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Equity Research
4 May 2020

Global Energy

Hydrogen – a climate megatrend

Hydrogen has the potential to transform hard-to-decarbonise parts of the economy and support electrification, helping save up to 15% of annual CO2 emissions by 2050E. We see a market growing 8x over the next 30 years.

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Please see analyst certifications and important disclosures beginning on page 62.

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Hydrogen – a climate megatrend

As the world recovers from the COVID-19 pandemic, we expect the issue of sustainability to come back into sharp focus with energy once again at the heart of this. Data and analysis from the IEA provides a tentative estimate that global CO_2 emissions will fall almost 8% in 2020 – the largest ever yearly fall. Yet in order to limit warming to less than 1.5 degrees above pre-industrial levels, global emissions need to fall close to this amount every year this decade. Big changes are clearly needed to move the world to a lower-carbon pathway without a sharp step-down in GDP, and hydrogen is rapidly emerging as a viable option to help decarbonise the hard-to-electrify parts of the economy and even help in the deployment of renewable power by acting as a form of energy storage. If the technology is deployed at scale, we estimate by 2050 potential annual savings in CO_2 emissions of 5Gt per year (or 15% of current emissions), a market size in excess of $1tn per year and cumulative capex just for equipment of c$500bn over the next 30 years. The ability to produce hydrogen from clean sources already exists and the development of a hydrogen economy is seeing unprecedented momentum, but like wind, solar and electric vehicles before it, early policy support is needed for hydrogen to be cost-competitive with fossil alternatives. This report provides a deep dive into how we see the deployment of hydrogen as an energy carrier evolving, and identifies key market players. We see energy services (including Wood, Technip FMC, Maire Tecnimont), electrolyser manufacturing (Nel Hydrogen, ITM Power, Ceres Power) and mining (Anglo American) as the areas most exposed to the theme in the near term, with Shell, BP, Total, Chevron, Eni, Equinor and Repsol amongst the larger energy companies looking to deploy the technology at scale.

An unsustainable path needs all solutions: The world is not yet on a pathway that is consistent with temperatures remaining at less than 2°C above pre-industrial levels, and rapid change is needed across government, companies, investors and consumers. In this context, hydrogen is emerging as a viable solution. Our analysis suggests that widespread deployment of blue or green hydrogen could avoid c5Gt per year of CO_2 emissions (15% of current emissions) by 2050, with >80Gt cumulatively saved in the next 30 years.

Hydrogen symbiotic with electrification: We see hydrogen as having two roles to play: first, as a form of energy storage in preference to batteries as electrification and renewable energy grow as part of the energy system; and second, as a fuel source in areas that are harder and more expensive to decarbonise, such as trucking, heating, steel and several other industrial uses. Within this report, we provide three scenarios (Development, Dynamism and Deadlock), which show a range of demand levels from 240mtpa up to 800mtpa. Our base case (Development) sees the hydrogen market growing to c575mtpa by 2050, an 8-fold increase. In turn, this implies an annual market of >$1tn at c$2/kg.

Scale, infrastructure and regulatory change all needed to help viability: For hydrogen to be competitive with alternatives, costs widely need to fall by at least 50%. This is likely to come with scale, but a clear regulatory framework and policy support, such as carbon pricing, are needed initially to help develop the infrastructure necessary for widespread deployment. We also provide analysis of what this means for the steel and platinum markets.

We identify a range of sectors and companies exposed to this fast-growing theme: In energy, large industrial hubs are a key opportunity for Shell, BP, Total, Equinor, Galp, Eni, Repsol and Neste. In energy services, TechnipFMC, Maire Tecnimont and Wood are key players. In metals and mining, platinum producer Anglo seems likely to benefit, as could steel producer ArcelorMittal. In chemicals Johnson Matthey, Air Liquide and Linde are leaders. In capital goods Siemens Energy is a key electrolysis supplier. There are also a number of small specialised electrolyser and hydrogen producers, including Nel Hydrogen, ITM Power and Ceres Power that look set to play a role.

Our report in five minutes…

Hydrogen economy to scale up

Energy a key source of GHG emissions – Close to 70% of GHG emissions are generated from the traditional fossil fuels of coal, oil and natural gas, and to meet a 2°C world a pathway to falling emissions is needed within the next decade.

Hydrogen offers significant CO_2 reduction potential – When burnt, hydrogen emits no CO_2, only water vapour. As such, it has significant potential to help decarbonise sectors that are hard to electrify, such as trucking and heating. Hydrogen can also act as a form of energy storage to help support the deployment of renewables as an alternative to batteries.

Green and blue – hydrogen production needs to be clean – Hydrogen is not an energy source in itself, but rather an energy carrier. As such, it has to be produced from primary energy sources and how this is done is key to whether it offers true decarbonisation. Blue hydrogen is hydrogen produced with natural gas with the associated CO_2 captured. Green hydrogen is hydrogen generated from renewable sources, mainly through electrolysis.

Both will be needed – We assess the economics of both blue hydrogen and green hydrogen within this report. Currently hydrogen produced using natural gas, even with carbon capture and storage, is lower-cost than green hydrogen. We estimate that the cost per kg of blue hydrogen is c$2-3 currently compared with $3.5-4.5/kg for green hydrogen. Reflecting this, we see blue hydrogen as the initial provider of significant volumes, with green hydrogen taking market share from 2030 onwards.

Potential for $1tn market by 2050 – Given the wide range of potential applications and the focus on moving towards net zero emissions for a number of countries, our base case is that hydrogen demand reaches 575mn tonnes per year (mtpa), a near 8-fold increase from current levels. At a price of c$2/kg H_2, this implies a market value of >$1tn. Within this report, we provide three scenarios (development, dynamism and deadlock), which show a range of demand levels from 240mtpa up to 800mtpa.

Significant investment needed – To transform the energy system to take out carbon emissions either through electrification or through the use of hydrogen is going to take significant investment. In our base case, we estimate that the capital costs just for production equipment over the next 30 years could amount to c$500bn. We estimate additional material spend needed on infrastructure, including distribution networks, could see this figure at least double.

Costs need to fall materially – Key to the deployment of hydrogen will be the scale-up of production. At present, we estimate global electrolyser capacity (needed for green hydrogen production) at just 3GW. Our base case calls for electrolyser capacity of 900GW. Yet to achieve this and for hydrogen to be competitive, we see costs needing to fall by nearly 75% for green hydrogen and 30% for blue hydrogen (or more without allowing for the cost of carbon).

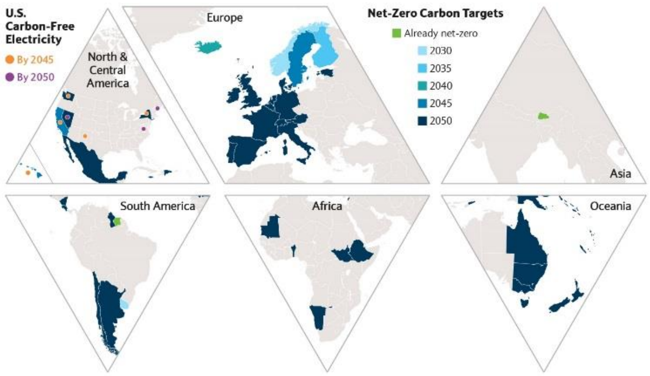
Policy support needed in early stages – Given the greater cost of hydrogen than alternatives at present, we expect government policy to move to support the development of infrastructure. We believe the simplest and most effective route to make clean hydrogen viable is for a price of carbon to be applied, or at least an offset for abatement at a level that incentivises production.

Multiple industries exposed to the hydrogen economy – We identify a range of sectors and companies exposed to this fast-growing theme. Near term the equipment manufacturers will be key, although longer term we see exposure broadening to include infrastructure, industrial and mobility names. Below we show an indicative (but not exclusive) list:

- **Energy providers** – Equinor, Shell, GALP, Eni, OMV, BP, Repsol, Total, Chevron, Saudi Aramco, Neste
- **Equipment providers** – Air Products, Alfa Laval, Nel Hydrogen, Ceres Power, ITM Power, Technip, Maire, Wood, Saipem, Siemens
- **Catalyst and chemical providers:** Air Liquide, Anglo American, Linde, Johnson Matthey
- **Infrastructure:** National Grid, Snam, Enagas, Engie, EDF, Drax
- **Heating/industry:** 3M, Airbus, Alstom, ArcelorMittal, Lafarge, Thyssenkrup, Bosch
- **Mobility – trucks, buses, trains** – Nikola Motors, Hyundai, Traton Group (Scania), ABB, Alstom, CNH Industrial
- **Mobility – cars** – Toyota, Hyundai, Honda, VW Group (Audi), BMW, General Motors, Symbio, Great Wall

FIGURE 1

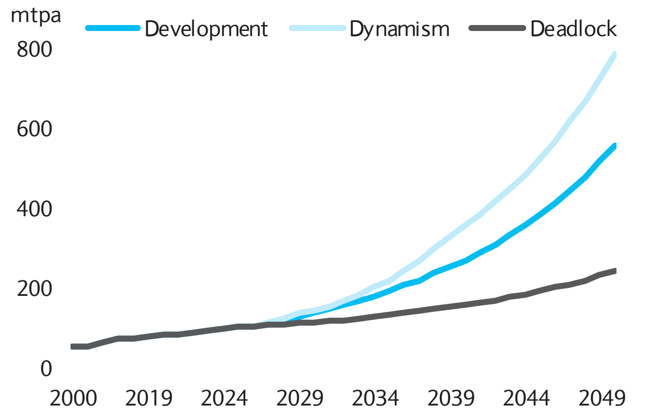
Net zero carbon targets



Source: Energy and Climate Intelligence Unit, Barclays Research

FIGURE 2

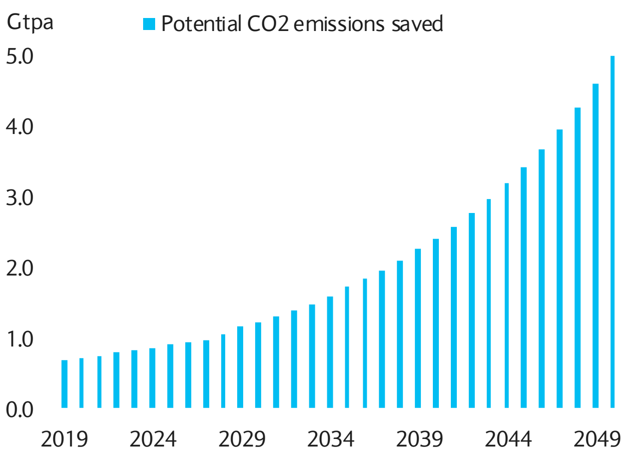
Hydrogen demand – scenarios



Source: IEA, Barclays Research estimates (from 2018)

FIGURE 3

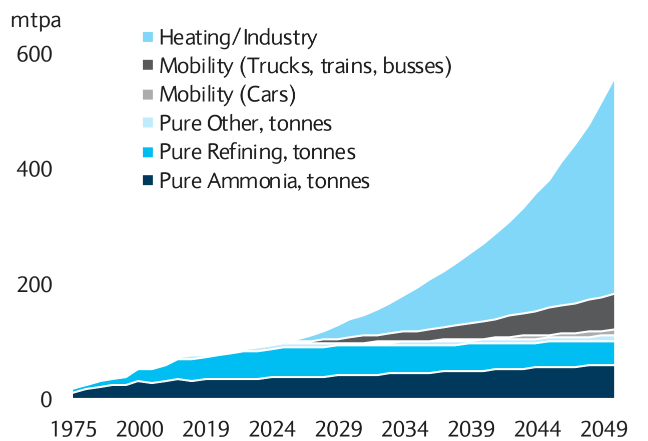
CO2 emissions saved – Development scenario



Source: Barclays Research estimates

FIGURE 4

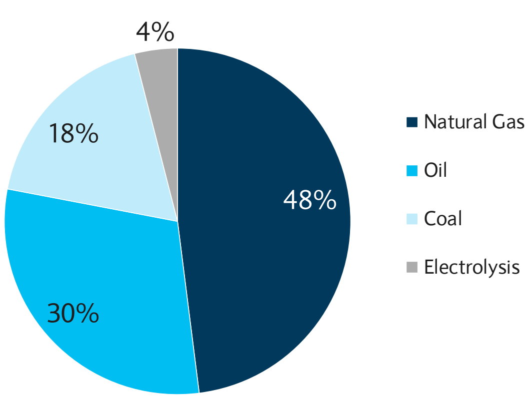
Hydrogen demand split by use – Development scenario



Source: IEA, Barclays Research estimates (from 2018)

FIGURE 5

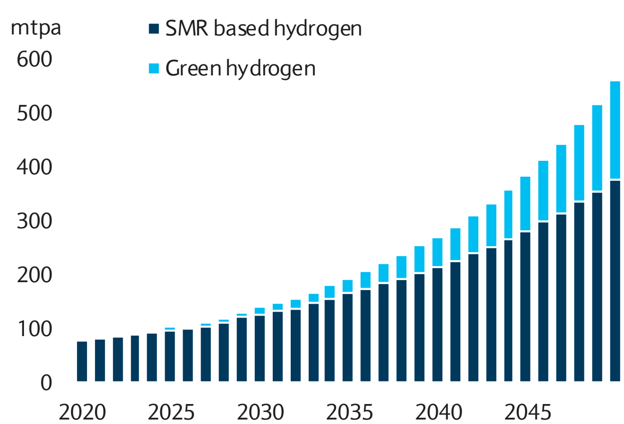
Current sources of hydrogen



Source: IEA

FIGURE 6

Future sources of hydrogen – Development scenario



Source: Barclays Research estimates

Significant hydrogen players

We identify below the key companies involved in the main stages of hydrogen development, based on our research and company membership of the Hydrogen Council. Many of the companies are likely to be involved in more than one segment of the market. In the table below, we assign each company to the area we see as most relevant to it.

Hydrogen			
Blue Hydrogen		Green Hydrogen	
Supply provider	Equipment provider	Supply provider	Equipment provider
BP	Air Liquide	BP	Air Liquide
Chevron	Air Products	EDF	AlfaLaval
Eni	Alfa Laval	Enagas	Anglo American
Equinor	Aker Solutions	Engie	ITM Power
Galp	Ceres Power	Eni	Johnson Matthey
OMV	Cummins	Equinor	Linde
Repsol	ITM Power	Galp	Maire Tecnimont
Saudi Aramco	Johnson Matthey	Iberdrola	McPhy
Shell	Linde	Neste	NEL Hydrogen
Sinopec	Maire Tecnimont	OMV	Plastic Omnium
Total	McDermott	Repsol	PowerCell
	Mitsubishi	Shell	Siemens
	NEL Hydrogen	Snam	Thyssenkrup
	Saipem	Total	
	Siemens		
	Technip FTI		
	Thyssenkrup		
	Wood		

Infrastructure	Industry	Mobility Trucks, Maritime, Rail	Mobility cars
Drax	3M	ABB	BMW
EDF	Airbus	Alstom	General Motors
Enagas	Alstom	CNH Industrial	Great Wall
Engie	ArcelorMittal	Cummins	Honda
National Grid	Bosch	Daimler-Volvo JV	Hyundai
Snam	Lafarge	Hyundai	Symbio
	Michelin	Nikola Motors	Toyota
	Thyssenkrupp	Traton Group	VW Group

Source: Barclays Research, Hydrogen Council

ESG: Sustainable & Thematic Investing

Decarbonisation is a key mega-trend within our 2030 Thematic Roadmap

Our 2030 Thematic Roadmap outlines 150 trends across 6 thematic paradigms that we believe will dominate our discussions with investors over the next decade – Figure 7. We selected 'Likelihood' and 'Impact' as our respective horizontal and vertical axes and thus the basis of our mapping. That is, the extent to which we believe these 150 thematic trends are likely to impact society by 2030, given some trends may be influenced by external factors such as regulation, infrastructure, consumer adoption and pricing.

2020s – The decade of decarbonisation…

Across our analysis of each thematic paradigm, there are several overarching areas of interest that we foresee becoming more meaningful to the debate through 2030 – *Sustainable & Thematic Investing – 2030 Thematic Roadmap: 150 Trends (12 February 2020).* The scaling of renewable deployment and long-term electrification will be key priorities for energy-intensive sectors, as reducing energy waste and decarbonising heating become focus areas for governments globally.

Our thematic roadmap makes the case for alternative energy (Renewable Energy and Biofuels) and additional infrastructure investment (Energy Storage, Hydrogen Fuel Cell, Carbon Capture & Storage and Waste Management). We expect the impact climate change is having on society to become more visible (Land Degradation, Natural Resource Scarcity and Climate Migration), leading to additional market opportunities (Battery Technologies and Electric Transportation) if backed by appropriate policy support (Carbon Pricing).

Commercialising hydrogen will extend far beyond our 2030 timeframe…

While our 2030 Thematic roadmap reflects the hydrogen story growing, the real period of scale will extend beyond our timeframe through to 2050 as heating and industry demand and mobility solutions ramp up. In addition to the need for a clear regulatory framework and further infrastructure investment, we believe investors also need to consider the broader implications that hydrogen as a market opportunity has for society.

ESG considerations

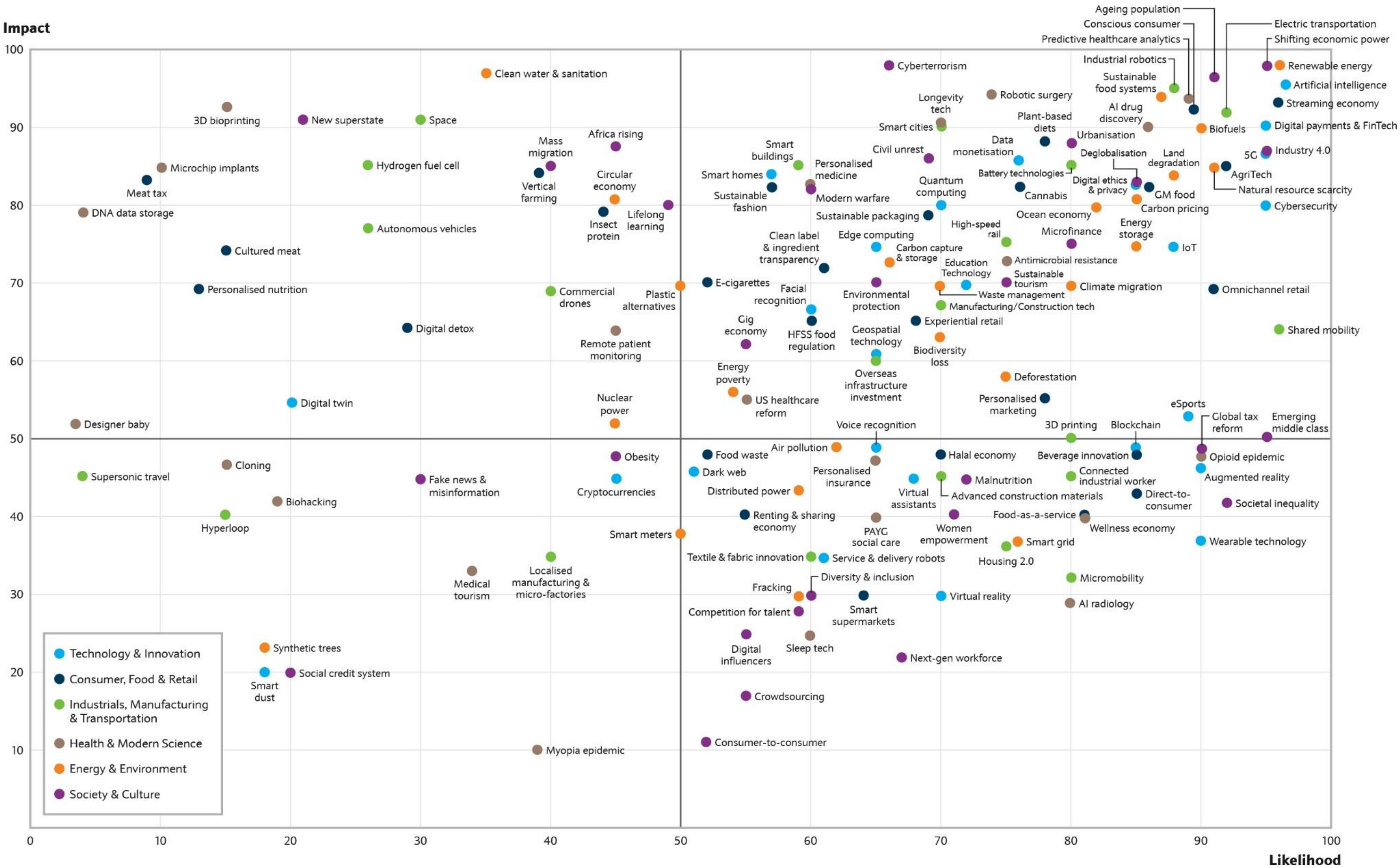
We put forward the following ESG considerations that we think are worthy of company engagement, when considering hydrogen as an enabler of long-term energy diversification.

- **Hydrogen safety:** Using mobility as an example, hydrogen is highly flammable and explosive relative to regular fuel and is harder to contain than oil. This means a car fitted with a hydrogen fuel cell is more at risk if exposed to extreme heat. In addition to flammable concentrations, ventilation and leak detection are important elements to consider in the design of safe hydrogen systems (*US – Department of Energy*). This is an important consideration as we move from local hydrogen production for local consumption, to long-haul transportation as demand for hydrogen importation grows.

- **Supply chain challenges:** Given the various methods of production, supply chain challenges are likely to include material sourcing, workforce health & safety, product end-of-life management, grid resiliency and emergency preparedness.

FIGURE 7

Sustainable & Thematic Investing – 2030 Thematic Roadmap



Source: Barclays Research – *Sustainable & Thematic Investing – 2030 Thematic Roadmap: 150 Trends (12 February 2020)*

Hydrogen – now or never

The need to provide sufficient affordable, reliable, low-carbon energy to a growing population is one of the world's most pressing challenges. As the sense of urgency surrounding greenhouse gas mitigation grows, interest from society, governments, industry and investors in scalable alternatives to fossil fuels has also grown. It is clear that to move the world onto a lower emissions pathway immediate action on all areas including carbon pricing, energy efficiency, greater use of renewables, and electrification will be needed, requiring not only stricter policy enforcement but also a change in consumer habits, with a significant reduction on the reliance on fossil fuels such as oil, coal and gas also a necessity. As part of this, hydrogen is increasingly emerging as a potential solution able to provide both energy storage and the ability to be burnt directly in areas that are hard to electrify, such as heating, long haul-transport and steel and cement production. Reflecting this, we see the expansion of hydrogen running in parallel with electrification, with unprecedented policy and industrial support. Companies and governments are already committing substantial resources to hydrogen and formulating long-term strategies to incorporate it into the energy network. Shell, BP, Total and Eni among others have all highlighted the importance of hydrogen for their net zero 2050 ambitions. Our own analysis suggests a market potentially growing c8x to 2050, saving up to 15% of current energy-related GHG emissions and worth more than $1tn a year, with a number of potential beneficiaries.

Hydrogen demand to grow rapidly – 2030-2050 the real scale-up period …

Hydrogen has a number of uses as an energy carrier. Currently it is widely used for industrial purposes across the steel, petrochemical and food sectors, and it is increasingly being used in mobility, particularly in long-haul trucking. Going forward it could also replace natural gas to heat residential and commercial buildings. It can also be used as a form of energy storage, supporting renewable electricity grids in preference to battery storage. Reflecting all these characteristics, we see the potential for a significant growth market.

Throughout our analysis we use a number of key assumptions that we set out below.

- Growing population: 9bn people worldwide by 2040 and 9.7bn by 2050, compared to 7.5bn today based on World Bank data.
- Increases in GDP per capita: Base-line growth of 1.7% per annum, ranging from 1.5% to 2.2% in our deadlock and dynamism scenarios, respectively, which our economists see as a reasonable range.
- GDP growth: The above combination implies total base-line GDP growth of 2.6% pa, ranging from 2.4% to 3.1% in our deadlock and dynamism scenarios, respectively.
- 1bn people without access to electricity in 2018 heading towards <200m by 2050, which is based on the trajectory set out by the IEA.

We expect these factors to be offset by increased energy efficiency through regulation, policy and technology. Energy demand has increased by an average of 1.7% per year in the past decade, or 65% of the average GDP growth of 2.6% per year over the same period – we expect this percentage to fall to 50% in our central scenario.

There is, however, no one guaranteed pathway as to how demand and supply for hydrogen will develop, given uncertainty over cost and policy developments, so we build on the framework from our report *Oil in 3D: Demand outlook to 2050* (7 May 2019). In that report, to reflect the vast array of possible outcomes for the energy mix, we use three key scenarios:

- Dynamism
- Development
- Deadlock

Dynamism is our best-case scenario for carbon emissions and is characterised by aggressive policies and technology uptake combined with rapid electrification. It reflects a concerted effort to limit global warming to below 2°C this century, with 1.5°C the ultimate goal, in line with pledges made by signatories of the Paris Climate Accords. From a hydrogen stand-point this assumes global support for the development of the infrastructure and a high degree of electrification (nearly 40% globally vs <20% today), with hydrogen used as a form of energy storage. In this scenario we assume hydrogen provides over 30% of overall heating demand, with that number 40% in Europe. In transport we assume hydrogen represents 30% of trucks and close to 10% of passenger cars.

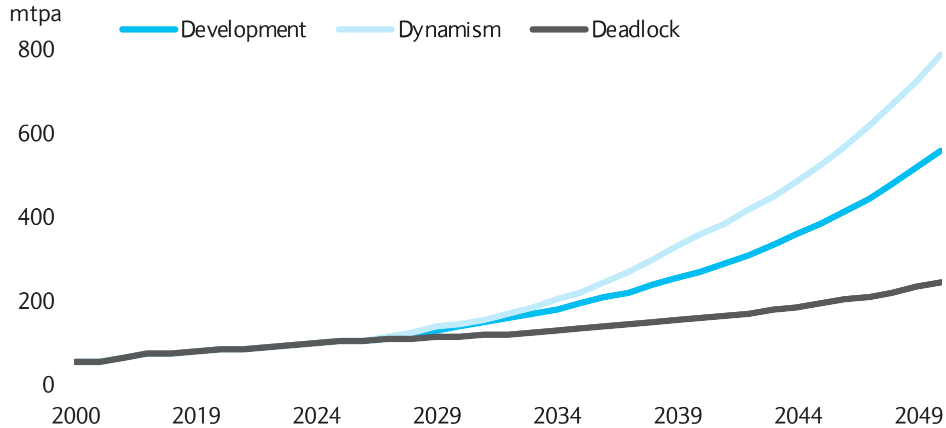
Development: This is our central or base-case scenario, and reflects continued tightening environmental policies. It foresees an increase in energy efficiency and progress towards a low-carbon economy but not enough to deliver the '2°C' pledge. From a hydrogen perspective, this involves a significant fall in costs and targeted policy support resulting in significant growth, but developed in conjunction with other technologies. As an example, battery electric vehicles remain dominant over fuel cell electric vehicles. In this scenario we assume hydrogen provides 20% of overall heating demand, with that number 40% in Europe. In transport we assume hydrogen represents 20% of trucks and just over 3% of passenger cars.

Deadlock is our worst-case scenario for emissions. The world still experiences modest economic growth, but is held back by trade wars, little technological adoption, and a lack of political will to prioritise low-carbon policies. In this scenario, we expect a reversal of current trends towards more sustainable economies in favour of near-term, low-cost transportation and industrial solutions. It also assumes a limited focus on low-carbon policies. Hydrogen demand still grows materially, but this is driven by individual industries looking to decarbonise without significant policy support. In this scenario we assume hydrogen provides just 5% of overall heating demand, with almost all of that from Europe. In transport we assume hydrogen represents 13% of trucks and just 1% of passenger cars.

Our scenario analysis is based on detailed conversations with a number of industry participants including the Hydrogen Council, Hydrogen Europe, electrolyser manufacturers, energy companies and academics. We have then applied these take-aways and our calculations of costs to our own modelling process and our view of what is reasonable in terms of systemic change. The chart below shows our hydrogen demand projections under the three scenarios. In all cases the industry grows in the coming five years but the real period of scale-up comes between 2030-2050, with both heating and industry demand and mobility solutions ramping up. We see the hydrogen market growing to between 240mtpa and 800mtpa by 2050, with our base case (Development) a near 8-fold increase.

FIGURE 8

Hydrogen demand – scenarios



Source: Barclays Research estimates

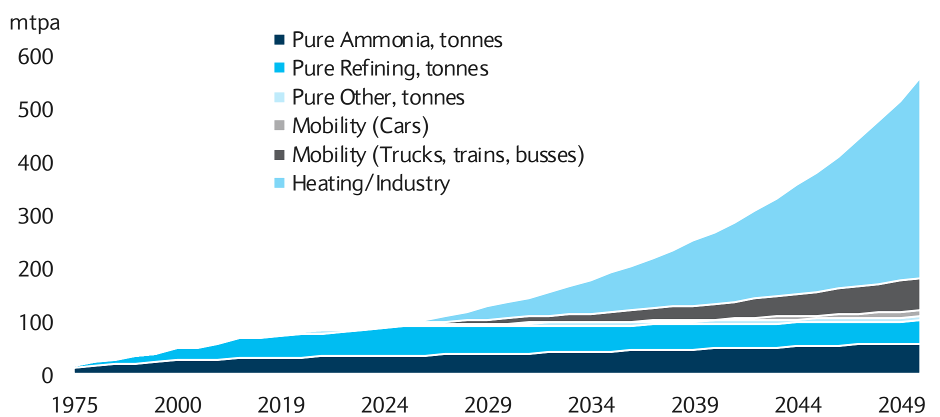
The sources of this growth are multiple and we show the main drivers of our base case in the chart below. Today, hydrogen is used in the refining industry for hydrocracking and desulphurisation. In the chemical industry, it is used for ammonia production and fertiliser for agriculture. It is also used for applications in metal production & fabrication, methanol production, food processing and electronics. Within this report we concentrate on the three main areas that we expect to drive hydrogen demand, namely:

- Heating & industrial use (including steel)
- Passenger car mobility
- Long-haul transport mobility (trucks, trains, busses)

We expect the main area of growth to be heating and industrial applications, followed by trucking. More and more passenger cars will become available and demand here does grow significantly in our base case, but, with battery electric vehicles still very much a competitive option, it forms a relatively small part of the growth we project.

FIGURE 9

Hydrogen demand growth by segment – Development scenario



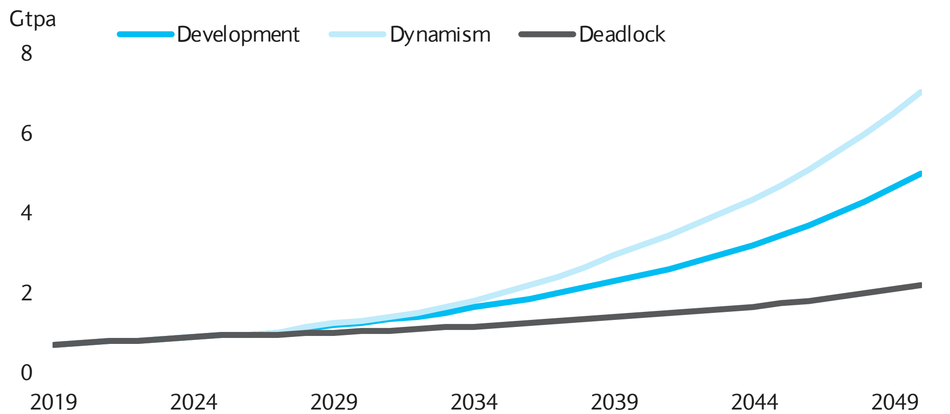
Source: IEA, Barclays Research estimates (from 2018)

… with a significant associated reduction in CO_2 emissions

As we outline later in the report, the production of hydrogen is not currently cost-competitive with fuel alternatives, and, without carbon pricing, it may be so only in a limited number of circumstances involving negative power prices. Yet the ultimate attraction of hydrogen is its ability to reduce emissions. The chart below shows the annual emissions that could be saved under our three scenarios, and we think that this potential will be enough to attract public policy support. The acceleration of electric vehicle growth and the deployment of renewable energy has benefited from governmental support across the world and we think these industries offer a template for the hydrogen economy.

FIGURE 10

Annual energy-related CO_2 emissions could be reduced by 15%

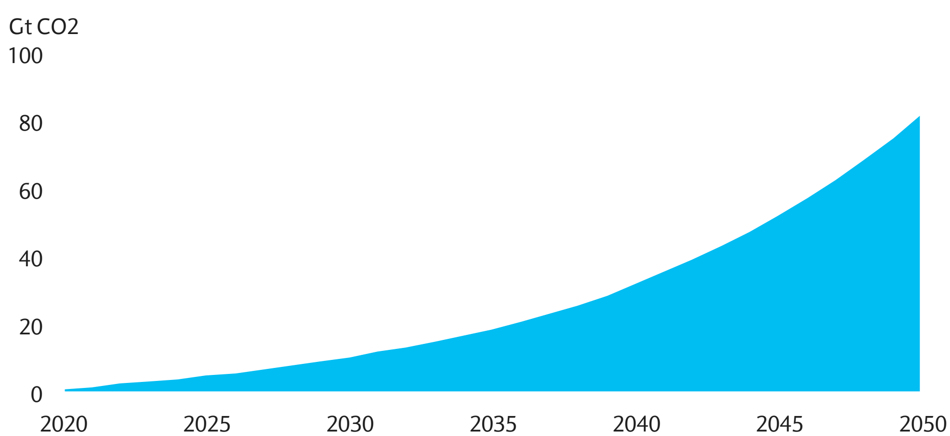


Source: Barclays Research estimates

That the amount of emissions saved in our development scenario is c15% of energy-related emissions highlights the scale of the challenge the world faces in moving to a lower-carbon pathway and emphasises the need for multiple solutions. Yet each individual solution can have a material impact, and the chart below shows the cumulative carbon emissions saved under our base case scenario.

FIGURE 11

More than 80Gt of cumulative emissions saved – Development scenario



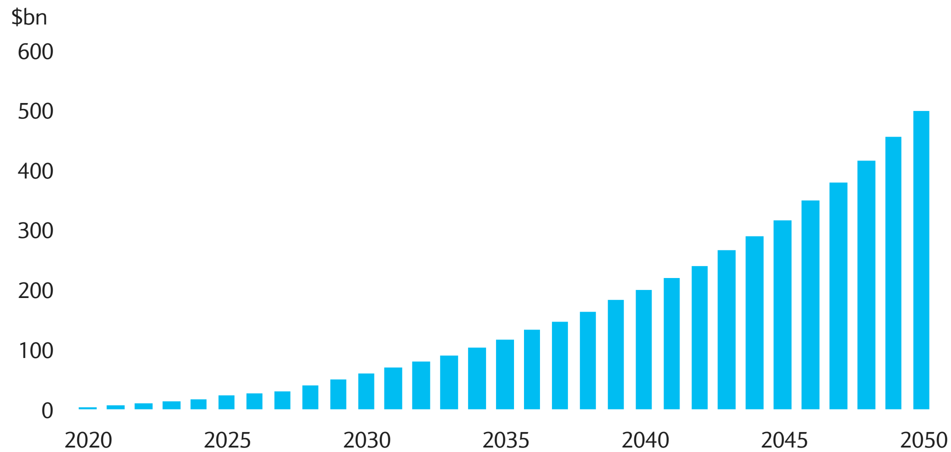
Source: Barclays Research estimates

A step-up in investment will be required

To facilitate the transition to a hydrogen-based economy is going to require significant investment, with deployment across manufacturing facilities, distribution networks and hydrogen sourcing. Our base case estimates suggest cumulative capex on equipment alone could be close to $0.5tn, with the cost of infrastructure deployment likely to see this figure at least double, creating a material opportunity for those companies transitioning away from traditional fossil fuels. The chart below shows the cumulative capex in this base case. Our calculation is based on the cost analysis which we present on page 25.

FIGURE 12

Cumulative capex on equipment could be close to $0.5tn – Development scenario



Source: Barclays Research estimates

Gas demand could rise 3-5%

It would be easy to assume that the growth in hydrogen will displace demand for fossil fuels, and we think this could be true for coal and parts of the oil chain. However, as we address below, natural gas is set to remain a key feedstock and, given the efficiency characteristics of hydrogen, could actually see increased demand (by 3-5%) relative to a 'no hydrogen' world, on our estimates.

Producing hydrogen – multi-coloured

Hydrogen is not an energy source in itself, but a secondary energy carrier. It also occurs naturally in a bonded form, rather than as a stand-alone form. As such, it has to be released, or 'produced' from its compounds by using energy. This section looks at methods of production and the current sources of energy used to release hydrogen, and how the costs of that compare and may change.

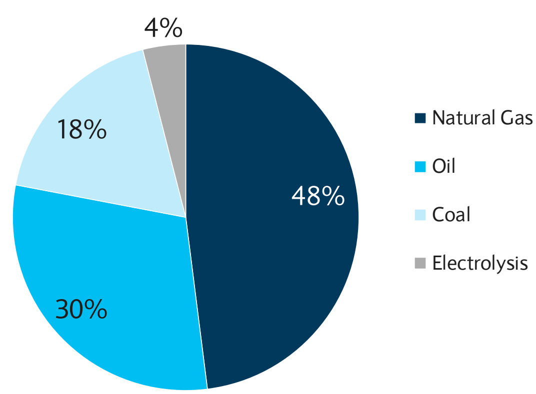
In terms of sources, industry convention has emerged that colours are typically used as shorthand to refer to the sources of energy that fuel production. These are widely known as:

- Green hydrogen - hydrogen generated from renewable sources, mainly through electrolysis.
- Brown hydrogen – used generically to refer to conventional production using fossil fuels by steam methane reforming, without reduced emissions via the use of carbon capture utilisation and storage (CCUS).
- Blue hydrogen – steam methane reforming with CO_2 emissions reduced by CCUS.
- Black hydrogen – coal-based hydrogen
- Grey hydrogen – natural gas-based hydrogen.

In general, there are no established colours for hydrogen from biomass, nuclear or different varieties of grid electricity, as the environmental impacts of each of these production routes can vary considerably by energy source, region and type of carbon capture and storage (CCUS) applied. The chart below shows the current primary sources of hydrogen production.

FIGURE 13

Primary energy sources of hydrogen production



Source: IEA

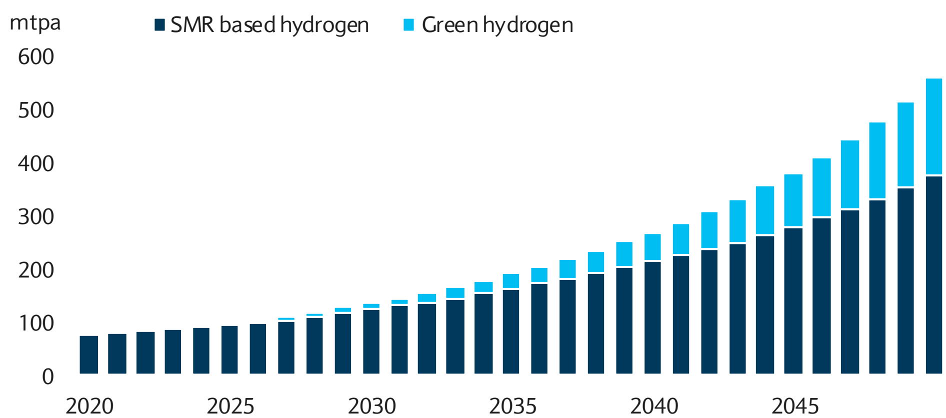
In terms of the current split of hydrogen production, only 4% is generated through electrolysis, with natural gas and steam methane reforming the main forms of production. Around 96% of hydrogen is currently produced from fossil fuels (48% from natural gas, 30% from oil and 18% from coal), leaving around 3-4% of hydrogen produced using renewables.

In terms of hydrogen production methods, these typically divide into thermochemical and electrochemical and include:

- Steam methane reforming (SMR)
- Partial oxidation (POX)
- Auto thermal reforming (ATR) (SMR and PO in sequence)
- Dry methane reforming (DMR)
- Tri-reforming of methane (TMR)
- H_2S cracking
- Electrolysis
- Biomass gasification
- Microwave technologies

Each of these methods has different implications for the source and costs of production and we outline this below. We see demand being met by a mix of SMR and electrolysers, and the chart below shows the split of production we assume in our Development scenario.

FIGURE 14
Hydrogen supply methods – Development scenario



Note: SMR based hydrogen assumes CCS through time Source: Barclays Research estimates

Steam methane reforming

Steam methane reforming is currently the most prevalent form of hydrogen production. Essentially natural gas, methanol and lighter hydrocarbons can be converted to H_2 by involving a reaction with steam. For example, the chemical reaction for methane (natural gas) is shown below:

$CH_4 + H_20 \rightarrow CO + 3H_2$

As the equation above shows, this generates carbon monoxide which then needs to be converted into CO_2.

$CO + H_20 \rightarrow C0_2 + H_2$

The temperature involved is relatively modest at 180°C for methanol and oxygenated hydrocarbons and more than 500°C for most conventional hydrocarbons. The catalysts used are typically nickel, platinum or rhodium, with nickel typically the most used, reflecting costs. The amount of CO2 produced depends on the feedstock hydrocarbon – eg coal will produce more CO2 than gas.

Partial oxidation and auto thermal reforming

Partial oxidation is a non-catalytic process in which raw material is gasified in the presence of oxygen. Temperatures are typically in the 1300-1500°C range.

$CH_4 + O_2 \rightarrow CO + 2H_2$

Of note is that more CO is produced in this process than with SMR. As such the two processes can be combined into auto thermal reforming. The stages here are as follows

$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$

$CH_4+H_2O \rightarrow CO + 3H_2$

In almost all cases desuphurisation is likely to be needed through hydrotreaters or hydrodesulphurisation units. CO_2 emissions are also a clear issue here and carbon capture and storage is going to be a factor in future production.

The table below shows the advantages and disadvantages of the different thermal methods outlined above, together with the key developers and licensors. We have not yet been able to finding reliable market share data, but we highlight Technip FMC, Air Liquide, Wood and Maire Tecnimont as the companies for which we have been able to identify most projects.

FIGURE 15

Advantages and disadvantages of different thermal production methods

Technology	Advantages	Disadvantages	Developers/Licensors
POX	Feedstock desulphurisation not required Most extensive industrial experience	High process operating temperature Usually requires oxygen plant	Texaco, Royal Dutch Shell
SMR	Oxygen not required, lowest process operating temperature Best H_2/CO ratio for production of liquid fuels	Highest air emissions More costly than POX and ATR Recycling of CO and removal of excess H_2 by means of membranes	Haldor Topsoe, Foster Wheeler (Wood), Lurgi (Air Liquide) Kinetics Technology (KT), Uhde, Technip FMC, KBR, Toyo, McDermott (MDR), Honeywell UOP, Caloric Anlagen, Heurty Petrochemicals (Axens). Air Products, Linde
ATR	Lower process temperature requirement than POX Syngas methane content can be tailored by adjusting reformer outlet temperature.	Limited commercial experience Usually requires oxygen plant	Lurgi, Haldor Topsoe, KBR, KT
DMR	Uses CO_2 instead of steam CO_2 can be consumed instead of released into atmosphere, almost 100% CO_2 conversion	Formation of coke on catalyst Additional heat required for reaction	Carbon Sciences
CSDR	Best H2CO ratio for production of liquid fuels. Coke deposition drastically reduced.	Separation of unreacted methane from SMR syngas Cost	Midrex Process
TMR	Directly using flue gases rather than pre-separated and purified CO_2. Over 95% of methane and 80% CO_2 conversion can be achieved	Usually requires oxygen plant Low H_2/CO ratios limit large-scale application	Haldor Topsoe, Foster Wheeler (Technip), Lurgi (Linde) Kinetics Technology, Uhde
H2S Cracking	H2S waste gas valorisation producing hydrogen and sulphur. Zero CO_2 emissions	Cost Unproven technology	KT (Maire)

Source: *https://www.researchgate.net/figure/Comparison-of-syngas-generation-technologies-with-natural-gas-feed-5_tbl1_298738258*, Barclays Research

One of the key advantages of the steam methane reforming technology is that it already exists and is capable of being built to produce large amounts of hydrogen – and with a capacity that simply isn't available at present in electrolysis. The picture below is a Technip FMC hydrogen plant and provides a sense of the scale of the plant.

FIGURE 16

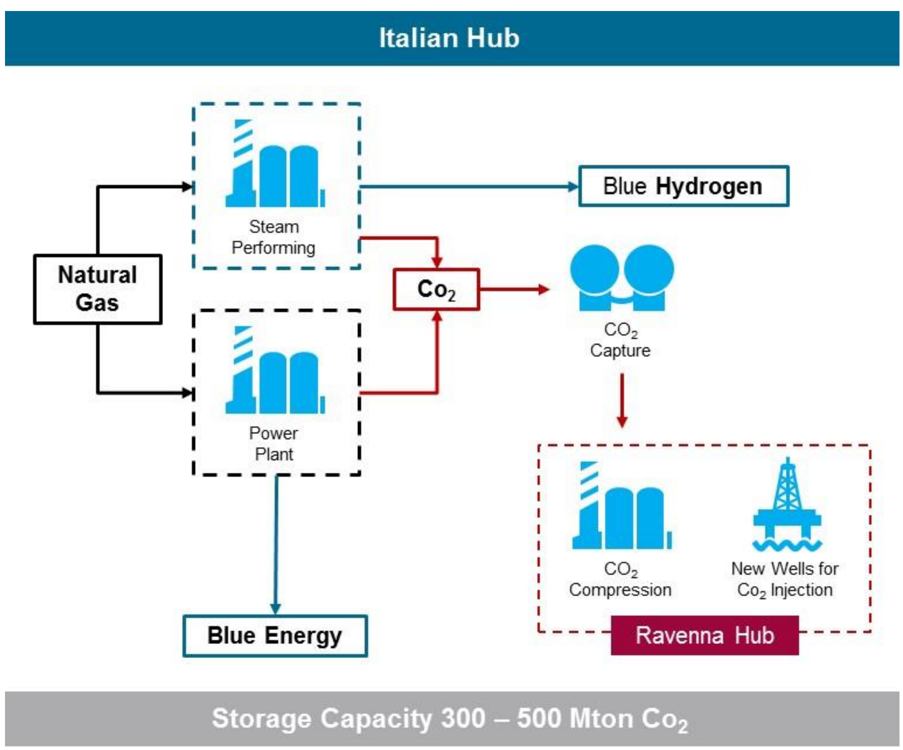
Steam methane reformer

Source: Technip FMC

Clearly for the production of hydrogen to have the desired effect in mitigating CO2 emissions there is a requirement to build hydrogen plants with CCS and we are seeing an increasing number of committed projects here. Aker Solutions is in currently conducting studies relating to a carbon capture plant for the hydrogen production unit at the Preem refinery in Scandinavia. Another example is from Eni, which alongside its new strategy presentation also highlighted that it is looking at a project for blue hydrogen in the Ravenna Hub, with c100 years of potential carbon capture for the SMR plant available.

FIGURE 17

Example of how blue H_2 can work



Source: Eni, Barclays Research

Electrolysis

The other main method for producing hydrogen is electrolysis, which involves the use of an electrical current to split water into hydrogen and oxygen. A direct current passes through two electrodes in a water solution resulting in the breaking of the chemical bonds into hydrogen and oxygen with the chemical reaction below:

Cathode: $2H_2O + 2_e = H_2 + 2OH$

Anode: $4OH = O_2 + 2H_2O + 4e$

Overall: $2H_2O = 2H_2 + O_2$

Of note is that there are no CO_2 emissions associated with this process itself, although there could be associated with the generation of the electricity source. Photoelectrolysis is also an effective method of production, with a photoelectrode absorbing solar energy and simultaneously creating the necessary voltage for the direct decomposition of water into hydrogen and oxygen. However, commerciality on this is limited at present. Below we look at the most promising sources of electrolysis.

FIGURE 18

Key features of electrolysers by type

	Temperature	Electrolyte	Plant size		Efficiency	Purity
Alkaline electrolysis (AE)	60-80	Potassium Hydroxide	0.25-760Nm3 H2/h	1.8-5300kw	65-82%	99.5%-99.9998%
Proton exchange membrane electrolysis (PEM)	60-80	Solid state membrane	0.01-240Nm3 H2/h	0.2-20000kw	65-78%	99.9%-99.9998%
Anion exchange membrane electrolysis (AEM)	60-80	Polymer membrane	0.1-1Nm3 H2/h	0.7-4.5kw	N/A	99.40%
Solid oxide electrolysis (SOE)	700-900	Oxide ceramic			85% (lab)	N/A

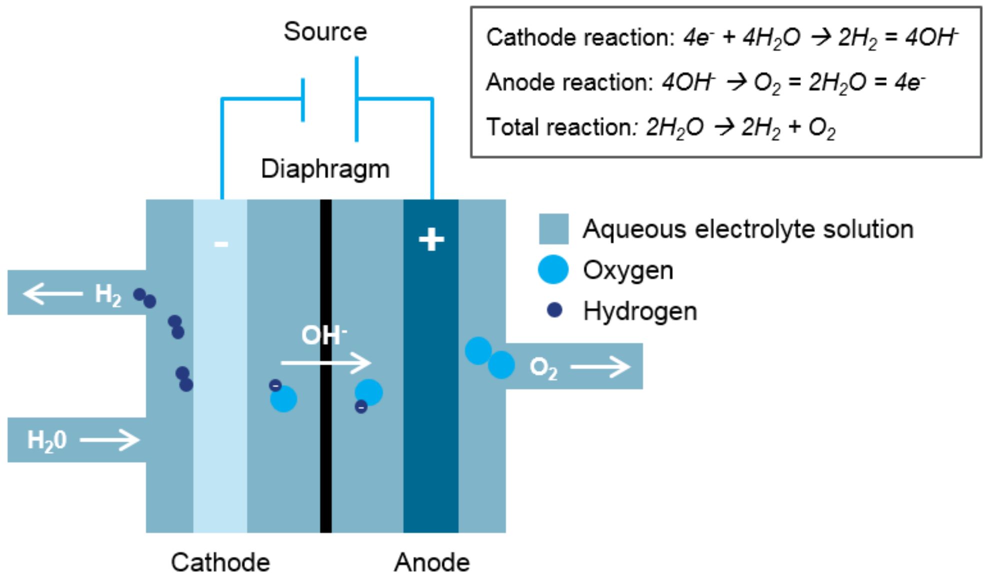
Source: Shell, Barclays Research

Alkaline electrolysis

Alkaline electrolysis is a well-established process in the chemical and refining industries. Electricity is used to split water molecules into hydrogen and oxygen The electrolyser is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide or sodium hydroxide. The electrodes are separated by a thin diaphragm, or foil. Typically nickel-based metals are used for water electrolysers. New alkaline electrolysers may be better than proton exchange membrane electrolysis (PEM) in terms of efficiency, but response time has been the key issue in the past, although some of the latest research does suggest that this can be addressed. Alkaline electrolysers operate via transport of hydroxide ions (OH-) through the electrolyte from the cathode to the anode, with hydrogen being generated on the cathode side. Electrolysers using a liquid alkaline solution of sodium or potassium hydroxide as the electrolyte have been commercially available for many years. Newer approaches using solid alkaline exchange membranes as the electrolyte are showing promise on the lab scale, but at present do not form a key part of our base case.

FIGURE 19

Alkaline electrolyser process



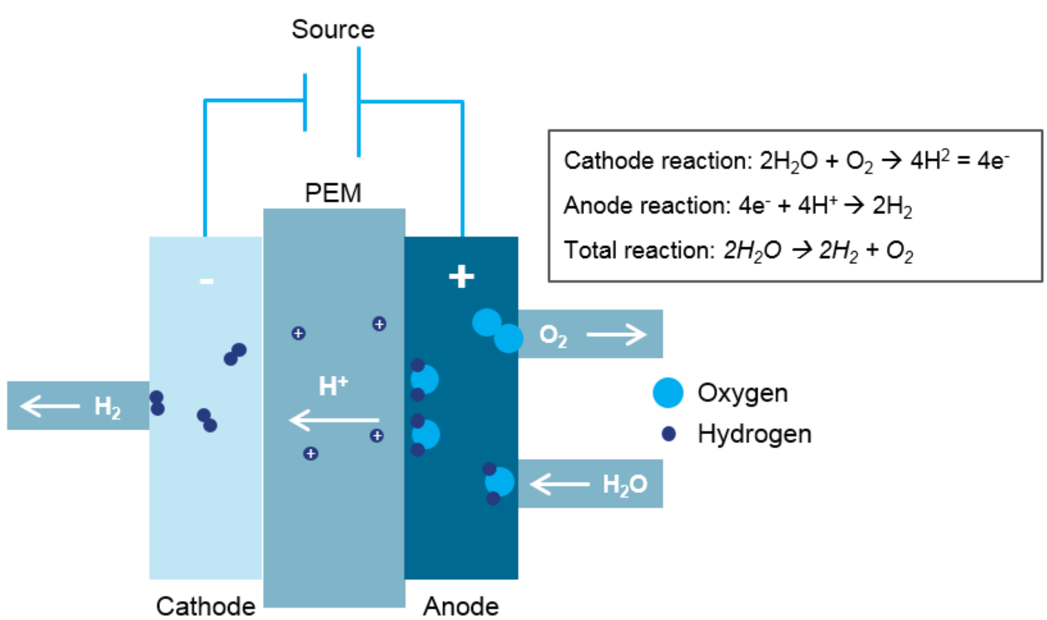
Source: BNEF

Proton membrane electrolysis (PEM)

PEM water electrolysis is less mature than alkaline water electrolysis. In a proton exchange membrane (also known as a polymer electrolyte membrane) electrolyser, the electrolyte is a solid specialty plastic material. Water reacts at the anode to form oxygen and positively charged hydrogen ions (protons). The electrons flow through an external circuit and the hydrogen ions selectively move across the PEM to the cathode. At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas. Anode Reaction: 2H2O → O2 + 4H2 + 4e- Cathode Reaction: 4H+ + 4e- → 2H2

FIGURE 20

PEM electrolyser process



Source: BNEF

PEM's special property is that it is permeable to protons but not to gases such as hydrogen or oxygen. As a result, the membrane takes on the function of a separator that prevents the product gases from mixing. On the front and back of the membrane are electrodes that are connected to the positive and negative poles of the electricity source. This is where water molecules are split. In contrast to traditional alkaline electrolysis, PEM technology has very rapid response times and requires very little base load and so is ideally suited to run on the inconsistent levels of power generated from wind and solar power. Proton exchange membrane fuel cells (PEMFCs) also dominate the mobility fuel cell market and platinum is the catalyst material used here.

Solid oxide electrolysers

Solid oxide electrolysers use a solid ceramic material as the electrolyte that conducts negatively charged oxygen ions (O2-) at elevated temperatures and generate hydrogen in a slightly different way. Water at the cathode combines with electrons from the external circuit to form hydrogen gas and negatively charged oxygen ions. The oxygen ions pass through the solid ceramic membrane and react at the anode to form oxygen gas and generate electrons for the external circuit. Solid oxide electrolysers operate at much higher temperatures (about 700-800°C) than PEM electrolysers (which operate at 70-90°C) and commercial alkaline electrolysers (which operate at 100-150°C). The solid oxide electrolysers can effectively use heat available at these elevated temperatures to decrease the amount of electrical energy needed to produce hydrogen from water.

The table below shows key advantages and disadvantages by type of electrolyser.

FIGURE 21

Key advantages and challenges of electrolysers by type

Technology	Advantages	Disadvantages
Alkaline electrolysis	Well established technology Cheaper catalysts High durability owing to an exchangeable electrolyte and lower dissolution of anodic catalyst Cost-effective Higher gas purity due to lower gas diffusivity in alkaline electrolyte	Low current densities Purity Low partial load range Corrosive liquid electrolyte Low operational pressures
Proton exchange membrane	Fast heat-up, cool-off time – rapid response time Higher purity of hydrogen Easier hydrogen compression, facilitates hydrogen storage. Operates under wide range of power inputs. Operates at higher current density	Higher manufacturing costs due to materials used (current collectors, bipolar plates, platinum-based catalysts, membranes) Limited choice of stable earth catalysts Solid thin electrolyte can be easily damaged. Sensitive to imperfections, dust, impurities, etc.
Anion exchange membrane	Replaces conventional noble metal catalysts with lower-cost transition metals Compact	Limited commercial applications
Solid oxide electrolysis		Lab tests only High temperatures (700-800°C)

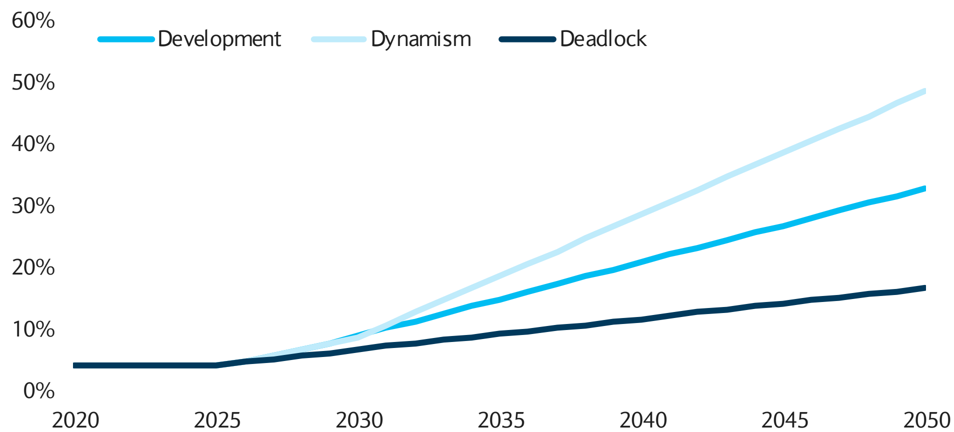
Source: Shell, Barclays Research

To meet our demand forecasts for hydrogen, there is a requirement for a significant step-up in the volume of electrolyser capacity. Exactly which technology prevails is unknown at this point, with new alkaline nickel-based electrolysers showing high efficiency, but their rapid response time and small scale likely meaning a focus on PEM electrolysers near term, particularly for on-site generation with a specific output.

The chart below shows our assumptions for the take-up of green hydrogen (effectively electrolysis) in our three scenarios (although we also acknowledge that each of these take-up rates can be applied within each of our scenarios as well and our model is available on request).

FIGURE 22

Green hydrogen as percentage of production mix – scenarios

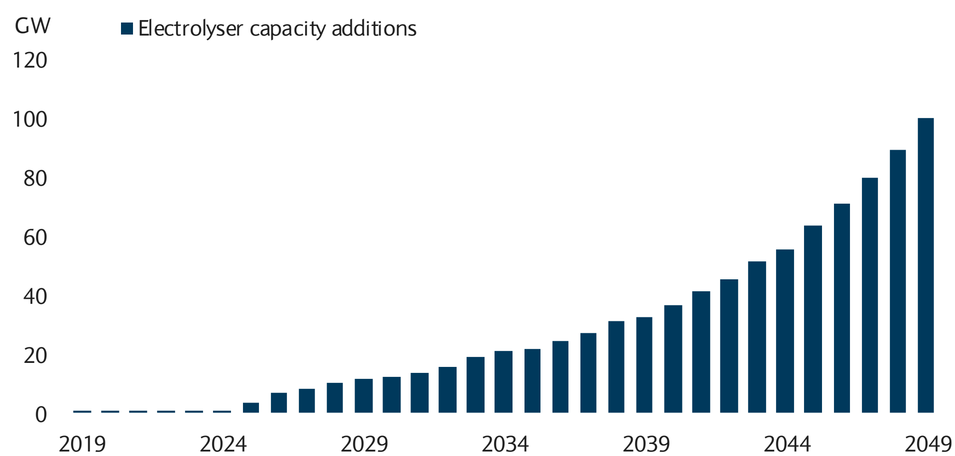


Source: Barclays Research estimates

This growth we project in electrolysis-based hydrogen requires a significant step-up in the growth of electrolysers to a scale far in excess of what we see in place currently. According to the International Energy Agency (IEA), the combined electrolyser capacity added over 2010-2018 was just 100MW. As such, our forecasts represent a step-change in the market vs what has been the case to date. On page 33 we outline some of the key projects that are ongoing in the green hydrogen market – based on this, it does appear that 2025-2028 are the key years for the scaling up of activity.

FIGURE 23

Electrolyser growth – Development scenario



Source: Barclays Research estimates

List of electrolyser producers

There are a large number of electrolyser manufacturers and we show those that we can identify below, although we note this is not an exclusive list. The companies below are included as they are a useful source for how the industry is evolving, with the cost data on electrolysers on which we base our demand projections coming from these companies.

FIGURE 24

Electrolyser manufacturers

Manufacturer
Acta
Areva H2 Gen
Cet H2
China Shipbuilding Industry Corporation
Diamond Lite
Enapter
Erredue
Giner ELX
Green Hydrogen
H2 Nitidor
H2b2
Haldor Topsoe
H-Tec Systems
Hydrogen Pro
Hydrogenics (Cummins/Air Liquide)
Hygear
Idroenergy
Industrie Haut Technolgie (IHT)
ITM Power
Jiangsu Ancan
McPhy
Nel Hydrogen
Ningbo Heli
PowerCell
Proton Onsite
Pure Energy Centre
Siemens
Shangdong Saikesaisi Hydrogen Energy
Sunfire
Suzhou Jingli
Teledyne
Thyssenkrupp
Tianjin Mainland
Wasserelektrolyse Hydrotechnik

Source: Company data, Barclays Research

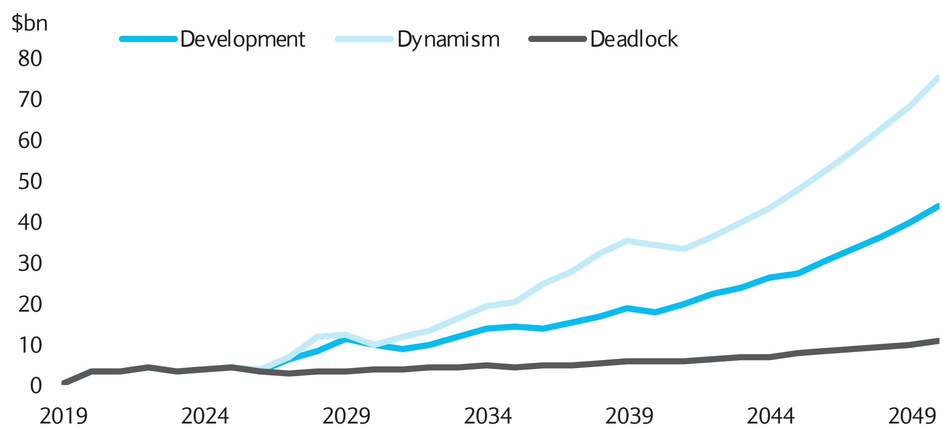
It is interesting to note that on March 6th Neste announced an investment in Sunfire which it describes as a leading developer of high-temperature water electrolysis as well as direct conversion of water and CO2 into raw materials for petrochemical products. Power-to-X (energy storage) is a key area of innovation, with green hydrogen the main technology behind it.

Capex – a $40bn+ p.a. market

The implication of our scenarios is a material step-up on capex being spent on hydrogen equipment – based on the incremental volumes we project, we see scope for a $40bn a year market to develop. The chart below shows indicative patterns of capex under our three scenarios. The somewhat lumpy nature of the capex profile under our Dynamism scenario reflects assumptions we make about rates of growth in 2040 and 2045.

FIGURE 25

Annual equipment capex – scenarios

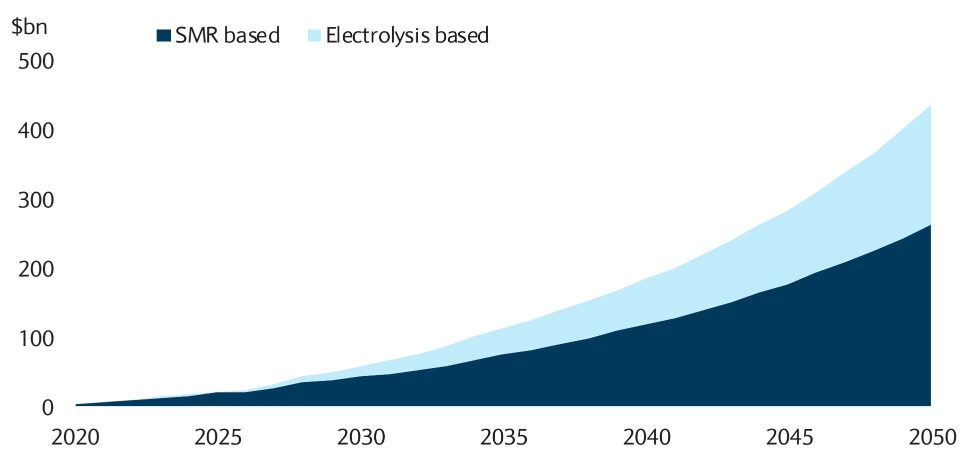


Source: Barclays Research estimates

In total, over the next 30 years, we see a market of close to $0.5trn dollars coming from a mix of electrolysis and SMR plants. We see those exposed to this theme being both the traditional energy equipment providers and new electrolyser producers. Technip FMC, Air Liquide, Wood, Maire Technimont and Saipem are notable on the SMR side. On the electrolyser side, listed (but not covered) companies include ITM Power, Nel Hydrogen, Powercell and Ceres Power.

FIGURE 26

Cumulative capex by hydrogen production type – Development scenario



Source: Barclays Research estimates

Spotlight on Chemicals

Air Liquide

Air Liquide has positioned itself at the centre of the hydrogen industry. The company produces 14 Bm^3 each year and operates almost 2,000km of pipeline to transport hydrogen from production facility to where it's needed. Air Liquide operates 46 steam methane reformers, which it calls HyCo plants (hydrogen and carbon monoxide are produced together from natural gas). In 2019 the company bought almost 20% in Hydrogenics – a Canadian company that manufacturers electrolysis equipment – and the two companies are jointly developing PEM (proton exchange membrane) technology. Air Liquide also operates 40 electrolysers and has helped build hydrogen filling stations.

Linde

Linde is a leader in the hydrogen manufacturing industry and according to its website has built more than 200 plants for the manufacture of hydrogen with capacities from 1000 to over 100,000 Nm_3/h. Linde's offering in the hydrogen value chain includes:

- The entire process for the manufacture, recovery, purification, storage, liquefaction and transportation of hydrogen.
- Petrochemical feedstock utilisation from natural gas to heavy oil to coal.
- Financing completion and commissioning of plants.

As an example, Linde has been involved in the Sadara petrochemical plant in Saudi Arabia and is responsible for the long-term supply of carbon monoxide, hydrogen and ammonia.

Johnson Matthey

Johnson Matthey produces the chemical catalysts that make the chemical reaction within a steam methane reformer more efficient. These predominantly nickel catalysts are essential for SMRs to function properly and lower the energy requirement of the reaction. Johnson Matthey also has a smaller business making membrane electrode assemblies (MEA) for hydrogen fuel cells for use in automotive, non-road transport and distributive power.

A closer look at costs

Whilst the scenarios we have presented above point to a significant growth market in hydrogen, the key challenge remains cost – which, because the process uses a primary energy source, is always going to be higher than the cost of that primary source. In this section we estimate the cost of production for both blue and green hydrogen.

For blue hydrogen, the largest cost is the natural gas itself, followed by the capital cost and then electricity and water. Production of each kilogram of hydrogen also emits 9kg of CO_2, which must be captured, which we would expect to increase the capital cost. Below, we show our estimates for SMR-based hydrogen production including and excluding CCS.

FIGURE 27

Calculating cost of hydrogen production for SMR

SMR costs	Without CCS	With CCS
Natural gas price, $/mbtu	6.0	6.0
Gas to Hydrogen ratio mmbtu per kg H_2	0.15579	0.15579
Natural gas cost, $/kg	0.9	0.9
Electricity consumption kw per kg H_2	0.569	0.569
Electricity cost, $/MWh	30	30
Electricity cost, $/kg	0.1	0.1
Water consumption, gallons per kg H_2	3.355	3.355
Capital costs, $/kg H_2	0.55	0.9
CO_2 emissions, tCO_2/kg H_2	0.009	0.009
CO_2 cost per tonne	30	30
Carbon cost, $/kg	0.3	0.3
Combined cost, $/kg	1.90	2.25

Source: Barclays Research estimates

The table below shows the cost per kg of hydrogen at a range of carbon and natural gas prices. Typically, costs of $1.5-2.0/kg are seen as competitive for certain fuel uses, which implies that gas prices as a feedstock need to be below $6/mbtu.

FIGURE 28

Cost of hydrogen production, $/kg – sensitivity to carbon and natural gas costs

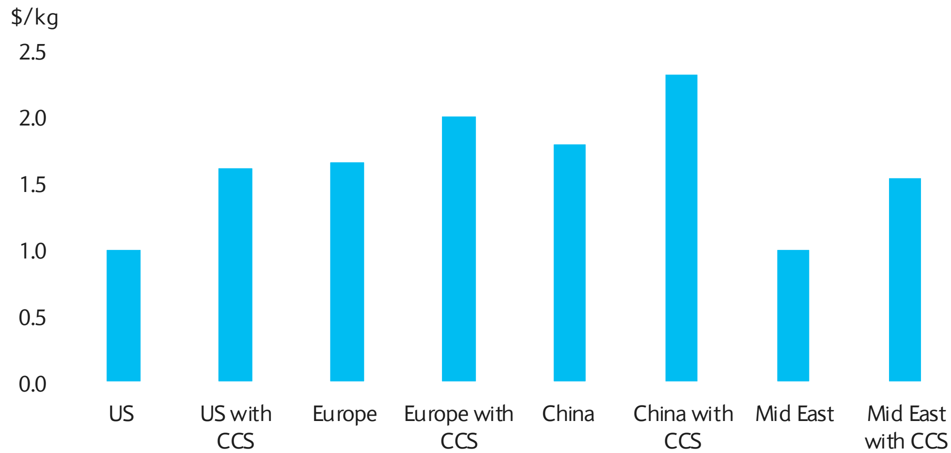
		Cost of carbon, $/t						
		0	10	20	30	40	50	60
Natural gas cost, $/mbtu	1.50	1.28	1.37	1.46	1.55	1.64	1.73	1.82
	2.00	1.36	1.45	1.54	1.63	1.72	1.81	1.90
	2.50	1.44	1.53	1.62	1.71	1.80	1.89	1.98
	3.00	1.52	1.61	1.70	1.79	1.88	1.97	2.06
	3.50	1.59	1.68	1.77	1.86	1.95	2.04	2.13
	4.00	1.67	1.76	1.85	1.94	2.03	2.12	2.21
	4.50	1.75	1.84	1.93	2.02	2.11	2.20	2.29
	5.00	1.83	1.92	2.01	2.10	2.19	2.28	2.37
	5.50	1.91	2.00	2.09	2.18	2.27	2.36	2.45
	6.00	1.98	2.07	2.16	2.25	2.34	2.43	2.52
	6.50	2.06	2.15	2.24	2.33	2.42	2.51	2.60

Source: Barclays Research estimates

In turn, this has implications geographically for how hydrogen might be produced. The chart below shows our estimates for the regional costs of hydrogen production with natural gas. The Middle East and US are the lowest-cost regions, reflecting natural gas prices that are typically sub-$2-3/mmbtu.

FIGURE 29

Estimated regional costs of hydrogen and SMR



Source: Barclays Research estimates

For green hydrogen the main cost is electricity and the capital costs of building the project. The table below shows the constituent parts. Each kg of hydrogen produces 33.3kWh of energy but requires 45-55kWh of electricity to produce, implying efficiency factors of 65-75%. The analysis below is based on an electrolyser cost of $800/kWh, which we assume in our capex analysis falls towards $350/kWh by 2050 (BNEF has indicated that Chinese manufacturers are already below that point owing to the scale of electrolysers installed).

FIGURE 30

Calculating the cost of hydrogen production from electrolysis

Hydrogen costs	
Electricity consumption kw per kg H2	47.6
Electricity cost, $/MWh	45
Electricity cost, $/kg	2.1
Capital costs electrolyser, $/kw	800
Load factor	50%
Cost per kg	33.6
Life, years	25
Per year cost, $/kg H_2	1.3
Opex as % of capital cost	3%
Per year cost, $/kg H_2	0.03
$/kg H2	3.5

Source: Barclays Research estimates

Given the importance of electrolyser costs and electricity prices to the cost of green hydrogen production, the tables below show sensitivities to these two variables at a 50% load factor, 35% load factor and 10% load factor. We note the upfront capex for electrolysers in China ($250/kW) and the Western world ($700-1300/kW), with scale the primary difference. While China is using electrolysers of 3-5MW capacity, the Western world is using capacity below 1MW. We estimate indirect costs per year equivalent to 10-11% of total capex, comprising 3% depreciation, 3% opex and 5% cost of capital.

FIGURE 31

Cost of hydrogen production ($/kg) – 50% load factor

		Cost of electrolyser, $/t						
Cost of electricity, $/Mwh		250	400	500	650	800	950	1100
	-5.0	0.19	0.45	0.62	0.88	1.14	1.40	1.66
	0.0	0.43	0.69	0.86	1.12	1.38	1.64	1.90
	5.0	0.67	0.93	1.10	1.36	1.62	1.88	2.13
	10.0	0.91	1.17	1.34	1.60	1.85	2.11	2.37
	15.0	1.14	1.40	1.58	1.83	2.09	2.35	2.61
	20.0	1.38	1.64	1.81	2.07	2.33	2.59	2.85
	30.0	1.86	2.12	2.29	2.55	2.81	3.06	3.32
	40.0	2.33	2.59	2.76	3.02	3.28	3.54	3.80
	50.0	2.81	3.07	3.24	3.50	3.76	4.02	4.27
	60.0	3.29	3.54	3.72	3.97	4.23	4.49	4.75
	70.0	3.76	4.02	4.19	4.45	4.71	4.97	5.23

Source: Barclays Research estimates

FIGURE 32

Cost of hydrogen production ($/kg) – 35% load factor

		Cost of electrolyser, $/t						
Cost of electricity, $/MWh		250	400	500	650	800	950	1100
	-5.0	0.32	0.66	0.89	1.23	1.57	1.92	2.26
	0.0	0.57	0.91	1.14	1.49	1.83	2.17	2.52
	5.0	0.83	1.17	1.40	1.74	2.09	2.43	2.77
	10.0	1.08	1.43	1.66	2.00	2.34	2.68	3.03
	15.0	1.34	1.68	1.91	2.25	2.60	2.94	3.28
	20.0	1.60	1.94	2.17	2.51	2.85	3.20	3.54
	30.0	2.11	2.45	2.68	3.02	3.37	3.71	4.05
	40.0	2.62	2.96	3.19	3.54	3.88	4.22	4.56
	50.0	3.13	3.48	3.70	4.05	4.39	4.73	5.08
	60.0	3.65	3.99	4.22	4.56	4.90	5.25	5.59
	70.0	4.16	4.50	4.73	5.07	5.42	5.76	6.10

Source: Barclays Research estimates

FIGURE 33

Cost of hydrogen production ($/kg) – 10% load factor

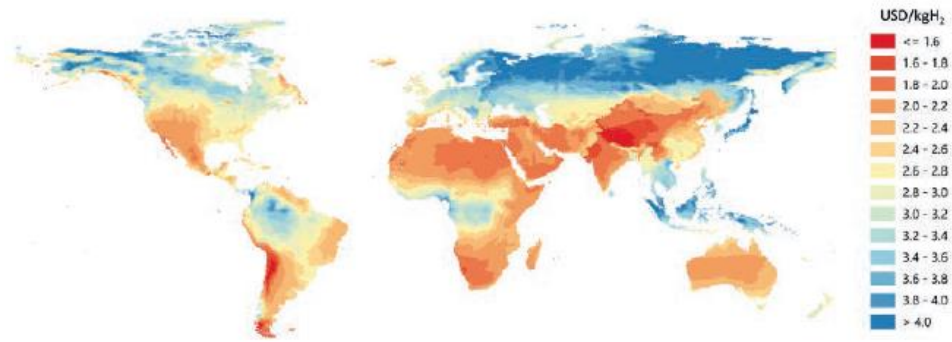
		Cost of electrolyser, $/t						
Cost of electricity, $/MWh		250	400	500	650	800	950	1100
	-5.0	1.21	2.13	2.75	3.67	4.59	5.52	6.44
	0.0	1.54	2.46	3.08	4.00	4.92	5.85	6.77
	5.0	1.87	2.80	3.41	4.33	5.26	6.18	7.10
	10.0	2.21	3.13	3.74	4.67	5.59	6.51	7.44
	15.0	2.54	3.46	4.08	5.00	5.92	6.85	7.77
	20.0	2.87	3.79	4.41	5.33	6.26	7.18	8.10

Source: Barclays Research estimates

Given the sensitivity of costs to power prices for electrolysis and to the natural gas price for SMR, it is likely that different markets will follow different routes to produce hydrogen. The map below, taken from the IEA, suggests to us that the most competitive areas for green hydrogen are likely to be the Middle East, China and North Africa, which opens up the possibility of an international traded market for hydrogen (addressed later in this report).

FIGURE 34

Projected hydrogen costs from hybrid solar PV and onshore wind systems, long term

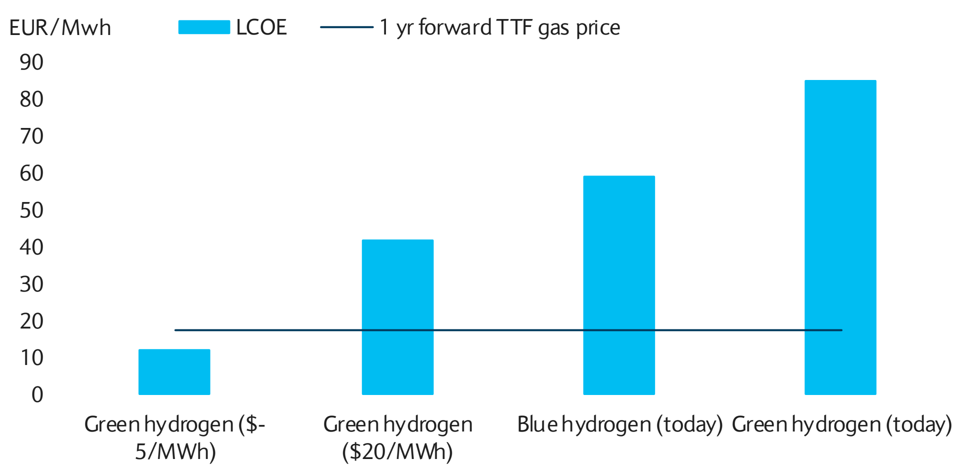


Source: IEA

The chart below shows a comparison in EUR/MWh based on the methodology above for Europe.

FIGURE 35

Comparing costs of hydrogen production methods



Source: Barclays Research estimates

The unavoidable conclusion from this analysis is that green hydrogen needs significant cost deflation to be cost-competitive and, as of today, hydrogen is not competitive against methane gas, requiring premiums of 400-700% to the TTF gas forward price. This shouldn't be a surprise, although we do note this is based on a forward gas price rather than the fully loaded capital cost price, which would be higher. The cheapest solution today is blue hydrogen, with a levelised cost of energy (LCOE) of cEUR60/MWh for hydrogen compared with EUR70-80/MWh for green hydrogen.

In a future scenario where the cost of electrolysers in Europe converged with Chinese electrolyser costs, hydrogen would still likely remain uncompetitive on a stand-alone basis. Yet if the move towards a net zero economy requires that natural gas can no longer be used as a fuel, then blue and green hydrogen solutions are viable, although this would imply a material step-up in costs for industry. How much of the economy can be electrified is also a factor, with our net zero case assuming 60% electrification in Europe.

At negative power prices, green hydrogen is the most cost-competitive method of production, using curtailed renewables electricity generation for hydrogen production. We would therefore expect this to be the preferred option to store excess power from renewable sources, at times when power prices are negative.

FIGURE 36

Hydrogen premium to TTF gas price

%		Cost of electrolyser, $/t			
		250	500	800	1100
Cost of electricity, $/MWh	-5.0	-65	14	109	204
	0.0	-21	58	153	248
	5.0	23	102	197	292
	10.0	66	145	240	335
	15.0	110	189	284	379
	20.0	154	233	328	422
	30.0	241	320	415	510
	40.0	328	407	502	597

Source: Barclays Research estimates

Green hydrogen – a market opportunity for utilities

Although green hydrogen is not a profitable option today, we forecast it will become an increasingly competitive option as both the costs of electrolysers come down and spot power prices spend an increasing amount of time in negative territory, a scenario we outline in *European Utilities & Energy: Net growth from net zero (03/02/2020)*. The efficiency of hydrogen production varies according to different utilisation rates and conditions. Reflecting this, there does need to be a good economic reason for most companies to make the switch, unless the main motivation is to be net zero on emissions – a goal that by itself we can't rule out. Our Utilities team see three main option to justify that process:

1. **Option 1:** A way of generating carbon-free gas, when full decarbonisation becomes a binding target. In this scenario, we believe load factors could reach 90% for electrolysers, as they will be generating 'green' gas most of the year at baseload to provide hydrogen for industrial consumption and some forms of transport. We estimate efficiency is at its highest level at 75%.

2. **Option 2:** A way of storing energy, in the form of 'green' gas, but with the final sale price attractive enough to cover the costs of storage and generation. In this scenario, we believe load factors of 35% for electrolysers are reasonable, as they will be generating green gas only as a backup of peak gas demand or gas for renewables' back-up power generation only 35% of the hours of the year. We assume efficiency decreases to 63%.

3. **Option 3:** A way of using curtailed renewables capacity when power prices hit negative price levels. We assume power prices turn sufficiently negative only 10% of the time, in an oversupplied market with renewable capacity. We assume efficiency decreases to 60% in our 10% load factor scenario.

Utilities likely to become main power suppliers for H_2 conversion

Our Utilities team highlighted in their net-zero report that they believe the sector faces internal challenges driven by increased regulatory requirements to provide solutions for the currently non-electrified sectors of the economy. These include:

1. An increase in intermittent capacity with an increased need for storage, particularly in a scenario of excess of capacity driven by massive deployment of renewables capacity.
2. A significant need for non-renewable power under nearly all scenarios of electrification for the EU27 and the UK. With even modest increases in electrification, we see the need for a net increase in non-intermittent power generation requirements, or a massive increase in storage needs.

We think that the introduction of 'green' hydrogen will lead to further integration between power and gas networks, as the gas sector will depend on future power prices, leading to cooperation schemes between TSOs and regulators within the framework of the energy transition and economies' de-carbonisation.

Considering the three options introduced in the previous section, we believe each might argue for a different business approach by the utilities sector:

1. **Option 1:** The generation of 'green' hydrogen and the transport of that fuel would involve the oil sector and the gas network operators. The oil sector might look for vertical integration by developing its own renewable generation units (or acquiring renewables assets), as electrolysers would become one of the biggest customers of the power generation sector (power being the biggest cost input for an electrolyser). Hydrogen networks would be the result of the transformation of current gas methane networks, after modifications to the different components and complementary investments to develop hydrogen pipelines to connect the hydrogen production facilities with hydrogen storage facilities.
2. **Option 2:** Hydrogen as energy storing, in the form of green gas or power, could be a business opportunity both for oil majors and utilities. The case for oil majors entering this business is explained in the previous point. Utilities could be attracted to this business as a way of storing power. Nevertheless, using power to produce hydrogen to be burned later in a combined cycle gas turbine plant seems like a very inefficient way of storing and re-using energy, considering all the thermal inefficiencies in the process. We see batteries as a more efficient and economical way of storing power.
3. **Option 3:** Using curtailed renewables capacity is a business opportunity for power and gas TSOs, as they decide which capacity is curtailed and the moment at which that hydrogen can access the hydrogen transport network. TSOs could invest in their own electrolysers in order to use that excess power in the market to generate hydrogen. The coordination between gas and power TSOs would need to be tighter than it is today, as the hydrogen produced by the power TSO would be injected directly into the hydrogen network or into hydrogen storage facilities.

We outline more of the examples from utilities in the heating and power section beginning on page 40.

Evidence of deployment beginning

Reflecting the increasing focus on decarbonisation and a clear belief that companies now have that hydrogen, both blue and green, could eventually prove competitive, a number of projects are now being undertaken, with 226 in Europe alone (*https://hydrogeneurope.eu/projects*), and there are also 23 global flagship projects for the Hydrogen Council which could add up to in excess of $60bn of investment.

FIGURE 37

Flagship projects from the Hydrogen Council

Project Type	Flagship projects
Large-scale electrolysis	Centurion Fukushima Green NH3 GreenHydroChem Hy Netherlands
Large-scale SMR + CCS/CO2 transportation and storage	Acorn HyNet NW H21 H-Vision Magnum Northern Lights
Large-scale LH2 transport	Hystra
H2 pipeline and storage	Centurion GreenHydroChem HyNetherlands
H2 refueling infrastructure for FCVs	H2M Germany HyNet Korea JHyM Force ZEV H2M California
Large scale FC train deployment	FC Train DE FC Train FR
H2 refueling infrastructure for fleet of FC trucks	Pan European Fleet of Trucks California fleet of trucks
H2 refueling infrastructure of large-scale captive FC fleet	Hype ZEV
H2 in electricity generation	Magnum
H2 heating	Ene-Farm Hynet NW H21 H-Vision
Large-scale industry feedstock	Green NH3 GreenHydroChem HYBRIT

Source: Hydrogen Council

In SMR and carbon capture, a key project to monitor is the Magnum project in Norway and the Netherlands being undertaken by Equinor, GasUnie and the Norwegian government. Initial indications suggest that the project investment is likely to be in excess of $1.5bn. It is designed to produce clean hydrogen from Norway (Equinor) and then capture and store the CO_2 under the Norwegian sea-bed and use the clean hydrogen in Vattenfall's gas-fired power plant in Eemshaven in the Netherlands. The project is targeted to be potentially on-stream by 2025, with 2mtpa of CO2 abatement, although one of the policy support areas the partners are looking for here is guaranteed offtake with financial support from national authorities.

Spotlight on H21 visit – 4th March 2020

One of the largest SMR-based hydrogen projects is H21 in the North of England with the aim to convert 3.7 million UK homes and businesses from natural gas to hydrogen in order to reduce carbon emissions beginning in 2028 and rolled out over 7 years. Eventually a further UK roll-out could mean 12mn additional homes converted to hydrogen by 2050.

Yet ahead of roll-out there are a number of stages to pass, including a full safety case needing to be made. We took the opportunity to visit the DNV GL research and testing site, Spadeadam, in Northern England to help further our understanding of the project and what is needed to see actual deployment into houses. The site includes a set of houses on 'Hy Street' that are used to see how hydrogen flows in the event of any leaks. The testing and research was described as being a similar process to that which was undergone when converting from town gas to natural gas in the UK in the 1960s.

What was clear to us from the visit is that the safety research is due to be finished by 2021 and is likely to confirm that a 100% hydrogen grid would carry compatible safety risk to current networks supplying natural gas or town gas. There are more steps to take, though, such as deciding whether to add smell/colour to the hydrogen as is done with natural gas.

The project will employ electrolysers for the pilot and low-scale facilities, but for full deployment it is anticipated that it will use SMR and carbon capture technologies. This is mostly related to the absence of cheap power sources:

1. The high cost of hydrogen, given the cost of electricity (electricity at 6p/kWh would result in a 10p/kWh cost of hydrogen).
2. For hydrogen production demand of 1,025MW it would require 2.6GW of renewable capacity to produce 'green' hydrogen (that capacity was not available at the time of launching the project).
3. The land footprint was also a pushback, considering the 2.6GW of renewable energy and the 1,040MW of electrolyser capacity required.
4. The amount of new electrical transmission and distribution infrastructure required to meet the heat load and power demand.

The project aims to achieve the following targets:

1. Hydrogen production capacity of 1,025MW split into four SMR plants located at Teesside. The estimated cost per MW of hydrogen is £0.4mn/MW, significantly below the cost of an electrolyser.
2. The four facilities will be fitted with 90% carbon dioxide capture, aiming to sequester 1.5 million tonnes of carbon per year deep under the North Sea. The estimate opex per tonne is £40/ tonne.
3. Intraday storage of hydrogen to supply one in 20 peak hour demand of 3,180MW, in salt cavern storage located at Teesside.
4. Hydrogen conversion of both medium- and low-pressure gas distribution networks through the summer months over a three-year period.

The total cost of the project is £2bn, with annual opex of £139mn.

Overall we see the pace of this project as critical as a demonstration of large-scale deployment for heating and residential purposes. Social acceptance of hydrogen as a fuel will also be important. It is interesting to note here that the metering system for natural gas may not be compatible with hydrogen.

Significant progress is also being made with respect to the electrolyser market. In February 2020 Shell and GasUnie announced Europe's largest green hydrogen project in the Netherlands, with a 10GW offshore wind facility in the North Sea. This is the NortH2 project with Groningen seaports and a large hydrogen electrolyser in Eemshaven. The partners want to have first hydrogen flowing by 2027 powered by an initial 3-4GW of offshore turbines growing to 10GW by 2040 with a production of 800kt of hydrogen annually. The cost of the project is not specified, but a press release from one of the consortium members did state that "the initial project phases may potentially require European and national subsidies available for the decarbonisation of energy". again demonstrating that at present it might not be competitive on a stand-alone basis.

In late 2019 Air Liquide, DLVA and Engie entered into a partnership to produce green hydrogen on an industrial scale. The plan is for 1.3GW of solar capacity with potential production start-up envisaged for 2027 onwards.

In Canada, Air Liquide will build a 20MW PEM electrolyser (we think the world's largest) to produce low-carbon hydrogen using hydropower, and will produce just under 3000 tons of hydrogen a year.

In Saudi Arabia, Saudi Aramco Mobil Refinery (SAMREF), a joint venture between Aramco and Exxon, will be the first to use the Yanbu hydrogen grid. A consortium including Air Liquidem Taqa is planning to provide hydrogen to three other clients in 2020, which should help enable an understanding of how a grid system and market-place for hydrogen can evolve

Storage, transportation and distribution

Once hydrogen has been produced, it must then be transported to end-users. It must also be safely compressed, stored and dispensed at refuelling stations or stationary power facilities. Storage of hydrogen represents a key component in hydrogen supply. Due to its low density, hydrogen must be converted into a more energy-dense form before it becomes economically viable to store and transport. At room temperature and pressure, hydrogen takes a very low-dense gas form (one-tenth the volume of natural gas). This gas can be compressed further in a pressurised tank, but still occupies 3x the volumetric space of pressurised natural gas. It can be liquefied under very low temperatures to a denser form, and can be combined with other elements to be stored more densely. One of the key advantages of hydrogen is that it can be stored for a long time, unlike electricity. This enables two main avenues – long-range transportation and partnership with renewables.

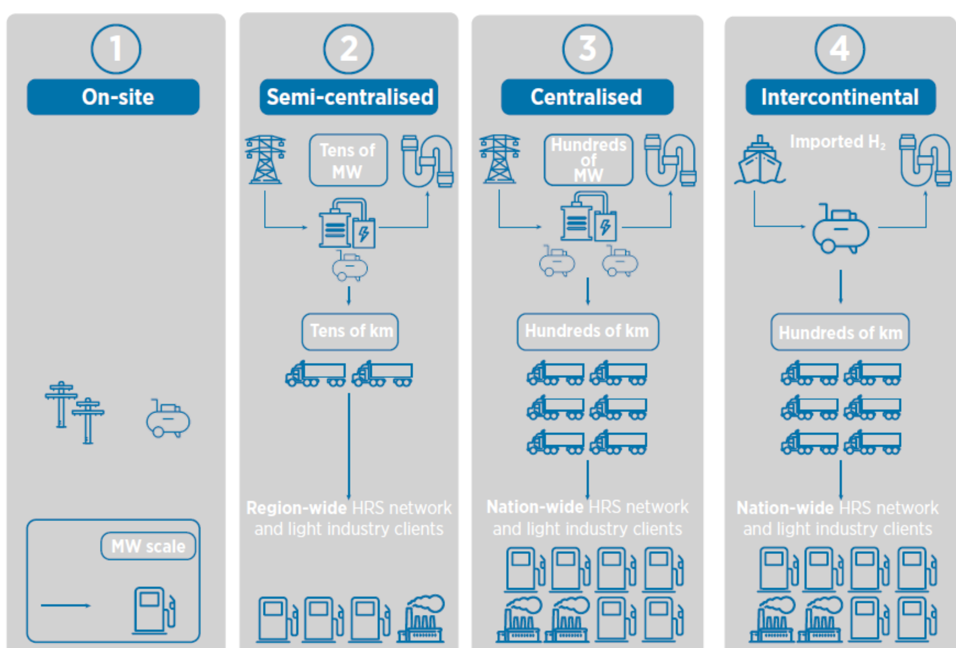
Hydrogen storage technologies can be broadly classified as:

1. **Compression**: Gaseous hydrogen stored at higher pressures to increase volume. Includes large-scale underground storage (e.g. salt caverns) and 'line packing' in gas pipelines. Underground storage typically <$0.6/kg.
2. **Liquefaction:** Pressurising and cooling hydrogen to -253˚C so that it is in a liquid state.
3. **Chemical:** Molecules such as ammonia, metal hydrides and toluene that carry hydrogen. All retain an additional energy penalty and cost associated with the recovery of hydrogen prior to use.

Transport and storage costs will play a significant role in the competitiveness of hydrogen. If hydrogen can be used close to where it is made, these costs could be close to zero. However, if the hydrogen has to travel a long way before it can be used, the costs of transmission and distribution could be material compared with the cost of production.

FIGURE 38

Production and distribution methods



Source: IRENA, Hydrogen a renewable energy perspective, September 2019 (p31)

How production of hydrogen happens will matter – this market comprises two segments: 'merchant' hydrogen (i.e. hydrogen generated on-site or in a central production facility and sold to a consumer by pipeline, bulk tank or cylinder truck delivery) and 'captive' hydrogen (hydrogen produced by the consumer for internal use and consumed at the point of usage. – initially likely to be on-site for specific projects).

The physical form in which hydrogen can be cost-effectively delivered and transported changes according to distance. Compressed hydrogen is more cost-effective over shorter ranges, whereas liquefaction works out more effectively via pipelines and rail for longer distances. The cheapest means of transportation is through ammonia, but, because of the costs involved in working backwards to extract hydrogen from this form, the operation only becomes cost-effective over longer distances, likely fulfilled via shipping.

If hydrogen needs to be shipped overseas, it generally has to be liquefied or transported as ammonia or in liquid organic hydrogen carriers (LOHCs). For distances below 4000 km, transporting hydrogen as a gas by pipeline is likely to be the cheapest delivery option; above 4000 km, shipping hydrogen as ammonia or an LOHC is likely to be more cost-effective. These alternatives are cheaper to ship, but the costs of conversion before export and reconversion back to hydrogen before consumption are significant. They may also sometimes give rise to safety and public acceptance issues.

FIGURE 39

Cost-effective distances for hydrogen transportation and delivery

Vehicle	Storage Type	Indicative Distances	Description/Use
Truck (Virtual pipelines)	Compression, liquefaction, ammonia	<1000km	Transport of liquefied and compressed hydrogen as well as ammonia is available commercially. Ammonia is less likely as a hydrogen carrier here given the scale requirements and need to convert back to hydrogen for use. Higher pressures/liquefaction are typically used for trucking distances greater than 300km
Rail	Compression, liquefaction, ammonia	>800-1100km	As per trucks but for greater distances travelled
Pipeline	Compression, liquefaction, ammonia	1000-4000km	More likely to be used for simultaneous distribution to multiple points or for intercity transmission
Ship	Ammonia, liquefaction	>4000km	Unlikely to use compression storage for shipping given cost of operation, distance and lower hydrogen density. Likely vehicle for export

Source: CSIRO

FIGURE 40

Relative costs of transportation in tonne per km

Method	Compression ($/tkm H2) 430 bar	Liquefication ($/tkm H2)	Ammonia ($/tkm H2)
Truck	2.33	0.92	0.33
Rail	0.55	0.28	0.04
Shipping	0.52	0.09	0.03

Source: CSIRO

Liquefaction transport viable for some international trade

As we highlighted in the cost section of the report, costs to generate clean hydrogen will vary by region and this may mean that some countries will find imports of hydrogen cheaper than domestic production, pointing to the development of a hydrogen import grid.

Hydrogen can flow through existing gas networks up to certain quantities and will need to be compressed. We see this as a potentially viable route for some international transport such as North Africa into Italy or Spain (particularly given existing infrastructure). In other cases, international shipping will need to be in liquid form – either through hydrogen liquefaction or through transformation into ammonia and conversion back into hydrogen.

There are a number of regions where hydrogen imports could be cheaper than domestic production. A study by the Hydrogen Council (*Path to Hydrogen Competitiveness*) indicates clean hydrogen production in 2030 from Saudi Arabia could cost $2/kg to produce and be landed in Germany at $3.4/kg and Japan at $3.7/kg. Given our estimate of production costs in Japan from domestic sources at over $6/kg, (using LNG as the gas-based feedstock) this may be a feasible alternative. Based on the same study, the Hydrogen Council report indicates the cost of shipping liquid hydrogen from Europe to Asia at $60/MWh compared to the $12/MWh cost of LNG. Even where importing hydrogen is not the cheapest option, some energy-importing countries may wish to consider imports to increase their energy diversity and access to low-carbon energy.

There are three major technologies for shipping hydrogen globally. These are liquid hydrogen (LH2), ammonia (NH3) and liquid organic hydrogen carriers (LOHCs – an emerging area). The advantages of liquefaction are the high purity and that it requires no dehydrogenation. The challenges include the requirement for very low temperatures (minus 250°C), a high energy requirement as a result, and therefore a high cost. Liquefaction currently consumes c45% of energy brought by H2, and there is also the risk of leakage. The advantages of ammonia are that it is possible for direct use, potentially the cheapest carrier, existing NH3 infrastructure and regulation. Disadvantages include that it requires treatment due to toxicity and smell, and it requires very high energy input for de-hydrogenation. LOHCs store hydrogen in a chemical bonded form through reversible, catalytic hydrogenation with the potential for application at scale a key advantage.

FIGURE 41

LH2 carrier

Source: Shell

Compression and transport through pipeline works for shorter journeys

There are close to 5,000 km of hydrogen pipelines around the world today, compared with around 3mn km of natural gas transmission pipelines. These existing hydrogen pipelines are operated by industrial hydrogen producers and are used mainly to deliver hydrogen to chemical and refinery facilities. The US has 2,600 km, Belgium 600 km and Germany just under 400 km, according to a Shell study in 2017, although we expect both of those figures to have grown in the intervening years. More independent pipelines are likely to be built, but the scale of replicating the natural gas network on a standalone basis for hydrogen would be prohibitively expensive. As a result, we expect to see integration with existing pipelines to facilitate the use of hydrogen. Hydrogen pipelines offer the most economical way of transporting hydrogen, assuming a scale-up in hydrogen consumption. Even at the early stages of blending hydrogen with other methane gases, the transition will require adjustments and replacement of infrastructure and appliances.

Implications of the hydrogen conversion for gas networks

Reflecting the work of our Utilities team, we are moderately optimistic about the additional capex required for converting conventional methane pipelines into hydrogen or blending pipelines. We estimate that the additional cost would not be higher than 1.1x the current replacement cost, if replacement is actually needed. This conclusion is based on the following assumptions:

1. The volume of energy transported through pipelines should decrease, as hydrogen is less dense than methane. The maximum blend allowed today (10%) would decrease the volume of energy transported by just 4%, but an 85% blend would reduce the energy volume transported by c25%. Considering the current under-utilisation of the average European pipeline, we do not see requirements to invest further in new pipeline capacity to transport volumes equivalent to current European gas methane consumption.

2. The current methane network will need to be amended with additional networks to connect hydrogen-producing facilities with either the converted network or with hydrogen storage facilities. As suggested by the Leeds City Gate project, the network will also need additional storage capacity for hydrogen.

3. Parts of the gas network will need to be replaced. Although polyethylene and other polymers are the materials best suited for hydrogen pipelines, current steel pipelines are also suitable, if they are made of low-grade steel (less exposed to embrittlement than high-grade steel pipelines). Additionally, we would expect reinforcement of the current methane gas network, as hydrogen production facilities and hydrogen storage will need to be connected to the network.

4. Opex could double, as more frequent inspections of leaks increase the cost of maintaining the pipeline. Further digitalisation of the network could offset part of that opex increase.

5. On the demand side, complexity increases exponentially. For gas network operators, the cost will relate to providing information about the product being transported. The pipeline will transport different degrees of blending, depending on the demands by zone: residential areas will demand low blending in the first stages of de-carbonisation, while industrial zones will demand higher blending, as they already have industrial appliances to handle high blending, such as membranes to separate methane from hydrogen.

Focus on Italy – Snam a key player in this market

As a useful example of how a country can adapt to a hydrogen network, we focus on Italy, which we see following the hydrogen route, given its abundant solar resource and the consequent risk of excess renewable capacity and power price deflation. Additionally, Italy has a long-established electrolyser manufacturing industry and imports via North Africa are also a possibility.

We see the key player in this market as Snam, as we think it is best-placed to capitalise on the Italian market de-carbonisation opportunity by developing a hydrogen network. Our Utilities team forecast total investments of over EUR3bn for this purpose executed by Snam.

Enel also offers a growth opportunity in the Italian market, in our view, where it currently holds the number one positions in Italian renewables (with only a 5% market share) and power distribution (with an 85% market share).

In April 2019, Snam was the first company in Europe to introduce a mix of 5% hydrogen and natural gas in its transmission network. The trial, which took place successfully in Contursi Terme, in the province of Salerno, involved supplying H2NG (hydrogen-natural gas mixture) for a month to two industrial companies in the area, a pasta factory and a mineral water bottling company. If Snam increased its total gas volumes transported annually by 5% through the addition of hydrogen, it would imply an increase to the network of 3.5bn cubic meters each year – equivalent to the annual consumption of 1.5mn households, which would allow CO2 emissions to be reduced by 2.5mn tons.

At present, Snam is committed to verifying the full compatibility of its infrastructure with increasing amounts of hydrogen mixed with natural gas, as well as studying hydrogen production from renewable electricity. By the end of the year the experiment will be repeated again on the same part of the network, bringing the amount of hydrogen in the mix supplied to the two companies involved to 10%.

Snam is also part of the HYREADY network, which involves major European players committed to cooperating to make existing gas transport networks compatible with the injection of increasing percentages of hydrogen. Internationally, the company is part of the Hydrogen Council, an initiative launched in 2017 at the World Economic Forum in Davos to create a coalition of leading companies in their respective sectors, committed to accelerating hydrogen investments.

According to a study conducted by Navigant and commissioned by the European consortium Gas for Climate, of which Snam is also a member, Europe has the potential to produce 270bn cubic meters of hydrogen and biomethane by 2050, which would lead to full decarbonisation with economic savings of EUR 217bn a year compared with an energy scenario that does not include the use of gas.

As part of the research, Snam also collaborates with the Bruno Kessler Foundation, which has developed a study on technologies designed to revolutionise decarbonised hydrogen production in the near future, with a view to making it an integral part of the long-term solution for a carbon-neutral energy system.

Snam, with the analytical support of McKinsey, has conducted a study on the potential role of hydrogen in the Italian energy system, which shows that Italy is particularly well suited owing to its excellent natural resources to generate renewable power and to its existing gas infrastructure network – including connections to North Africa.

The key findings of the report are as follows:

- **Hydrogen could provide almost one-quarter of all energy in Italy by 2050.** In a 95% decarbonisation scenario (needed to reach the 1.5°C threshold), hydrogen could supply as much as 23% of its total energy consumption by 2050 – more than today's combined electricity share (20% in 2018) from renewable and fossil fuels. The biggest potential is in transport, buildings and industrial applications where some players use grey hydrogen today (e.g. refining, high-heat processes).

  - Long-haul trucking should become one of the first segments to make hydrogen economic. Hydrogen will achieve total cost of ownership parity with diesel by 2030, even without additional incentives.

  - Blending hydrogen in the grid (up to a 10-20% mix) for building heating is another area of potential widespread adoption that could take place in the short to mid term.

  - Hydrogen will also integrate renewables into the electricity grid: it can provide flexibility, seasonal storage – in collaboration with other storage solutions covering shorter-term balancing needs (e.g. batteries for intraday balancing) – and alternative energy transportation solutions to the grid.

- **Low-cost hydrogen should break-even before 2030 – earlier than other European markets.** Given Italy's strong renewables endowment, 'green hydrogen' from renewable sources will break even with 'grey hydrogen' from natural gas 5-10 years earlier than in many other countries, including Germany. This makes Italy an ideal place to begin the deployment and scale-up of electrolysis for industrial and other uses (especially in cases where break-even should occur in the next decade).

- **Italy could import hydrogen from North Africa, at a cost 14% below domestic production.** Italy could employ its existing pipelines to Northern Africa to put solar panels 'where the sun shines' more, produce hydrogen locally, and then transport the hydrogen to Italy through the pipes. This could also allow for hydrogen exports through Italy into Europe.

- **Italy's gas infrastructure supports hydrogen's potential.** Italy's wide-ranging infrastructure can connect the renewables-rich south with the demand centres in the north, and make possible highly independent, fully renewable energy systems on Italy's islands.

- An interesting reference case is Sicily. Hydrogen in Sicily is a cost-competitive way to start decarbonising industry that is hard to decarbonise in other ways. 50MW of electrolyser capacity could initially be built to produce renewable hydrogen, leveraging wind and solar lower production costs, which could be transported in (existing) pipelines, used in a local refinery, for a hydrogen-fuelled train and as part of the local gas grid for household heating. Future expansion could increase the scale of the project to include a 2 GW electrolyser, the supply of two refineries and the replacement of a significant share of the 10-20% of natural gas in household heating.

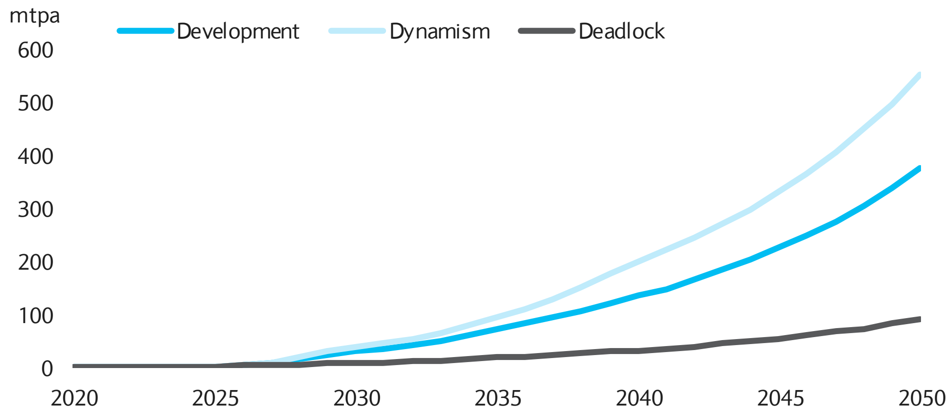
- Reflections on the Italian system: enablement of hydrogen value chain development. To start the deployment of hydrogen in Italy, industry and policy-makers should work together to put a supporting regulatory framework in place and begin deployment. International co-operation could accelerate the uptake of hydrogen across the EU and create a single unified European hydrogen market in the future.

Hydrogen in heating & industry

The key driver of the increase in demand for hydrogen we project is its use in the industry and heating segments. This covers both domestic and industrial heating, including low-carbon steel and furnaces for medium-grade heat. The chart below shows our demand assumptions from this segment under our three scenarios.

FIGURE 42

Evolution of heating and industry demand – scenarios



Source: Barclays Research estimates

Residential demand

Based on IEA data, buildings globally account for 30% of global final energy use, with c75% of that used for heating, hot water and cooking. Using the IEA data, energy demand was 2200mtoe in 2017, of which half was fossil fuels and 620mtoe natural gas based. It also accounted for nearly 28% of global energy-related CO2 emissions. As we highlight above, hydrogen can provide a low-carbon alternative for heating as it can largely use the same infrastructure network from pipeline to boilers. There are a number of different methods to deploy hydrogen through the grid for heating, which we show in the table below.

FIGURE 43

Methods for deploying hydrogen in buildings heating

Strategy	Advantages	Requirements
Blending	Low-cost alternative Compatible with most existing infrastructure and equipment	Blending ratios 5-20% More efficiency measures needed to further abate CO2
Methane produced from clean hydrogen	Full decarbonisation of gas if low CO2 inputs Use of existing gas networks	Investment in methanation plants increases cost R&D to improve process efficiency Source of carbon
100% hydrogen	Full decarbonisation of gas if low-carbon hydrogen Lower losses than synthetic methane	Investment to upgrade gas network and equipment Co-ordination between gas suppliers and distributors
Use of fuel cells and cogeneration	Multiple energy services – eg heat and electricity. Demand-side response potential	Investment needed in fuel cell or cogeneration technology R&D needed to improve equipment efficiency

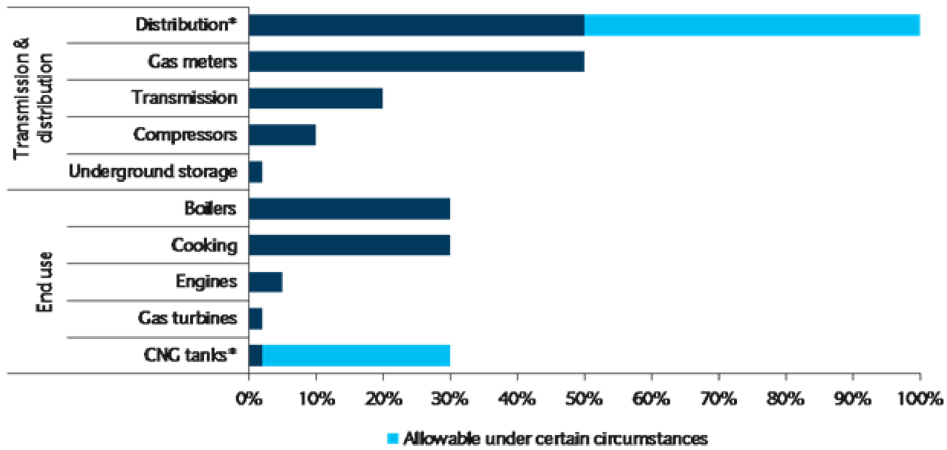
Source: IEA, Barclays Research

The chart below shows the tolerance of existing elements of the natural gas network to hydrogen blend shares by volume

FIGURE 44

Tolerance of selected existing elements of the natural gas network to hydrogen blend shares by volume

Source: IEA



Hydrogen is essentially used very little in building heating at present and so in the early days we see initial deployments as likely to be through blending. Based on IEA data, a 3% blend of hydrogen would boost require close to 12mt of hydrogen. Eventually 100% hydrogen deployment is possible if it uses existing infrastructure. The alternative is the full electrification of heat using high efficiency heat pumps. We see both co-existing given different cost implications.

There are some demonstration projects today and one of the Hydrogen Council flagship projects is the Ene-Farm project in Japan. The $10bn project aims to deploy 1.15m hydrogen fuel cell combined heat and power units on top of 250k already operating, with the potential for a future roll-out of 3.9mn units by 2030. It is expected that the initial programme will see the abatement of 1.33 tonnes of CO_2 per year. The initial unit cost has come down 75% in 10 years but is still subject to government subsidy. This is currently 6-10%.

Hydrogen will not make sense for all buildings – some will be cheaper and easier to electrify, others will find the near like-for-like infrastructure will be attractive, particularly if the blending route is used nearer term, which would have relatively little impact on boilers and cooking.

Cost is a consideration here, with gas vs electricity tipping points, and hydrogen blending is likely to lead to higher natural gas prices than otherwise – and this increase in costs could trigger a switch to heat pumps.

100% hydrogen is likely to make sense for a number of buildings and it is interesting that Bosch has introduced a 100% hydrogen-ready boiler.

Key to deployment will be changes in household behaviour. And this can work both ways. Hydrogen-ready boilers will involve little customer behaviour change, whereas electric heat pumps may involve greater infrastructure change.

Yet there is likely to be resistance from households to spend money upfront even if the returns might be worth it. In that regard, we see more potential for heating sources where the upfront investment is similar to a gas boiler, even though the heat cost might be more expensive, like the H2 boiler or electric resistance. If power prices decline as a consequence of higher renewables penetration, there is a chance that electric resistance might be the cheapest solution for households, as the delivered heat cost might decline compared to the heat cost for a hydrogen boiler.

Based on BNEF data, hydrogen used for heating a household is more expensive than electricity but on average more economic than using an oil boiler. Compared to a gas boiler, the cost of delivered heat is cheaper for air- and ground-sourced heat pumps, and both are cheaper than a hydrogen gas absorption heat pump from a perspective of upfront cost. Less capital-intensive hydrogen boilers and fuel cells have similar consumption costs as electric resistance, but significantly higher upfront costs.

FIGURE 45

Operating costs and indicative upfront costs for different heating technologies, for an average 4-bedroom house

			Delivered heat cost ($/GJ)			Delivered heat cost (gas boiler)		
	Thermal efficiency	Fuel	Low	High	Future capital cost ($/ unit)	Low	High	Future capital cost ($/ unit)
Gas boiler	92%	Natural gas	6.2	37.1	3660	100%	100%	100%
H2 boiler	90%	Hydrogen	15.7	47.0	4000	253%	127%	109%
H2 fuel cell	30-55%	Hydrogen	25.6	141.0	5000	413%	380%	137%
H2 gas absorption heat pump	n.m.	Hydrogen	10.8	32.5	12000	174%	88%	328%
Air-sourced heat pump	n.m.	Electricity	3.1	42.3	6000	50%	114%	164%
Ground-sourced heat pump	n.m.	Electricity	2.5	24.3	11400	40%	65%	311%
Electric resistance	100%	Electricity	13.9	97.2	3100	224%	262%	85%

Source: BNEF, Barclays Research

Compared to an oil boiler, a hydrogen boiler follows similar patterns, although the cost of delivered heat is in both cases (hydrogen and electricity) significantly cheaper than with an oil boiler. Hydrogen boilers could be an interesting option to replace oil boilers, but electricity power devices are cheaper.

FIGURE 46

Operating costs and indicative upfront costs for different heating technologies, for an average 4-bedroom house

			Delivered heat cost ($/GJ)			Delivered heat cost (oil boiler)		
	Thermal efficiency	Fuel	Low	High	Future capital cost ($/ unit)	Low	High	Future capital cost ($/ unit)
Oil boiler	90%	Fuel oil	19.7	49.1	4200	100%	100%	100%
H2 boiler	90%	Hydrogen	15.7	47.0	4000	80%	96%	95%
H2 fuel cell	30-55%	Hydrogen	25.6	141.0	5000	130%	287%	119%
H2 gas absorption heat pump	n.m.	Hydrogen	10.8	32.5	12000	55%	66%	286%
Air-sourced heat pump	n.m.	Electricity	3.1	42.3	6000	16%	86%	143%
Ground-sourced heat pump	n.m.	Electricity	2.5	24.3	11400	13%	49%	271%
Electric resistance	100%	Electricity	13.9	97.2	3100	71%	198%	74%

Source: BNEF, Barclays Research

Industrial demand

Industrial demand is key in the deployment of hydrogen and the main source of demand that growth we project. The table below summarises the use of hydrogen in industrial applications and future potential based on the IEA report '*The Future of Hydrogen*' (June 2019). The four main sources of industrial demand are:

- Oil refining
- Chemical production
- Iron & steel production
- High-temperature heat

FIGURE 47

Summary of hydrogen use in potential industrial applications and future potential

Sector	Current hydrogen role	2030 hydrogen demand	Long-term demand	Opportunities	Challenges
Oil refining	Used primarily to remove impurities such as sulphur from crude oil and upgrade heavier crude. Used in smaller volumes for oil sands and biofuels.	Increased due to tighter pollutant regulations but moderated by lower demand growth.	Highly dependent on future oil, but still likely to remain an important source of demand in 2050. Our own projects are based on peak demand 2025-2030.	Retrofit natural gas or coal based hydrogen with CCUS. Replace merchant hydrogen purchases with hydrogen from low-carbon electricity.	Hydrogen production and use is closely integrated with refining operations. Will be dictated by long-term demand for oil
Chemical production	Central to ammonia and methanol production and used in several smaller scale chemical processes.	30% plus increase for ammonia and methanol due to economic and population growth.	Hydrogen demand for existing uses set to grow despite efficiency and recycling.	Retrofit or new-build hydrogen with CCUS. Use low-carbon hydrogen for ammonia and methanol production.	Competitiveness' of low-carbon hydrogen depends on gas supplies and electricity prices. CCUS retrofitting not a universal option.
Iron and steel production	7% of primary steel is produced via the direct reduction of iron route, which requires hydrogen. The blast furnace route produces by-product hydrogen as a mixture of gases which are often used on-site.	A doubling under existing policies as the DRI route is used more.	Steel demand keeps rising even accounting for efficiency. 100%-based hydrogen production could dramatically increase demand for low-carbon hydrogen long term.	Retrofit DRI facilities with CCUS. Around 30% of natural gas can be substituted for electrolytic hydrogen in the current DRI route. Fully convert steel plants to utilise hydrogen as the key reducing agent.	
High-temperature heat	Virtually no dedicated hydrogen production for generating heat.		Heat demand likely to rise, providing an opportunity if hydrogen can be cost competitive.	Hydrogen from any source could replace natural gas, particularly in industrial clusters. Blends with natural gas are more straightforward but less cost effective	Hydrogen expected to compete poorly with biomass and direct CCUS. Key will be competitiveness with electrification.

Source: IEA, Barclays Research

Of these, we expect to see the main focus on industrial demand from chemical production and steel production.

Spotlight on steel

Steel industry under pressure to eliminate emissions over the long term

Producing a ton of blast furnace steel releases between 1.6-2.2t of CO2, depending on electricity grid mix and energy efficiency of the steel mill. Steelmaking accounts for ~9% of world carbon emissions. Consumer demand for zero-carbon lifecycle products will only grow. As a result of this, plus likely higher carbon prices as a result of tightening allowances under EU ETS phase four (2021-30), European steelmakers are under increasing pressure to reduce and ultimately eliminate CO2 emissions. This is demonstrated by most major European steelmakers' targets to reach carbon neutrality 2045 (SSAB) or 2050 (Mittal and ThyssenKrupp).

There are a number of technological routes to deliver zero-emissions steel:

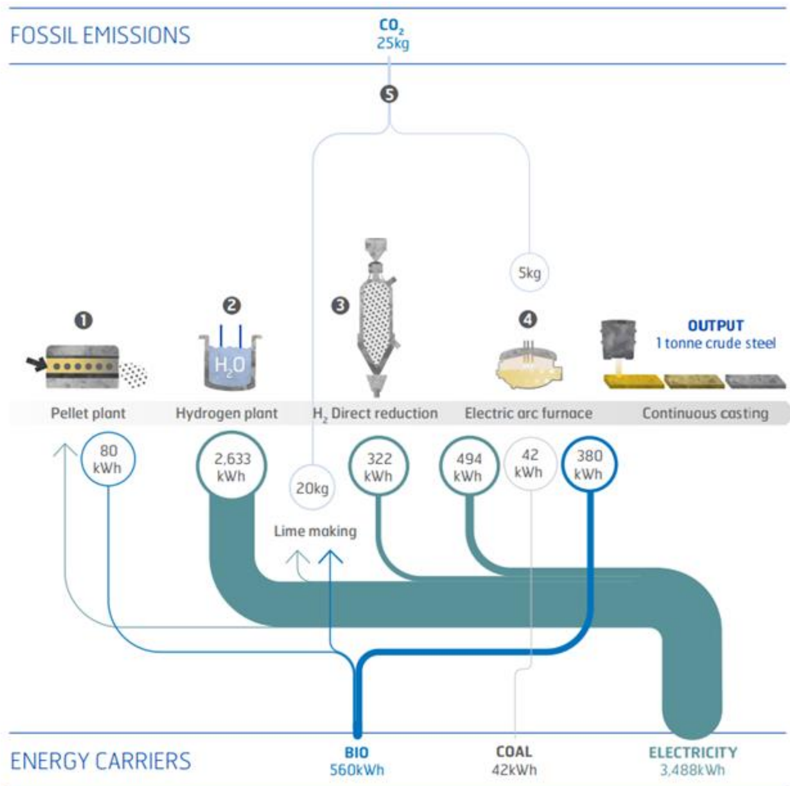
- **EAF + renewables:** Electric arc furnaces (EAFs) based on recycling steel scrap which, combined with renewable energy, can reduce carbon emissions almost entirely. EAFs charged with direct reduced iron (DRI) (>70% Fe iron ore) using natural gas as a reductant and renewable energy sources can also reduce emissions significantly compared to conventional blast furnaces. Several European steelmakers are converting legacy blast furnaces (BFs) to EAFs fed with scrap or DRI, with emission levels dependent on the carbon intensity of the power source and iron ore feed. EAF technology is mature, accounting for 28% of global steel output.

- **Fossil fuels with carbon capture:** Conventional blast furnace steelmaking converts iron ore to metallic iron by reduction with coke. The iron oxide and carbon then react to form CO and CO_2 gases, as well as metallic iron. Capturing CO2 from this route (or indeed from conventional DRI with natural gas) with carbon capture and storage (CCS) is an alternative low/zero carbon steelmaking route. However, CCS technology is currently not commercial under current regulatory/fiscal regimes in Europe. As a result, Mittal for example estimates CCS would add 30-50% to capex/opex per ton and estimates a horizon for commercial viability of 5-10 years. There are no examples of this technology being deployed at scale yet. Global Carbon Capture and Storage Institute (GCCSI) estimates at the end of 2019, there were 51 carbon capture and storage facilities across the world - 19 in operation, four under construction and 28 in different stages of development. Collectively, they have an estimated capacity of 96m tonnes of CO2 per annum (~0.3% of global emissions).

- **Hydrogen-based DRI:** The potential for hydrogen in steelmaking is to produce DRI or iron using hydrogen as the main reductant rather than coke or natural gas. The off-gas of the reduction process would be water rather than CO2, according to the simplified reaction: $FeO + H_2 \Rightarrow Fe + H_2O$. The result is a solid porous sponge iron, which then is fed into the EAF alongside scrap, as above. Assuming this is produced using renewable electricity, the reduction in CO2 emissions is almost 100% compared to traditional methods.

FIGURE 48

Schematic of HYBRIT technology route with associated energy and carbon intensities



Source: Company data

Who is doing it?

Most listed European steel producers are currently piloting variants of hydrogen-based steelmaking, including SSAB, ArcelorMittal, voestalpine and ThyssenKrupp.

- **SSAB** is the most advanced, having formed a JV called HYBRIT with Vattenfall (Swedish renewable power company) and LKAB (Swedish iron ore company) to produce zero-emission steel. In 2018 construction began on a hydrogen electrolysis and storage facility and pilot-scale steel plant at SSAB's site in Lulea, Sweden. The total cost for the pilot phase is estimated at SEK1.4bn, with funding from the Swedish government and JV partners. The pilot phase will run until 2024, moving to a demonstration phase in 2025 and targeting first commercial sales of fossil-free steel from 2026. The technology route is EAF fed by DRI produced using hydrogen, powered by renewables as shown in the schematic above.

- **ArcelorMittal** is building a pilot plant at its Hamburg mill to use hydrogen as a reductant in DRI production with a €65m initial investment. It targets production of 100ktpa of DRI using 'grey hydrogen' sourced from natural gas initially, with subsequent conversion to 'green hydrogen' to follow when renewable energy capacity is available. The company is piloting a number of alternative potential 'green steel' technologies in addition.

- **Voestalpine** is building a pilot plant at the Linz steelworks in Austria to process high-grade iron-ore concentrates using hydrogen as a reductant. The pilot plant will be commissioned in Q2-20 with capacity of 250ktpa, using hydrogen from a 6MW green hydrogen electrolysis pilot plant, which was commissioned at Linz in November 2019 by the H2FUTURE consortium, of which Voestalpine is a member alongside Siemens and Verbund with financial backing from the EU.

- **ThyssenKrupp** is testing the use of hydrogen injection into blast furnaces as a reductant to replace met coal/PCI at the Duisburg steelworks. The company plans to gradually extend the use of hydrogen to three blast furnaces at the site from 2022 assuming the pilot testing demonstrates commercial and technical viability.

Constraints – renewable energy and hydrogen capacity

Alongside proving commercial and technical viability for the technology, the principal constraint we see is power availability and prices to facilitate hydrogen production. The estimated electric power intensity of 3488kWh/ton for HYBRIT compares to 235kWh/t for conventional BF route i.e. 15x higher. The CEO of SSAB's HYBRIT JV estimates it would require 15TWh per year to replace SSAB's current steelmaking footprint with zero carbon steel, equivalent to 10% of Sweden's current electricity consumption.

However, the HYBRIT pre-feasibility study in 2017 concluded that fossil-free steel at then-prevailing electricity, coal and CO2 emissions prices would be 20-30% more expensive than conventional BF steel. Assuming significant growth in renewable power capacity, resultant lower power prices and increasing CO2 emissions costs under the EU ETS, the competitiveness of hydrogen-based steel should improve over time. The product could also command a premium reflecting consumer demand.

Timeframes for commercialisation long-dated

The timeframe for the technology to be commercialised is relatively elongated due to the immaturity of the technology, limitations on renewable generation capacity and hydrogen production/storage infrastructure. SSAB is targeting first commercial production from 2026 and broader commercialisation by 2035. ArcelorMittal estimates a 10- to 20-year commercial horizon for hydrogen-based EAF steelmaking, as much reflecting energy constraints as technical viability. Voestalpine estimates 2035 for technical maturity of the technology with commerciality depending on availability of competitively priced renewable energy at that point. Thyssenkrupp expects the hydrogen route should become fully effective by 2050.

Commodity implications – bearish met coal over the (very) long term

Clearly the major negative implication is for met coal demand which would be eliminated by using the hydrogen-based steelmaking route. We expect the steel industry to pursue a number of different zero-carbon steel technologies and at this point the hydrogen-based process remains commercially unproven. So any impact on met coal demand is likely to be very gradual but could potentially affect a meaningful amount of global demand over the long term: European met coal imports are ~60mt out of a global seaborne trade of ~250mtpa (24% of the market). It is likely that if proven commercially the technology deploys globally over the longer term: we note Baowu in China has built a pilot plant experimenting with nuclear power. Stocks most directly at risk would be US and Russian met coal exporters (Warrior, Mechel, Evraz) which supply the European market, while other major exporters into the Pacific basin could also be affected indirectly (BHP, Anglo American, Teck, South32).

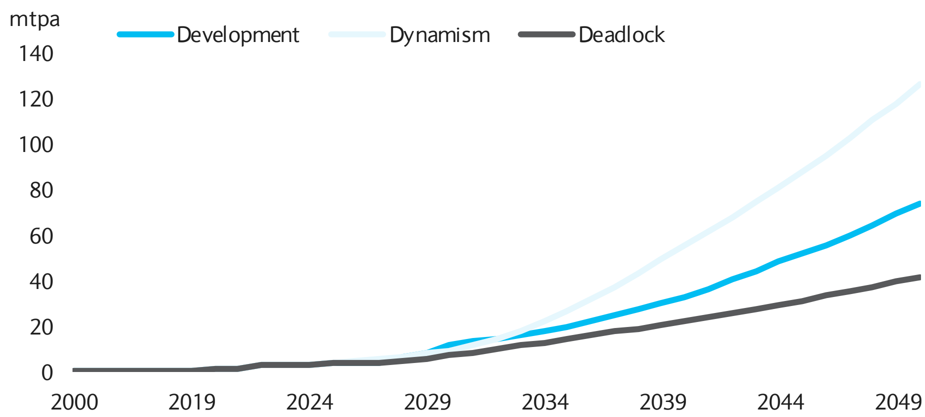
Implications for iron ore producers: over the long term we see significant demand growth for higher grade iron ore for DRI feedstock in Europe, regardless of the success of hydrogen technology given moves by steelmakers to convert BFs to EAFs. Over time this will dictate significant capital investment by pellet producers to upgrade their beneficiation facilities to produce DR grade pellet. Stocks impacted: Ferrexpo, Vale (pellet operations) and Rio Tinto (via IOC). Beneficiaries would be Anglo American which already has the highest grade iron ore portfolio via Kumba and Minas Rio, and Vale whose IOCJ product is the most liquid high-grade product. We see potential for Rio Tinto to participate in the development of Simandou infrastructure to potentially give it access to higher grade ore for blending over the longer term to mitigate grade decline in the Pilbara mine portfolio.

Clean fuels – hydrogen has a major role to play in decarbonisation

After the industrial and heating segment, one of the key areas where we see material developments is in the decarbonisation of transport. We see the mobility segment as making up 10-15% of end-user hydrogen demand, with the chart below showing demand under our three scenarios reflecting the shift in consumer preferences to more environmentally friendly mobility combined with tougher emission legislation and eventually banning of the sale of internal combustion vehicles (ICEs), we expect demand for zero emission vehicles to grow materially in coming decades.

FIGURE 49

Hydrogen demand from mobility solutions – scenarios

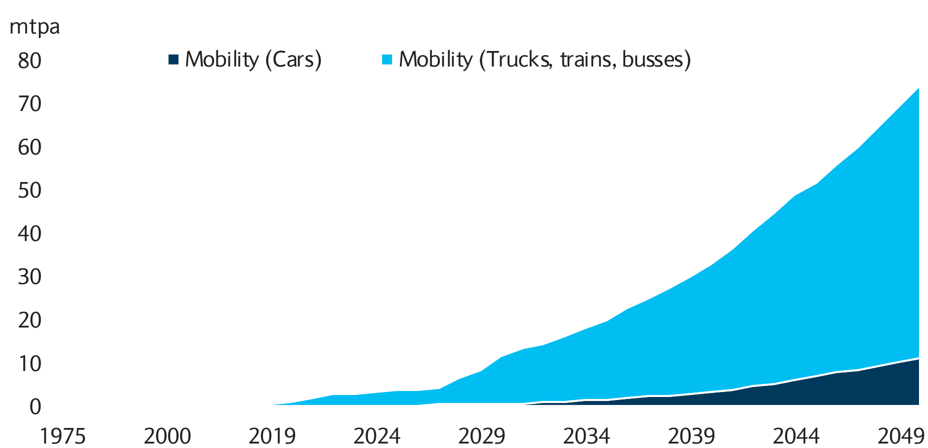


Source: Barclays Research estimates

This breaks down into demand from long-haul or mass transportation – such as trucks, trains and buses and then passenger cars – and fuel cell electric vehicles (FCEVs). Our assumption is that battery electric vehicles (BEVs) remain the dominant form of transport mode for passenger vehicles. As a result, although demand from this segment grows in our scenarios, it remains a relatively small part of the mix. Our upside scenario does assume a more rapid penetration rate, primarily from passenger cars.

FIGURE 50

Hydrogen demand from transport – Development scenario



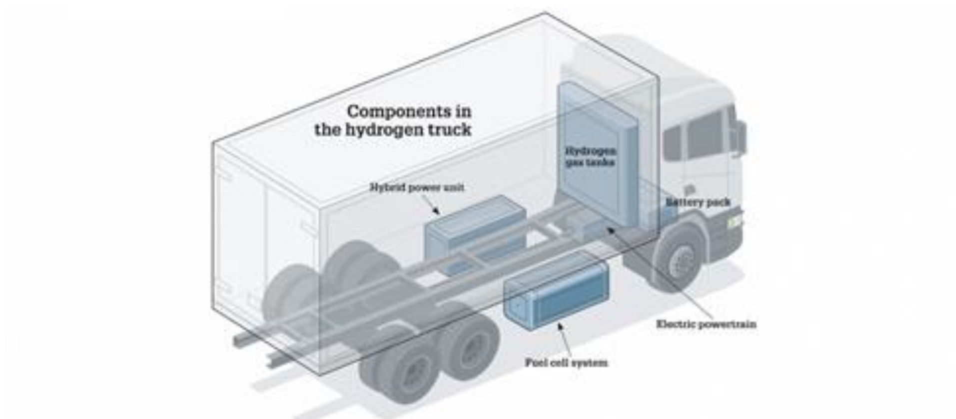
Source: IEA Barclays Research estimates (from 2018)

Hydrogen fuel cells

An FCEV uses hydrogen as a fuel, stored under pressure in a small lightweight tank with a fuel cell system which includes the fuel cell stack. The fuel cell stack is as it describes – a stack of many individual fuel cells. Hydrogen and air (containing oxygen) are fed respectively into the anode (negative) and cathode (positive). At the anode, the hydrogen molecules release electrons, which travel to the cathode, creating an electrical current. The hydrogen ions, created when the electrons are released, travel by a different route to the cathode, where they combine with oxygen and the released electrons to form water. The power generated from this is then supplemented by additional power from a battery when needed. The battery is also used to store additional short-term energy generated in FCEVs equipped with regenerative braking. Fuel cells are typically highly efficient relative to internal combustion engines. The fuel cell technology is used in both trucks and passenger cars alike

FIGURE 51

How fuel cell trucks work



Source: Scania

An x-EV powered by a fuel cell is, just like a battery EV, pollution-free on a tank-to-wheel basis. If the hydrogen is from renewable sources (via hydrolysis which typically also requires platinum and iridium electrodes to convert water into hydrogen), then the FCEV can become fully zero-emission on a well-to-wheel basis. As a result, we believe fuel cell technology is needed to achieve complete decarbonisation of transportation. The increased availability of low-cost renewables, coupled with pressure on emissions, is helping major corporations and governments consider hydrogen as part of their long-term options.

Key to our analysis is our assumption as to the extent to which FCEVs will penetrate the transportation mix over coming decades. We believe that the adoption of FCEVs will be largely a function of cost-competitiveness relative to BEVs and convenience of use underpinned by widespread availability of re-fuelling infrastructure.

Why choose an FCEV?

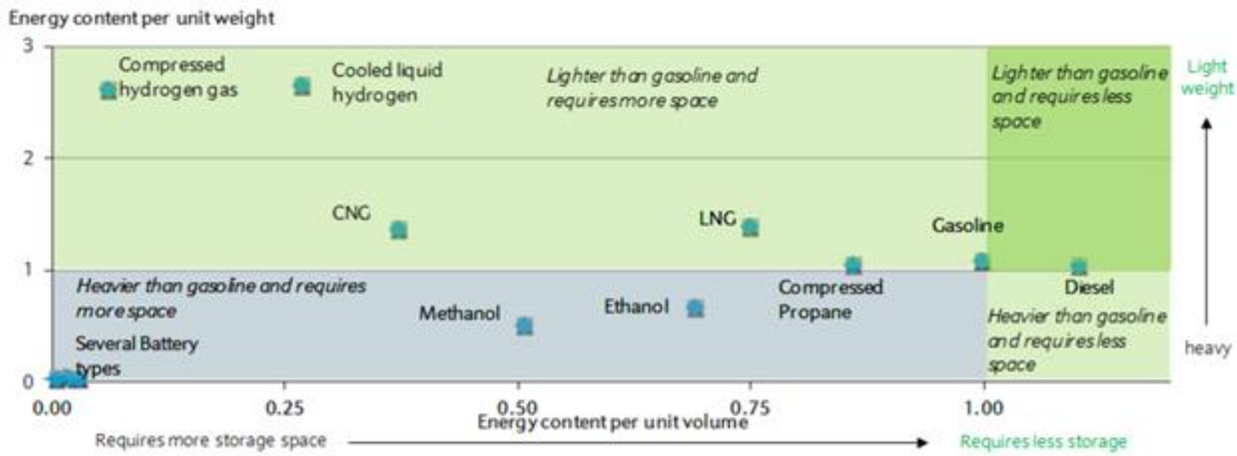
- **Range is superior to BEVs** – one of the chief challenges for the BEV is range. The range for most BEVs is at or under 250 miles. It just happens that the vast majority of trips undertaken by drivers cover less than 100 miles, but range anxiety remains a concern. For FCEVs, however, this isn't an issue given they have comparable range to conventional cars. As long as BEVs struggle to match that range, FCEVs might be viewed as the more obvious zero-emission substitute for vehicle owners.

- **Refuelling is a matter of minutes** – closely related to the issue of range is the length of time it takes to refuel an electric car. Most BEVs currently on sale can only manage 20-

35km after an hour's charge – making a 'pit-stop' during a long journey less than speedy. The FCEV refuelling experience is similar to that for conventional vehicles and, based on our own calculations, assuming a $16/kg price of hydrogen, the cost is at a c15% premium to regular fuel in the US and close to cost-competitive in Europe. Given that compressed hydrogen gas has a much higher energy content per unit of weight, fuel-cell systems can be more easily scaled up without the weight penalties that make BEVs impractical for large sedans, SUVs and pickup trucks.

FIGURE 52

Compressed hydrogen gas is much lighter than battery packs in vehicles

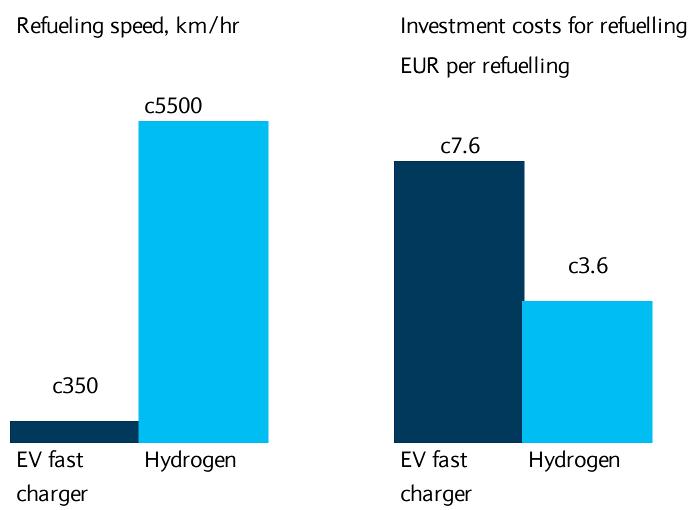


Source: US Energy Information Administration, Barclays Research

- **Infrastructure dynamics don't need to change** – infrastructure characteristics will be dictated by refuelling speeds. Current infrastructure allows hydrogen dispensers to refuel at rate of 80,000-120,000km/day (compared to 240,000km/day for a gasoline nozzle). Electric fast chargers, on the other hand, can manage just 2,000-5,800km/day.

FIGURE 53

Advantages of hydrogen compared to EVs



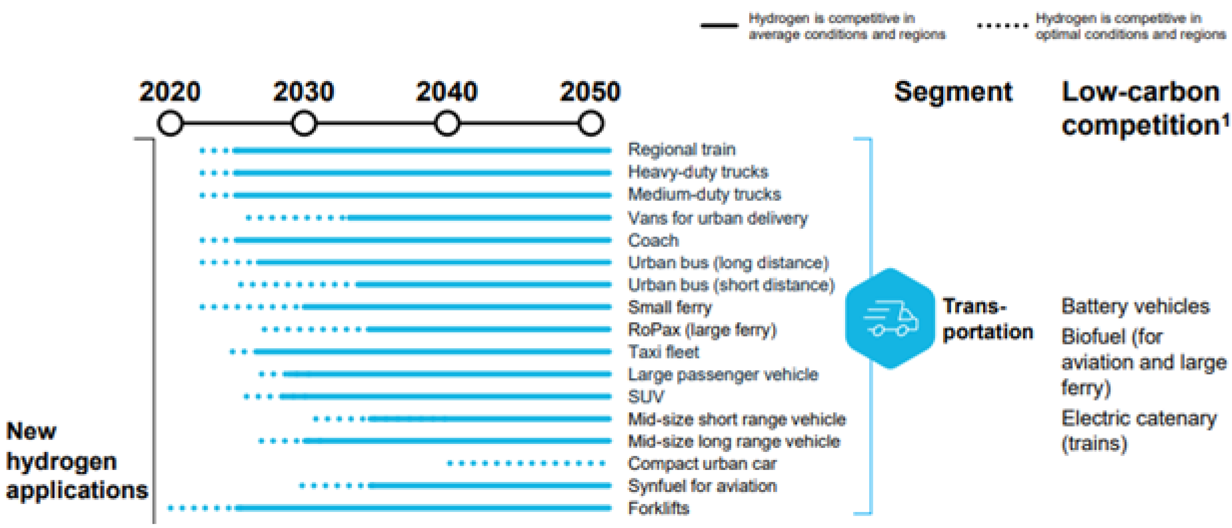
Source: Nationale Plattform Elektromobilitat (NPE), Fastned, Forschungszentrum, McKinsey, Barclays Research

What are the barriers to widespread adoption of fuel cells?

- **Cost** – technological advancements in fuel cell development (PEMFC system) have brought the cost of manufacturing down significantly. Ballard, which develops fuel cells for heavy duty vehicles, highlighted that overall variable costs for the fuel cell modules are down 64% vs 2009 and it is targeting a further 45% reduction by 2023. The cost-reduction trend has progressed reasonably close to the targets originally set by the US Department of Energy (DOE): currently $50/kW (net) for 100,000 units of manufacturing vs. $250/kW in 2011. The DOE's 2025 target is $40/kW with the ultimate goal of $30/kW, which would essentially be the cost-parity with ICE vehicles. Currently this equates to roughly 0.125g per kW for an 80kW stack, a loading of 10g PGMs per car (ICEs contain 3-6g of PGMs) vs. 30g in 2017. The challenge currently is scale, with just over 10,000 FCEVs on the road and 1,000 fuel cell buses and trucks in service. This makes manufacturing costs still too costly relative to ICEs.

FIGURE 54

Cost-competitiveness trajectories of hydrogen applications



Source: Hydrogen Council

- **Infrastructure** – there is still some way to go in developing extensive hydrogen infrastructure for the consumer market. The lead time to develop the fuelling infrastructure should not be underestimated. Only 376 hydrogen refuelling stations were in operation at the end of 2018, with 100 in Japan, 43 in Germany and 38 in the US, although Chevron is planning to conduct "test and learn" pilots in California. Many countries have announced targets to build a total of 1,000 hydrogen refuelling stations during 2025-30. This compares to the Hydrogen Energy Ministerial Meetings vision of 10,000 by 2030. Based on data from a number of company and industry sources, a capital commitment of US$50bn-200bn could be required to build the infrastructure just to enable fuel cell vehicles to achieve 40% market penetration. Finally, since the gas has an extremely low density, storage is an ongoing challenge, since current compression technologies are highly energy-intensive. The use of FCEVs in commercial fleets or public transport (where vehicles regularly return to a single 'point' where a hydrogen refuelling point could be installed) has significant greater attractions.

- **Hydrogen supply** – fuel cells likely won't have an opportunity to take off until a more complete ecosystem, with broader distribution and clean hydrogen generation infrastructure, is created. The cost of hydrogen is likely to fall as demand increases from increasing vehicle adoption.

Mobility – passenger cars

Passenger cars are perhaps the most visible examples of hydrogen progress, with a number already on the market, as we show below, although our base case assumption is that BEVs remain the dominant source of growth. At the end of 2018 the global FCEV stock was 11,200 units, with sales of around 4,000 in that year (80% more than in 2017). Most of the sales continue to be Toyota Mirai cars in California, supported by the Zero Emission Vehicle (ZEV) mandate and expanding refuelling infrastructure. Japan has the second-largest stock, followed by South Korea and Germany. China's presence in FCEVs expanded significantly in 2018, with up to 2,000 small trucks produced. However, as these vehicles wait for the corresponding refuelling infrastructure, just 400 were registered for road use in 2018.

FIGURE 55

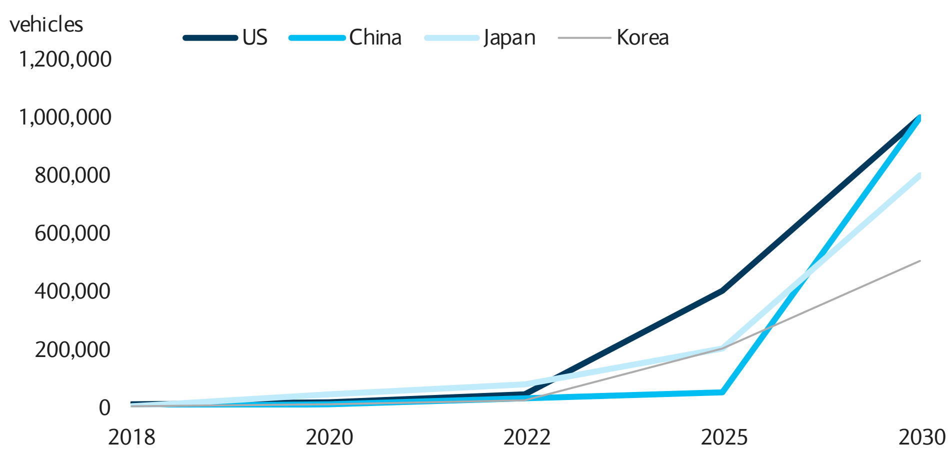
There are already a number of commercially available FCEVs

Source: Company data, Barclays Research

While deployment of FCEVs is low compared with plug-in hybrids (PHEVs) and BEVs, several countries have announced ambitious targets towards 2030, currently amounting to 2.5 million FCEVs. South Korea has gone further with its hydrogen roadmap in January 2019, targeting FCEV production capacity of 6.3 million and 1,200 hydrogen fuelling stations by 2040. The California Fuel Cell Partnership, an industry-government collaboration, issued a vision report in July 2018 targeting 1 million FCEVs and 1,000 hydrogen fuelling stations by 2030. Hyundai announced plans late last year to invest $6.75 billion in hydrogen fuel cell technology, allowing it to produce 500,000 fuel-cell vehicles annually by 2030.

FIGURE 56

FCEV ambitions of key countries



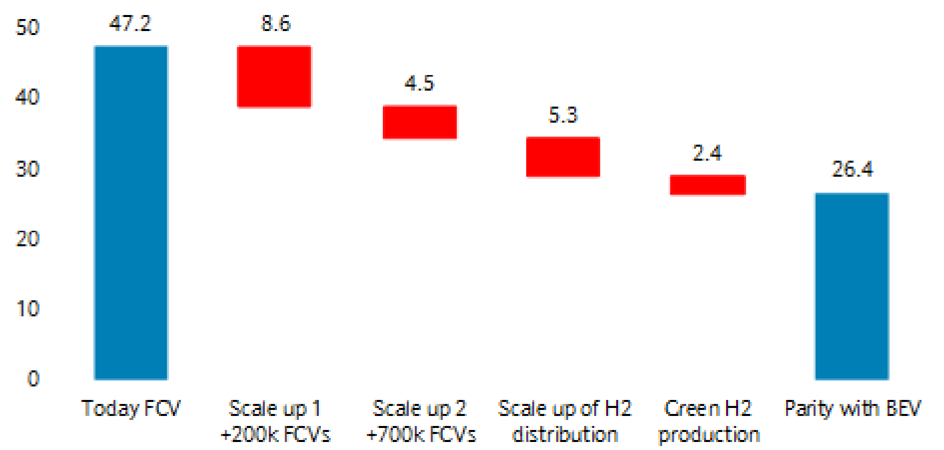
Source: IEA, Barclays Research

FCEVs and BEVs likely to co-exist in a lower-carbon world

As we highlight above, we believe that technological advances will lead to lower production costs, whilst infrastructure investment (supported by government policy) will encourage adoption/penetration, further leading to lower unit costs through economies of scale and enhancing the attractiveness of FCEVs (multiplier effect). That said, we envisage that the two zero-emission powertrains (BEV and FCEV) will co-exist in a lower-carbon world, albeit serving different market segments. FCEVs will be more suited for the commercial/heavy duty segment, given superior technical performance, whilst BEVs will appeal more to the light-duty and passenger motor vehicles segments on lower cost, in our view. Interestingly, the Hydrogen Council anticipates that the cost of a large passenger FCEV could achieve parity with BEVs in 2030, based on a 45% reduction in TCO from US47.2c/km today to US26.4c/km, with the bulk of the savings driven by scaling up to 200k vehicles pa.

FIGURE 57

Total cost of ownership USD/km



Source: Hydrogen Council, Barclays Research

Mobility – trucking, trains, buses and shipping

Trucking and road freight transportation is now the largest oil-consuming sector, comprising 25% of overall oil demand, or about 24.5 mb/d. Road freight transport also represents the lion's share of diesel demand, at 84% of overall consumption, or 14 mb/d. We estimate consumption of oil to range between 17.8mb/d in our Dynamism scenario and 35.3 mb/d in our Deadlock scenario by 2050, and see our Development scenario of 30 mb/d as the most likely outturn. Virtually the entire trucking fleet (97%) is powered by gasoline and diesel, with compressed natural gas, liquid petroleum gas and hybrids making up the rest. There are few electric-powered trucks on the road today.

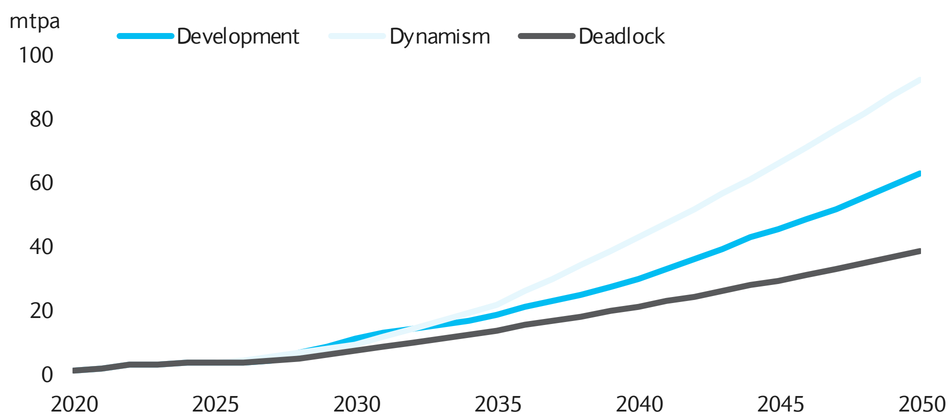
As such, in mobility we see the most potential from long-haul and public transport, with trucking one of the most promising areas and we see demand reaching 60mt by 2050. Currently hydrogen-fuelled trucks make up just 0.3% of the total trucks. There is clear evidence that hydrogen trucks will become increasingly available and are becoming competitive with a fuel efficiency 2-3x that of regular diesel. As examples, the first of Hyundai's hydrogen-fuel-cell-powered, heavy-duty trucks will be on the road in Switzerland in 2020 as part of an order for 1,600 trucks that will be delivered between January 2020 and 2025; the vehicles will be leased out through Hyundai Hydrogen Mobility. Hyundai has equipped its trucks with two hydrogen-fuel-cell stacks driving electric motors. It's a 190kW system with a range of around 400km, depending on the load. There are eight large hydrogen tanks.

Nikola Motors, based in the US, has also seen multiple orders (at least 14,000) with brewing company Anheuser Busch making a booking for 800 Class 8 trucks. According to multiple industry journals, the Class 8 rig is expected to retail for $375k when it goes into production in 2022, compared with $180,000 for the all-electric Tesla Semi with a 500-mile range. A comparable diesel truck sells for about $120k. Since 2018, Shell has been part of a Californian consortium to develop three new large-capacity refuelling stations for heavy-duty hydrogen fuel-cell trucks being developed by Toyota and Kenworth Truck Company.

Our analysis assumes that hydrogen-powered trucks eventually reach 20% of the total fleet – a rapid expansion, but one we see as feasible given the drive towards decarbonisation. The chart below shows total demand from long-haul mobility under our different scenarios.

FIGURE 58

Hydrogen demand from long-haul mobility – scenarios



Source: Barclays Research estimates

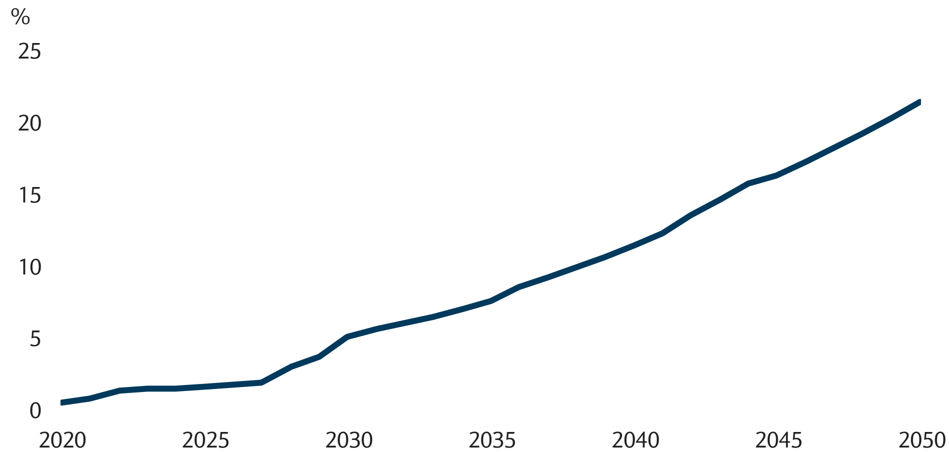
Given the significance of the trucking market, it is worth highlighting the current state of the market. The majority of trucks worldwide are light commercial vehicles (LCVs) – at 117 million, they make up more than 70% of the fleet mix, or over 130 million trucks, according to the IEA. Over 40% of LCVs are in located the US and Europe, with 15% in China and 4% in India. We forecast Heavy-freight trucks (HFTs) to experience the largest growth, and LCVs the least, although LCVs are expected remain the dominant truck on the road, with more than 200 million vehicles globally by 2050. Medium-freight trucks (MFTs) are forecast to experience steady growth under our baseline Development scenario.

The biggest regional trucking market is the US, which at 3.3 mb/d represents 20% of global ground freight oil demand, according to the IEA. HFTs almost exclusively consume diesel. As a result of the US's large HFT fleet, nearly 75% of the overall fleet runs on diesel. The EU has the largest absolute number of HFTs, which gives it a higher diesel mix, as essentially all 2.1 mb/d of oil consumption in the region is diesel. However, the public backlash targeting diesel in EU cities due to health and climate concerns could drive change. China has similar demand levels to the EU, but the majority of trucks are powered by gasoline, which could slow a transition to alternative fuels.

The chart below shows limited penetration to 2027 and then an acceleration in the subsequent two decades. Our base case Development scenario assumes nearly 20% penetration, while our Dynamism scenarios sees faster take-up pushing this to over 30%. Our Deadlock scenario still assumes some hydrogen penetration, but the rate is lower at c10%.

FIGURE 59

Market penetration of hydrogen trucks – Development scenario



Source: Barclays Research estimates

Implications for the platinum market

Platinum used in both fuel cells and hydrolysers to produce green hydrogen

Investors and producers have long regarded hydrogen fuel cells as the next major source of platinum demand, yet have been continually disappointed as PEMFCs (proton exchange membrane fuel cells) still lack wide market acceptance in vehicles. However, recent developments – including companies sharing investment risk and expertise in the supply chain; growing hydrogen refuelling infrastructure; and technical advances that reduce costs and improve durability – indicate that the outlook over the next 10-15 years could be different. Platinum is also used in electrolysers to produce 'green' hydrogen.

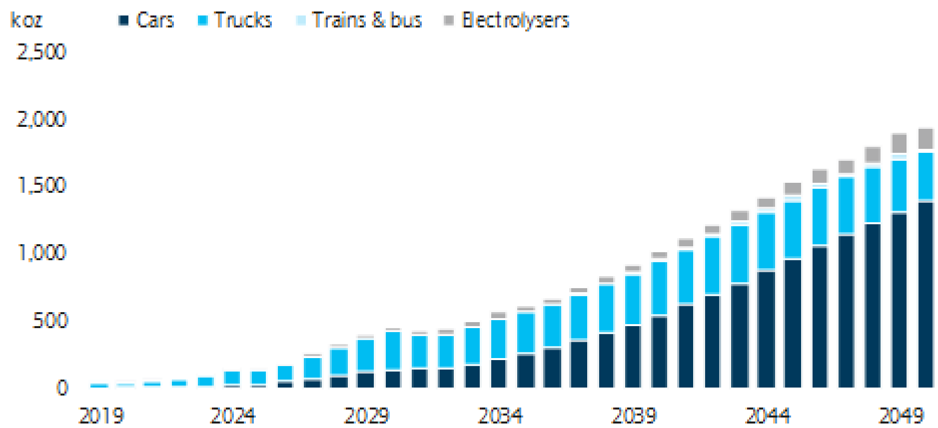
Potential upside for PGM demand more significant beyond 2030

At the Hydrogen Energy Ministerial Meetings in Tokyo in September 2019, 30 countries pledged to deploy 10m FCEVs and 10,000 H_2 refuelling stations over the next 10 years (10-10-10 plan) vs. 10k currently. To put this pledge into context: 10m vehicles by 2030 x c.10g Pt per vehicle would equate to c.3moz cumulative platinum demand over the next 10 years, c.3% of global demand or 8% of autocat demand. These are very ambitious targets indeed. Our discussions with industry contacts suggest even half of this target would be a stretch.

We analyse a number of scenarios assuming varying levels of FCEV penetration and eletrolyser capacity: our base case assumes 2% penetration in annual vehicle registrations and c.10GW electrolyser capacity by 2030, rising to c.7% and 20GW, respectively, by 2040, and 14% and 55GW, respectively, by 2050. We also present high and low cases where we assume 54%/60GW and 3%/18GW by 2050, respectively. Our base case equates to 2.2moz cumulative platinum demand by 2030 or c.2% of total global demand over the period. In 2030 FC platinum demand of c.450koz would be c.5% of global platinum demand and 13% of autocat demand, on our estimates.

FIGURE 60

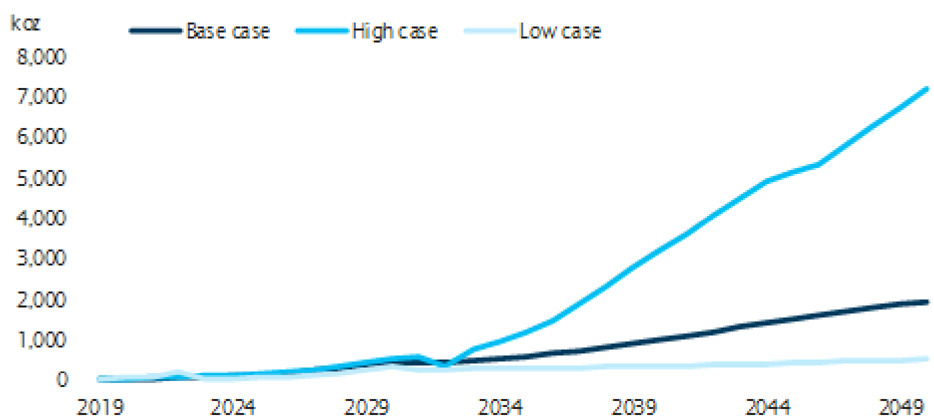
Base case platinum demand in fuel cells and hydrolysers



Source: Barclays Research

FIGURE 61

Base case vs. high and low case for platinum demand



Source: Barclays Research

Shipping

About 80% of the world's 5mb/d of shipping demand comes from international shipping and there is a focus on the sector achieving net zero carbon by 2050 and hydrogen is one of the most promising technologies to help meet this. There are currently no ammonia-fuelled ships in operation but the equivalent of about 3.5mn tonnes a year is traded using ships, according to the IEA. Earlier this year Equinor signed an agreement with Eidesvik Offshore for the modification of the Viking Energy supply vessel to make it capable of covering long distances fuelled by ammonia. The five-year contract will see the vessel act as part of a research project with carbon-free ammonia fuel cells tested on the vessel from 2024 with the ship still able to use LNG. What is interesting about this is that, as the image below shows, the technology can be applied to older vessels. Hydrogen for this project will be produced by Yara through electrolysis. We currently have limited information on the comparative costs of shipping, but the IEA work suggests a 30% premium to LNG.

FIGURE 62

The Viking Energy Vessel

Source: Equinor

Trains

Rail is already highly electrified and is likely to remain the option of choice, but hydrogen is also an option for hard-to-electrify areas. The first zero-emission 'hydrail' project in the US will be in southern California, where the San Bernardino County Transportation Authority plans to operate a FLIRT H2 train from Swiss supplier Stadler from 2024. The first train, with two cars and a rooftop power pack containing fuel cells and hydrogen tanks, will run on a 9-mile commuter rail line between San Bernardino and Redland. In Europe, Alstom already has hydrogen-powered Coradia iLint trains running in Germany on a commuter rail line, with plans in place to run trains in France and the UK.

Government policy

As we have highlighted throughout this note, some form of initial government support is needed, but so too is regulation and policy – from seemingly obvious questions as to determining the appropriate smell and colour for hydrogen through to comprehensive infrastructure support and the removal of critical barriers to hydrogen deployment.

Below we outline key countries and regions and their approach. One of the observations we make is that these policies are rapidly evolving. Another is that, where early policies were focused on fuel-cell vehicles, more recent policies are focusing on hydrogen replacing natural gas for heat and buildings.

UK

In March 2020, ten organisations "at the heart of the UK energy system" launched the Hydrogen Taskforce to offer a shared cross-sector vision for hydrogen in the UK. Its objective is to align a wide range of stakeholders including the government, industry, and an informed public, with the aim of driving investment in hydrogen to promote large-scale deployment.

The Taskforce reported that the UK's commitment to achieving net zero greenhouse gases (GHGs) has sharpened the conversation around hydrogen, which could help the UK to meet its 2050 goal. Last year, the UK became the first major global economy to commit to achieving net zero emissions by 2050.

In addition to a commitment of £1bn from the government over the next Spending Review Period to hydrogen production, storage and distribution projects, the Taskforce's policy recommendations include:

1) Collaborating to establish 100 hydrogen refuelling stations – infrastructure designed for filling vehicles with hydrogen – by 2025 to support the roll-out of hydrogen transport.

2) Developing a cross-departmental hydrogen strategy within the UK government.

3) Developing financial support for the production of hydrogen to blend into the gas grid, industrial use, power generation and transport.

4) Amending gas safety management regulations to enable hydrogen blending into the UK gas grid, and taking the next steps towards achieving 100% hydrogen heating by supporting public trials and mandating hydrogen-ready boilers by 2025.

In Feb 2020, the UK government announced £28m in funding for five projects focused on hydrogen production. The funding is part of a £90m pound package which in turn comes from a £500m innovation fund. The government is also providing funding for 20 projects under its hydrogen supply and industrial fuel switching programmes.

The ten companies involved in the UK task force are BP, Shell, ITM Power, Cadent, Storengy, BOC, BAXI, ARUP, Arval.

China

China is aggressively driving hydrogen and fuel-cell development, and is on track to outpace development in the EU and US. Hydrogen could account for 10% of the entire Chinese energy system by 2040, based on government ambitions.

China is the largest hydrogen producer, producing 22mtpa. This is the one-third of global production. However, production is mostly coal-based and well below $1/kg. China is also home to some of the world's larger electrolyser manufacturers and we expect this to be a source of growth, with the potential to export green hydrogen a real possibility.

Following the national policy changes, local authorities have actively rolled out plans to boost the sector. Over 11 provinces have announced local subsidy schemes to provide additional support to hydrogen fuel-cell vehicles. Most notable have been announcements of hydrogen clusters – areas of highly concentrated industrial activity where the capital cost of hydrogen infrastructure can be shared across market participants.

Over 20 cities have announced plans to develop hydrogen clusters. Chengdu, Datong, and Wuhan (the capital cities of Sichuan, Shanxi and Hubei provinces, respectively) are forging hydrogen capitals. Beijing-Tianjin Hebei between Beijing and Zhangjiakou has plans that include 3,000 fuel-cell vehicles by 2021, a hydrogen corridor to Beijing, cogeneration for communities, backup power and blending hydrogen into existing natural gas infrastructure. Yangtze River delta across Shanghai Jiangsu Province has plans for more than 20 hydrogen expressways before 2020 and more than 500 hydrogen refuelling stations connecting all cities in the region, as well as the Pearl River delta across Foshan-Yunfu, Dongguan and Guangdong.

The first Hydrogen Fuel Cell Vehicle Technology Roadmap was released in 2016, and later that year H2 new energy vehicles and hydrogen infrastructure were added to the 14th Five-Year Plan, outlining targets for mass application of hydrogen in the transport sector.

The target is to have 10k vehicles on the road in 2020 and increase commercial vehicle and passenger vehicles to 10k and 40k in 2025, respectively. There are also ambitious targets to achieve 1 million vehicles on the road and operate 1,000 hydrogen stations by 2030. However, the planned elimination of hydrogen fuel-cell car subsidies at the end of 2020 is unlikely to help it achieve its goal to have a million of vehicles on the road by 2030.

US

In the US policy has been focused on fuel-cell vehicles and we outline the key initiatives below.

	Federal laws and incentives related to hydrogen
Airport Zero Emission Vehicle (ZEV) and Infrastructure Incentives	The Zero Emissions Airport Vehicle and Infrastructure Pilot Program provides funding to airports for up to 50% of the cost to acquire ZEVs and install or modify supporting infrastructure for acquired vehicles. Grant funding must be used for airport-owned, on-road vehicles used exclusively for airport purposes.
Alternative Fuel Excise Tax Credit	A tax incentive is available for alternative fuel that is sold for use or used as a fuel to operate a motor vehicle. A tax credit in the amount of $0.50 per gallon is available for certain alternative fuels including hydrogen. This incentive originally expired on December 31, 2017, but was retroactively extended through December 31, 2020, by Public Law 116-94.
Alternative Fuel Infrastructure Tax Credit	Fueling equipment for natural gas, propane, liquefied hydrogen, electricity, E85, or diesel fuel blends containing a minimum of 20% biodiesel installed through December 31, 2020, is eligible for a tax credit of 30% of the cost, not to exceed $30,000. This incentive originally expired on December 31, 2016, but was retroactively extended through December 31, 2020, by Public Law 116-94.
Fuel Cell Motor Vehicle Tax Credit	A tax credit of up to $8,000 is available for the purchase of qualified light-duty fuel cell vehicles, depending on the vehicle's fuel economy. Tax credits are also available for medium- and heavy-duty fuel cell vehicles; credit amounts are based on vehicle weight. This incentive originally expired on December 31, 2017, but was retroactively extended through December 31, 2020, by Public Law 116-94.
Improved energy technology loans	The US Department of Energy (DOE) provides loan guarantees through the Loan Guarantee Program to eligible projects that reduce air pollution and greenhouse gases and support early commercial use of advanced technologies, including biofuels and alternative fuel vehicles.
Alternative Fuel Tax Exemption	Alternative fuels used in a manner that the Internal Revenue Service (IRS) deems as non-taxable are exempt from federal fuel taxes. Common non-taxable uses in a motor vehicle are: on a farm for farming purposes; in certain intercity and local buses; in a school bus; for exclusive use by a non-profit educational organisation; and for exclusive use by a state, political subdivision of a state, or the District of Columbia.

Source: EIA, Barclays Research

The map below shows the plan for stations in the US.

FIGURE 63

Hydrogen refueling infrastructure planned in the US

Source: Nikola Motors

Most of the development in the US at the moment is currently in California with the California Air Resources Board (ARB) establishing the Zero Emission Assurance Project (ZAP) to offer rebates for the replacement of a battery, fuel cell, or other related vehicle component for eligible used ZEVs and near-ZEVs. Rebates will be limited to one per vehicle. Rebates will be available through July 31, 2025.

The ZEV promotion plan includes:

- By 2020, the state will have established adequate infrastructure to support one million ZEVs.
- By 2025, there will be 1.5 million ZEVs on the road in California and clean, efficient vehicles will displace 1.5 billion gallons of petroleum fuels annually.
- By 2025, there will be 200 hydrogen fuelling stations and 250,000 plug-in electric vehicle (PEV) chargers, including 10,000 direct current fast chargers, in California.
- By 2030, there will be 5 million ZEVs on the road in California.
- By 2050, greenhouse gas emissions from the transportation sector will be 80% less than 1990 levels.

The scheme provides meaningful and tangible benefits to drivers such as preferential spaces, reduced fees, and fuelling infrastructure.

Annually, the ARB must aggregate and share the number of hydrogen vehicles that manufacturers project will be sold or leased over the next three years and the total number of hydrogen vehicle registered in the state. Based on this information, the ARB must evaluate the need for additional publicly available hydrogen fuelling stations for the subsequent three years and report findings to the California Energy Commission (CEC) including the number of stations, geographic areas where stations are needed, and minimum operating standards, such as number of dispensers and filling pressures.

The CEC will allocate up to $20m per year to fund the number of stations deemed necessary based on the ARB's evaluation and reports. The CEC may stop funding new stations if it determines, in consultation with the ARB, that the private sector is developing publicly available stations without the need for government support.

The California Fuel Cell Partnership (CaFCP), an industry-government collaboration, issued a vision report in July 2018 targeting 1 million FCEVs and 1,000 hydrogen fuelling stations by 2030.

Japan

Japan was the first country to formulate a basic hydrogen strategy in December 2017 and hosted the first Hydrogen Energy Ministerial Meeting in October 2018, which resulted in the Tokyo Statement outlining four key areas in which to accelerate hydrogen technology progress. In March 2019, Japan amended its hydrogen and fuel-cell roadmap, and a more quantitative cost target was set. The meeting outlined four points:

1) Collaboration on technologies and coordination on harmonisation of regulation, codes and standards so as to accelerate a decrease in costs involving hydrogen supply and products, e.g., fuel-cell vehicles (FCVs) – to try to reduce the hydrogen cost to a level comparable to that of existing energy sources such as LNG. Japan plans to the cut cost of hydrogen to 30 yen/NM3 by around 2030 and to 20 yen/NM3 long term.

2) Promotion of international joint research and development among member countries to expand hydrogen utilisation, e.g., ensuring the safety of hydrogen at hydrogen stations and hydrogen storage facilities and establishing supply chains suitable to a variety of regional characteristics.

3) Study and evaluation of hydrogen's potential economic effects and CO2 emission-reduction potential, which contribute to fostering and sharing awareness of hydrogen towards the realisation of a 'hydrogen society'.

4) Communication, education and outreach activities to increase the understanding of hydrogen, which will lead to the expansion of investment in hydrogen-related business.

The 2020 Olympics were being marketed in part as the hydrogen Olympics, with even the Olympic flame being hydrogen-fuelled. Based on initial industry estimates, the establishment of an international hydrogen supply chain coupled with production technology improvements could see demand by 2030 rise to 300ktpa. Its final 2050 scenario sees Japan's annual hydrogen procurement at greater than 10 mega tonnes (Mt).

Germany

Germany's draft hydrogen strategy envisages the use of CO2-free gas for the industry and transport sector, with a large part of the hydrogen to be purchased from abroad. According to the Economy Ministry's draft proposal for its hydrogen strategy, Germany intends to produce at least 20% of hydrogen from renewable energies by 2030. For this purpose, 3-5GW of electrolysers are to be built.

At present Germany uses grey hydrogen produced from natural gas. In order to provide sufficient renewable electricity for electrolysis, the strategy foresees using electricity from offshore wind farms in the North Sea.

Germany, the Netherlands and the State of North Rhine are also exploring the possibilities to generate green hydrogen on an industrial scale. They commissioned a feasibility study that will look into establishing a transnational value chain for green hydrogen from the North Sea to industrial clusters in the border area of the Netherlands and North Rhine-Westphalia.

Other key countries

France announced its Hydrogen Deployment Plan for Energy Transition in June 2018, the targets of which include 20-40% low-carbon hydrogen use in industrial applications of hydrogen, and a reduction in electrolysis cost to EUR 2-3/kg by 2028.

South Korea announced its hydrogen roadmap in January 2019, targeting FCEV production capacity of 6.3 million and 1,200 hydrogen fuelling stations by 2040. The previous month, Hyundai Motors had unveiled aggressive fuel cell production capacity targets to 2030.

Europe & HYLAW – A roadmap for Europe estimates that 5 million vehicles and 13 million households could be using hydrogen by 2030 while 600kt of hydrogen could be used to provide high-grade heat for industrial uses. In this scenario, by 2030 hydrogen would be abating 80Mt CO2 annually and account for an accumulated overall investment of €52bn, while by 2050 the industry would reach €820bn in annual revenue, would account for the abatement of 560Mt CO2 annually and would directly employ 5.4 million people.

The European Commission's HYLAW project is an example of multilateral progress that could be expanded beyond Europe's borders. *https://www.hylaw.eu/*.

HyLaw stands for Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications. It is a flagship project aimed at boosting the market uptake of hydrogen and fuel cell technologies, providing market developers with a clear view of the applicable regulations whilst calling the attention of policy-makers to legal barriers to be removed. The project brings together 23 partners from Austria, Belgium, Bulgaria, Denmark, Finland, France, Germany, Hungary, Italy, Latvia, Norway, Poland, Romania, Spain, Sweden, Portugal, the Netherlands and the UK and is coordinated by Hydrogen Europe.

The HyLaw partners will first identify the legislation and regulations relevant to fuel cell and hydrogen applications and legal barriers to their commercialisation. They will then provide public authorities with country-specific benchmarks and recommendations as to how to remove these barriers.

HyLaw started in January 2017 with a database that will be maintained by Hydrogen Europe for a minimum of three years after the end of the project.

Saudi Arabia – Air Liquide E&C has built hydrogen production and purification units at its site at Yanbu, Saudi Arabia. The plant supplies hydrogen 'over the fence' to the nearby oil refinery, which has a capacity of 400kb/d. Hydrogen will allow a reduction in the sulphur content of the produced fuels, and meet the environmental standards for cleaner transportation fuels.

Japan and Saudi Arabia are together exploring the possibility of extracting hydrogen from Saudi crude oil so that it can be transported to Japan in the form of ammonia.

ANALYST(S) CERTIFICATION(S):

We, Lydia Rainforth, CFA, James Hosie, Mick Pickup, Joshua Stone, Jeanine Wai, Hiral Patel, Peter Crampton, Dominic Nash, Jose Ruiz, Amos Fletcher, CFA, Ian Rossouw, CFA, Kennedy Nyangoni, CFA, Sebastian Satz, CFA, Alex Stewart, CFA and J. David Anderson, CFA, hereby certify (1) that the views expressed in this research report accurately reflect our personal views about any or all of the subject securities or issuers referred to in this research report and (2) no part of our compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this research report.

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