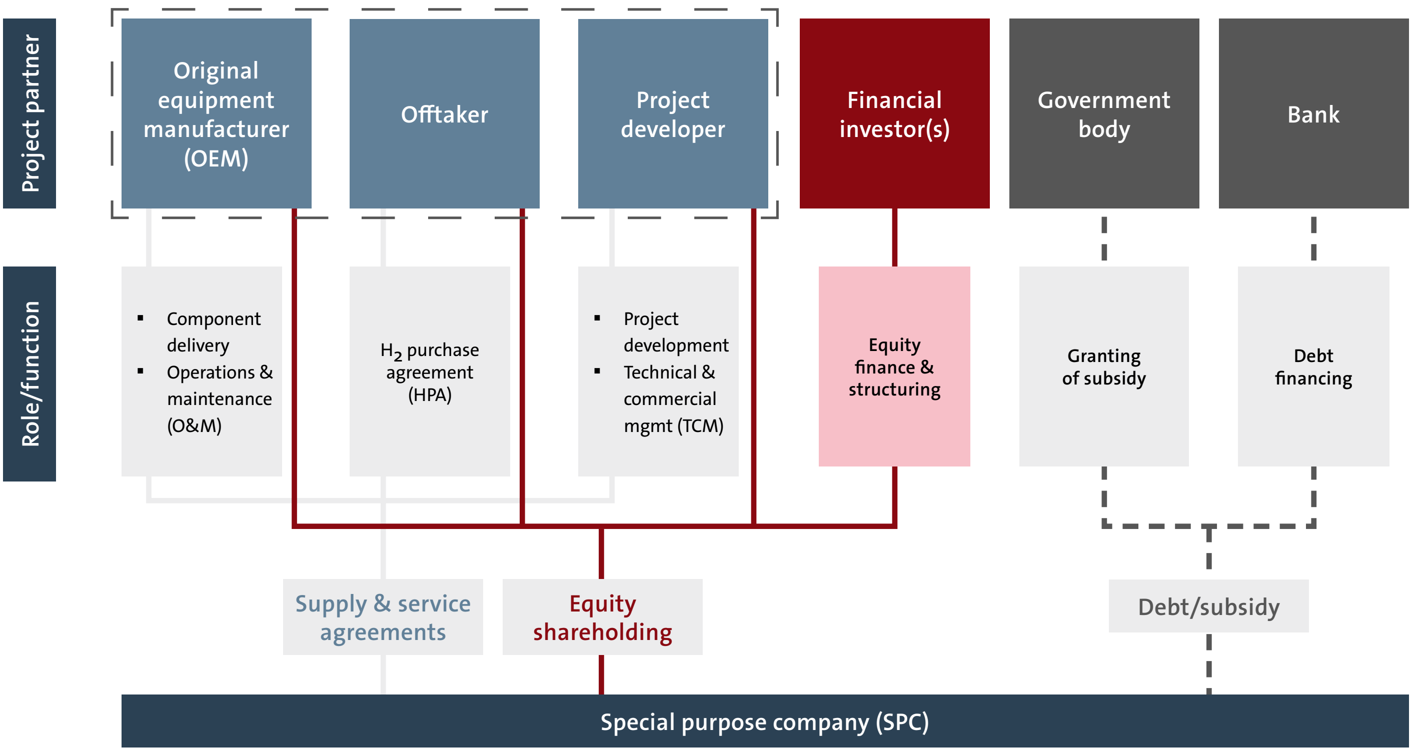
SFDR and impact reporting

Investors have started integrating sustainability criteria into their investment strategies, not only for ethical or reputational considerations, but also for financial reasons. Assets or companies that will no longer comply with tightening environmental regulation, or that will become uneconomical under these conditions, such as fossil-fuel-related infrastructure, may face a loss of value or stranded asset risk in the medium to long term. This has motivated an increasing number of financial investors to start decarbonising their portfolios and to integrate sustainability aspects into their investment decisions.

However, disclosure and measurability of sustainability criteria has however been a challenge so far. A set of new EU legislation, in particular the EU Taxonomy and the EU Sustainable Finance Disclosure Regulation (SFDR), aims to address this problem.

- **EU Taxonomy:** With the aim of channelling capital flows towards sustainable activities, the EU has implemented a classification system – the so-called Taxonomy – of economic activities and a set of technical criteria for defining such activities as environmentally sustainable.

FIGURE 28: INTEGRATION OF A FINANCIAL INVESTOR INTO A PARTNERSHIP STRATEGY



Source: KGAL

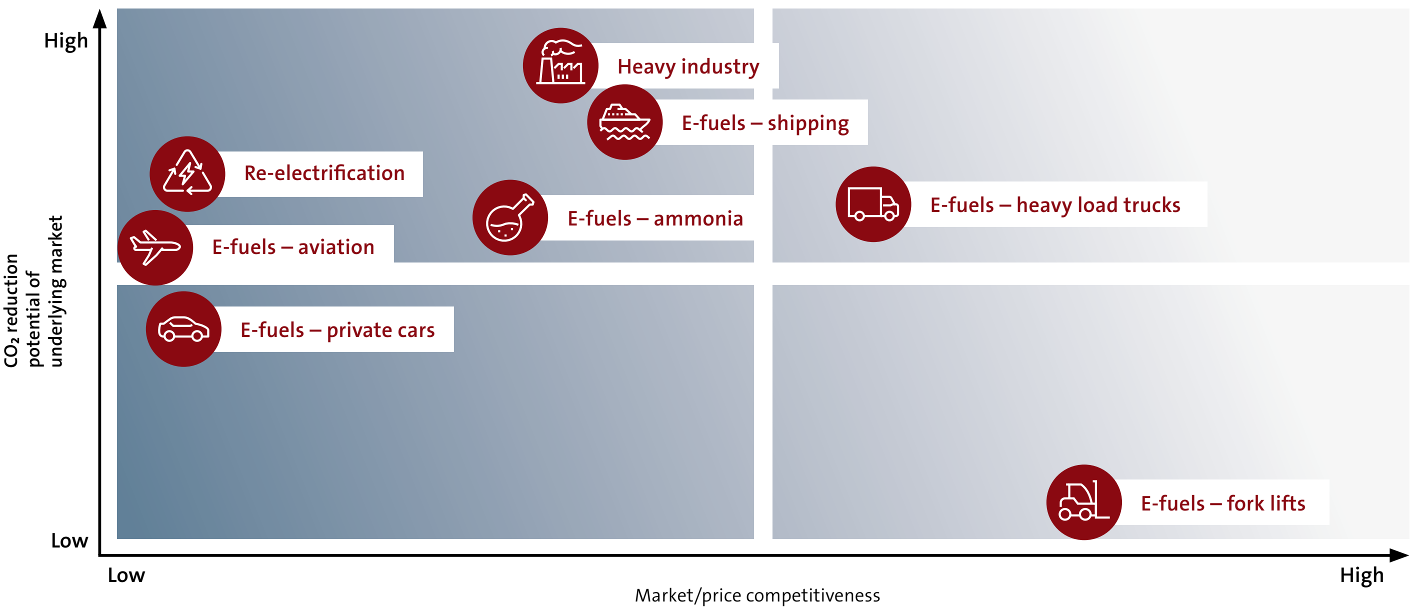
- **SFDR:** The SFDR is a set of regulations on specifying the disclosures that asset managers must make regarding the sustainability factors and risks associated with their investments, thereby allowing investors to evaluate and incorporate sustainability aspects into their investment decisions. Activities defined as environmentally sustainable under the EU Taxonomy also qualify as sustainable under the SFDR.

Economic activities defined under the EU Taxonomy also include the production of hydrogen, which may qualify as sustainable if the resulting life-cycle GHG emissions are lower than 3 tCO_2e/tH_2. While certain blue hydrogen pathways (see Chapter 2) may comply with this threshold, the definition clearly includes and favours green hydrogen.

Additionally, green hydrogen as an asset class may be particularly relevant for institutional investors who have already invested into renewable electricity generation assets like solar PV and wind, and hence already have a certain exposure to electricity prices. Since green hydrogen projects procure and consume renewable electricity, they present an ideal hedge for an existing renewables portfolio. Depending on the business model (see Chapter 3), a green hydrogen project procures electricity by way of a PPA or on the spot market, thereby benefitting from the expected long-term decline in renewable electricity prices – a trend that will likely put pressure on operators of renewable electricity plants. Investors who have invested in renewable electricity generation assets may consider SFDR-compliant green hydrogen investments as a suitable addition and diversification opportunity for both financial and sustainability reasons.

The time for private investors to enter the green hydrogen market appears to be just right. In light of the Ukraine crisis, rising natural gas prices and the imminent risks of climate change, the EU and its member states consider green hydrogen to be crucial, and are considerably accelerating their efforts to promote this emerging market by way of new legislation and support schemes. There is a consensus that this fundamental transformation of the European energy system will require capital flows from private investors. The increasing number of project announcements hints that this market will offer attractive investment opportunities in the upcoming years, in particular for investors convinced that sustainability is no longer an option, but a financial necessity.

FIGURE 29: INDUSTRY SELECTION BASED ON CO_2 REDUCTION POTENTIAL AND MARKET COMPETITIVENESS



Source: KGAL

ABBREVIATIONS IN ALPHABETICAL ORDER

[AEL]	Alkaline electrolyte electrolysers
[ASTM]	American Society for Testing and Materials
[ASU]	Air separation unit
[ATR]	Autothermal reforming
[BoP]	Balance of plant
[CCfD]	Carbon Contracts for Difference
[CCUS]	Carbon capture use and storage
[COD]	Commercial operation date
[CRI]	Carbon Recycling International
[DAC]	Direct air capture
[DD]	Due Diligence
[EPC]	Engineering, Procurement and Construction
[ETS]	Emissions trading system
[EU]	European Union
[FID]	Final investment decision
[FOM]	Fixed operations and maintenance
[FT]	Fischer-Tropsch
[FX]	Foreign exchange
[GHG]	Greenhouse gas
[GW]	Gigawatt
[H2]	Hydrogen
[HHV]	Higher heating value
[HPA]	Hydrogen (H2) purchase agreement
[HSE]	Health, safety and environmental
[IEA]	International Energy Agency
[IP]	Intellectual property
[IPCEI]	Important Projects of Common European Interest
[IPO]	Initial public offering
[LCOE]	Levelised cost of electricity
[LCOH]	Levelised cost of hydrogen
[LOHC]	Liquid organic hydrogen carrier
[MENA]	Middle East and North Africa
[MeOH]	Methanol
[MtG]	Methanol-to-gasoline
[MtJ]	Methanol-to-jet fuel
[NH3]	Ammonia
[NPV]	Net present value
[O&M]	Operations & Maintenance
[OEM]	Original equipment manufacturer
[PEM]	Polymer electrolyte membrane
[PPA]	power purchase agreement
[PSA]	Pressure-swing adsorption
[PtA]	Power-to-ammonia
[PtM]	Power-to-methanol
[PtX]	Power-to-X
[PV]	Photovoltaic
[RFNBO]	Renewable fuels of non-biological origin
[RO]	Reverse osmosis
[RTB]	Ready to Build
[RWGS]	Reverse water gas shift
[SFDR]	Sustainable Finance Disclosure Regulation
[SMR]	Steam Methane Reforming
[SOE]	Solid oxide electrolysis
[SPC]	Special purpose company
[TRL]	Technology readiness levels
[VOM]	Variable operations and maintenance

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ABOUT KGAL'S RENEWABLES EXPERTISE

KGAL Investment Management GmbH & Co. KG is a leading European renewables asset manager. It has a comparatively large team, a long heritage and a focus on solving the problems faced by modern asset owners. Since its pioneering first investment in 2003, the business has acquired, developed or constructed around 150 renewable assets across eleven developed and developing European countries – representing an infrastructure investment of over €3 billion.

By entering the green hydrogen market, KGAL follows an early adopter strategy. KGAL's energy transition team has extensive experience in the energy sector and is is embedded in the KGAL's 60-strong Sustainable Infrastructure department.

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