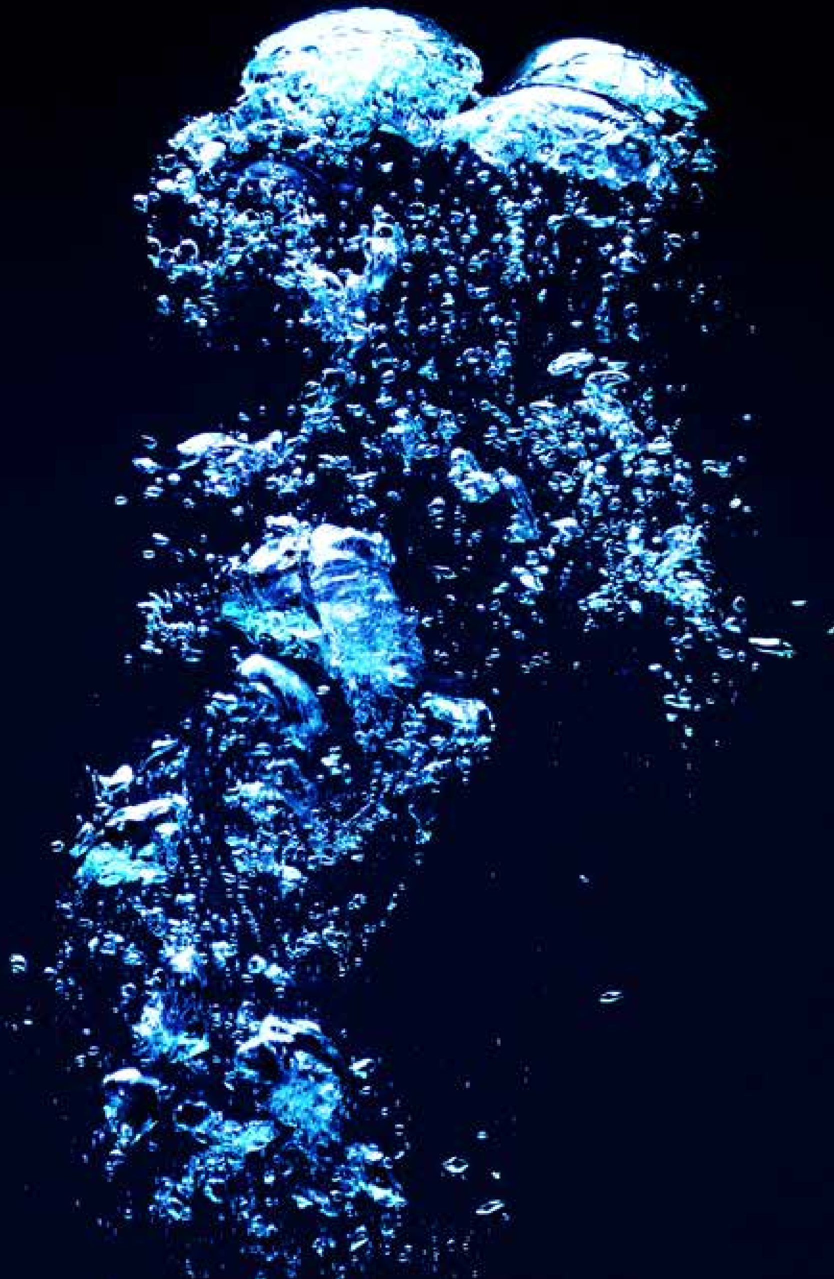
# Clean Hydrogen Investment Framework



**February 2024**
(August 2024 Update)

# Authors

## Stan Miranda
*Founder, Chairman*

- Partners Capital Chief Executive (2001-2020)
- Founder, CEO of the True North Institute
- Evolution Global Partners (Venture Capital)
- Bain & Company Director
- Harvard MBA

## Christopher Jan
*Principal*

- CVCapital Securities
- R.W. Baird
- University of Michigan, Harvard MPP

---

This is the first publication to be produced by the True North Institute, which is dedicated to the creation of seminal pieces of investment research. True North was founded by Stan Miranda in 2023.

---

Charity think tank OpenMinds, international strategy consultants Bain & Company and Clean Air Task Force are among the valued sources of insight on the future role of clean hydrogen as summarised in this document.

OpenMinds

BAIN & COMPANY

CLEAN AIR TASK FORCE

*Right:*
Large capacity Alkaline electrolyser manufactured by French company McPhy Energy
*Image: McPhy_EnergieDienst*

# Contents



*Left:*
Hydrogen renewable energy production pipeline, Germany
*Image: Audioundwerbung/Istock*

# Executive Summary

The most basic model for thinking about global decarbonisation is that we want to use electricity generated from renewable sources for as many energy usage applications as we can. Where we can't, we need a low carbon fuel. The choices for low carbon fuel are clean hydrogen and biofuels. Biofuels are limited by feedstock supplies and hydrogen is limited by cost, while its feedstock, water, is in ample supply. In summary, where we cannot electrify an application economically relative to clean hydrogen, clean hydrogen should have a role to play.



Based on an application-by-application analysis of the likely future competitiveness of both blue and green hydrogen and its methanol and ammonia derivatives, we expect hydrogen will ultimately contribute to approximately 6% of total global decarbonisation. The bulk of this will only start to kick in in the late 2030's. Hydrogen has potential application to oil & gas refining, agricultural, transport, industrial and power generation end uses. Hydrogen as a long-duration electricity storage medium has a role likely to be limited to less than 5% of all electricity generation.

This 6% estimate of total decarbonisation from clean hydrogen falls at the low end of expert estimates that range from 3% up to 20% estimated by the most bullish hydrogen supporters. This range of possible outcomes points to the vast dispersion of opinion from even deep experts on hydrogen. Each application has a different competing low-carbon solution with controversial technical and cost comparisons on which we conclude here. Our conclusion is heavily influenced by the very nascent starting position, with just 24 million tonnes (Mt) of announced hydrogen projects today vs the over 600 Mt of hydrogen required for $H_2$ to offset 10% of all emissions as targeted in the IEA's 2050 Net Zero Scenario.

Cost is a major impediment for hydrogen produced from electrolysis (green $H_2$) which is the natural outcome of huge inefficiencies that plague $H_2$ from electrolysis to transport to storage and then to reconstitution. Hydrogen employing carbon capture from steam reforming of natural gas (blue $H_2$) is twice as expensive as the grey hydrogen used today as chemical feedstock, relative to green $H_2$ at three times as expensive as grey. When and if a carbon tax is charged on grey $H_2$, or regulatory limits are applied, blue $H_2$ will have a competitive market for replacing grey in those feedstock applications.

Clean hydrogen will achieve the most economic and early penetration in select geographic locations where low-cost supply hubs can be built. These will be in geographic corridors between low-cost natural gas and renewable electricity and end users where compression, liquefaction and transport costs are minimised or avoided altogether. Government subsidies are significant additional support for this selective region-by-region build out scenario.

We see the most significant clean hydrogen applications in transport including long-haul ground transport, shipping and aviation, but not in passenger vehicles. Steel will slowly adopt hydrogen in its expanded direct reduction iron (DRI) pellet-making process in order to maximise the use of Electric Arc Furnaces and shut down more coking coal-fuelled blast furnaces. Power generation will make use of hydrogen in low-capacity utilisation plants to fill gaps in electricity production against peak demand, which will amount to less than 5% of all electricity generation. Green hydrogen is unlikely to reach the high end of the experts' production forecasts due to the sheer magnitude of renewable energy required in green hydrogen production.

While the burning of hydrogen as a fuel does not emit greenhouse gases, hydrogen released into the atmosphere acts as an indirect greenhouse gas, which reacts with other greenhouse gases in the atmosphere to increase

**their global warming potential (GWP). A 2022 study by the UK government's Department of Business, Energy and Industrial Strategy (BEIS) has found that hydrogen's GWP is somewhere between six and 16, with 11 being the average — whereas the GWP of $CO_2$ is one. The hydrogen molecule is much smaller than natural gas, being one-third the size of a methane molecule, resulting in a much higher risk of leakage than other gases. Any leakage of $H_2$ will result in an indirect global warming, offsetting greenhouse gas emission reductions made as a result of a switch from fossil fuel to hydrogen. Fugitive hydrogen emissions occur from the electrolysis process itself. This study estimates that 9.2% of the hydrogen produced through electrolysis will make its way into the atmosphere through venting and purging, but this would fall to 0.52% with full recombination of hydrogen from purging and crossover venting.**

**The worst offender for $H_2$ leakage would be tanker transport of liquid hydrogen, with 13.2% of its cargo leaking into the air, followed by above-ground compressed-gas storage (6.52%), fuel cells (2.64%) and refuelling stations (0.89%). All other production, transportation, storage and uses of hydrogen would see leakages of less than 0.53%). This "small molecule" problem underscores the difficulty and likely high cost of hydrogen transport, as expense will be incurred to prevent leakage by whatever transport means.**

Hydrogen is the most abundant element in the universe and a well-established energy carrier, but it is not found naturally in its pure form in any significant quantities on earth. Obtaining hydrogen gas in large, usable quantities typically involves the separation of hydrogen from compounds such as water, natural gas, or biomass through various methods like electrolysis, steam methane reforming, or other chemical processes.

Hydrogen has significant potential in a net zero economy as it can be used in transport, heat, power, and energy storage with no greenhouse gas emissions at the point of use. Ammonia, a compound of hydrogen and nitrogen, is also a powerful zero-carbon fuel.

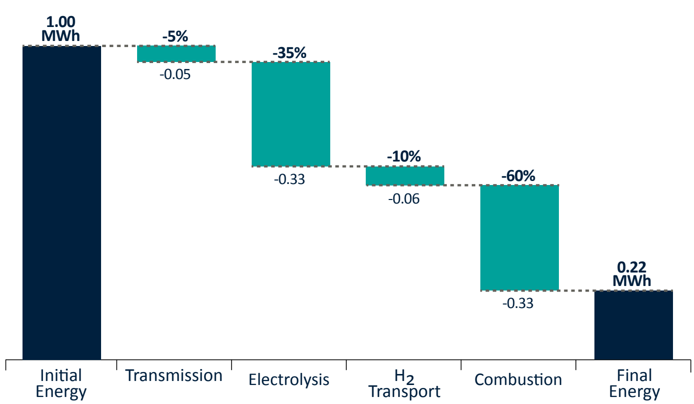
But the most common current form of hydrogen production involves the burning of hydrocarbons and emission of 8-10 tonnes of $CO_2$ for each tonne of hydrogen produced. And presently, the cost of low-emission hydrogen is very high relative to the incumbent high carbon emitting fuels used in most end-use applications today.

As an energy storage medium, hydrogen has a <50% round-trip efficiency, i.e., less than 50% of the electricity required to electrolyse water into hydrogen makes it to the end use after storage, transport and conversion to electricity. The conversion losses of transmitting the electricity, breaking apart water using electrolysis, transporting the energy, and combusting it in a combined cycle turbine result in an estimated loss of c.78% of the initial energy inputted into the process.

As shown in Exhibit 1, the energy produced is only 22% of the energy consumed in

**Exhibit 1**

**Conversion losses when using electrolytic hydrogen for power results in high costs, all depending on the cost of the renewable energy used**




***Source:*** *CATF Analysis*

**Exhibit 2**

**Hydrogen is mainly produced from fossil sources today. Blue and green hydrogen are low carbon alternatives but currently at a higher cost**

Lower disruption → Higher disruption

| | "GREY" *(Fossil)* | "BLUE" *(Climate Neutral)* | "GREEN" *(Sustainable)* |
|---|---|---|---|
| | **Steam methane reforming (SMR)**<br>• Hydrogen produced from natural gas[2], but has high $CO_2$ emissions<br>• Used as industrial feedstock for ~40+ years | **'Grey' + CCUS[1]**<br>• 'Grey' hydrogen supplemented by CCUS technology to capture $CO_2$ emissions<br>• Serves as a bridge to longer-term sustainable supply of hydrogen | **Electrolysis**<br>• Hydrogen produced by using electricity to split water into hydrogen and oxygen<br>• Long-term potential for supply disruption given zero emission product when electricity from renewable energy sources |
| **2020 supply, Mt** | **~95%** | **<1%** | **~5%** |
| **2020 average production cost** | **~$1-1.5**/kg $H_2$ | **~$1.5-2**/kg $H_2$ | **~$4-4.5**/kg $H_2$ (global average)<br>**~$3-8**/kg $H_2$ (range) |
| **GHG emissions** | **8-10** $tCO_2/tH_2$ | **0.2** $tCO_2/tH_2$ | **0** $tCO_2/tH_2$ |

***Source:*** *Navigant, Hydrogen Council, Aurora, BNEF, FCH, IEA, IRENA, Shell, BP Energy Outlook 2020, Deloitte*

***Note:*** *1) CCUS = Carbon Capture, Utilisation, and Storage; 2) Hydrogen produced from coal gasification or oil reforming also referred to as "black" hydrogen but is included under grey in this overview*

the electrolysis process. There are two main processes to produce hydrogen today.

As shown in Exhibit 2, approximately 95% of current hydrogen is produced out of a thermochemical steam methane reforming (SMR) process for which fossil fuels are the dominant raw material (mostly natural gas). This process is emissions intense, emitting around 830Mtpa of $CO_2$ (IEA 2019; Global CCS Institute 2020). Less than 1% of hydrogen production from fossil fuels includes carbon capture and storage (CCS) to produce what is called blue hydrogen. Approximately 5% of hydrogen produced by water electrolysis is powered by renewable electricity, to create what is called green hydrogen.

Electrolysis is believed to be the low carbon alternative process of the future but is a highly inefficient process in terms of the final energy produced relative to the renewable energy input.

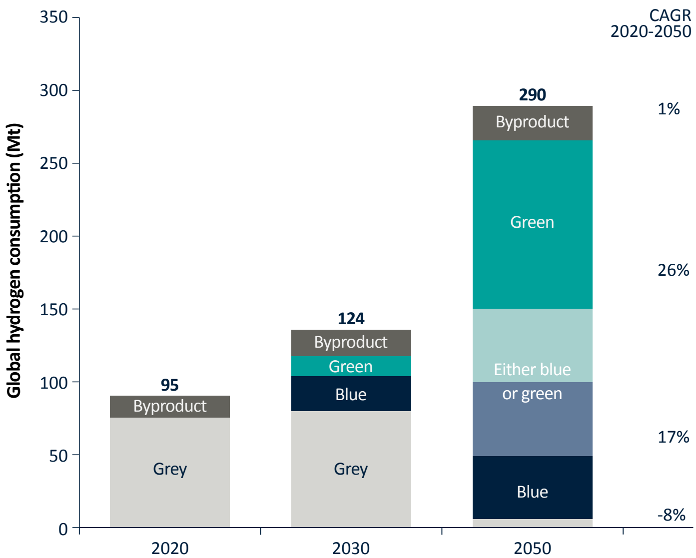
We believe that in the period from now until 2030, blue hydrogen will be the preferred low emission hydrogen, largely due to the much lower cost with average 2023 cost estimates of $1.00 to $1.50/kg for grey hydrogen, $1.50 to $2.00/kg for blue and $4.00 to $4.50/kg for green hydrogen. These costs ignore any US IRA or other subsidies and tax credits, which can be as high as $3/kg for blue and green hydrogen.

Hydrogen has very good gravimetric energy density, which is the amount of energy carried per unit weight. On this measure, hydrogen beats diesel, petrol and jet fuel by a factor of around three, and LNG by a factor of 2.7, which is why it makes a great rocket fuel. However, it has very poor volumetric energy density, which is the amount of energy carried per unit volume. A cubic meter of hydrogen weighs only 71 kilograms, compared to a cubic meter of water at 1000 kilograms, or less than 1% of the weight. So any applications which involve on-board movement (ships, airplanes and ground vehicles) or long distance shipment from source to use (via pipelines or fuel cells) requires conversion to a higher density through compression, liquification or conversion to derivative fuels like ammonia and methanol. The vast bulk of today's hydrogen never leaves the compound on which it is made, let alone crosses an international border.

The long-term prospects for clean hydrogen are one of the most hotly debated topics under the energy transition heading. According to lobbying group the Hydrogen Council which is supported by McKinsey, hydrogen can be expected to contribute more than 20% of emissions reductions needed

## Exhibit 3

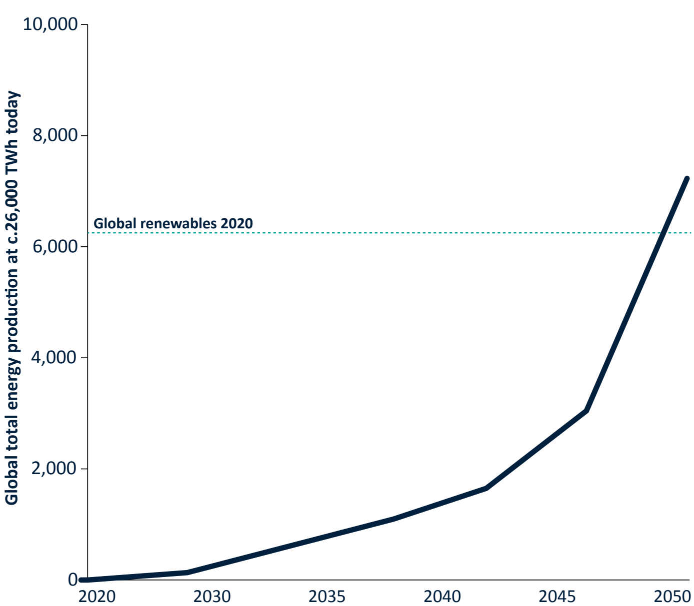
**Bain & Company's base case scenario for hydrogen growth aligns with our own views informed by many of the leading experts on the energy transition**




*Source: IEA, IHS, IRENA, BNEF, EIA, NREL*

## Exhibit 4

**To meet this demand, green hydrogen production would require c.7,300 TWh of renewable electricity by 2050**




***Source:*** *Bain & Company*

for the world to reach net-zero emissions, or 660 Mt of total low-emission hydrogen. The lowest estimate is less than half of this: 270 Mt by 2050, implying between 10-14% of all emissions may be abated with the use of hydrogen by 2050. Fully replacing grey $H_2$ with clean $H_2$ will cut 1.6% of total emissions (800 Mt out of 50 Gt), which is fairly certain, but even that milestone will not be reached by 2030.

Announced hydrogen projects suggest production of approximately 24 Mt by 2030. However, only 10% of these have an identified buyer according to BNEF in November of 2023. Of this, only 1 Mt per year has contracted volumes. Most of this 24 Mt of projects are just MoUs that are not binding. In stark contrast, Exhibit 8 below shows what experts say is needed by 2030 to stay on track to net zero by 2050 – estimates ranging from 70 to 172 Mt – which clearly will not happen.

To meet 2050 projected demand of c.280 Mt of clean hydrogen (of which 20 to 30% is blue), green hydrogen production would require c.7,300 TWh of renewable electricity by 2050 or what is estimated to be c.65,000 TWh of total electricity generation (or 11% of total electricity).

**End use markets in which clean hydrogen will become most competitive.** Within hydrogen's current use as a chemical feedstock, there are no alternatives to the molecule – hydrogen is irreplaceable. As such, low-emission (blue / green, also referred to as "clean" or "low-emission") hydrogen will eventually displace grey hydrogen use in those sectors – refining, ammonia and steel manufacturing. This assumes grey is being regulated (taxed or capped) out of existence over time.

These and all other energy applications for hydrogen are listed in Exhibit 5 in order of the estimated cost of carbon abatement today. For each application, we have examined many different expert estimates and formed our own based primarily on the relative cost of the various alternatives. We have arrived at an estimate of 47 Mt of clean hydrogen demand by 2030 and 300 Mt by 2050. Critically, this assumes $100/ tonne of CO2 emissions taxation or subsidies on the fossil fuel alternatives. Without policy support, clean hydrogen will have virtually no commercially viable opportunity beyond substitution of the current 95 Mt of grey hydrogen usage. **This policy risk is paramount to any investment in hydrogen opportunities given the challenging unsubsidized economics.** The following application by application forecasts for H2 usage assume policy support is in place.

**Exhibit 5**
**Partners Capital Clean Hydrogen Application Ranking**

| Application | Current Demand (Mt / year hydrogen) | Total Carbon Emissions (Mt / year CO2) | Cost of abatement ($ / tonne CO2) | 2050 Base Case Scenario (Mt) |
|---|---|---|---|---|
| **Guaranteed Applications:** | | | | |
| Refining | 41 | 200 | c.$80 | 32 |
| Ammonia | 34 | 500 | c.$60 | 26 |
| Methanol | 15 | 130 | c.$100 | 12 |
| **Likely Applications:** | | | | |
| Steel Production | 5 | 60 | c.$120-140 | 40 |
| Power Generation | - | 14000 | c.$140 | 50 |
| Aviation and Shipping | - | 1550 | c.$250-300 | 70 |
| Long Distance Trucking | - | 3200 | c.$300-340 | 70 |
| **Unlikely Applications:** | | | | |
| Passenger Vehicles | - | 4800 | c.$300-375 | 0 |
| Domestic Heating | - | 3000 | c.$475 | 0 |
| **Totals** | 95 | 27440 | | 300 |

***Source:*** *Goldman Sachs Carbonomics 2023 for cost of abatement figures; IEA for total carbon emissions; aviation cost of abatement is not broken out from shipping cost, so we show the same costs for both. 2050 base case scenarios from Partners Capital analysis of each application.*

**Steel.** Decarbonisation of steel will most likely occur from using hydrogen in the capacity, CCS is cheaper to implement and looks to be not just the best system of emission reduction, but the only system.

**Aviation.** Aviation should see e-fuels replacing the current high emission kerosene-based jet fuel very slowly given the nascency of sustainable aviation fuels (SAF) technology. The leading technology appears to make heavy use of hydrogen in the manufacture of e-fuel SAFs but costs two to three times as much as current jet fuels. The theoretical demand for hydrogen is so great that it will be needed. Biofuels will win in the short term, until demand exceeds the relatively limited supply and then e-fuels will take over.

**Shipping.** Given the density properties of hydrogen, methanol appears to be the near-term solution for shipping, while ammonia would appear to be the long-term solution. At this point we see no significant demand for hydrogen other than as the green hydrogen to be used as feedstock to be manufacturing ammonia or methanol for maritime fuels.

**Long-haul Trucking.** The nearest thing we have to a consensus view in the energy transition space is that long-haul trucking will transition to fuel cell electric vehicles where large hydrogen storage tanks will be onboard and refuelled every 500 km or more without having the range anxiety of a purely battery-charged electric truck. More importantly, 8 hour charging times cripple productivity of both the vehicle and the driver. Long-haul trucking could be one of the largest markets for low-emission hydrogen, with one global estimate described below of nearly 20 Mt per year by 2040.

Passenger vehicles and building heating are very unlikely to embrace hydrogen in any material way.

**Infrastructure is required to transport clean hydrogen.** Today hydrogen is mostly produced close to where it is used as feedstock to oil refining and to ammonia and methanol production. A small amount is transported through pipelines in much the same way as is natural gas. Today, the US has 2,600 km of hydrogen pipelines according to the IEA, while Europe has 2,000 km and China has only 100 km. To highlight how little this represents, we compare these numbers to the EU gas network which comprises more than 200,000 km of transmission pipelines.

In the future, most of the newer applications for $H_2$ described above require hydrogen to be transported from where it is produced to where it is used, in steel mills, truck fuelling stations, airports and ocean fuelling stations. The ideal situation is that wind and solar produced electricity, electrolysis and green $H_2$ usage are all in the same place. Given the geographic constraints on where the wind blows and the sun shines, we will need to build transport networks in anticipation of the growing demand for clean hydrogen.

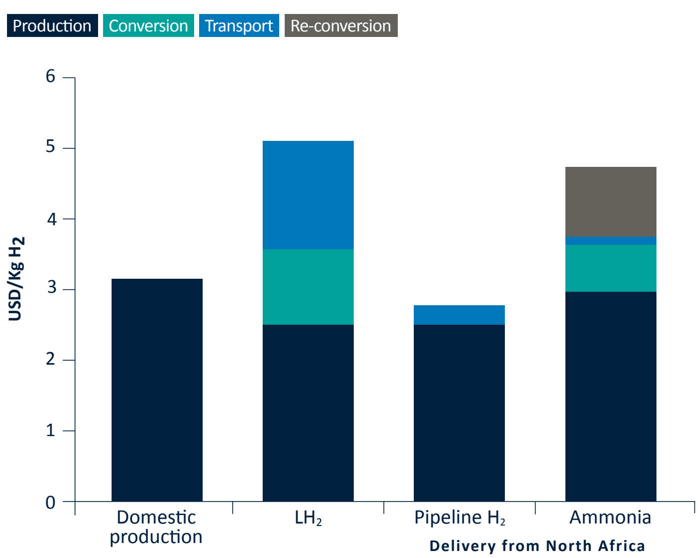
The first solution is retrofitting and repurposing existing natural gas networks which will be cheaper than building new dedicated hydrogen pipelines. Longer transport distances will require compression or liquification and shipping to overcome the low volumetric energy density of hydrogen. Depending upon the exact transport routes, conversion of hydrogen to a higher density form may make the most economic sense. The main options include compression, liquification and liquid organic hydrogen carriers (LOHCs), with ammonia being the most talked about LOHC.

Research is ongoing in the field of LOHCs with, beyond ammonia, Dibenzyltoluene and the Toluene/Methylcyclohexane systems considered to have the most potential for widespread use, mainly due to their balance of efficiency, safety, and economic viability.

**Repurposed natural gas pipelines and ammonia are the favored mechanisms to transport clean hydrogen over large distances.** Exhibit 6 is from the IEA's 2023 Global Hydrogen Review and estimates the total cost of liquid hydrogen ($LH_2$), compressed hydrogen via pipelines, and ammonia compared to $3/kg domestically produced green hydrogen with no

**Exhibit 6**

**Transport of green hydrogen gas by pipeline is lower cost than transporting liquid hydrogen or ammonia**

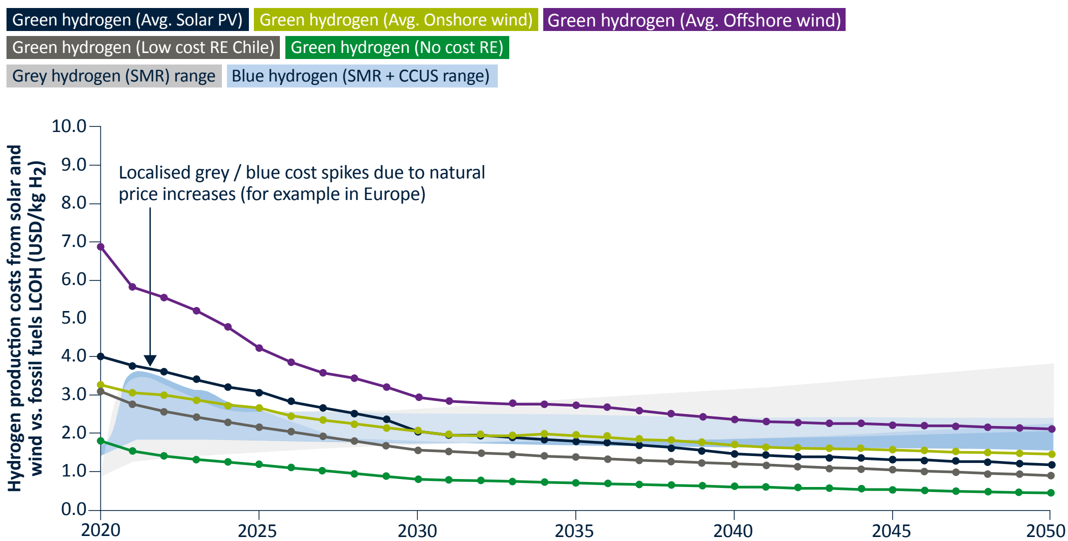



**Source:** *Based on data from McKinsey & Company and the Hydrogen Council: IRENA (2020); IEA GHG (2014); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).*

**Note:** *"$H_2$" = hydrogen; "$NH_3$" = ammonia; "$LH_2$" = liquefied hydrogen; "LOHC" = liquid organic hydrogen carrier. Domestic production in North-West Europe uses offshore wind; production in other regions uses solar PV. "Conversion" includes a compressed hydrogen storage cost to allow for stable input to the synthesis and to the liquefaction processes. The cost of capital is assumed at 6%. Costs refer to the Net Zero Emissions by 2050 Scenario (NZE Scenario) in 2030. More techno-economic assumptions are available in a separate forthcoming Annex.*

## Exhibit 7

**Over time, green hydrogen will be cost advantaged versus grey and blue**




**Source:** *IRENA 2019, NREL, EIA, BNEF, Lazard, Chile Department of Energy, Wood Mac, Bain analysis*

**Note:** *Remaining $CO_2$, emissions are from fossil fuel hydrogen production with CCS. PEM electrolyser installed cost assumptions: $990/kW (2020), $460/kW (2030), $330/kW (2040) and $260/kW (2050). Electrolyser efficiency: 65% in 2020, 70% in 2030, and 80% by 2050. $CO_2$ prices/taxes: $50 per tonne (2030), $50-100 per tonne (2040) and $100-200 per tonne (2050) added to the cost of grey hydrogen. Low range for natural gas feedstock to blue hydrogen $3/MMBTU, high range $8/MMBTU. Assumes subsidised costs of solar and wind with solar PV at $51/MWh today falling to $20/MWh in 2050 in current value of money. Onshore wind is assumed to be $39/MWh today falling to $20/MWh in 2050. Offshore wind is assumed to be $84/MWh today falling to $30/MWh in 2030. Chile Renewable Energy is assumed to be $25/MWh today falling to $11/MWh in 2050.*

transport costs. Pipeline transport of compressed green hydrogen represents the lowest cost, which suggests there may be more limited prospects for ammonia as a transport medium. Worldwide production of ammonia is about 175 Mt/yr, with the bulk of it being used in the manufacture of fertiliser. Ammonia has well-established infrastructure making it easy, safe, and cheap to transport. Since ammonia has a higher volumetric energy density than liquid hydrogen, more energy can be transported via ammonia for the same volume than if it were in the form of liquid hydrogen. After the green ammonia is shipped, it can be split back into green hydrogen and nitrogen in the destination countries or used directly, all at a cost.

While green or blue ammonia is imbued with these advantages over hydrogen in the green energy system, it is inherently higher cost than blue or green hydrogen as it is produced from green or blue hydrogen in the Haber-Bosch process. Both this process, as well as cracking ammonia back into hydrogen, add further costs.

**The cost of low-emission hydrogen.** The primary cost drivers of blue and green hydrogen are the cost of natural gas and renewable energy, respectively. The relationship between blue and green hydrogen and their fuel source, shown in Exhibit 7, is based on analysis performed with CATF's Hydrogen Financial Model. The largest component cost of blue hydrogen is natural gas which accounts for c.30-50% of the levelised cost. To compete with $2.10/kg grey hydrogen (the high end of US cost), the cost of natural gas must be less than $5/MMBtu. Current natural gas prices in the US are around $2.55/MMBtu which underscores blue hydrogen's current good cost situation, taking advantage of current low natural gas prices.

Turning to green hydrogen, the cost of electricity usually accounts for c.50-70% of the levelelised cost of green hydrogen. To compete with $2.10/kg grey hydrogen, electricity prices must be below $15/MWh. Current US industrial electricity prices (excluding any transport costs) average $80/MWh. So without a massive discount for "excess" wind and solar electricity, green hydrogen is prohibitively expensive.

There will be a role for both blue and green hydrogen to play in the energy transition. In the near term, blue hydrogen will be the transitional technology while electrolytic production ramps up. As renewable energy becomes more abundant, affordable, and ubiquitous, green hydrogen will be able to compete and scale, eventually reaching parity with blue hydrogen. This will be largely location-specific, driven by the access to and cost of renewable electricity.

In the long run, green hydrogen is likely to dominate, falling below the price of grey hydrogen in regions with very low-cost renewables. There may still be a significant role for blue production in regions enjoying very low gas prices.

The two key contributing factors of technological innovation and economies of scale, on our estimates, lead to green hydrogen costs falling more swiftly than previously anticipated, while utilisation is likely to increase too as the de-carbonisation process unfolds. Blue hydrogen costs are also likely to come down as technological innovation and scale-up continue in carbon capture technology with more projects currently in the pipeline as well as the ongoing scale-up of carbon storage infrastructure, particularly in CCS clusters that have started to emerge across key regions.

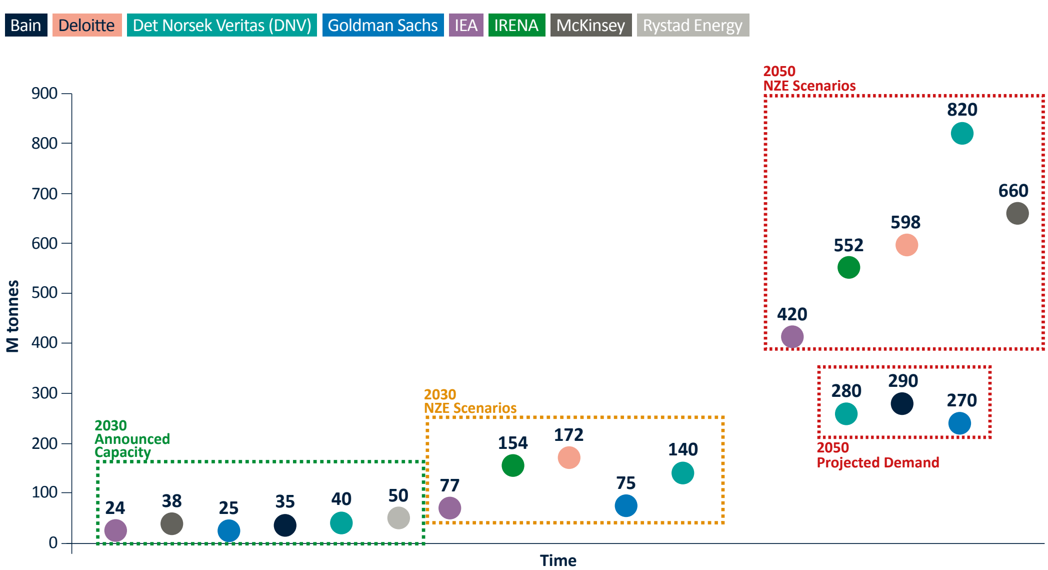
**The primary headwinds facing low-emission hydrogen.** Green hydrogen requires renewable electricity and hence could be constrained by the level of renewable capacity. For example, if all of the 95 Mt of hydrogen currently used globally was produced through electrolysis it would require 5,200 terawatt hours (TWh) of electricity per year (using PEM electrolysis at 55 kWh/kg-$H_2$), substantially more than the total electricity generation of the EU.

The main constraints to achieving such high levels of penetration are costs and the pace of build out of carbon capture for blue hydrogen and electrolysis for green hydrogen. We are still at such a nascent level of experience that it is difficult to project the pace of development. Over the long term, and ignoring government subsidies, blue



**Exhibit 8**

**Announced hydrogen projects suggest c.24 Mt by 2030, but experts suggest something closer to 120 Mt by 2030 and 300 Mt by 2050. 2050 Net Zero Emission scenarios need around 600 Mt**




***Source:*** *Bain, Deloitte, DNV, Goldman Sachs, IEA, IRENA, McKinsey*
***Note:*** *Bain 2030 announced capacity number excludes $H_2$ produced as byproduct.*

hydrogen costs are bound to exceed grey hydrogen costs at whatever natural gas price since they require the addition of CCS to the underlying SMR process. Green hydrogen costs will be driven by the market price of "excess wind and solar" and should eventually fall below that of grey and blue hydrogen.

Expert forecasts do tend to cluster around each other as you can see in Exhibit 8. Announced projects point to 24-50 Mt of new clean hydrogen production by 2030, but Net Zero Emissions (NZE) scenarios, which specify what experts estimate "needs" to happen by 2030, cluster between 70 and 172 Mt. Experts project demand between 270 Mt and 290 Mt by 2050, which is half the size of what McKinsey and the IRENA say is required as part of their net zero plans where $H_2$ accounts for approximately 10% of all carbon emissions reduction.

Achieving net-zero greenhouse gas emissions by 2050 will likely require the development of a c.170 Mt $H_2$ clean hydrogen market by 2030, which must grow to nearly c.600 Mt $H_2$ by 2050. In the IEA's 2050 net zero emissions scenario, it expects 65% of clean hydrogen production in 2050 to be green hydrogen, with the remaining 35% blue hydrogen.

Using the same hydrogen $Co_2$ abatement factor of 10 that we used for replacing the current grey hydrogen applications with clean $H_2$ (perhaps the maximum levels of abatement from each tonne of clean $H_2$ substituted), and the 2050 NZE scenarios hydrogen demand assumptions (considered to be the maximum levels of potential hydrogen utilisation at 500-600 Mt in 2050) we arrive at a maximum carbon abatement of 5-6 Gt which is approximately 10-12% of total current GHG emissions. But using more realistic estimates of 2050 clean $H_2$ usage at 300 Mt, and the same maximum abatement factors of 10, we arrive at our base case assumption of 3 gigatons of $Co_2$ abatement from hydrogen or 6% of total current GHG emissions.

What we can say with certainty from this analysis is that clean hydrogen will play a vital role in achieving global decarbonisation in settings where the direct use of electricity is impossible or inconvenient (e.g., long-haul trucking, steel production, maritime shipping, and aviation), or where hydrogen itself is important to the use case (e.g., fertiliser production). Hydrogen can also be used to smooth the intermittent electricity generation issues associated with renewable sources. In a future net-zero emissions world, hydrogen must win its way into the economy, use case by use case. It must overcome its fundamental thermodynamic constraints to beat out simpler, cheaper, and more efficient competitors of clean electricity and batteries.

Undoubtedly, high levels of uncertainty around the technology, subsidies/taxes, cost and customer adoption will stall the \$150B to \$300B a year of capital investment that experts estimate is needed to achieve the range of outcomes described above. The most viable opportunities will exploit location advantages that drive low natural gas and renewable energy input costs and hydrogen transportation costs. Large public companies have the greatest strategic advantages to pursue such investments and public equity investors with deep insights into the hydrogen economy will be best positioned to help asset owners generate outsized returns and drive the greatest decarbonisation from the deployment of clean hydrogen.

## What are the most investible conclusions for investing in the emerging clean hydrogen economy?

This is the “so what?” or the key assumptions on which investors should be able to rely when making investments in and around clean hydrogen. Very little we have written is certain, but the list below comprises our key conclusions about hydrogen’s role in the global energy transition. These are the conclusions which we believe at this point in time are the broadest reaching and relevant assumptions that investors should factor into their range of possible scenarios for any given hydrogen or hydrogen-related investment.

**1.** Hydrogen is high on key governments' energy agendas and will receive the regulatory, investment, taxation and subsidy supports needed to overcome the technology and economic risk impediments to investing. Europe is leading, the US is catching up and China will inevitably contribute to driving the cost of hydrogen down its experience curve.

**2.** Clean hydrogen is not yet nascent, but embryonic in its stage of development. We really have yet to even start producing blue or green hydrogen in any significant scale (just one to two million tonnes in the last 12 months vs. a target of 600 Mt by 2050, and c.140 Mt just seven years from now).

**3.** We have hit a turning point with 186 Mt of projects in feasibility stages, and 24 Mt slated to be completed by 2030. The recent ramp up in project filings is across the globe.

**4.** The pace of growth will be slow due to the 3-to-7-year time scale from feasibility to commissioning, but from 2030 to 2040 we should see large profit pools emerging.

**5.** The economics of clean hydrogen will ultimately be most easily justified in the applications that are hardest to electrify and where clean hydrogen replaces carbon-intensive fuels or feedstock. So, firstly, clean will replace grey hydrogen as feedstock to refineries, ammonia and methanol.

**6.** The most significant clean hydrogen applications will be seen in transport including long-haul ground transport, shipping and aviation, but not in passenger vehicles. Steel will slowly adopt hydrogen in its expanded direct reduction iron (DRI) pellet-making process in order to maximise the use of Electric Arc Furnaces and shut down more coking coal-fuelled blast furnaces. Power generation will make use of hydrogen in low-capacity utilisation plants to fill gaps in electricity production against peak demand, which will amount to less than 5% of all electricity generation.

**7.** The technology is far from mature and this provides significant opportunities for innovators from the energy sector or venture capital. Technological developments are needed across the value chain including in electrolysers, CCUS, compression, liquefaction, pipelines, fuel cells and derivatives like ammonia and other liquid organic hydrogen carriers.

**8.** The most attractive and accessible investment opportunities we see are in the public equity market, in the form of well-resourced companies with long experience in dealing with the many challenges of hydrogen who are most determined to lead in its long-term development. We are looking to build portfolios around the biggest winners in the transformation from brown to green in these sectors. The focus should be on those sectors being disrupted the most and transformed by clean hydrogen, starting with transport (air, maritime, long-haul trucking), industrial (steel, ammonia, refining) and then the power industry.

**9.** Wind and solar power will outgrow its own transmission infrastructure, leading to lower levels of penetration than forecast. Growing electricity demand from EVs and building electrification will require more fossil fuel sourced electricity for longer than expected. This will lead to an acceleration of carbon capture retrofitting to produce base level electricity, but increasing the need for solving peak electricity consumption needs which can be solved by stored clean hydrogen. We expect this to account for 5% of all electricity, but not until the 2035 -40 time frame or later.

**10.** Public equity investors need to model the future cash flows for companies operating in these sectors to incorporate the cost of retrofitting existing processes and building supply chains for hydrogen sourcing, along with forecasting subsidies, carbon taxes, pricing and customer reaction. Clearly, the level of uncertainty around companies in these sectors is already elevated and reflected in current valuations.

**11.** Clean hydrogen will be most successful in regions that constitute "low cost supply hubs" with supply and cost-advantaged $H_2$ feedstock (e.g., US Gulf Coast, Middle East), cost-advantaged renewables where there are limited obstacles to building out wind and solar (e.g., Chile, Australia and Middle East) and where compression, liquefaction and transport costs are minimised.

**12.** Current oil major producers of grey hydrogen are likely to play a leading role in the production of blue hydrogen.

**13.** The industrial gas industry also plays a large role in the production and transport of off-site grey hydrogen today and is seeking to extend this role into clean hydrogen.

**14.** Investing in electrolyser manufacturers should be in those most likely to be strategically important to the largest hydrogen producers.

**15.** Infrastructure fund investments, at some point, will be required in the areas of storage, transport and distribution of hydrogen. Such investments classically are justified only when technology, development, regulatory and commercial risks are low. This is not the case today and will not be until late in this decade.

**16.** There is no certainty that China will dominate the hydrogen sector as they have other segments of the energy transition including solar panels, lithium-ion batteries, wind turbines and nuclear power.

# Question 1: How is hydrogen produced?

**There are two main processes to produce hydrogen. 98% of all hydrogen produced today employs a thermochemical process called reforming. There are three methods of reforming but steam methane reforming (SMR) is by far the most prominent. SMR produces hydrogen from unabated natural gas (75%) or coal (23%) and is referred to as "grey" hydrogen. The IEA estimates that the process of producing these 95 Mt of grey hydrogen results in 830 Mt of direct $CO_2$ emissions on a net basis, or 1.7% of all GHG emissions. Approximately 8 to 10 tonnes of $CO_2$ is emitted for every tonne of grey hydrogen produced, per the IEA.**

The second most important process for producing hydrogen is electrolysis which is the process of using electricity to split water into hydrogen and oxygen. Electrolysis is believed to be the low carbon alternative process of the future. Less than 0.1% of dedicated hydrogen production globally comes from water electrolysis today, and the hydrogen produced by this means is mostly used in markets where high-purity hydrogen is necessary (for example, electronics and polysilicon). In addition to the hydrogen produced through water electrolysis, around 2% of total global hydrogen is created as a byproduct of chlor-alkali electrolysis in the production of chlorine and caustic soda. With declining costs for renewable electricity, in particular from solar PV and wind, interest is growing in electrolytic hydrogen.

There is an emerging technology introduced by Monolith Materials, a US firm, called Methane Splitting. Methane Splitting produces hydrogen from electricity and natural gas (methane) through a three-phase alternating current plasma generator. While it requires more natural gas than grey hydrogen to produce, it uses three to five times less electricity than traditional electrolysis. It has very low $CO_2$ formation but creates solid carbon as a byproduct. Monolith has a pilot plant in California and is building a commercial scale plant in Nebraska which will sell hydrogen to the local power company for burning in place of coal. Given how nascent this technology is, we focus the rest of this document on clean hydrogen from electrolysis or carbon capture.

**Steam methane reforming (SMR):** SMR produces hydrogen from water and natural gas which is 90%+ methane ($CH_4$) as shown in Exhibit 9. The process consists of heating the gas to 700–1,100 °C in the presence of steam over a nickel catalyst. The resulting endothermic reaction forms carbon monoxide and molecular hydrogen ($H_2$). The second stage of this process generates additional hydrogen through a lower temperature, exothermic, water-gas shift reaction process at about 360 °C. This overall process requires the burning of fossil fuels to generate these high levels of heat and results in $CO_2$ emissions of around 6 kg $CO_2$ per kg of hydrogen produced, which may be captured.

Traditional hydrogen produced in the SMR process using fossil fuels is referred to as "grey hydrogen" which is used primarily by heavy industry for refining petroleum, producing ammonia and methanol, and treating metals (e.g., steel). SMR produced hydrogen from natural gas is the cheapest source of industrial hydrogen today.

Each year, around 6% of the world's natural gas and 2% of its coal is used to make grey hydrogen. Demand for pure hydrogen has reached around 95M tonnes per year ($MtH_2$ /

year), a threefold growth since the 1970s. Today, hydrogen is almost entirely used as a chemical feedstock, not as a fuel. It is a feedstock in oil refining (41 Mt/year) to remove impurities such as sulphur, ammonia synthesis (34 Mt/year), methanol (15 Mt/year) and the reduction of iron to produce steel using electric arc furnaces (5 Mt/year).

As you can see from Exhibit 10, carbon capture equipment can be added to the SMR process to reduce the $CO_2$ emissions by 90% or more, but at twice the cost. Hydrogen produced from SMR with CCS is referred to as “blue hydrogen.” Blue hydrogen is already operating at scale, for example at the Air Products Steam Methane Reformer in Texas, US, the Shell Quest CCS facility in Alberta, Canada, and the Air Liquide facility at Port Jerome, France.

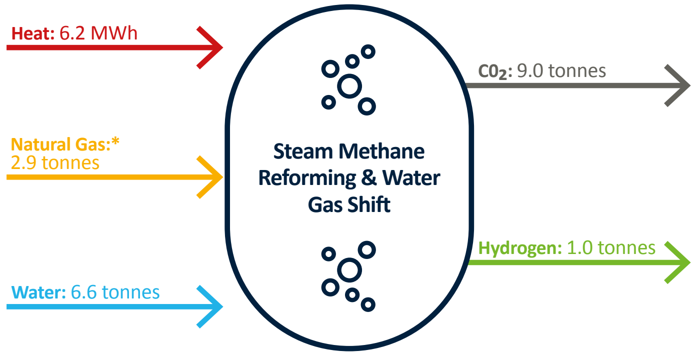
**Oil and Coal gasification:** The process of oil and coal gasification uses steam and oxygen to break molecular bonds in coal and form a gaseous mixture of hydrogen and carbon monoxide. Carbon dioxide and pollutants are more easily removed from gas obtained from oil or coal gasification versus combustion. This process involves $CO_2$ emissions and, as such, produces grey hydrogen.

**Methane Pyrolysis:** A relatively new technology for producing hydrogen is methane pyrolysis as shown in Exhibit 11. The pyrolysis process is the thermal decomposition of materials at elevated temperatures, often in an inert atmosphere. This produces so-called “turquoise hydrogen” when the high temperatures are achieved with renewable fuels.

**Electrolysis:** Electrolysis is the process of using electricity to split water into hydrogen and oxygen as shown in Exhibit 12. This reaction takes place in a unit called an electrolyser. Hydrogen produced from

**Exhibit 9**

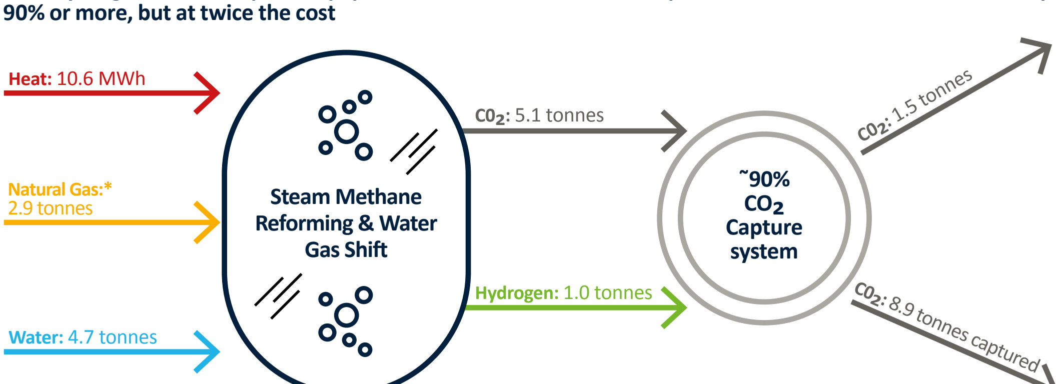
**Grey Hydrogen: steam methane reforming (SMR) is the most common hydrogen production method, produced from electricity, natural gas (methane) and water and emits 6 tonnes of $CO_2$ for every ton of hydrogen produced**




***Source:*** *IEAGHG*
***Note:*** **Mostly but not pure methane*

**Exhibit 10**

**Blue Hydrogen: carbon capture equipment can be added to the SMR process to reduce the $CO_2$ emissions by 90% or more, but at twice the cost**




***Source:*** *IEAGHG*
***Note:*** **Mostly but not pure methane*

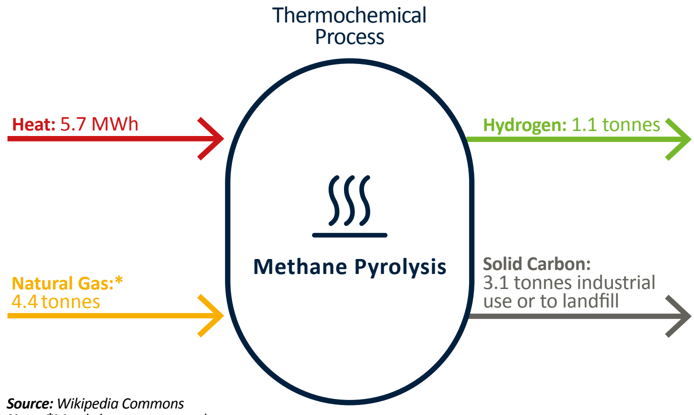
water using renewable energy via electrolysis is carbon free and referred to as "green hydrogen". Green hydrogen represents just 1% of all hydrogen produced today but is believed by many experts to be crucial to the success of the world's efforts to move to net zero by 2050.

Alkaline electrolysers are the most mature electrolyser technology today, but do not work well with intermittent renewable energy sources. One core investment thesis behind electrolyser-produced green hydrogen was that low-cost surplus renewables sourced electricity would solve the economic challenges. But there is an offsetting higher cost of amortising the electrolyser's capital investment over fewer operating hours if it is limiting its access to renewable power in periods of excess renewables generation. Newer polymer electrolyte membrane (PEM) electrolysers react quicky to the fluctuation of renewable power and are in early deployment. Solid oxide cell electrolysers (SOEC), which work at higher temperatures, are less mature but potentially offer a higher efficiency.

Green hydrogen requires renewable electricity and hence could be constrained by the level of renewable capacity. For example, if all of the c.95 Mt of hydrogen currently used each year globally was produced through electrolysis it would require 4,750 TWh of electricity per year (95 Mt x 50 MWh/tonne); more than the total electricity generation of the EU.

**Exhibit 11**

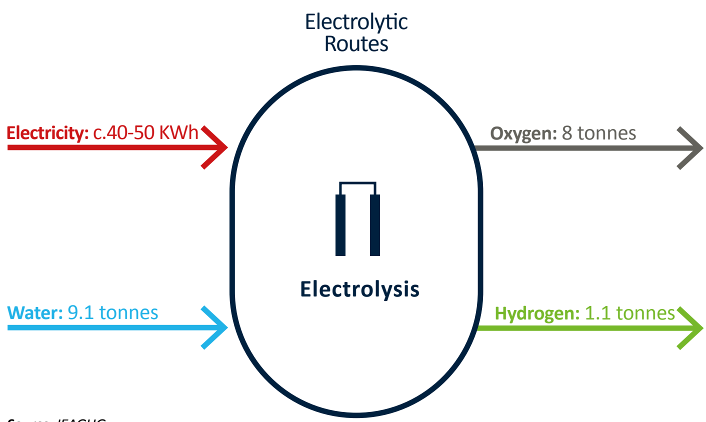
**Turquoise hydrogen: methane pyrolysis is a relatively new technology for producing a low carbon hydrogen when using renewable fuels as a source of heat**




**Source:** *Wikipedia Commons*
**Note:** **Mostly but not pure methane*

**Exhibit 12**

**Green hydrogen from electrolysis using electricity from renewable energy sources represents just 1% of all hydrogen production today but is expected to be the dominant form of low carbon hydrogen in the future**




**Source:** *IEAGHG*

Nuclear power generated electricity can be used in an electrolyser to produce carbon free hydrogen, often referred to as "pink" or "purple hydrogen".

**Biomass gasification** is a mature technology pathway that uses a controlled process involving heat, steam, and oxygen to convert biomass to hydrogen and other products, without combustion. Because growing biomass removes carbon dioxide from the atmosphere as it grows, the net carbon emissions of this method can be thought of as low or even negative, especially if coupled with carbon capture.

In Exhibit 13 we put in one large table all of the various forms of hydrogen produced from the three different routes: thermochemical, electrolysis and via ammonia.

Exhibit 13
## Classifications of hydrogen

Different Ways to Produce Hydrogen or Hydrogen Derivatives (Ammonia) – Thermochemical Routes (1/3)

| I. Thermochemical routes using Fossil Fuels | | | | | | 96% |
|---|---|---|---|---|---|---|
| **Source/ Colour Code** | **Process Name** | **Process Description** | **GHG Emissions** | **Approx. Cost/kg** | **Status and Competitiveness** | **% of Current Global H2 Production** |
| **Grey** | Natural gas reforming (mostly steam methane reforming - SMR) | Steam methane reforming (SMR) produces hydrogen from natural gas (which is 70-90% methane ($CH_4$) and water. The process consists of heating the gas to 700–1,100 °C in the presence of steam over a nickel catalyst. The resulting endothermic reaction forms carbon monoxide and molecular hydrogen ($H_2$). This process creates carbon emissions because it requires the burning of fossil fuels to generate these high levels of heat | **Medium/ High:** 8-10 $kgCO_2/kgH_2$, and upstream methane emissions resulting from natural gas supply | \$1-1.50/kg $H_2$ | It is the cheapest source of industrial hydrogen, being the source of nearly 50% of the world's hydrogen. | 49% |
| **Blue** | Natural gas reforming with CCS | Complements grey hydrogen with carbon capture and storage (CCS) technology. By leveraging on current grey hydrogen infrastructures, blue hydrogen can help rapidly build up the demand for clean hydrogen. | **Low:** Can't achieve pure carbon neutrality due to residual emissions (the highest carbon capture rate is currently estimated at around 95%) and upstream methane emissions. | \$1.50-2.00/ kg $H_2$ | Early stage of build-out of CCS attached to grey-hydrogen SMR process. Blue hydrogen is lower cost than green and more easily built so that blue will lead the early stages of the hydrogen economy in regions that can leverage natural gas reserves such as the Middle East, North Africa, North America, and Australia. | <1% |
| **Black/ brown** | Oil & Coal Gasification | Uses steam and oxygen to break molecular bonds in oil and coal and form a gaseous mixture of hydrogen and carbon monoxide. Carbon dioxide and pollutants are more easily removed from gas obtained from coal gasification versus coal combustion. | **High:** 20 $kgCO_2/kgH_2$ | \$1/kg | Widely used in China and Australia | 47% |
| **Turquoise** | Methane Pyrolysis | The thermal decomposition of materials at elevated temperatures, often in an inert atmosphere. | **Low:** Solid carbon by-product which can be sequestered | \$2-3/kg | "Green" hydrogen without the need for an electrolyser or CCS facility; relatively new technology. Nothing at commercial scale today. | <1% |

***Source:*** *Partners Capital Analysis, literature review*
***Note:*** *costs/kg are not comparable between hydrogen and ammonia, but we use the Kleinman Center for Energy Policy, Harvard University estimates that liquid ammonia produces 55% more energy/kg than liquid hydrogen.*

Exhibit 13
## Classifications of hydrogen

Different Ways to Produce Hydrogen or Hydrogen Derivatives (Ammonia) – Water Electrolysis Routes (2/3)

| II. Water Electrolysis | | | | | | 4% |
|---|---|---|---|---|---|---|
| **Source/ Colour Code** | **Process Name** | **Process Description** | **GHG Emissions** | **Approx. Cost/kg** | **Status and Competitiveness** | **% of Current Global $H_2$ Production** |
| **Green** | Water Electrolysis using renewable electricity (hydro, wind or solar) | Is produced from electrolysis using renewable electricity (e.g. solar and wind). | **Low:** It is amongst the least carbon intensive technologies for producing hydrogen and releases no direct emissions | \$3-8/kg depending on cost of electricity (assumes no subsidies) | Early stage of buildout in progress. Easily scalable; expected to become highly cost-competitive with blue beyond 2030 when electrolyser capacity at large scale is in place. | 4% |
| **Pink** | Water electrolysis using nuclear generated electricity | Produced via electrolysis of water using nuclear power. | **Low:** carbon neutral | >\$6/kg | May face social acceptance and scale-up issues | 0% |

***Source:*** *Partners Capital Analysis , literature review*
***Note:*** *costs/kg are not comparable between hydrogen and ammonia, but we use the Kleinman Center for Energy Policy, Harvard University estimates that liquid ammonia produces 55% more energy/kg than liquid hydrogen.*

**Exhibit 13**
**Classifications of hydrogen**

Different Ways to Produce Hydrogen or Hydrogen Derivatives (Ammonia) – Ammonia Routes (3/3)

| III. Ammonia, and Hydrogen from Ammonia | | | | | | 0% |
|---|---|---|---|---|---|---|
| **Source/ Colour Code** | **Process Name** | **Process Description** | **GHG Emissions** | **Approx. Cost/kg** | **Status and Competitiveness** | **% of Current Global $H_2$ Production** |
| **Grey Ammonia** | Ammonia from natural gas generated electricity | Ammonia is produced by stripping hydrogen from natural gas using steam, producing $CO_2$ that is captured in the Haber-Bosch process. If the steam is created from electricity supplied from unabated gas plants, this has emissions. | 1.5 kg $CO_2$/kg $NH_3$ | $0.45/kg | Incumbent process and cheapest high volume source of ammonia, none of which is cracked back to hydrogen. | 0% (as $H_2$ end product) |
| **Green Ammonia** | Ammonia from renewables generated electricity | Same process as above but using renewables generated electricity; green ammonia as ammonia produced from green hydrogen (from electrolysis) | Low to none | $0.90/kg | Used in current grey ammonia process, but with green hydrogen feedstock. | 0% |
| **Blue Ammonia** | Ammonia from blue hydrogen | Blue hydrogen feedstock and nitrogen are heated by renewable electricity in the Haber-Bosch process. | Low to none | $0.55/kg | Used in current grey ammonia process, but with blue hydrogen feedstock. | 0% |
| **Green Hydrogen** | Hydrogen from cracking ammonia back to $H_2$ | To decompose ammonia back into its original hydrogen and nitrogen, an ammonia cracker is used. First, the ammonia is heated until it evaporates into a gaseous state. It is then fed into the reactor, where ammonia splitting takes place catalytically. Usually, the process runs at temperatures of 600-900 °C and a pressure of 50-100 bar. | Low to none as long as renewable energy is used throughout the process | Expected to be more expensive than blue due to the additional PEM fuel cell cracking step | Commercial scale cracking technologies for the recovery of hydrogen from ammonia remain in their infancy. ThyssenKrupp, KBR, Duiker and Topsoe, all claim to have commercially ready plants. | 0% |

***Source:*** *Partners Capital Analysis , literature review*
***Note:*** *costs/kg are not comparable between hydrogen and ammonia, but we use the Kleinman Center for Energy Policy, Harvard University estimates that liquid ammonia produces 55% more energy/kg than liquid hydrogen.*

# Question 2: What are the main applications for clean hydrogen?

**Today, total hydrogen consumption is around 95 million tons annually (Mt/y). Hydrogen is almost entirely used as a chemical feedstock (not as a fuel) in refining (40 Mt/y), ammonia production (34 Mt/y), methanol (15 Mt/y), and steel manufacturing (5 Mt/y). Virtually all hydrogen used is produced from unabated natural gas or coal. The IEA estimates that this results in 830 Mt of direct $CO_2$ emissions on a net basis, or c.1.7% of global energy-related $CO_2$ emissions in 2022.**

Because hydrogen can be produced in a low-carbon manner and emits no carbon dioxide at the point of use, clean hydrogen is seen as offering a potential solution for certain industrial processes, fuel replacements and energy end-uses that are technically impossible or prohibitively expensive to decarbonise through other means, like electrification.

Low-emission hydrogen production was less than 1 Mt (c.0.7% of all hydrogen produced) in 2022, almost all from fossil fuel with CCUS, with only c.100 Kt hydrogen produced from electrolysis. While the amount of green hydrogen produced is very small, it has increased 20% from 2020, starting in 2018.

The main applications of low emission hydrogen are described below with our view on the attractiveness of low emissions hydrogen to decarbonise each and summarised in Exhibit 14. The likelihood of low emission hydrogen adoption within certain applications must be weighed against their most viable low carbon alternative. We have grouped potential applications into three categories: guaranteed (unavoidable), likely and unlikely applications.

Exhibit 14

**Partners Capital Clean Hydrogen Application Ranking in order of likelihood**

| Application | Current $H_2$ Demand (Mt / year hydrogen) | Total Carbon Emissions (Mt / year $CO_2$) | Current Est. Cost of abatement ($ / tonne $CO_2$) |
|---|---|---|---|
| **Guaranteed Applications:** | | | |
| Refining | 41 | 200 | $80 |
| Ammonia (total) | 34 | 500 | $60 |
| Methanol | 15 | 130 | $100 |
| **Likely Applications:** | | | |
| Steel Production (DRI method) | 5 | 60 | $120-140 |
| Power Generation | – | 14,000 | $140 |
| Aviation | – | 800 | $250-300 |
| Shipping | – | 1,000 | $250-300 |
| Long Distance Trucking | – | 3,200 | $300-340 |
| **Unlikely Applications:** | | | |
| Passenger Vehicles | – | 4,800 | $300-375 |
| Domestic Heating | – | 3,000 | $475 |

***Source:*** *Goldman Sachs Carbonomics 2023, IEA for total carbon emissions; aviation cost of abatement is not broken out from shipping cost, so we show the same costs for both.*

## Guaranteed (Existing) Applications: Areas where hydrogen is already being used and there is no alternative

The following existing applications of low emissions hydrogen are in hard to decarbonise sectors where hydrogen is irreplaceable. If clean hydrogen can be produced at a price competitive with grey, whether through its own merits or because of supportive policy, it should be straightforward for it

*Right:*
ExxonMobil's refining facility at Baytown, Texas will be its first world-scale operation for the production of low-carbon hydrogen which will be used as fuel at an onsite olefines plant. The facility is expected to produce up to 1 billion cubic feet of hydrogen made from natural gas, and over 98% of the associated $CO_2$ is expected to be captured and safely stored underground.
*Image: Kim Steele/Alamy Stock Photo*

to penetrate these existing markets. **Unfortunately, the scale of hydrogen projects in place or announced today (tracked by the IEA) are forecast to generate just under 4 Mt of low-emission hydrogen replacing just 4% of grey hydrogen by 2030.**

This excludes announced projects without a cooperation stakeholders. It is quite possible that the industry moves to deliver supply beyond just the announced projects by 2030. The Global CCS Institute's CCS facility database shows the construction of CCS projects that entered operation in the last decade, on average, took 3-4 years from project announcement to commissioning.

## Refining

Refineries use hydrogen to remove impurities (i.e., sulphur, nitrogen, oxygen, olefins) in a process known as hydrotreating, and to upgrade heavy oil fractions into lighter products in a process known as hydrocracking. The refining industry operates 24/7, and so until there is a consistent, around-the-clock, and affordable supply of green hydrogen, carbon capture (i.e., blue hydrogen) will be the preferred method of decarbonisation in refining.

Today, hydrogen demand in refining is c.41 Mt/year, accounting for c.42% of global hydrogen consumption. Almost all hydrogen used in refineries is produced from unabated fossil fuels, resulting in more than 310 Mt $CO_2$ emitted in 2022, per the IEA. About 80% of the hydrogen used in refineries was produced onsite at the refineries themselves, with around 55% of that amount



**Exhibit 15**
**Summary of expected grey hydrogen replacement by blue and green hydrogen by application by 2030**

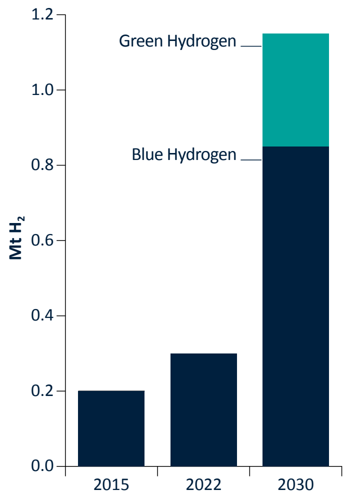
| Application | Current $H_2$ Demand (Mt / year hydrogen) | Total Carbon Emissions ($Mt\ CO_2$ / year) | Expected Mt substitution from green $H_2$ by 2030 | Expected Mt substitution from blue $H_2$ by 2030 | Total expected Mt of $LEH_2$ used by 2030 | Tonnes of $CO_2$ Abatement by 2030 |
|---|---|---|---|---|---|---|
| Refining | 41 | 250 | 0.3 | 0.9 | 1.2 | 7.1 |
| Ammonia (total) | 34 | 500 | 1.3 | 0.8 | 2.1 | 30.9 |
| Methanol | 15 | 130 | 0.2 | 0.3 | 0.5 | 4.5 |
| **Total** | **90** | **880** | **1.8** | **2.0** | **3.8** | **42.5** |

***Source:*** *IEA, Goldman Sachs, Partners Capital Analysis* produced from dedicated hydrogen production and the rest produced as a by-product from different operations (i.e., naphtha crackers). The remaining 20% of hydrogen used in refineries are produced externally in plants operated by another company, typically very close to the refinery.

The IEA maintains a comprehensive data base of hydrogen projects as of the end of 2022. Exhibit 16 shows the production of low-carbon hydrogen from those projects, which indicates that 1.15 Mt will be produced by 2030 which does not even put a small dent in the 41 Mt/year of hydrogen demand in refining.

**Exhibit 16**

**Planned production of low-emission hydrogen for use in refining will mostly be from fossil fuels with CCUS (blue hydrogen) out to 2030**




**Source:** *IEA Global Hydrogen Report 2023*

## Ammonia Production

Hydrogen is a key component of Ammonia ($NH_3$). Most ammonia is manufactured by steam reforming of natural gas, followed by water gas shift to isolate pure hydrogen and $CO_2$, where the $CO_2$ is "captured" and the hydrogen is then reacted with nitrogen to form ammonia in the Haber-Bosch process.

Ammonia is used to produce all mineral nitrogen fertilisers, which account for c.60% of global ammonia demand. The remaining c.40% of ammonia demand is for a wide range of industrial applications, including refrigerant gas, water purification, and the manufacture of plastics, pesticides, explosives, dyes, synthetic fibres, and specialty materials.

The 60% of global ammonia used for fertilisers goes towards making urea, an organic compound with chemical formula $CO(NH_2)_2$. Urea is widely used in fertilisers as a source of nitrogen and is an important raw material for the chemical industry. An impediment to fully decarbonising the ammonia production value chain is that carbon is a necessary ingredient to form urea. Today, that carbon is formed from natural gas or coal. Decarbonising urea will require introducing captured carbon which is expensive. Today, hydrogen demand in ammonia production is 34 Mt/year, virtually all of which is supplied from fossil fuels. Worldwide, c.70% of ammonia is produced from natural gas, with the remaining from coal. CATF estimates that global ammonia production emits c.500 Mt/year of $CO_2$.

*Left:*
Ammonia production site in El Dorado, Arkansas, run by LSB Industries. The facility allows LSB to become one of the first suppliers of blue ammonia to the international markets and will enable the Company to reduce its scope 1 Greenhouse Gas emissions by 25%. This is the equivalent of permanently removing approximately 109,000 passenger cars from the road, which represents approximately 11% of the cars registered in Arkansas.
*Image: Saoirse2013/Shutterstock*

From negligible volumes today, electrolysis and CCUS projects look set to replace only 2.1 Mt of the 34 Mt/year of ammonia production by 2030 as shown in Exhibit 17. The vast majority of clean hydrogen used in ammonia production today comes from onsite CCUS-equipped natural gas plants. To achieve cost parity with natural gas-based hydrogen production, renewable energy generation must continue to scale with corresponding cost reduction in low-carbon hydrogen produced from carbon capture or electrolysis.

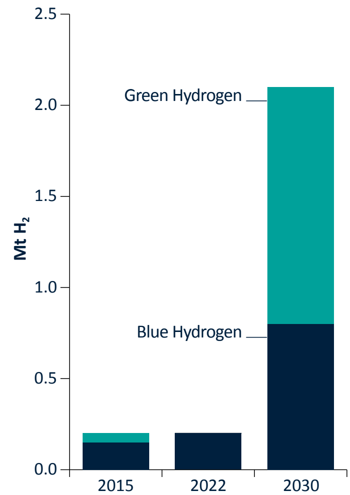
## Methanol Production

Methanol ($CH_3OH$) is produced through the reaction of hydrogen and carbon monoxide in a process known as methanol synthesis. Methanol is used mainly as an intermediate product to produce other chemicals such as formaldehyde, resins, adhesives, and dyes. Methanol by definition requires carbon in its production. As such, its production cannot be fully decarbonised – but the carbon intensity of production can be lowered using low-emission hydrogen.

Today, hydrogen demand in methanol production is c.15 Mt/year. Virtually all of the hydrogen used is supplied from fossil fuels, resulting in c.130 Mt/year of $CO_2$ emissions. The use of electrolysis and CCUS can reduce emissions from the production of hydrogen as feedstock, which accounts for the vast majority of $CO_2$ generated. One tonne of methanol production results in around 2.2 tonnes of $CO_2$ emissions on average with coal-based production, which is dominant in China and accounts for around half the global total. This is significantly more emissions-intensive than the natural gas-based production, which is dominant in the rest of the world. Carbon Recycling International (CRI) is an innovative Icelandic company that has developed technology to produce low emission methanol. CRI takes $CO_2$ naturally emitted from the Svartsengi Geothermal Power Plant's boreholes and converts this gas into liquid methanol.

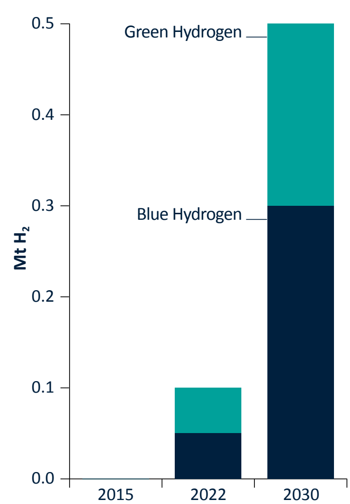
As in ammonia production, scaling electrolysis capacity can lead to reductions in fossil fuel demand in methanol production. The availability and access to renewable energy will determine whether blue or green hydrogen is the primary pathway for emissions reduction, and as such the technology used will be region-specific. Today methanol is mostly produced in regions where renewable energy is scarce, such as China. The United States is the second-largest producer and produces methanol primarily from natural gas. Iran is the third-largest methanol producer, accounting for approximately 10% of global production, and

**Exhibit 17**
**Both electrolysis and CCUS will be key technologies to achieve substantial emissions intensity reductions for ammonia**




**Source:** *IEA Global Hydrogen Report 2023*

**Exhibit 18**
**Electrolysis will be the primary technology in Asia and Europe, and CCUS in North America in efforts to reduce emissions intensity in methanol production**




**Source:** *IEA Global Hydrogen Report 2023* produces methanol primarily from natural gas. Given the relatively small volumes of natural gas-based methanol capacity in Europe, there is limited scope to displace natural gas consumption in the region. The IEA's hydrogen projects database points to just over 0.5 Mt/year of the 15 Mt/year of grey hydrogen being replaced in methanol production as shown in Exhibit 18.

We believe clean hydrogen will play a role in decarbonising each of the aforementioned applications that grey hydrogen already plays a role in, but progress will be very slow. The harder question to answer is where else clean hydrogen will be a part of in a net zero future. Hydrogen has proven its use case in the next set of applications.

## Likely Applications: where clean hydrogen is competing with other technologies

### Steel Production

Global steel production emits approximately 3.6 Gts of $CO_2$ accounting for 7% of global carbon emissions. 70% of steel is produced today via the Blast Furnace – Basic Oxygen Furnace (BF-BOF) process, where coal is used as the main reductant for iron ore at high temperature. This route produces 1.9 to 2.3 tonnes of $CO_2$ per tonne of crude steel. BF-BOF plants emit carbon from heating up coal to create coke, and then from burning the coke to melt iron ore. 70% of $Co_2$ emissions from the blast furnace process comes from the initial step of separating iron from oxygen in the raw iron ore (iron oxides) through the blast furnace process which uses coke as the fuel. Coke is usually derived from low-ash and low-sulphur bituminous coal by a process called coking. Coking is the heating of coal with coke oven gas in the absence of oxygen to a temperature above 600°C to separate off the volatile components of the raw coal, leaving a hard, strong, porous material of high carbon content called coke.

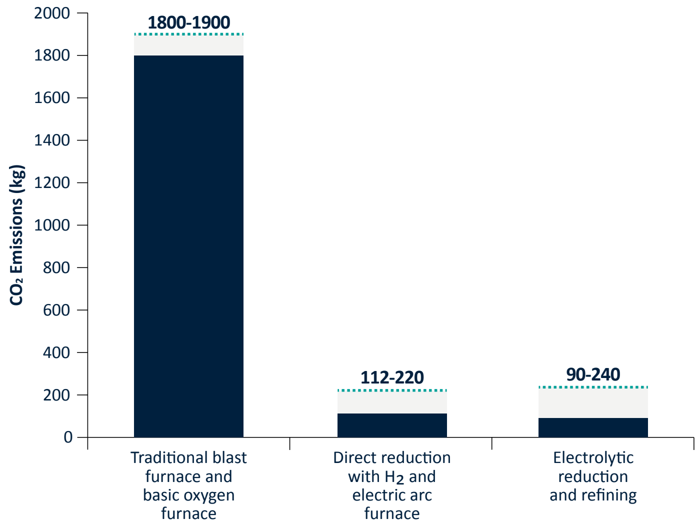
The remaining 30% of steel is produced from electric arc furnaces (EAF), which produce steel from a combination of scrap steel, Direct Reduced Iron (DRI) pellets and iron ore.

**Direct reduced iron (DRI)** is a steel-making raw material made by removing oxygen from iron ore without melting it. Traditionally, DRI is produced from the direct reduction of iron ore using natural gas, but emerging technology is enabling the production of DRI using hydrogen as well. Green hydrogen can be used to reduce emissions from existing steel production processes by blending it into conventional DRI units, substituting natural gas and coal with only minor modifications to the equipment. DRI is excellent

*Left:*
The steel industry produces around two billion tonnes of steel each year, while emitted more than three billion tonnes of $CO_2$ annually.
*Image: Christine olsson/TT/Alamy*

**Exhibit 19**

**Shifting steel production from traditional blast furnaces to EAFs using low-emission hydrogen produced DRI as feedstock cuts emissions from c. 1,800kgs/tonne to c. 200kgs/tonne**




***Source:*** *Mark Peplow for Chemical & Engineering News (C&EN), 2021*

feedstock for EAF steel making. The more DRI, the more EAF steel making. DRI accounts for 5% of the metallics used in the steelmaking process globally and is forecast to double to 10% by 2030 (McKinsey).

**The greatest near term decarbonisation of steel will come from increasing the proportion of steel manufactured in electric arc furnaces using renewable electricity.** The amount of steel scrap and direct reduced iron (DRI) produced as feedstock for EAFs is the gating factor on global steel decarbonisation. A minor amount of decarbonisation will come from using green hydrogen in the DRI process as it goes from accounting for 5% of steel feedstock to 10% by 2030.

The less proven alternatives are carbon capture on blast furnaces and partial coke substitution for hydrogen in the blast furnace process. Another entirely new steel making process being tested by Boston Metals is Molton Oxide Electrolysis (MOE) which aims to produce iron ore without the coking process, followed by direct reduction using green hydrogen.

Ignoring the carbon and methane emissions from the mining of the bituminous coal and the coking of that coal into coke, **decarbonisation of steel will occur from using hydrogen in the DRI pellet-making process and increasing the production of DRI in order to maximise the use of Electric Arc Furnaces. Shifting steel production from traditional blast furnaces to EAFs using low-emission hydrogen produced DRI as feedstock cuts emissions from c.1,800kgs/tonne to c.200kgs/tonne as shown in Exhibit 19**.

Today, DRI accounts for c.5 Mt/year of (currently grey) hydrogen demand and produces 120 Mt of iron a year (c.5% of the 2.6 billion metric tonnes produced in 2022). DRI is among the lowest emitting steelmaking processes, with experts estimating that this 120 Mt of DRI-produced iron ore generates c.60 Mt/year of $CO_2$ emissions which is just 2% of all steel sector emissions. With the expected doubling of DRI production by 2030, low emission hydrogen demand for DRI steel production is expected to double to 10 Mt/year. DRI is project to be nearly 15% of all steel making by 2050 which points to approximately 25 Mt of $H_2$ being required. Compared to shipping, aviation, long-haul trucking and power generation, steel has a relatively small potential market for $H_2$.

Moving on from steel, we turn to hydrogen used in transport. While hydrogen is unlikely to be a solution for passenger vehicles and land transport, it is more attractive for aviation and maritime use cases where range concerns with batteries are more important and demands on fuelling infrastructure are less. The dominant Sustainable Aviation Fuels (SAF) are likely to be e-fuels dependent on hydrogen feedstock. Hydrogen derivatives in the form of ammonia and methanol are expected to be the primary substitutes to help decarbonise shipping where electricity and pure hydrogen may not be viable solutions.

## Long Haul Trucking

Heavy trucking is a transportation end-use case where, similar to marine vessels and airplanes and unlike passenger cars, vehicle size makes it difficult to decarbonise with on-board batteries. Well-known companies in the EV space, such as Tesla, have a product on the horizon to address medium-haul, 300-500-mile, operating ranges. However, for long-haul routes the hydrogen fuel cell technology is better suited to the task in more use cases. It is very likely that the future will see a mix of both EV and hydrogen fuel cell electric vehicles (FCEVs).

Fuel cell trucks use the same basic electric drivetrain as battery trucks (and even have a battery) but due to their on-board hydrogen storage, fuel cell trucks have a much longer range, require fewer stops on long routes, can be fuelled much faster, and can carry more cargo. Fuel Cell Electric Vehicles (FCEVs) are fuelled with pure hydrogen gas stored in a tank on the vehicle which is combusted to generate electricity to power the vehicle. Similar to conventional internal combustion engine vehicles, they can refuel in about 5 minutes and have a driving range of approximately 500 kms. Exhibit 20 compares the current estimated range and fuel economy of diesel, BEV and FCEV heavy duty trucks as estimated by CATF. The hydrogen powered truck has over twice the range of the BEV truck, but the BEV truck gets over 50% better mileage than the hydrogen powered FCEV.

A recent paper from NREL (DOE funded research lab) concluded that a battery electric, long-haul heavy truck (750-mile range, multi-shift, weight-limited class 8 sleeper) will have a higher total cost of ownership (TCO) than its hydrogen counterpart even though the price of hydrogen remains high and fuel cells have a somewhat lower efficiency compared to batteries. This is primarily due to the capital expense of a larger battery and a longer average down time from recharging. Other studies say the opposite with respect to TCO, including the Goldman research in Exhibit 21, so researchers such at CATF say

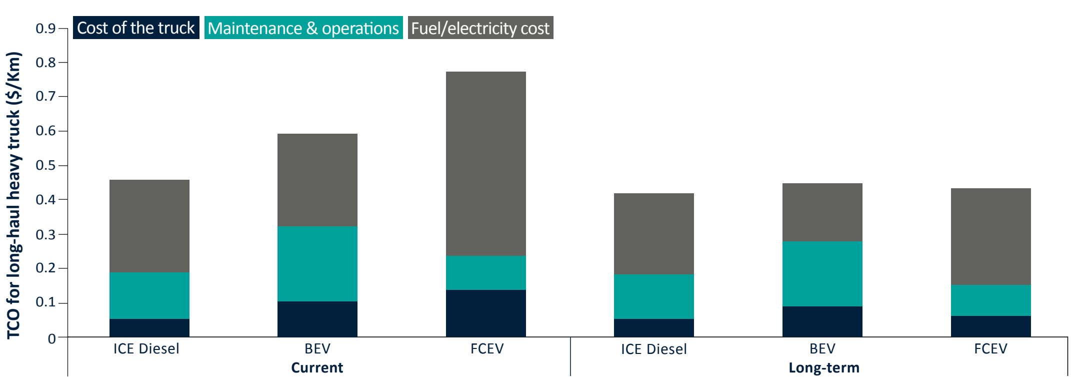
### Exhibit 20
**The FCEV also beats the BEV on range and fuel economy**

| Range | | |
|---|---|---|
| **Diesel** | 2123 | miles |
| **BEV** | 470 | miles |
| **FCEV** | 1019 | miles |

| Fuel Economy | | |
|---|---|---|
| **Diesel** | 8.85 | mpdge |
| **BEV** | 17.39 | mpdge |
| **FCEV** | 11.31 | mpdge |

***Source:*** *CATF Zero Emission Long-Haul Heavy-Duty Trucking study (March 2023)*
***Notes:*** *mpdge = miles per diesel gallon equivalent*

### Exhibit 21
**Long-haul heavy transport could be a new potential end market for hydrogen, with FCEV trucks becoming more cost competitive with further fuel cell technological innovation and offering faster refuelling times, longer ranges and lower weight**




***Source:*** *Company data, Goldman Sachs Global Investment Research* "the jury is still out on BEV vs FCEV TCO". Goldman argues that, over time, FCEV trucks will become more cost competitive with further fuel cell technological innovation and offering faster refuelling times, longer ranges and lower weight. Exhibit 21 shows Goldman Sachs' current (2022) and future estimated total costs of ownership (TCO), comparing diesel, electric (BEV) and hydrogen (FCEV).

Switching a significant portion of long-haul heavy-duty trucks to a battery electric drivetrain will require a more robust infrastructure, in terms of size or number of charging stations – whereas the equivalent infrastructure for hydrogen, while still challenging, is comparatively more similar to diesel. In both cases, however, significant infrastructure work will be needed to meet the requirements of a predominately zero-carbon, long-haul heavy-duty truck fleet.

The stock of fuel cell long-haul heavy duty trucks globally has grown faster than FCEV light-duty vehicles, with the IEA estimating an increase of over 60% in 2022 to bring the total to more than 8,000 as of 30 June 2023. China accounts for over 95% of fuel cell trucks, but adoption is beginning to pick up around the world. Hyundai's Xcient fuel cell truck has been operating in Switzerland since 2020, and is now also in Germany, Korea, and New Zealand. Progress is slower in the United States even though 85% of truck journeys are less than 500 km. In summary, compared to conceptual battery EV trucks, fuel cell vehicles' run for longer, avoid long battery recharging sessions, and may cost less to operate over the life of the vehicle. These advantages will not apply to local trains and buses, but the slow but steady adoption of fuel cell trucks in long haul trucking leads us to believe that clean hydrogen will see a significant market here. This of course could be upended if battery densities increase and charging times decrease while the trucking hydrogen infrastructure is being built out. We discuss this possibility in more detail in our separate research on batteries.

The total potential market for $H_2$ in road freight could be 260 Mt to 520 Mt based on the 17M bbl/day of oil used for diesel fuelled trucks. There are 159 litres of diesel in a barrel of oil suggesting 2,703M litres of diesel is consumed each day, or 986B litres operating 365 days a year. One kilogram of hydrogen replaces 3.8 litres of diesel according to the Rocky Mountain Institute, suggesting if 100% of all diesel in trucking was replaced with hydrogen, we would need 260 Mt of $H_2$ in 2030 just for large trucking transport. Road freight miles are expected to double around the world by 2050, indicating that is a huge potential market for clean hydrogen. Against this large potential total addressable market, Goldman Sach's base case for trucking and buses is approximately 70 Mt of clean hydrogen by 2050, or 13% of the total addressable market by our estimates.

## Shipping

Shipping is currently responsible for nearly 3% of global emissions, generating around 1 billion tonnes of $CO_2$ and greenhouse gases each year. Today, most ocean liners and container ships rely on diesel engines to generate electricity to propel the vessel. A transitional fuel contemplated to replace diesel is liquified natural gas (LNG). LNG is formed when natural gas (methane) is cooled from gaseous to liquid form, making it 600 times smaller by volume. This makes it easier to transport and store. Increasing the temperature turns it back into a gas. Although LNG is still a fossil fuel, it is included in the EU Taxonomy, which lists it as a transitional fuel that will assist the switch to renewable energy in the near future. But environmental campaigners have warned that it falls far short of the ambition needed to decarbonise the industry.

The EU Taxonomy currently incentivises the use of LNG and biofuels, "but what we really need is to strongly incentivise long-term, scalable solutions, which are green hydrogen and hydrogen fuels like ammonia," said Tristan Smith, an expert in shipping and energy at University College London's Energy Institute.

Hydrogen, ammonia, and methanol are viewed by experts to be the leading low-carbon and renewable alternatives, but concerns remain over how ready these alternatives are for wide-scale deployment.

**Hydrogen is unlikely to be used at scale in shipping due to the volumetric density of a liquid hydrogen molecule**, which is 1/3 that of liquified natural gas. This means that 3x the volume of hydrogen vs. LNG will need to be shipped to provide the same amount of energy. Pure hydrogen also has a low boiling point, making it difficult and expensive to compress. In order to liquify hydrogen, it must be frozen to -250 Celsius (compared with -162 Celsius for natural gas).

**Ammonia is currently seen as the most efficient way to decarbonise the shipping sector in the long-term.** Ammonia is widely used in the chemical industry and is best known as the key ingredient in fertiliser. Colourless and with a pungent smell, the fact that the ammonia molecule ($NH_3$) is rich with hydrogen makes it perfect to adapt as a fuel. When used as a fuel, the only emissions are water, with no carbon present to emit $CO_2$.

Ammonia is a relatively energy-dense means to store and transport green hydrogen generated by renewables. Liquid ammonia packs more energy into the same volume as liquid hydrogen, and can be stored at minus 33°C, as opposed to minus 253°C for hydrogen. In practice, this means there is no need for large, pressurised tanks to store concentrated hydrogen gas, but we can simply store chilled liquid ammonia on board. Nonetheless, care is needed to ensure no leakage, since ammonia is toxic. The other challenge is ensuring harmful nitrous oxide gases are scrubbed from exhaust fumes when ammonia is consumed.

Of course, the ammonia itself will need to be clean ammonia, whether green or blue. At the moment, ammonia is not a carbon-free alternative because fossil-fuel energy is used in its creation in a highly energy-intensive process, which releases large amounts of $CO_2$ and methane. The technology to produce renewable ammonia at scale and store it is not yet available.

Today there is no commercial ammonia-fueled engine that can be installed on board a ship, while there are hydrogen-fueled engines in commercial use. Compagnie Maritime Belge (CMB) is backing hydrogen as shipping's future fuel. The Antwerp-based group has three hydrogen-powered ships on the water today, including the world's first hydrogen-powered tugboat. It is also building 28 large vessels that can operate on ammonia for Chinese companies.

CMB is investing in hydrogen for shorter routes and ammonia for international journeys, both ideally produced using renewable energy sources. "Hydrogen in compressed form is ideal to decarbonise small ships that operate on shorter trade links and can refuel frequently," said Saverys.

**Methanol can be used today.** While today we produce methanol from natural gas, methanol can also be made from renewable sources, such as renewable natural gas, biomass, and green hydrogen combined with recycled carbon dioxide. Some companies see "green methanol", produced using renewable energy, as a better option than ammonia in the short term. The cost to build new vessels and retrofit existing ones to run on methanol is significantly lower than for alternative zero-carbon fuels. And unlike ammonia, liquid methanol does not need to be stored under pressure or at extremely cold temperatures. In the immediate term, methanol has a role to play. It is easier to store on a ship, the engines are already working, and it is safer to handle as a fuel.

Maersk, until last year the world's largest container shipping line, is betting on methanol to help it reach its 2040 net-zero target. The shipping giant is investing in a fleet of 12 container ships powered by either marine fuel oil or methanol, produced using biofuels and renewable energy. Maersk says the new vessels will reduce its annual $CO_2$ emissions by 1.5 million tonnes when they start operating.

Meanwhile, Swiss engine manufacturer WinGD has said its engines will be able to run on methanol and ammonia by 2024 and 2025, pursuing "multi-fuel solutions" that will allow flexibility with current diesel fuels as they work towards a full transition.

Unlike ammonia, methanol is constrained by the quantity of sustainably sourced carbon.

Methanol production is more costly then ammonia, as it requires capturing $CO_2$, which is an immature technology that is extremely expensive and highly inefficient.

China, the world's largest shipbuilder and the country with the largest shipping fleet, has started building methanol-powered tankers and recently began the first sea trials. China stands to benefit from being a leader in the race to find alternative fuels, given they have the industry, the ports and the manufacturers.

Given the density properties of hydrogen, methanol appears to be the near-term solution for shipping, while ammonia would appear to be the long-term solution. The International Maritime Organisation's (IMO) recently revised GHG Strategy includes an ambition to reach net-zero GHG emissions from international shipping by 2050, which includes a commitment to ensure an uptake of alternative zero and near-zero GHG fuels by 2030 as you can see in Exhibit 22.

Our estimates of the total addressable market for $H_2$ in shipping (via methanol and ammonia) range from 112 Mt in 2030 to 136 Mt in 2050. This is based on the total amount of bunker fuel used today converted to methanol and then calculating the amount of hydrogen required for producing this quantity of methanol. Goldman Sachs' base case forecast for $H_2$ usage in shipping is for virtually nothing in 2030 and approximately 20 Mt by 2050, the latter representing 18% penetration of our calculation of total potential.

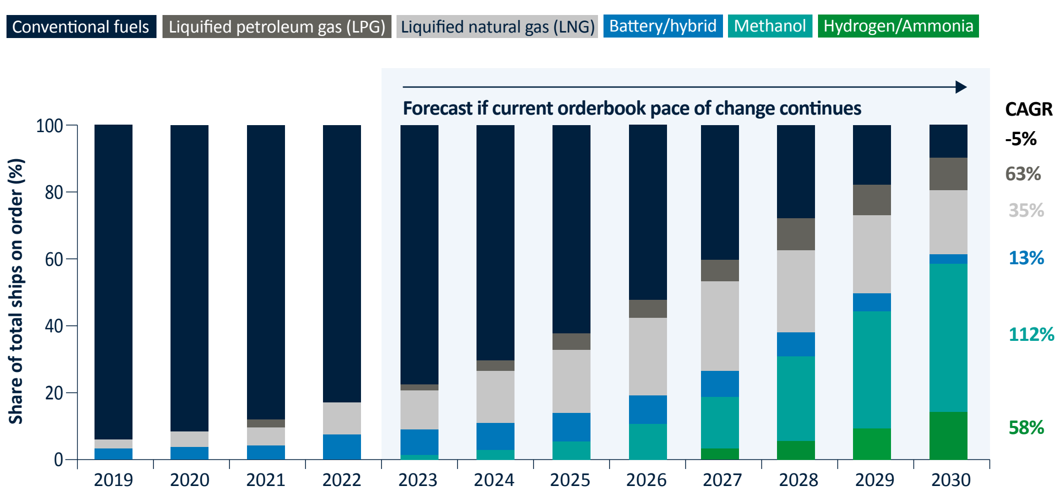
## Aviation

In 2022 aviation accounted for 2% of global energy-related $CO_2$ emissions, having reached almost 800 Mt $CO_2$, about 80% of the pre-pandemic level. Planes today mostly burn jet fuel, also called kerosene—a fossil fuel with a mix of carbon-containing molecules. Alternative fuels have the same basic chemical makeup as fossil fuels; the difference is that sustainable air fuels (SAFs) are derived from renewable sources and can largely be used by existing aircraft. Hydrogen is not often discussed as a core alternative source of jet fuel in its pure form of hydrogen. However, low-emission hydrogen is used as a core feedstock in the production of jet e-fuels described below.



**Exhibit 22**

**The recent IMO agreement will drive demand for alternative fuels focused on LNG and methanol between now and 2030**




**Source:** *International Maritime Organisation*

Pure hydrogen can be used to fuel short-haul aircraft (via combustion or fuel cells), while biofuels and e-fuels remain the better options to fuel longer-haul aircraft. Despite the likely SAF winner being e-fuels, Airbus' ZEROe initiative carries on from its launch in 2020 with ambitions to develop the world's first hydrogen-powered commercial aircraft by 2035.

The most likely alternative jet fuels fall into two main categories: biofuels and synthetic electrofuels.

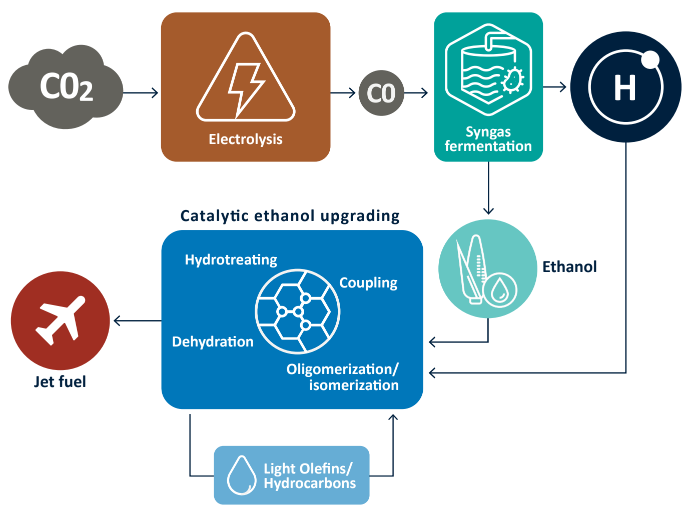
**Biofuels** come from a range of biological sources. Some are derived from waste like used cooking oils, agricultural residues, or landfill trash, while others can be made from crops grown specifically for fuel, from corn to palm trees to switchgrass. Making fuel from biological sources requires chopping up the complicated chemical structures that plants make to store energy. Fats and carbohydrates can be broken apart into smaller pieces and purified, sometimes using existing refineries, to make the simple chains of carbon-rich molecules that are jet fuel's primary ingredient.

Today, the small amount of commercially available alternative jet fuels are biofuels made from fats, oils, and greases. Even with increased collection, waste fats, oils, and greases probably will not provide more than 5% of global jet fuel supply. If they are derived from waste sources like used cooking oils, these fuels reduce carbon dioxide emissions by roughly 70% to 80% compared with fossil fuels but still leave us with too little supply. Some new biofuels, like those made from agricultural residue, municipal solid waste, and hardy crops like switchgrass, are starting to enter the market; a few facilities are under construction or producing jet fuel from these sources worldwide, and the carbon dioxide emission savings they achieve can range from 50% to 90%.

**Electrofuels** (e-fuels) do not start with plants but rather start with hydrogen that has been generated by electrolysing water into its constituent elements using renewable electricity, plus carbon dioxide that has been pulled out of the atmosphere through any

**Exhibit 23**

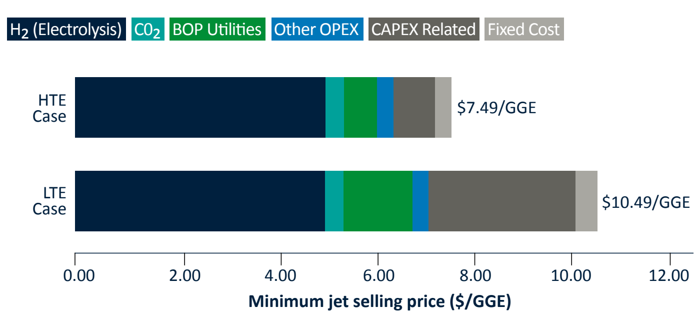
**C02 and hydrogen are the main ingredients for jet e-fuels. To cut emissions, both the C02 electrolysis needs to be from renewable energy sources and the hydrogen must be low-emission hydrogen**




*Source:* Royal Society of Chemistry (October 2022) (https://pubs.rsc.org/en/content/articlehtml/2022/ee/d2ee02439j)

**Exhibit 24**

**The cost of C02-to-SAF jet e-fuel is estimated to range from $7.50 to $10.50 per gallon vs. $3/gallon for today's high carbon emitting jet fuels**




*Source:* Royal Society of Chemistry (no incentives, conservative market scenario) number of carbon capture processes. These are then combined and transformed in chemical reactions powered by electricity like the process shown here in Exhibit 23.

The Royal Society's research estimates that up 95% of the carbon emissions from natural gas-based jet fuel can be avoided using this $Co_2$ to SAF using bioethanol in the process. Making e-fuels is expensive today because the process is inefficient, and e-fuels of any sort are still not produced widely and at commercial scale. This same RSC research estimated that the cost per gasoline gallon equivalent (GGE) of e-fuel will vary from $7.50 to $10.50 compared to current kerosene-based jet fuels at $3 to $3.50 per gallon as you can see in Exhibit 24.

Despite this economic challenge, experts say that in order to reach its 2050 target, aviation will largely need to rely on e-fuels because they are the most effective at cutting carbon dioxide emissions, and they will not be limited by supply or collection logistics like fuels made from plants or waste.

Like conventional jet fuel, alternative fuels produce carbon dioxide and other emissions when they are burned for energy in planes. Some crop-based biofuels can actually produce more carbon dioxide emissions overall than fossil fuels. That is frequently the case for biofuels made from palm oil, since growing that crop can decimate rainforests. Even synthetic e-fuels can approach the $CO_2$ emissions of jet fuel if they're produced using electricity from fossil fuels.

A startup called Twelve is building the U.S.'s first large-scale factory to make jet e-fuel from $CO_2$ in Washington state. By next year, Alaska Airlines plans to buy the fuel. Over the next several months, the company will be deploying its core "carbon transformation" technology, designed to efficiently split $CO_2$ and water and then recombine carbon and hydrogen molecules into the building blocks for jet fuel. Nearby paper mills and ethanol plants will supply the captured $CO_2$. Twelve built its first commercial plant in Washington in part because of the state's high percentage of clean energy sources, including more than two-thirds that come from hydropower. When production begins next year, the Washington factory will produce around 40,000 gallons of fuel annually.

But Twelve's goal is to scale its production to 1 million gallons of fuel a year. Other companies are also beginning to make jet fuel with clean energy and $CO_2$, including Air Company, a New York-based startup.

Globally, airlines and other aircraft users are expected to consume 2.9 billion barrels of jet fuel in 2030. On average, the production of one barrel of hydrogen based SAF will require 27 kilograms of hydrogen which sums to 108 Mt of hydrogen to produce all of the world's jet fuel needs in 2030. Given the expected growth of air travel, forecast jet fuel needs of 6.6B barrels translates into 245 Mt of $H_2$ to satisfy 100% of jet fuel demand. Biofuels are the cheapest source, but have limited feedstock for producing jet fuel and there are competing uses for that bio-feedstock. So we expect hydrogen-based SAF would be the dominant source of e-fuels, if sufficient hydrogen could be supplied. Goldman assume zero hydrogen based jet fuel in 2030 and 35 Mt of hydrogen for jet fuel in 2050, which represents just 14% of the potential demand.

### Power Generation
(as long duration electricity storage medium)

Hydrogen has the potential to play an important role in the power system for energy storage and flexible supply. Hydrogen can be used to store excess energy created during high supply periods from renewable sources, such as solar and wind power. By producing hydrogen via electrolysis and storing it in underground salt caverns, to be converted back to electricity in excess demand periods, hydrogen can provide flexibility to the power system.

Hydrogen stores 33.6 megawatt hours (MWh) of energy per ton of hydrogen. However, the current best available technology to produce hydrogen electrolytically requires approximately 48 MWh per ton of hydrogen. This difference between the amount stored and the amount required to drive electrolysis can only be overcome economically if the cost of the 48 MWh to produce the hydrogen is lower than the price of electricity sold or used at a later date when renewable and other sources of electric power are not available or more expensive. Hence, the economic justification for green energy is tied critically to the cost of excess renewable electricity being significantly below average cost. So this is relatively long duration storage (weeks or months, but could be a matter of days).

Additional energy is also required to convert hydrogen back into usable energy. This process can be achieved through a fuel cell or an internal combustion engine (ICE). Hydrogen fuel cells can derive a theoretical maximum energy output of 33.6 kWh/kg of hydrogen; however, most only achieve efficiencies of about 60%. Since they are converting heat energy into kinetic energy, these efficiencies, combined with the energy requirements of electrolysis result in a roundtrip efficiency of approximately 42% for fuel cells and just 17% for hydrogen powered combustion engines. Exhibit 1 at the beginning of this chapter shows an example with 22% round trip efficiency for the latter.

Although it is possible to compress or liquefy hydrogen and transport it through pipelines or by rail, its properties make this both a challenge and a risk. Hydrogen is the lightest element, escaping even air-tight vessels, and can cause embrittlement in unprotected metals including steel, aluminum, and titanium. This means that repurposing any existing infrastructure, such as natural gas pipelines, would require significant retrofitting.

Notwithstanding these challenges for green hydrogen in power generation, there may be a role in providing flexible electricity supply in peak demand periods. Different countries will achieve different renewable electricity (including hydroelectric) penetration rates based on their geographic makeup, transmission constraints, national energy policies, and other factors. For example, today Sweden is virtually 100% supplied by renewable energy and has no need for long-duration storage solutions like green hydrogen. In sharp contrast, Japan today has 27% of its energy supplied from renewable sources and will struggle due to land constraints to take this beyond 40%, leaving 20% from nuclear and 40% from coal and gas. For countries like Japan, carbon capture and clean hydrogen are the two core competing options to further decarbonise their power grid. Japan are also pursuing low-emission ammonia as a solution, discussed below.

While the optimal energy strategy will differ for any given country (or region within the country), a recent 2023 set of formal comments from CATF in response to the US EPA's request for public comment concludes that carbon capture has superior economics in the next decade or so relative to green hydrogen which is also constrained by supply growth. More specifically, carbon capture works best when the plant is operating at high levels of capacity utilisation and is not relied on for flexible supply due to the need to amortise the high cost of carbon capture equipment over high utilisation rates. CATF calls for the US EPA to use very low-emissions hydrogen blending to set emissions standards for low- and intermediate-load power plants, as low emissions hydrogen is likely more cost effective than alternatives for plants with lower capacity factors. Overall, however, CATF calls for limited hydrogen deployment in the power sector given potential availability of more cost-effective or energy-efficient decarbonisation alternatives. We discuss this more completely below in the section covering the cost of various forms of hydrogen.

Hydrogen used in this manner as fuel in the power sector is virtually non-existent today. The IEA estimates it to have a share of less than 0.2% in the global electricity generation mix – and largely not from pure hydrogen, but mixed gases containing hydrogen by-products from steel production, refineries, or petrochemical plants.

However, technologies to use pure hydrogen for power generation are commercially available today and interest in using hydrogen or ammonia as a fuel in the power sector has


*Right:*
The Toyota Mirai fuelcell car at the CES Show in Las Vegas
*Image: Alamy Stock Photo / Yaacov Dagan*



been growing. In the United States, the Intermountain Power Project has retrofitted two coal-fired units in Delta, Utah to utilise a 30% hydrogen co-firing blend. The hydrogen-capable gas turbine combined cycle power plant will utilise renewable energy from a clean hydrogen storage facility capable of providing long-term, seasonal energy storage. This Dneselta, Utah project will be operational in 2025 and intends to be incrementally fuelled by 100 percent clean hydrogen by 2045.

In the United Kingdom, SSE Thermal and Equinor acquired the Saltend Power Station in September 2022. The conventional combined cycle gas turbine will be retrofitted by Equinor and SSE Thermal to use up to 30 percent hydrogen from 2027, with an ambition to eventually increase it to 100 percent hydrogen. The hydrogen could come from Equinor's $H_2H$ Saltend hydrogen project, which reforms natural gas into hydrogen by CCUS.

Using our assumption that 10% of total electricity will need to be supplied by long duration stored clean hydrogen, this will amount to 118 Mt by 2030 and 254 tonnes by 2050. Goldman Sachs' base case estimate calls for a combination of hydrogen used in power generation and grid blending with natural gas, which sums to 28 Mt by 2030 and 95 Mt by 2050, representing something closer to 2% and 4% of all electricity needs. The IEA projects the potential size of the hydrogen power generation market to be of similar size at c.20 Mt / year by 2030 and c.125 Mt per year by 2050.

In the further applications described below, hydrogen comes into competition with other battery-electric solutions. These will be hard battles for hydrogen to win, and we believe it is unlikely clean hydrogen will be used in these sectors.

1 Our World in Data

## Unlikely Applications: where other clean technologies are likely to win out

**Passenger Vehicles:**
Road travel accounts for three-quarters of transport emissions, and 15% of total $CO_2$ emissions.[1] Pure hydrogen can be consumed in fuel cells or internal combustion engines in the road freight sector, complementing electric vehicles especially for long-haul freight requirements.

However, in fuel-cell automobile uses, hydrogen fuel cells must overcome battery-based electric vehicles that have a head start through government support and extensive supporting infrastructure. More importantly, hydrogen cars are less energy efficient than battery electric vehicles. Bloomberg BNEF estimates hydrogen cars to be half as efficient as EVs given the losses in electrolysis, compression, transport, storage, and reconversion associated with hydrogen cars. These fundamental thermodynamic constraints will not change much over time.

Hydrogen cars, critically, can be refuelled quickly during long trips. However, with the lack of hydrogen fuelling infrastructure and rapidly expanding range of electric vehicles, this advantage is moot. We are ready to say that electric vehicles (i.e., Tesla, BYD) have won the war for consumer road travel. Over time and as hydrogen fuel cell volumes increase, the cost difference between fuel cells and batteries may decrease and a point will be reached at which the benefits of the fuel cell system outweigh the additional cost. The IEA has reviewed the announcements of FCEV deployments by several key countries. These suggest that widespread deployments are unlikely before 2030.

**Domestic Heating:**
Hydrogen can be used as a clean fuel for heating and cooling buildings. An estimated 47% of US homes currently have natural gas space heating, and another 3-8% use liquified petroleum gas heating.[2] Replacing or blending some natural gas with low-carbon hydrogen would lower GHG emissions of residential, commercial, and industrial heating, without new infrastructure deployment. This can be achieved by blending hydrogen into the natural gas grid or deploying stationary fuel cells directly in buildings to generate electricity and use the heat they produce in lieu of traditional space and water heaters. However, because of efficiency losses between renewable power and green hydrogen, if electricity can be used as a heat source, it should be. Using wind power to generate hydrogen, and then using that for heat, would have efficiency losses of around 50%.

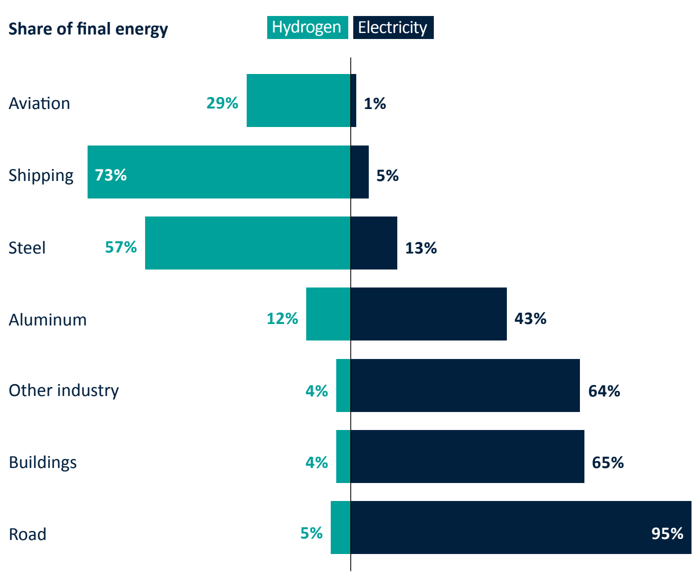
Heat pumps are a more efficient and cost-effective alternative. Bloomberg BNEF estimates that heat pumps produce four times more heat per unit of wind or solar power than could be delivered via hydrogen boiler.

### Summary of potential low emission hydrogen demand creation from all applications

BloombergNEF has summarised its own views in the Exhibit 25 below which graphically makes the point on where electrification is difficult, hydrogen has a market opportunity. This supports our view that shipping, aviation, and steel are opportunities beyond simply replacing existing grey hydrogen applications.

One of the reasons that hydrogen's role in the energy transition is so controversial is that it is very complicated. From an overall energy systems perspective, solving for maximum emissions

Exhibit 25
**BloombergNEF Net Zero scenario forecasts for where hydrogen tackles tough to electrify applications**

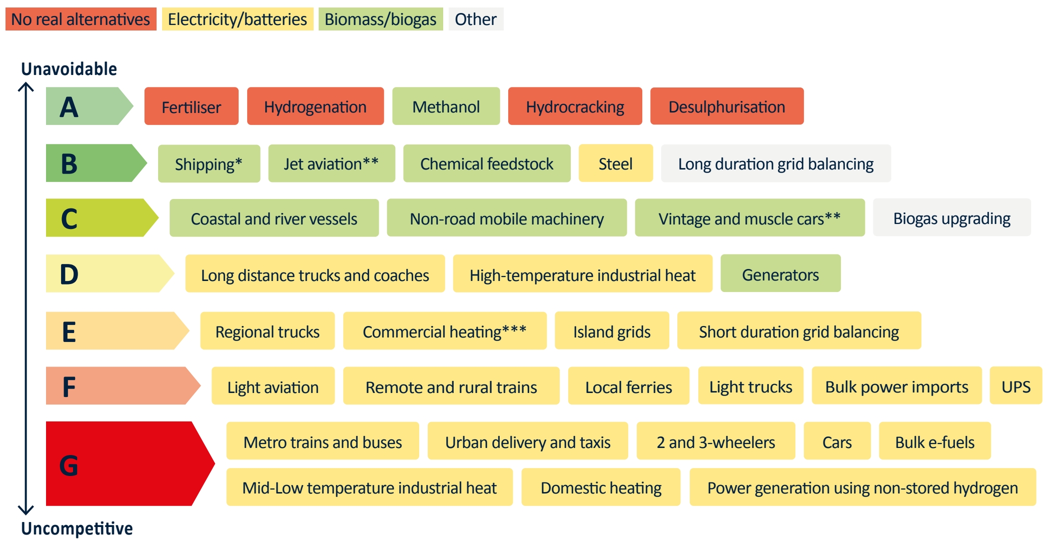



*Source: BloombergNEF. Note: "Other industry" includes low-and medium-temperature industrial processes. Where hydrogen and electricity do not add up to 100%, the remaining share has been provided by the other sources of primary energy, such as bioenergy, heat or fossil fuels.*

2 US Energy Information Administration

## Exhibit 26

**Hydrogen will replace current high emission fuels where grey hydrogen is currently used and then only a handful of other applications including shipping, jet fuels, and steel**




***Source:*** *Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 4.1, 2021. Concept credit: Adrian Hiel, Energy Cities. CC-BY 3.0*
***Note:*** **Most likely via ammonia or e-fuel rather than $H_2$ gas or liquid ** As e-fuel or PBTL *** As hybrid systems*

reduction, the electrons generated by renewables are quite likely better used in other applications. The founder of Bloomberg New Energy Finance, Michael Liebreich, devotes a huge amount of his current firm's research to hydrogen and publishes a rank ordering of likely economic and technical application of a much longer list of end uses which we show in Exhibit 26.

Rows A through C are applications which Michael believes will see successful commercial application and include the current grey $H_2$ applications, shipping, jet fuel and long-duration grid balancing, the latter being what we are suggesting in terms of the "auxiliary" needs during peak demand for electricity generation. The applications on rows F and G are highly unlikely including passenger vehicles and domestic heating. Rows D and E are on the fence with Michael and include long-haul trucking and short duration electricity grid balancing. This broadly corresponds with our ranking and that of Goldman Sachs' market sizing of $H_2$ applications which you can see in Exhibit 27.

In Exhibit 27 we have attempted to calculate the total addressable market (TAM) for each major application of $H_2$ in both 2030 and 2050 in order to judge the reasonableness of the Goldman Sachs and other experts estimates. Our definition of total addressable market is the amount of hydrogen required to replace the current fossil fuel used.

The conclusion is that the TAM for the major applications, Goldman is assuming zero or near zero penetration of shipping, aviation and long-haul trucking, but 24% penetration of our estimate of 10% of electricity being the TAM for hydrogen storage based auxiliary electricity generation. By 2050, Goldman's assumptions sum to 28% penetration of our estimates of the total addressable market for $H_2$.

The point of our estimates of the total addressable market for each application is to highlight the potential upside beyond out current base case estimates. The large gaps between TAM and our estimates is generally explained by the unfavorable economics of clean hydrogen.

## Exhibit 27

**The Goldman Sachs base case scenario assumes 20% and 28% penetration of the total addressable market for the major $H_2$ applications**

| Application | 2030 $H_2$ TAM (Mt) | Goldman 2030 Estimates (Mt) | % Penetration of TAM | 2050 $H_2$ TAM (Mt) | Goldman 2050 Estimates (Mt) | % Penetration of TAM | Total Addressable Market (TAM) Assumptions and Methodology |
|---|---|---|---|---|---|---|---|
| Current grey $H_2$ applications – feedstock to refineries, ammonia and methanol | 100 | 100 | 100% | 125 | 95 | 76% | TAM is the forecast demand for existing applications growing by 1% a year. |
| Steel | 13 | 10 | 75% | 25 | 40 | 161% | Assume hydrogen's primary use is in DRI which is growing from current 6% of all steel production to 15% by 2050, while steel grows by 30% to 2050. 58 kgs of $H_2$ is needed per tonne of DRI-produced steel. Goldman estimates assume hydrogen used in blast furnaces, not limited to DRI. |
| Long-haul trucking | 261 | 5 | 2% | 521 | 70 | 13% | Long-haul trucking will transition to fuel cell electric vehicles (FCEVs) where large hydrogen storage tanks will be onboard and refuelled every 500 kms or more without having the range limitations and recharging downtime of a purely battery-charged electric truck. This could be a huge market for low-emission hydrogen. TAM = total diesel currently used with conversion to $H_2$ needed to replace that volume of diesel. |
| Shipping | 112 | 0 | 0% | 245 | 35 | 14% | Assume no significant demand for hydrogen other than as the green hydrogen to be used as feedstock to manufacture ammonia or methanol for maritime fuels. Methanol in short term and ammonia as the longer term solution. TAM calculation for both 2030 and 2050 assumes 100% methanol. Start with total shipping diesel used in shipping today and converted into methanol and then calculated the quantity of hydrogen required for each tonnne of methanol. |
| Aviation | 109 | 0 | 0% | 245 | 35 | 14% | Aviation should see a combination of biofuels and e-fuels replacing the current high emission kerosene-based jet fuel very slowly given the nascency of sustainable aviation fuels (SAF) technology. The leading e-fuel technology makes heavy use of hydrogen but costs 2 to 3 times as much as current jet fuels. The theoretical demand for hydrogen is so great that it suggests multiple alternative fuels will be needed. Biofuels are cheaper but limited in supply. TAM calculation starts with total current kerosene jet fuel and converts into e-fuels using enough hydrogen to achieve the equivalent btus as kerosene. |
| Power Generation | 118 | 28 | 24% | 254 | 95 | 37% | Assume that 10% of all electricity generation will need to rely on $H_2$ which is the auxilliary capacity (variable during peak needs) that cannot be met by renewables, hydroelectric, Nuclear and geothermal and Nat Gas CCUS. We calculate how much hydrogen is needed to satisfy 10% of a growing global quantity of electricity using 53.7 kt of $H_2$/GW of electricity (per Bain & Co). |
| **Totals** | **705** | **143** | **20%** | **1305** | **370** | **28%** | |

***Source:*** *Partners Capital analysis*

# Question 3: What is the potential for hydrogen derivatives such as ammonia?

**For the majority of project sizes and transport distances, ammonia and natural gas pipelines repurposed for compressed hydrogen will be the most cost-effective options. Once ammonia can be produced with near zero net emissions from green or blue hydrogen, it may become an economically competitive source of electric power and transport fuel relative to low-emissions hydrogen. Ammonia may also be used as a hydrogen carrier in long-distance transport and storage before being converted back into hyrogen for its use across its full range of applications (current and future). Most near-zero-emission ammonia technologies are not yet available at commercial scale in the marketplace, simply because the blue and green hydrogen feedstocks supply is 10 years or more into the future. For shorter transport distances, compressed and uncompressed hydrogen is the most cost effective. The decision between compressed and uncompressed hydrogen will likely be influenced by the specific circumstances of each pipeline project, including the distance of transport, pipeline condition, available infrastructure, and economic factors.**

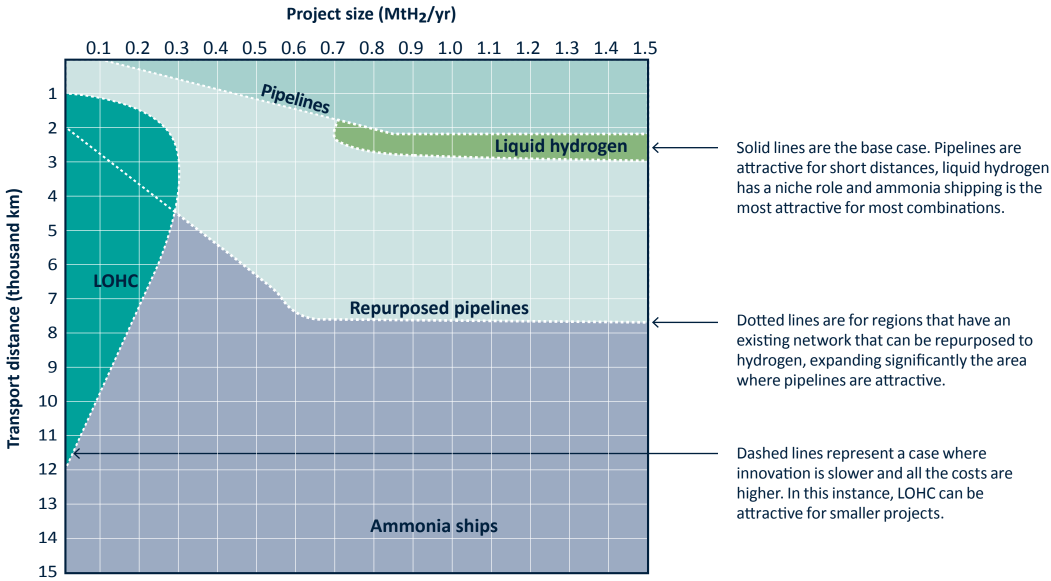
Today hydrogen is mostly produced close to where it is used as feedstock to oil refining and to ammonia and methanol production. A small amount is transported through pipelines in much the same way as is natural gas. Today, the US has 2,600 km of hydrogen pipelines according to the IEA, while Europe has 2,000 km and China has only 100 km. To highlight how little this represents, we compare these numbers to the EU gas network which comprises more than 200,000 km of transmission pipelines.

In the future, most of the newer applications for $H_2$ described above, require hydrogen to be transported from where it is produced to where it is used, in steel mills, truck fuelling stations, airports, and ocean fuelling stations. The ideal situation is that wind and solar produced electricity, electrolysis, and green $H_2$ usage are all in the same place. Given the geographic constraints on where the wind blows and the sun shines, we will need to build transport networks in anticipation of the growing demand for clean hydrogen.

The first solution for transportation is to transport gaseous hydrogen with no modification via retrofitted and repurposed existing natural gas networks which will be cheaper than building new dedicated hydrogen pipelines. Longer transport distances will require compression or liquification and shipping to overcome the low volumetric energy density of hydrogen. Depending upon the exact transport routes, conversion of hydrogen to a higher density form may make the most economic sense. The main options include compression, liquification, and liquid organic hydrogen carriers (LOHCs), with ammonia being the most talked about LOHC. Research is ongoing in the field of LOHCs with, beyond ammonia, Dibenzyltoluene and the Toluene/Methylcyclohexane system considered to have the most potential for widespread use, mainly due to their balance of efficiency, safety, and economic viability. LOHC is a heat-resistant oil with a capacity of 57 kg hydrogen per 1 $m^3$. Hydrogen is chemically bound to and released from the LOHC in a chemical reaction on a catalyst. This liquid substance is then stored and conveyed to fuelling stations using regular

## Exhibit 28

**For the majority of project sizes and transport distances, ammonia and natural gas pipelines repurposed for compressed hydrogen will be the most cost-effective options**




***Source:*** *IRENA*



means of transport at ambient temperature and pressure, making it safer and more cost-efficient. LOHC can be attractive in a scenario with slower technology progress which leads to higher shipping costs for other options leaving LOHC most attractive for relatively small projects.

The main challenge for liquid hydrogen is the cryogenic temperatures needed (-253 °C) as it requires expensive equipment for transport, storage, and handling. It also requires 30-36% of the energy contained in the hydrogen for liquefaction. Due to the high capital intensity, liquid hydrogen becomes more attractive as the project size increases which leads to an overlap with the conditions where pipelines are the most cost-effective.

Herib Blanco at IRENA concludes that ammonia and pipelines are the best options for starting the global trade in hydrogen. The transport cost of hydrogen is mainly dependent on the size of the project and the transporting distance. The larger a facility the lower the costs until a maximum size is reached and cost benefits decrease. Distance is more critical for pipelines since their costs are directly proportional to distance, while for shipping, 70-90% of the total cost is in the terminals (plants and storage). Exhibit 28 shows that for the majority of project sizes and transport distances, ammonia and natural gas pipelines repurposed for compressed hydrogen will be the most cost-effective options.

Ammonia is a compound of one nitrogen atom and three hydrogen atoms ($NH_3$). Worldwide production of ammonia is about 175Mt/year, with 80% used in fertiliser and the majority of the remainder used in refrigerants. Beyond fertiliser and refrigerant, ammonia can be burnt in an engine or used in a fuel cell to produce electricity. There are three energy transition stories relating to ammonia:

1. Abating the estimated 500 $MtCO_2$/year of emissions ammonia's production currently produces through changing the hydrogen feedstock to near-zero emissions hydrogen,

2. Once ammonia can be produced with near zero net emissions, it may become an economically competitive source of electric power and transport fuel relative to low-emissions hydrogen, and

3. Ammonia may be used as a hydrogen carrier in transport and storage before being converted back into hydrogen for its use across its full range of applications (current and future).

Ammonia is itself not a greenhouse gas. When used, ammonia's only by-products are water and nitrogen. Following deposition to soil in fertilisers, it may be converted to nitrous oxide, an important contributor to radiative forces of climate change. Most ammonia today is manufactured by steam reforming of natural gas, followed by water gas shift to isolate pure hydrogen and $CO_2$, where the $CO_2$ is "captured." Just over 70% of ammonia production is via natural gas-based steam reforming, while most of the remainder is via coal gasification. Natural gas steam reforming is an energy intensive process running at temperatures of 500°C, with most of the heat supplied from burning natural gas unabated.

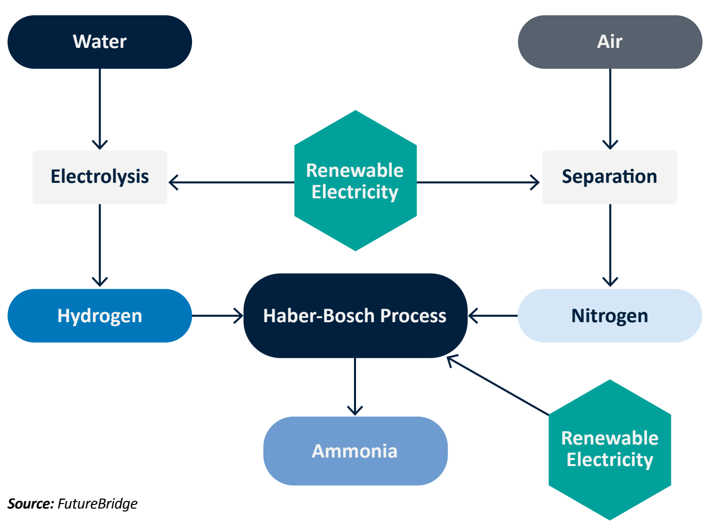
Ammonia accounts for direct and indirect GHG emissions of approximately 420 Mt $CO_2$/year. Indirect $CO_2$ emissions are around 170 Mt $CO_2$ per year and stem from two main sources – electricity generation to produce the hydrogen feedstock that goes into making ammonia, and the chemical reaction that takes place when urea-based fertilisers are applied to soils. Ammonia is one of the most emissions-intensive commodities produced by heavy industry. At between 1.6 t and 2.4 t $CO_2$ per tonne of production, it can be up to twice as emissions intensive as crude steel production and four times that of cement, on a direct $CO_2$ emissions basis.

The production of low-emissions ammonia is possible by sourcing the required hydrogen feedstock as blue (from CCS) or green (from electrolysis). Exhibit 29 shows green ammonia being produced from green hydrogen in the Haber-Bosch process.

The advantage of ammonia over hydrogen involves its ease of handling and transportation in bulk. Since ammonia has a higher volumetric energy density than liquid hydrogen, more energy can be transported via ammonia for the same volume than in the form of liquid hydrogen. Systems for moving ammonia are well established. This is not the case with hydrogen, which poses corrosion challenges with respect to steel pipelines and other containers. After the green ammonia is shipped, it can be split back into green hydrogen and nitrogen in the destination facilities or used directly.

While systems and processes for moving ammonia are well established, **retrofitting existing natural gas infrastructure for ammonia may be significantly more involved than for hydrogen**, since the characteristics of existing ammonia pipelines are quite distinct from natural gas pipelines. Whereas natural

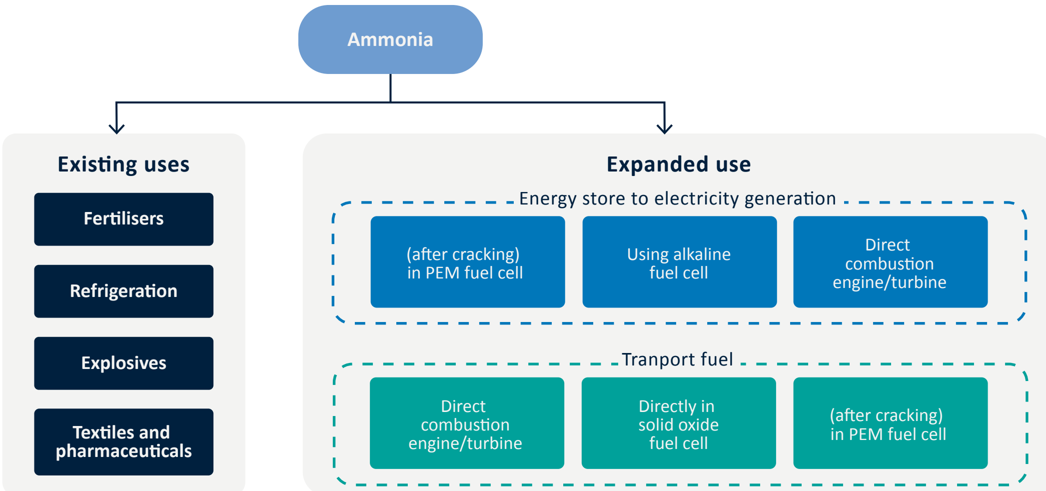
**Exhibit 29**
**Blue and green ammonia is produced from blue and green hydrogen and renewable electricity as the resulting blue/green hydrogen is combined with nitrogen**




***Source:*** *FutureBridge*

## Exhibit 30

**Blue or green ammonia will first be used to replace the brown and grey ammonia currently used in fertilisers and refrigerant, but there may be expanded direct ammonia uses once cracked back into hydrogen in electricity generation and transport fuel**




**Source:** *FutureBridge*

gas transmission pipelines are typically pressurised to 500– 1,200 psi, ammonia pipelines typically operate at just 250 psi. At this pressure, ammonia is a relatively heavy liquid. This means that if natural gas pipelines were to be repurposed for ammonia transport, they would either need to be adapted to operate at much lower pressures or under a much higher weight burden. On the other hand, liquid ammonia is non-corrosive and does not exhibit the same embrittlement properties as hydrogen, meaning that materials restrictions are not as stringent.

Among energy-importing countries, Japan in particular has been clear about its preference for a hydrogen carrier such as ammonia as part of its energy mix, beginning before the end of this decade. In Japan's Strategic Energy Plan, Japan sets out to introduce 1% of hydrogen or ammonia in its power generation fuel mix by 2030. It also aims to begin burning 20% ammonia at its coal-fired plants by 2030. Already, major Japanese utilities are making investments in ammonia.

The possibility of using ammonia as a hydrogen carrier has shown promise in the lab and in prototypes that split the ammonia molecule back into its hydrogen and nitrogen constituents as needed at the point of use. However, commercial scale cracking technologies for the recovery of hydrogen from ammonia remain in their infancy.

Any green ammonia produced will first be applied to where brown and grey ammonia are currently used (fertilisers and refrigerant), but there may be expanded direct ammonia uses or uses once cracked back into hydrogen as shown in Exhibit 30.

These include:

- **Energy storage to electricity generation** – ammonia is easily stored in bulk as a liquid at modest pressures (10-15 bar) or refrigerated to -33°C or in a fuel cell to produce electricity. There is an existing distribution network, in which ammonia is stored in large, refrigerated tanks and transported around the world by pipes, road tankers, and ships.

- **Transport fuel** – ammonia can be burnt in an internal combustion engine. When used, ammonia's only by-products are water and nitrogen. The maritime industry is likely to be an early adopter, replacing the use of fuel oil in marine engines.

While the use of ammonia as a fuel shows promise in the context of clean energy transitions, this application currently remains nascent. The focus for ammonia over the coming 10 years is on replacing brown/grey ammonia in existing agricultural and industrial uses.

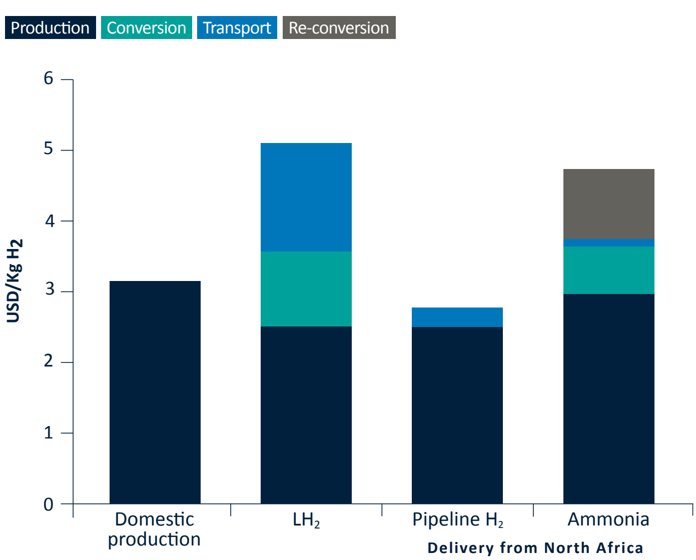
While green or blue ammonia is imbued with density and related transport and storage advantages over hydrogen in the green energy system, blue/green ammonia appears to us to be inherently higher cost than blue or green hydrogen as it is in fact produced from green or blue hydrogen, in the Haber-Bosch process which adds cost, before the final step of cracking ammonia back into hydrogen, adding further costs. The benefits of higher density, in the form of lower storage and transport costs along with the benefits of avoiding the CO and $CO_2$ removal from hydrogen in the SMR process, are unlikely to offset the additional ammonia conversion and reconversion to hydrogen costs. However, we are still several years away from knowing the economics of a large-scale ammonia reforming unit. The Ammonia to Green Hydrogen Project report in 2020, produced by the Science & Technology Facilities Council in the UK, arrived at estimates as low as $0.55/kg for carbon free ammonia or $550/tonne. According to IRENA, current production costs for new green ammonia plants are in the range of $720 – 1,400 per ton which is about six times higher than the traditional ammonia (natural gas-based ammonia and coal-based ammonia), which is in the range of USD 110-340 per ton.

Exhibit 31 is from the IEA's 2023 Global Hydrogen Review and estimates the total cost of liquid hydrogen ($LH_2$), compressed hydrogen via pipelines, and ammonia compared to $3/kg domestically produced green hydrogen with no transport costs. Pipeline transport of compressed green hydrogen represents the lowest cost, which suggests there may be more limited prospects for ammonia as a transport medium.

However, the form in which the imported hydrogen will eventually be used strongly influences the choice of hydrogen carrier and the supply costs. If hydrogen is consumed in the form of ammonia and not hydrogen, for example in the fertiliser industry, the imported ammonia can be used directly, avoiding the costs of reconverting ammonia back into hydrogen. In this case, importing ammonia from North Africa, Latin America, or the Middle East can actually be cheaper than domestically producing ammonia in north-west Europe. Given that some of the technologies required for conversion, shipping, and reconversion are at a relatively early stage of development, with just a few pilot or demonstration

**Exhibit 31**

**Transport of green hydrogen gas by pipeline is lower cost than transporting liquid hydrogen or ammonia according to McKinsey**




***Source:*** *Based on data from McKinsey & Company and the Hydrogen Council: IRENA (2020); IEA GHG (2014); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).*

***Note:*** *"$H_2$" = hydrogen; "$NH_3$" = ammonia; "$LH_2$" = liquefied hydrogen; "LOHC" = liquid organic hydrogen carrier. Domestic production in North-West Europe uses offshore wind; production in other regions uses solar PV. "Conversion" includes a compressed hydrogen storage cost to allow for stable input to the synthesis and to the liquefaction processes. The cost of capital is assumed at 6%. Costs refer to the Net Zero Emissions by 2050 Scenario (NZE Scenario) in 2030.*

projects having been realised so far, the economics of the different trade options may change in the future, as technologies advance.

**Most near-zero-emission ammonia technologies are not yet available at commercial scale in the marketplace, simply because the blue and green hydrogen feedstock supply is 10 years or more into the future**. In addition, $CO_2$ separation is an inherent part of commercial ammonia production today, but permanent storage of the $CO_2$ is not yet widely adopted. Electrolysis-based ammonia production has already been conducted at scale using high-load-factor electricity, but challenges remain in the use of hydrogen (to be converted to ammonia) produced from variable renewable energy (such as solar PV and wind) directly in captive installation arrangements. If ammonia was to be near zero emissions, the IEA estimates that green and blue ammonia would be supplied roughly 50/50 by electrolysis and fossil fuel/gas with CCUS. Both of these are technologies that are currently still in the demonstration phase.

Proof of the nascent state of low-emission ammonia technology, the IEA's range of scenarios forecast an insignificant increase in ammonia demand from the current 175Mt. The IEA points to existing and announced projects totalling nearly 8 Mt of near-zero-emission ammonia production capacity scheduled to come online by 2030, equivalent to 3% of total ammonia capacity in 2020.

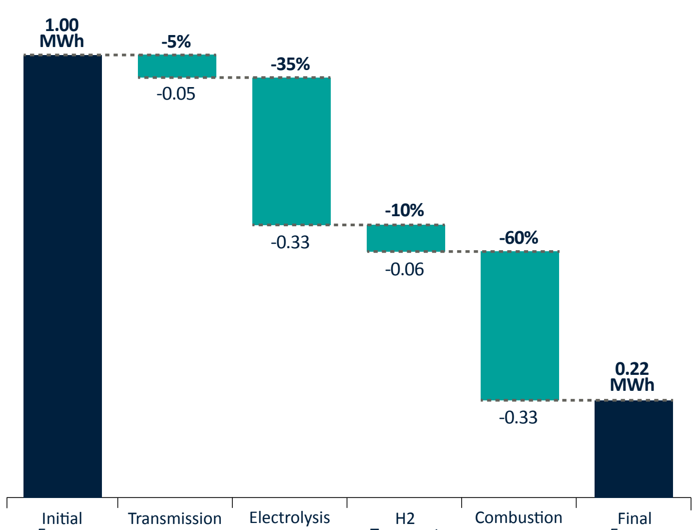
# Question 4: What are the technology challenges for clean hydrogen?

**The primary challenge for green hydrogen is the energy intensiveness of producing, transporting, and using hydrogen. As illustrated in Exhibit 32, the conversion losses of transmitting the electricity, breaking apart water using electrolysis, transporting the energy, and combusting it in a combined cycle turbine result in a loss of c.78% of the initial energy inputted into the process.**

The primary source of conversion loss is attributed to the electrolysis process.

Electrolysis is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in electrolyser unit which can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production to large-scale, central production facilities that could be tied directly to renewable or other non-greenhouse-gas-emitting forms of electricity production. An electrolyser consists of a conductive electrode stack separated by a membrane to which a high voltage current is applied.

Exhibit 32
**Conversion losses when using electrolytic hydrogen for power**




***Source:*** *CATF Analysis*

This causes an electric current in the water which causes it to break down into its components of hydrogen and oxygen. The oxygen generated is released into the atmosphere or can be stored for later use as a medical or industrial gas in some cases. The hydrogen is stored as a compressed gas or liquefied for use in industry or in hydrogen fuel cells.

Hydrogen electrolyser production has grown at a 5-year (2018-2023) CAGR of 76%, from marginal (0.1 GW) capacity shipped in 2018 to 1.7 GW shipped in 2023. It is expected to continue to grow at high rates, with the IEA expecting global electrolyser capacity to reach 170-365 GW by 2030 based on the current project pipeline.

**China** accounts for 40% of global electrolyser manufacturing capacity today and leads both in terms of electrolysers installed capacity, with a cumulated capacity of almost 220 MW in 2022 and 750 MW under construction to be online in 2023, and manufacturing capacity for electrolysers. **The European Union** installed about 80 MW in 2022, more than twice that installed in 2021. In July 2022 the Commission approved funding of EUR 5.4 billion to support its first hydrogen-related Important Project of Common European Interest (IPCEI), Hy2Tech, with a focus on hydrogen technologies, including incentives for electrolyser manufacturers. The United States announced critical incentives in 2022 under the Inflation Reduction Act (IRA), including a credit to fund manufacturing projects. The IRA provisions have started to bear fruit and announcements for new electrolyser manufacturing facilities in the US are increasing.

The pace of deployment is not constrained by the electrolyser manufacturers, but by the capacity of project developers to find sites and install electrolyser stacks. Late subsidy policy specifications, longer permitting processes, and technical issues have contributed to many electrolyser projects being delayed or even cancelled. Late subsidy policy specifications and longer permitting processes make it difficult to plan investments, secure financing, and lock in off-takers (like Air Products).

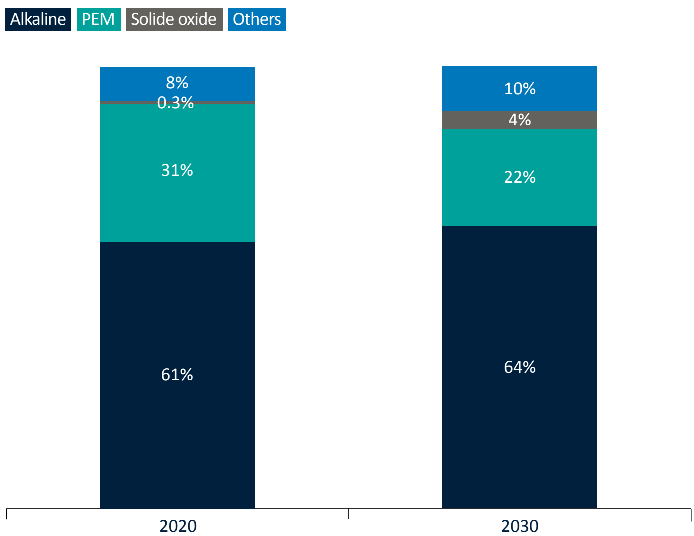
Technical challenges include electrical component malfunctioning, but also the broader issue of just little experience in electrolyser installation and operation. Before the current wave of interest in green hydrogen, most electrolyser stacks were less than 1MW, typically several tens or hundreds of KWs. The expertise accumulated in making those units did not create enough know-how to make larger stacks and to produce the balance of plant and equipment. Today in China, there are reports of 10 MW stacks in large projects being developed by Sinopec. However, there have also been reports of technical issues observed in commissioned large projects equipped with 5 MW stacks. Under the right conditions, large stacks can be built rather quickly. BloomEnergy reports that their 4 MW electrolyser was built, installed, and operationalised in two months. Experts like BloombergNEF are sceptical about the fast adoption of 10 MW products, considering the technical issues observed in commissioned large projects equipped with 5 MW stacks.

Alkaline electrolysers dominate the market today and are expected to continue being the most preferred technology as estimated by the IEA and shown in Exhibit 33. Of the other technologies, PEM is emerging to be a promising electrolysis technology, which is coming down a steeper cost curve than Alkaline, and S&P/IHS see PEM gaining share by 2030 (in contrast to what the IEA is forecasting in Exhibit 33).

Today, alkaline technology is cheaper, with an average cost of \$700 to \$1,100 per kW and has an efficiency of ~70% (producing 0.021kg $H_2$ per kWh). PEM technology costs between ~\$1,200 and \$2,000 per kW, having an efficiency of ~60% (producing 0.018kg $H_2$ per kWh). As the PEM technology advances, it is expected to achieve parity

**Exhibit 33**

**The IEA forecasts that alkaline will continue to be the dominant electrolyser technology**




***Source:*** *IEA*

with alkaline (~$500 per kW) by FY2030.

NEL has exposure to both alkaline and PEM technologies, which offers an edge in case one of the technologies prevails in the future. Solid oxide and AEM technologies are at a nascent stage today with some players like Bloom Energy (US) and H2e Power (IN), developing electrolysers based on solid oxide, while Enapter (IT) and Hydrolite (IL) are a few players that are developing AEM.

Other electrolyer technologies are emerging into commercial application including Solid Oxyde Electrolysis (SOEC), Anion exchange membrane (AEM), capillary technology, catalyst coated membrane (CCM) and membrane free electrolysers. SOEC is closest to commercialisation. They have the potential to be much more efficient than alkaline and PEM electrolysers. SOEC is performed at very high temperatures – typically 700-1000°C, and the repurposing of thermal heat energy or waste heat (such as from steel or ammonia production) can significantly improve efficiency by reducing the need for electrical energy. CAPEX requirements for an installed electrolyser system are currently in the range of $500-1400/kWe for alkaline technology and $1100-1800/kWe for PEM, while estimates for SOEC range from 2800-5600/kWe.[3] So a 5MW plant would have CAPEX requirements of $2.5M to $28M.

Anion exchange membrane (AEM) electrolysers are at earlier stages of development. Alchemr has a readily available AEM electrolyser at the kilowatt scale, and Enapter aims to produce them at scale from 2023 thanks to a new factory being built in Germany.

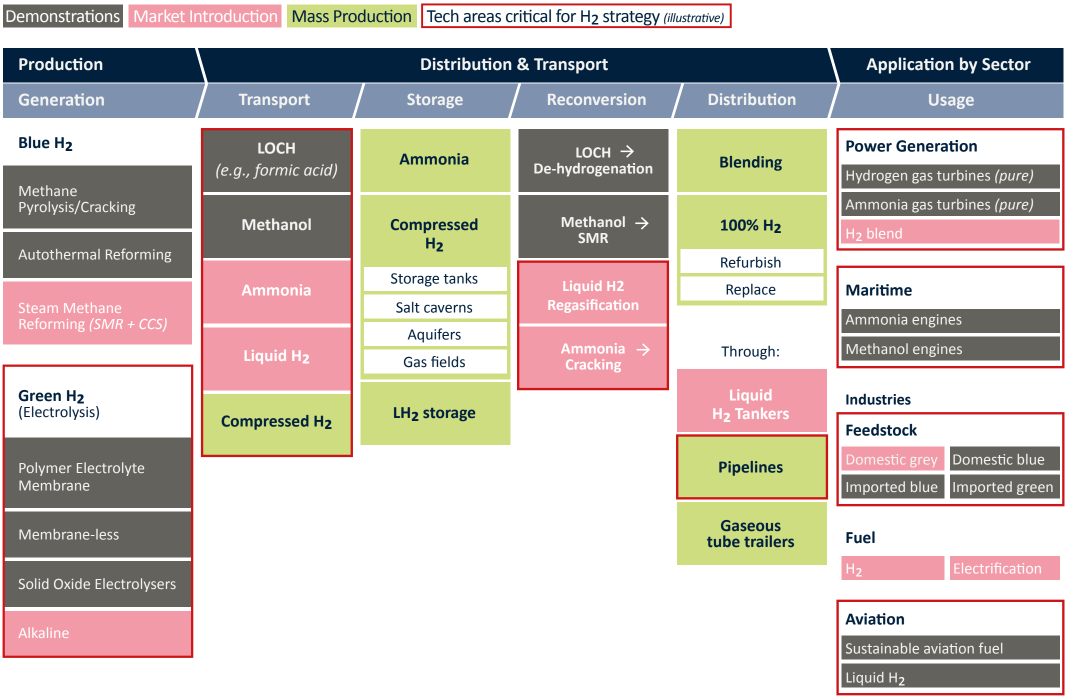
In the past few years, new electrolyser designs have reported very high efficiencies, such as Hysata's capillary technology (80% efficiency on a low heating value basis). Innovation in critical materials intensity reduction is also progressing. For example, in 2023 start-up Bspkl raised capital to commercialise a catalyst coated membrane (CCM) with 25 times less iridium and platinum compared to traditional PEM designs. Clean Power Hydrogen (CPH2) has developed a membrane-free electrolyser that uses no platinum-group metals (PGM) and, at the same time, can increase the life of the system.

Average electrolyser capital costs have fallen from more than $3,700 per kW in 2020 to about $2,700 per kW today and are projected to continue falling as increased manufacturing and production leads to realising economies of scale. PEM electrolysers have a wider operating range which gives them a potential advantage in matching their production to low-cost variable renewable energy

3 https://www.iea.org/energy-system/low-emission-fuels/electrolysers

## Exhibit 34

**Bain summarises the state of current technology. There are no applications in mass production today**




***Source:*** *Lit Search, Bain Analysis*



generation. As the costs of both technologies fall, capital costs become less significant in total costs of hydrogen production. This development could make it attractive to sacrifice some electrolyser capacity utilisation for lower energy costs (by reducing the need to deploy storage in order to keep up a minimum supply of generation). Under these circumstances, the more flexible PEM electrolysers could be preferred if their costs are low enough.[4]

Moving from green on to blue hydrogen production technology, autothermal reforming (ATR) is emerging as the preferred technology. It combines both partial oxidation and steam methane reforming processes, enabling higher hydrogen yields from natural gas. Most newly announced blue $H_2$ projects globally are ATR-based.

In Exhibit 34, Bain & Company summarise the state of the various technologies involved throughout the hydrogen value chain. Only the light green shaded technologies are in mass production today. The pink shaded technologies are at the early stages of market introduction and the dark grey shaded technologies are at the demonstration stage.

4 CSIRO GenCost report

# Question 5: What are cost projections for clean hydrogen?

**Our key sources for low-emission hydrogen cost projections are Bain & Company, CATF, and the UK resources consultancy, CRU. Experts argue about expected 2050 unsubsidised green hydrogen costs ranging between $1/kg and $3/kg, compared against $6/kg today. Listening carefully to these sources, we believe that costs will vary between $1.50/kg and $3.00/kg in 2050, depending on the location which determines renewable energy costs and the cost of connection, compression, and transportation. Taxes in Europe and subsidies in the US will make green hydrogen competitive with grey hydrogen and with competing low-cost solutions around 2030, depending on the application as we described above.**

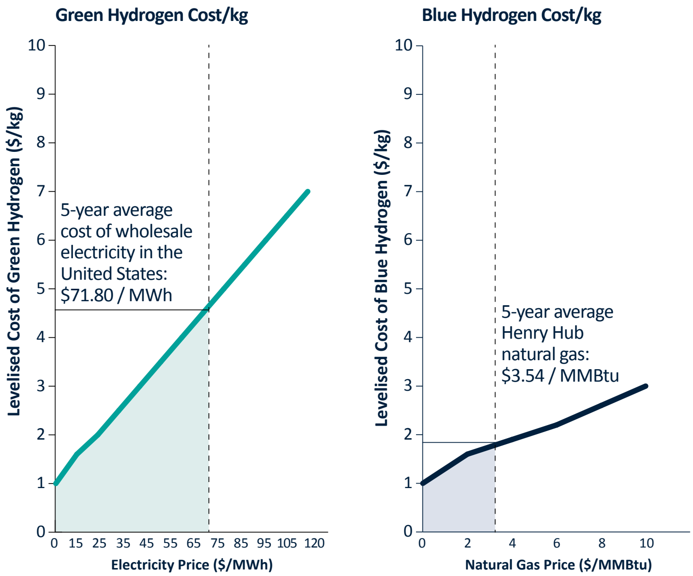
Ignoring government subsidies, we expect green hydrogen to be more expensive than grey until shortly after 2030, while blue hydrogen will only fall below grey when grey is burdened with carbon taxes, which suggests breakeven around 2030 as well. In the 2035 to 2040 time frame, green hydrogen's costs should fall below blue. We stress however, that the success of clean hydrogen is not dependent on being lower cost than grey hydrogen, but being the best solution vs all other low carbon alternatives. Here we summarise the likely path of clean hydrogen costs, but each application needs its own economic examination against its own set of alternatives (e.g., hydrogen vs battery power in long-haul trucking, hydrogen blended gas vs CCS in power generation).

The primary cost driver of blue hydrogen is the cost of natural gas being reformed. To compete with $1.50/kg grey hydrogen, the cost of natural gas must be less than $2.MMBtu. Current natural gas prices in the US are around $2.55/MMBtu and have averaged around $3.30/MMBtu over the past 10 years, with a low of $1.60 and high of $8.93/MMBtu. The cost of natural gas accounts for c.30-50% and transport and storage c.15% of the levelised cost of blue hydrogen.

The primary cost driver of green hydrogen is the cost of electricity which usually accounts for c.50-75% of the levelised cost of green hydrogen. To compete with $1.50/kg grey hydrogen, the cost of electricity must be less than $15/MWh while the cost of wind and solar in the US today averages between $42 and $67/MWh (per 2023 Lazard LCOE analysis). The main cost trade-off is between the electrolyser capacity utilisation rate which is optimised at c.90%. To achieve such high electrolyser utilisation rates requires the electricity provider to shift to higher cost and higher emitting gas-powered electricity to compensate for intermittent renewable electricity. The cost estimates shown in Exhibit 35 confines the electroyser to wind or solar power which results in a more normal 50% electrolyser capacity factor. Using an average of $50/MWh 100% renewable electricity, this still leaves unsubsidised green hydrogen costing $3/kg. So without a massive discount for "surplus" wind and solar electricity, green hydrogen is prohibitively expensive.

The relationship between blue and green hydrogen and their fuel source, is shown in Exhibit 35, based on analysis performed with CATF's, Hydrogen Financial Model. Focusing on the cost of green hydrogen, the CATF model shows that for each $21/MWh cost increase in renewable energy, the cost of green hydrogen goes up by $1/kg. The long-term viability of green hydrogen is clearly in the hands of renewable energy supply costs.

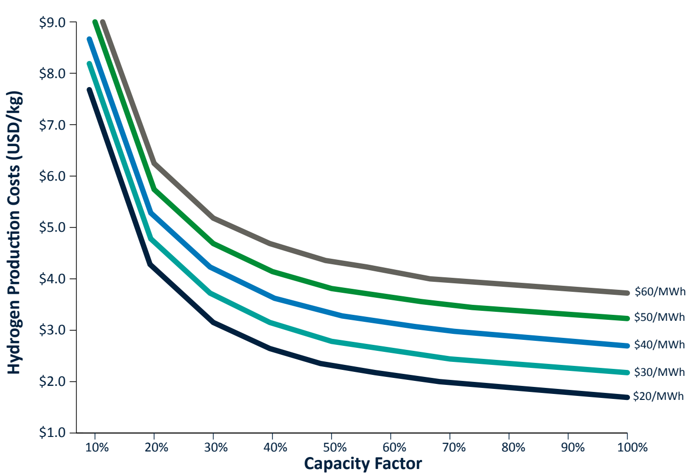
### Exhibit 35
## The cost of clean hydrogen is primarily driven by the cost of its fuel source




***Source:*** *Clean Air Task Force Hydrogen Cost Model. Green Hydrogen costs assume 50% capacity factor and improved electrolyser efficiency estimates from the CATF Fraunhofer study, with green hydrogen produced from an Alkaline or PEM electrolyser. Blue Hydrogen costs assume a $100 / tonne carbon price and cost of electricity of $85 / MWh, with blue hydrogen produced from SMR with 90% CCS. EIA, as of November 2023.*

***Note:****shading shows the range of expected input prices over one standard deviation –ie, present 67% of the time.*

### Exhibit 36
## Production costs for low-carbon hydrogen from electrolysis




***Source:*** *CATF internal modelling*

***Notes:*** *The analysis focuses on the costs of dedicated electrolytic hydrogen production as opposed to electrolytic hydrogen produced from curtailed renewable electricity which can be potentially be used as a form of long duration energy storage (LDES).*

*There are regional variations in PPA prices, which can be attributed to how these power arrangements are structured and to the effects of subsidies and tax incentives for developers. Lazard (2023) shows that the additional cost to source 'firm' electricity from renewable generators significantly increases the LCOE from these sources. Firming costs are not necessarily indicative of long-term total electricity costs in that these are not the costs to deliver energy every hour of every day (24/7).*

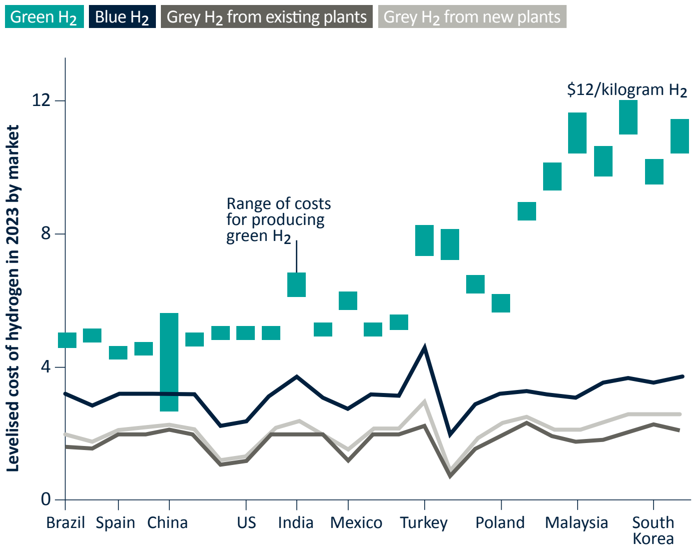
*To calculate simple levelised cost of hydrogen for this analysis we assume a hydrogen production level that is constant throughout the life of the project. The real weighted average cost of capital (WACC) is assumed to be 8%. We further assume a total installed cost (TIC) of $950/kW for PEM electrolysers, with system-specific energy consumption of 48.1 kWhAC/kg hydrogen, where this energy consumption increases linearly up to 10% higher than start-of-run conditions after 60,000 hours of stack operations. Stack replacement is calculated at 10% of TIC. Annual operating expenditures are assumed to be 3% of TIC. We assume that hydrogen is delivered at 30 barg at the battery limit of the electrolysis facility.*

Shown in Exhibit 36, the same CATF data modelling illustrates the importance of capacity utilisation, in addition to the cost of renewable energy on the cost of green hydrogen.

We believe, in the period from now until 2030, blue hydrogen will be the preferred low-emission hydrogen, largely due to the much lower cost. Costs vary hugely across the globe and depending on the cost of electricity and natural gas, blue hydrogen appears to be cheaper than green across most markets in the world today as you can see in Exhibit 37.

Most experts believe that there will be a role for both blue and green hydrogen to play in the energy transition. In the near term, blue hydrogen will be the transitional technology while electrolytic production ramps up. As renewable energy becomes more abundant, affordable, and ubiquitous, green hydrogen will be able to compete and scale, eventually reaching parity with blue hydrogen. This will be largely location-specific, driven by the access to and cost of renewable electricity. Exhibit 38 presents analysis produced by UK resources consultancy, CRU, to show what is required to lower the cost of green hydrogen from its current $6/kg to $1.50/kg. In CRU's most optimistic case, green hydrogen costs could drop to $1.5 /kg by 2050 (assuming no power connection, $H_2$ storage, compression, or distribution costs), a price that puts green hydrogen broadly on a par with grey and blue

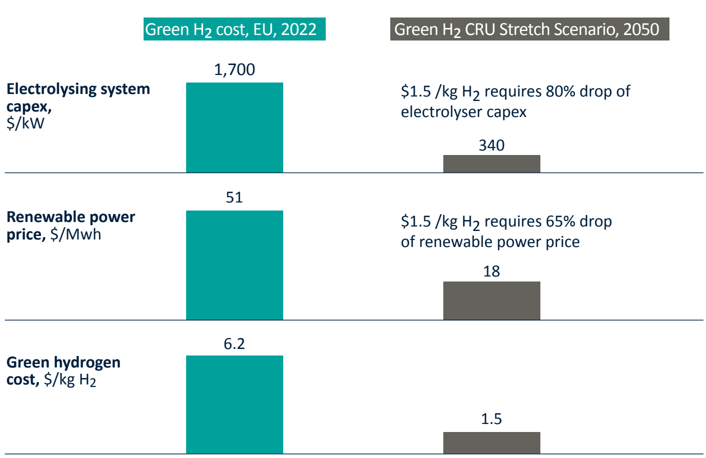
## Exhibit 37
### Today, green hydrogen is consistently more expensive than blue




**Source:** *BNEF. Blue $H_2$ is the average of ATR and SMR production. Green $H_2$ includes Western-made PEM electrolysers (top of range) and alkaline electrolysers (bottom of range), except in China, which includes Chinese-made alkaline electrolysers (bottom of range).*

hydrogen in most regions. However, to achieve this, the scale of cost improvements needed is significant, requiring an 80% cost reduction of system capex and 65% reduction of renewable energy costs. The electrolyser would need to be able to deal with a fluctuating electricity supply with a 54% utilisation rate. CRU do not believe a price below $2 /kg $H_2$ (real 2022) is feasible even without the connection, storage, compression and transportation costs. They estimate further costs associated with an electrical grid or renewables connection (even for a local grid), hydrogen storage, compression and distribution would produce costs in the range of $3 to 7 /kg (real 2022) in 2050.

## Exhibit 38
### Green hydrogen at $1.50/kg requires an 80% drop in capex, a 65% drop in renewable energy prices and zero connection, compression and transportation costs




**Source:** *CRU Group*

**Note:** *23 Feb 2023, CRU Hydrogen Cost Model, CRU Long-term Renewable Energy Cost Model; Note – hydrogen costs do not include renewables connection cost or $H_2$ storage, compression, or distribution*

Bain & Company's analysis as shown in Exhibit 39 is the most optimistic, which assumes a 75% reduction in capex and low starting and finishing prices for renewable energy, and no cost for connection, storage, compression or transport. Even then, it is not until 2035 to 2040 that they expect to see green hydrogen prices falling below the price of grey hydrogen.

In regions with very low-cost renewables, we will see cost parity achieved earlier. The grey line (second from the bottom) shows the price of green hydrogen falls below grey $H_2$ around 2028, by using low-cost Chilean renewable electricity to illustrate. Some hydrogen advocates argue that excess renewable electricity in peak periods will go unused and therefore can achieve a near zero cost for electrolysis. The dark green line (at the bottom) models this theoretical line models this theoretical possibility showing that this makes green hydrogen competitive with grey, today. Exhibit 40 shows BloombergNEF forecasts for falling solar and wind electricity prices in this decade which broadly support Bain's forecasts which embed similar forecasts but extended out to 2050.

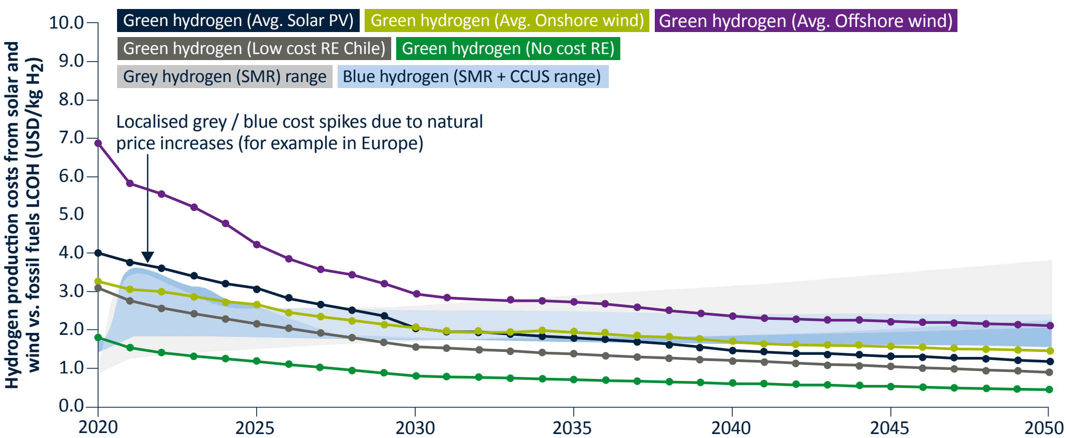
There is almost no case for factoring in near-zero priced renewables for green hydrogen electrolysis. Firstly, surplus renewable electricity generation comes in spikes which is the enemy of high electrolyser capacity utilisation. The cost savings in electricity prices are offset by lower amortization rates on capex and operating expenses. Second, there will be many competing demands for surplus renewable energy that will likely limit how much surplus is actually available. These demands include energy storage arbitrage, EV charging, home heating and cooling, electrified industry demand, DAC, etc. More transmission development and interconnection will also reduce pockets of surplus, reducing price spreads between regions. As such, a green hydrogen developer would be facing a lot of risk by making a business case forecasting cheap clean energy surplus conditions over the lifetime of the electrolyser asset. Faced with such risk, one would expect a developer to sign a contract for consistent firmed energy supply (i.e., with fossil fuel auxiliary supply) likely priced well above $50/MWh. Costs will come down, but not due to cheap renewable electricity. The three key contributing factors to driving the cost of green hydrogen





## Exhibit 39

### Over time, green hydrogen will be cost advantaged versus grey and blue

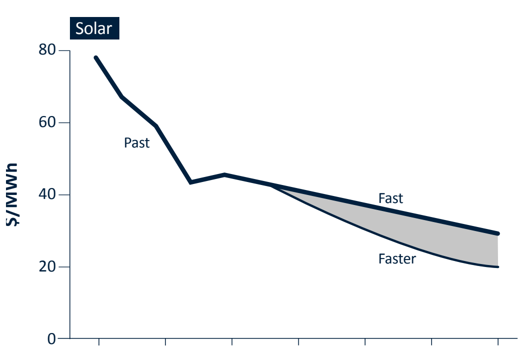


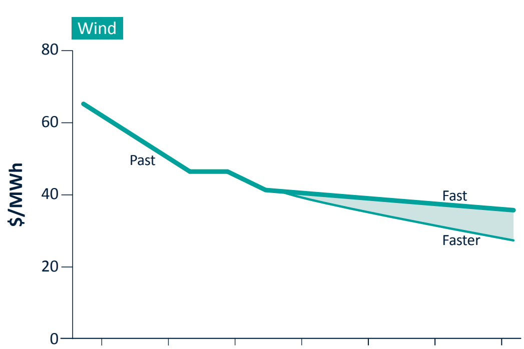

**Source:** *IRENA 2019, NREL, EIA, BNEF, Lazard, Chile Department of Energy, Wood Mac, Bain analysis*

***Note:*** *Remaining $CO_2$, emissions are from fossil fuel hydrogen production with CCS. PEM electrolyser installed cost assumptions: $990/kW (2020), $460/kW (2030), $330/kW (2040) and $260/kW (2050). Electrolyser efficiency: 65% in 2020, 70% in 2030, and 80% by 2050. $CO_2$ prices/taxes: $50 per tonne (2030), $50-100 per tonne (2040) and $100-200 per tonne (2050) added to the cost of grey hydrogen. Low range for natural gas feedstock to blue hydrogen $3/MMBTU, high range $8/MMBTU. Assumes subsidised costs of solar and wind with solar PV at $51/MWh today falling to $20/MWh in 2050 in current value of money. Onshore wind is assumed to be $39/MWh today falling to $20/MWh in 2050. Offshore wind is assumed to be $84/MWh today falling to $30/MWh in 2030. Chile Renewable Energy is assumed to $25/MWh today falling to $11/MWh in 2050.*

## Exhibit 40

### Solar electricity prices are expected to fall from $42/MWh to $20-$30/MWh by 2030 while onshore wind is expected to fall from $40/MWh to $28-$33/MWh by 2030




**Source:** *BNEF New Energy Outlook 2022, RMI analysis, University of Oxford Institute for New Economic Thinking* down are technological innovation, economies of scale and renewables intermittency. The Bain analysis below estimates that the installed capital cost will fall from the current \$990/kW to \$460/kW in 2030 and \$260/kW by 2050. Electrolyser utilisation is likely to improve as renewables' intermittency is reduced by battery storage, grid interconnections and consumer electricity usage time shifting (daytime car battery charging).

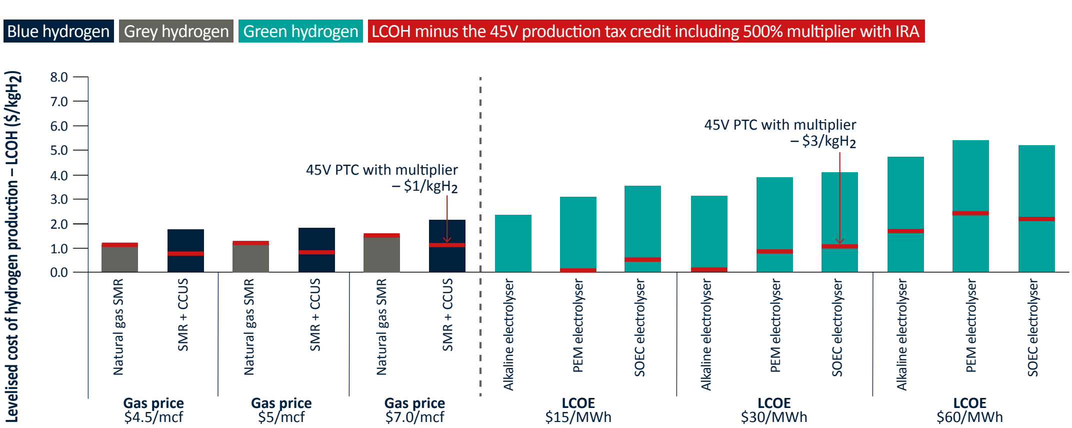
There may still be a significant role for blue hydrogen production in regions enjoying very low gas prices well past 2040. Blue hydrogen costs are also likely to come down as technological innovation and scale-up continues in the carbon capture technology with more projects currently in the pipeline as well as the ongoing scale-up of carbon storage infrastructure, particularly in CCS clusters that have started to emerge across key regions.

The US Inflation Reduction Act is transformational for the economics of clean hydrogen. The Clean Hydrogen Production Tax Credit (PTC) significantly improves the economics of Green Hydrogen and, more modestly, Blue Hydrogen. The IRA introduces a production tax credit for clean hydrogen of up to \$3/kg of hydrogen, provided lifecycle $CO_2$-equivalent emissions are not greater than 4 $kgCO_2$-eq/kg of hydrogen produced. The PTC applies to clean hydrogen produced after 2022 at a qualifying facility on which construction starts before 2033. The PTC appears to apply to all hydrogen produced in the US, even if such hydrogen is exported.

In Exhibit 41, Goldman Sachs illustrates the economic impact of the PTC for low-emission hydrogen production economics. The bars show the levelised cost of producing grey, blue and green hydrogen at various coal, natural gas and renewable power prices respectively without the use of any credits. Goldman use a required cost of capital (IRR) of 8% and current costs of electrolysis equipment for green hydrogen. A \$3/$kgH_2$ production tax credit for green hydrogen would make green hydrogen produced with a levelised cost of renewable power of <US\$45/MWh (including their relevant PTC/ITC for renewables) already at cost parity with grey. For blue hydrogen, a \$3/$kgH_2$ tax credit achieves a cost advantage vs. grey as long as natural gas prices are below \$7.50/mcf. Note that the \$3/kg includes the 5x multiplier mechanism that is triggered if producers build new facilities within a certain time period and if they meet certain wage and labor requirements for the project. This effectively fully bridges the cost gap between grey (fossil based) hydrogen and green hydrogen from renewable power.

**Exhibit 41**

**The 45V production tax credit could prove to be a game-changer for clean hydrogen economics (both green and blue), bridging entirely the cost differential vs. green hydrogen**




*Source: Goldman Sachs Global Investment Research. LCOH figures based on current technology costs (i.e., electrolysers) and with a required IRR of 8%. 45V PTC includes the multiplier impact. For blue $H_2$ we assume up to 95% of the $CO_2$ is captured.*

# Question 6. How are governments supporting hydrogen?

**As with the US IRA, European, Japanese and other governments appear to be forging ahead with targets and subsidies. The new and updated national hydrogen targets in aggregate show an increase in global ambitions to deploy low-emission hydrogen technologies to 27 to 35 Mt /year by 2030.**

**A total of 41 governments, accounting for nearly 80% of global energy-related $CO_2$ emissions, have now adopted hydrogen strategies. The EU has announced aggressive targets, planning to produce 10 Mt / year of hydrogen domestically and import 10 Mt / year of renewable hydrogen by 2030. In the US, the Department of Energy aims to increase low-emissions hydrogen production from nearly zero today to 10 Mt / year by 2030. India's National Green Hydrogen Mission includes a c.2B INR (c.$25M) subsidy to produce 5 Mt of clean hydrogen for domestic consumption and 10 Mt of hydrogen for exports by 2030. While these strategies are not equivalent to binding policy mechanisms enacted in laws, they do represent significant milestones for the long-term vision of these industries. In the EU, the recently agreed RED III will boost the development of hydrogen projects by establishing policies for member states to reach certain renewable energy targets.**

Under the Important Projects of Common European Interest mechanism, EUR 10.6B of public investments in the hydrogen value chain have been approved as incentive to attract private investment in the hydrogen sector. That amount will be available under the Recovery and Resilience Facility to support hydrogen projects to be implemented by the end of 2026. Electrolyser manufacturers in Europe committed to increase their capacity to manufacture electrolysers tenfold to 17.5 GW by 2025.

Canada announced a Clean Hydrogen Investment Tax Credit in their Budget 2023. Contracts for Difference (CfDs) have been adopted in the United Kingdom, Germany, Japan, and Canada. CfDs are well-established mechanisms in which the government agrees a fixed price with a producer for a product, in this case clean hydrogen.

In the US, the recently enacted IIJA provides $8 billion for creating regional low-carbon hydrogen hubs, $1 billion for an electrolysis program to reduce hydrogen production costs, and $500 million each for creating hydrogen manufacturing and hydrogen-recycling equipment supply chains.

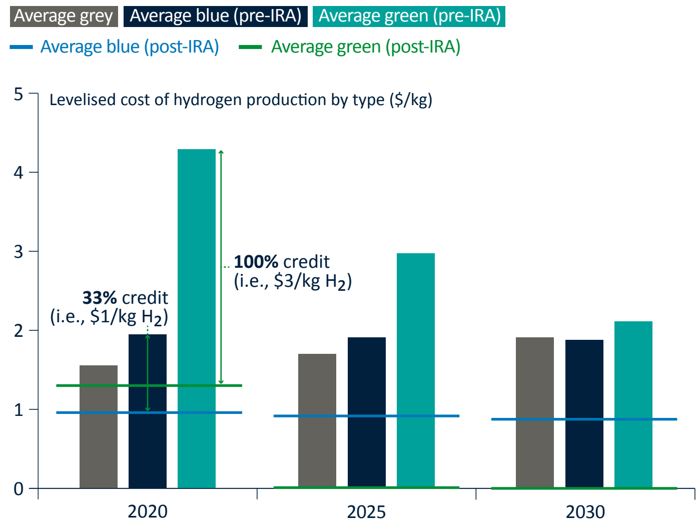
The US Inflation Reduction Act (IRA) includes up to a $3/kg tax credit for the production of hydrogen and hydrogen-based fuels which causes green $H_2$ to become cost competitive today in the US rather than after 2030 as we previously forecast. But it is unclear whether this will increase demand in the short term given the long development lead times. What the IRA does for hydrogen is make greenfield or retrofit facilities constructed before 2033 eligible for the clean hydrogen tax credit (CHTC) for 10 years from the start of producing $H_2$. Green and blue $H_2$ projects qualify for different levels of support up to $3/kg of clean hydrogen. The CHTC cannot be combined with other carbon credit programs in the IRA.

While Exhibit 41 showed you the impact of the IRA on clean hydrogen costs today, Exhibit 42 shows forecasted costs out to 2030 before and after the effects of the IRA subsidy.

Hydrogen has been embraced as a major strategic initiative in Brussels since 2000 with several large industry associations operating to accelerate progress behind hydrogen penetration mostly as a clean energy carrier in transport systems.

In the US, the Fuel Cell and Hydrogen Energy Association (FCHEA) is the leading industry association representing more than 90 leading organisations advancing production, distribution, and use of innovative, clean, safe, and reliable hydrogen energy. In 2021, the US bipartisan infrastructure law committed $8 billion for the development of six to ten regional hydrogen hubs, with the US Department of Energy setting up a program by early 2023 to provide funding support to shortlisted government led or private hydrogen hub initiatives in US. It has spurred hydrogen infrastructure developers to step forward with more than 15 government led and private hydrogen hub initiatives proposed for development in US.

**Exhibit 42**
**IRA could bring green production cost decline forward > 10 years**




***Source:*** *: RMI, DLA Piper, IRENA 2019, NREL, EIA, BNEF, Lazard, Chile Department of Energy*
***Notes:*** *[1] CHTC = Clean hydrogen tax credit; $H_2$ = Hydrogen; ITC = Investment tax credit; Electrolyser costs: 990 USD/KW (2020), 460 USD/KW (2030), 330 USD/KW (2040) and 260 USD/KW (2050). Electrolyser efficiency: 65% in 2020, 70% in 2030, and 80% by 2050. $CO_2$ prices: USD 50 per tonne (2030), USD 50-100 per tonne (2040) and USD 100-200 per tonne (2050). Low range for fossil fuel hydrogen $3/MMBTU, high range $8/MMBTU.*

Despite the progress made, more must be done to attract private capital. Goldman Sachs estimates that $5.0T of cumulative investments in the direct clean hydrogen supply chain will be required to meet net zero scenarios by 2050. It is quite possible that the combination of government support and industry collectives will drive low-emissions hydrogen well beyond where our forecasts for the technology would take us based on the economic and technology challenges.

Exhibit 43 summarises all of the various industry associations supporting hydrogen development as clear evidence that Europe seeks to lead the world in hydrogen development.

**Exhibit 43**
**Europe seeks to lead the world in hydrogen power development**

| Hydrogen Association | Start year | Members | Aims |
|---|---|---|---|
| European Hydrogen Association | 2000 | 300+ linking 15 national member associations to EU and national funding facilities | Focused on transport:<br>• 4.5 million Fuel Cell vehicles on the road globally<br>• 280 $H_2$ Inland shipping vessels on the Rhine<br>• 10,500 active $H_2$ fuelling stations in the world |
| Clean Hydrogen Partnership | 2002 | the European Union, represented by the European Commission, the fuel cell and hydrogen industries represented by Hydrogen Europe and the research community represented by Hydrogen Europe Research | • to strengthen and integrate EU scientific capacity, in order to accelerate the development and improvement of advanced clean hydrogen applications |
| Hydrogen Europe | 2009 | 100 companies, 68 research organisations and 16 national associations | • be the sole and united voice of the European hydrogen industry through the joint efforts of its Members at European level |
| European Clean Hydrogen Alliance | 2020 | industry, public authorities, civil society, and other stakeholders | • promote investments and stimulate clean hydrogen production and use; maintain a database of 750+ $H_2$ projects |

***Source:*** *Partners Capital*

# Question 7. What size of clean hydrogen markets are experts forecasting?



**We expect the hydrogen market to grow from the present 94 Mt in grey hydrogen and 1 Mt in blue and green hydrogen to become approximately 300 Mt of clean hydrogen by 2050 with virtually all grey having been replaced. It is likely that clean hydrogen can reach somewhere around 30 to 50 Mt by 2030 given the huge governmental efforts, mostly driven out of Europe. The 2050 300 Mt forecast falls 50% short of the Net Zero 2050 targets which are between 420 and 820 Mt. These larger clean hydrogen Net Zero 2050 targets translate into five gigatons of carbon emission reduction or 10% of all $Co_2$. Our estimates point to three gigatons of carbon emission reduction or 6%.**

Estimating the likely size of a market 27 years from now, which currently has not really got off the ground (1 Mt of production), is arguably a futile exercise. Clean hydrogen will replace other fuels in specific geographical applications where the end-to-end value chain can be planned and mapped out in practical terms and validated to be more economical than other alternatives, net of all subsidies and credits. To arrive at any reliable market size estimate, thousands of specific geographical applications would need to be costed out.

Our total addressable market (TAM) analysis highlighted in Exhibit 27 shows that if all current incumbent fuels (e.g., kerosene for air travel and diesel for long-haul trucking) were replaced with clean hydrogen, there would be demand for approximately 1,300 Mt of clean hydrogen. Our estimate of 300 Mt, which is close to what Bain and Goldman Sachs also forecast, results in a 22% penetration of the TAM estimates.

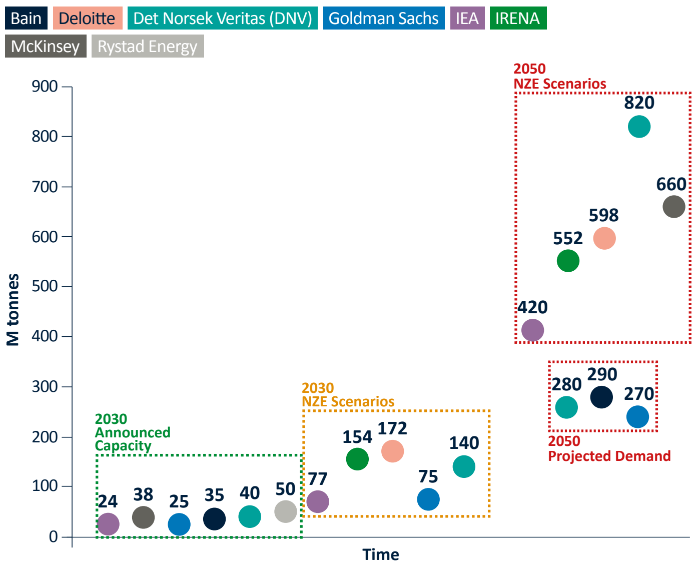
Expert forecasts of future demand tend to cluster around each other as you can see in Exhibit 44. Announced projects point to 24-50 Mt of new clean hydrogen production by 2030, but the lowest expert NZE forecast calls for 75 Mt of clean hydrogen production, with the average being 124 Mt. Exhibits 16, 17 and 18 from earlier show that the IEA estimates grey hydrogen replacement by blue and green sums to just 3.7 Mt by 2030.

By 2050, experts project demand for between 270 to 290 Mt which is half the size of what McKinsey and the IRENA say is required as part of their net zero scenarios where $H_2$ accounts for approximately 20% of all carbon emissions reduction. Achieving net-zero greenhouse gas emissions by 2050 will likely require the development of a c.170 Mt $H_2$ clean hydrogen market by 2030, growing to nearly c.600 Mt $H_2$ by 2050. To put these numbers in energy terms, c.600 Mt $H_2$ is equivalent to more than 100% of total electricity consumption today (25,500 TWh). In the IEA's net zero emissions by 2050 ("NZE" scenario), it expects 79% of clean hydrogen production in 2050 to be green hydrogen, with the remaining 21% blue hydrogen.

Current demand for hydrogen is met almost entirely by hydrogen production from unabated fossil fuels. In 2022, total global hydrogen production was 95 Mt with associated emissions of approximately 830 Mt $CO_2$. Natural gas without CCS is the main route and accounted for 62% of hydrogen production, while unabated coal, mainly located in China, was responsible for 21% of global production.

**Exhibit 44**

**Announced hydrogen projects suggest c.24 Mt by 2030, but experts suggest something closer to 120 Mt by 2030 and 300 Mt by 2050. 2050 Net Zero Emission scenarios need around 600 Mt**




***Source:*** *Bain, Deloitte, DNV, Goldman Sachs, IEA, IRENA, McKinsey*

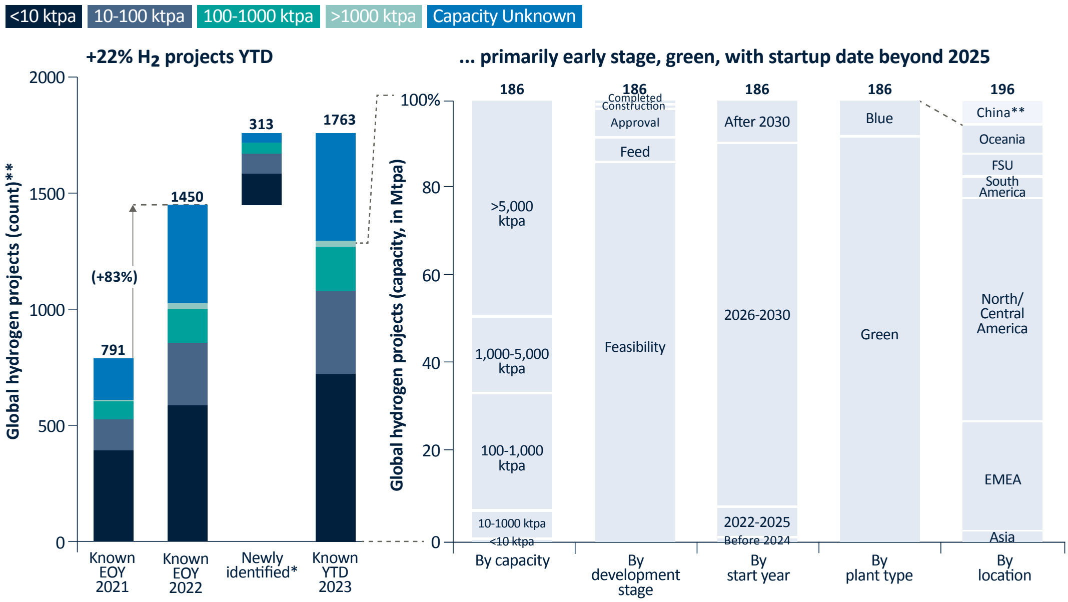
Hydrogen is also produced as a by-product of naphtha reforming at refineries (16%) and then used for other refinery processes (e.g., hydrocracking, desulphurisation). The naphtha reforming process requires significant energy from fossil fuel combustion but its application in processes like hydrocracking or desulfurisation does not. Low-emission hydrogen production was less than 1 Mt (0.7%) in 2022, almost all from fossil fuels with CCUS, with less than 100 kt $H_2$ from electricity via water electrolysis.

Low-emission hydrogen is a nascent industry and has gone through several waves of interest in the past 50 years. None of these translated into sustainably rising investment and broader adoption of clean hydrogen in energy systems. Nonetheless, the recent focus on de-carbonisation and the scale up and accelerated growth of low carbon technologies such as renewables have sparked a new wave of interest. We believe that this is not another false start for clean hydrogen, but the pace of growth will be slow. According to the pipeline of hydrogen production projects that the IEA tracks, the number of announced projects that will produce low emission hydrogen from water electrolysis or fossil fuels with CCUS currently under development suggests that the annual production of low-emission hydrogen could reach more than 24 Mt $H_2$ by 2030, up from 1 Mt in 2021. Exhibit 45 profiles the 122% increase in the number of hydrogen projects logged in the GlobalData Hydrogen Plant Database from 1,450 projects as of EOY 2022 to 1,763 announced projects in September 2023. The database catalogued an increase of 10 Mt of planned capacity from January 2023 (not pictured) to present, for a total of 186 Mt of capacity in some stage of planning, the vast majority in the feasibility study stage. Two large Canadian hydrogen projects from Green Hydrogen International account for ~85 Mtpa of announced global production capacity. The vast majority of these projects are green, rather than blue, hydrogen projects. The jump in planned capacity is not biased towards the US which we would have expected on the back of the IRA. The increase is across the globe and does not include anything happening in China, as they are not contributing to the database. China produced about 33 million tonnes of grey hydrogen in 2021, making it the world's largest hydrogen producer. By 2025, China will have about 50,000 hydrogen fuel-cell vehicles and its annual hydrogen production from renewable energy will reach 0.1 Mt and 0.2 Mt according to China's National Energy Administration.

Of the 186 Mt of capacity estimated from the 1,763 projects in the GlobalData Hydrogen Database, less than 10% or 19 Mt of hydrogen project capacity is attached to announced projects where they are almost certain to go ahead. Exhibit 46 (left chart) summarises the announced project total production up

Exhibit 45

**The clean hydrogen project pipeline shows 38% growth in 2023 on the back of 81% growth in 2022, with most projects still in the feasibility stage, targeting production after 2025**



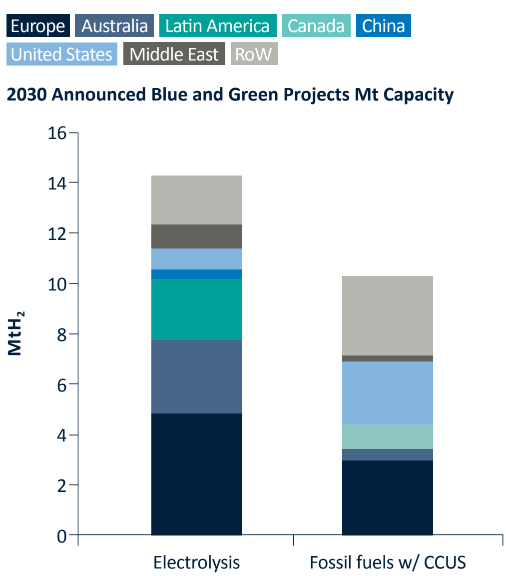

***Source:*** *Bain assessment based on GlobalData Hydrogen Plant database (Sept 2023 update); Literature search*

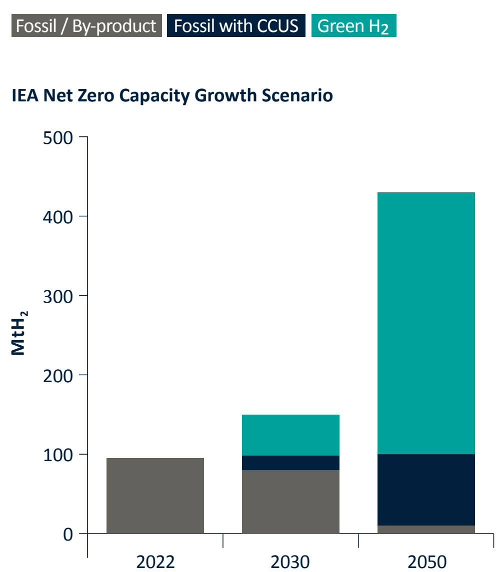
***Note:*** **Estimate based on communication date, not reflecting exact timing of project initiation and does not include projects which have not been communicated to the market **China projects are underrepresented in the overall project count and capacity estimates and are thus excluded and only added in aggregate for the planned capacity by location (based on ~10 mmtpa 2030 supply estimate)*



Exhibit 46

**2030 IEA forecast growth in low emission $H_2$ from 1 Mt in 2021 to 24 Mt in 2030 based on database of $H_2$ projects announced (left chart). In sharp contrast, the IEA's Net Zero Emission scenarios call for nearly 10 times as much hydrogen in 2030 (right chart)**



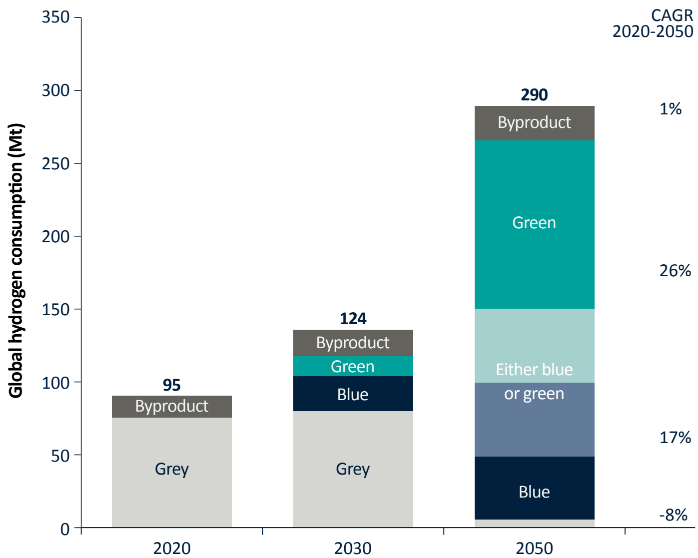

***Source:*** *IEA, Hydrogen Projects Database (2022). Right chart is from IEA 2023 Net Zero Roadmap.*
***Notes:*** *Includes projects at advanced planning and early planning stages. Only projects with a disclosed start year for operation are included.*

from approximately 4 Mt of low emission hydrogen to a total of 24 Mt by 2030. Blue hydrogen will account for another 10 Mt up from just under 1 Mt in 2022 with green hydrogen production growing to 14 Mt from approximately 3 Mt today. If the only new capacity between now and 2030 was from this 24 Mt of new capacity, global production would be at approximately 119 Mt including 95 Mt of grey hydrogen, ignoring any clean hydrogen replacing grey.

The left chart in Exhibit 46 is not a forecast by the IEA, but rather "what has to be true" to meet the IEA Net Zero Scenario where clean hydrogen accounts for 10% of all $CO_2$ reduction by 2050. As stated in our summary, for 2050, we are forecasting something closer to what Bain & Company has forecast below, summing to 310 Mt which would still see emissions reduction of about three gigatons. Note that the byproduct $H_2$ is from the Naphtha process we described above which, over time, will see Naphtha produced from renewable sources.

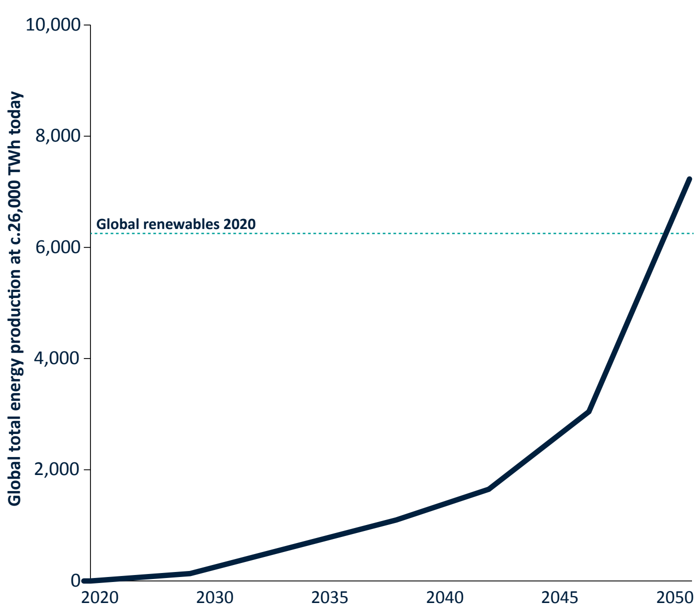
Any 2030 forecast is picking a number between 1 Mt of clean $H_2$ production today and the 186 Mt of capacity attached to all projects in the database today. The total time from the start of a feasibility study to the commissioning of a green hydrogen electrolyser facility typically ranges from about 3 to 7 years. This range can fluctuate based on the

### Exhibit 47
**Bain & Co forecast just c.30 Mt of new clean $H_2$ capacity additions by 2030, but accelerating by 26% CAGR to 310 Mt by 2050**




*Source: IEA, IHS, IRENA, BNEF, EIA, NREL*

### Exhibit 48
**To meet this 310 Mt $H_2$ 2050 forecast, green hydrogen production would require c.7,300 TWh of renewable electricity supply by 2050 (vs. c.26,000 TWh global electricity production today)**




***Source:*** *Bain & Co*

project's scale, location, complexity, and the efficiency of the processes involved. Exhibit 44 shows a large range of forecasts from 35 Mt by Bain and 172 Mt by Deloitte. The IEA's Net Zero target is 70 Mt by 2030. Given the huge acceleration of projects and the 3 to 7 year lead time, we believe that there should be approximately 120 Mt of clean hydrogen production capacity in place by 2030.

This reminds us of how intertwined the overall energy "Rubik's cube" is. We forecast global electricity production to grow to 65,000 TWh by 2050, so this 7,300 TWh for green hydrogen production would consume 11% of all electricity. The IEA's NZE scenario would therefore require 22% of all electricity be directed to electrolysers producing green hydrogen.

Our 300 Mt 2050 estimate is an important input to the overall pathway that we underwrite for investment decisions. But we recommend that investors model scenarios which could range from 150 to 700 Mt of clean hydrogen by 2050. Nearer term 2030 scenarios point to a similarly broad range of between 30 and 170 Mt.

# Question 8. What are the investment implications?

**The investment dilemma for hydrogen is no different than that for the bulk of the capital that supports the $5 to 6 trillion per year of investment that experts state is required to support the energy transition. Clean hydrogen is at such an early stage of development that it is challenging to find enough investors wanting to take the combination of technology, development, economic, and offtake risk with such large, required tickets. This is why governments get involved – i.e., to kickstart industries with subsidies and regulations. The earliest entrants learn from those experiences and get out in front for when these risks have subsided. We expect that the bulk of the investment will be made by large, mostly public companies with strategic joint-ventures to lower risk. Other than selective early-stage venture investments, we do not see a large role at this stage for private capital.**

**Infrastructure investments, at some point, will be required in the areas of storage, transport, and distribution of hydrogen. Such investments classically kick in when technology, development, regulatory, and commercial risks are low. This is not the case today.**

**The major investment implications fall mostly on large pubic companies in those sectors being disrupted and transformed by clean hydrogen, starting with transport (air, maritime, long-haul trucking), industrial (steel, ammonia, refining) and then the power industry. Public equity investors need to model the future cash flows for companies operating in these sectors to incorporate the cost of retrofitting existing processes and building supply chains for hydrogen sourcing, along with forecasting subsidies, pricing, and customer reaction. Clearly, the level of uncertainty around companies in**

**these sectors is already elevated and reflected in current valuations. We are looking to build portfolios around the biggest winners in the transformation from brown to green in these sectors.**

**Next are public and private investments in the large enablers of the hydrogen transitions including the electrolyser manufacturers and the clean hydrogen producers. There is no more certainty in this investment arena as these enablers embody technology and commercial scaling risks right through their entire value chains to include transportation, compression, storage, and carbon sequestration in the case of blue hydrogen.**

**Early-stage venture capitalists are seeing a significant inbound flow of new technology-based businesses. An analysis by Breakthrough Energy Ventures, which is one of the largest current investors in early-stage energy transition venture capital, shows that 5 of its 105 investments to date are in clean hydrogen companies listed in Exhibit 49. This provides you with examples of the sorts of early-stage technology investments that are being made today.**

Exhibit 49

**Breakthrough Energy Ventures hydrogen investments**

| Company Name | Description | Initial Investment Date | Location |
|---|---|---|---|
| **Syzygy Plasmonics** | Low-emissions hydrogen solution which eliminates combustion from traditional GHG-heavy steam methane reforming. And zero-emissions hydrogen solution which leverages renewable electricity to transform green ammonia into clean hydrogen. | Mar 2018 | USA |
| **Electric Hydrogen** | Building the world's most efficient and low-cost electrolysers to produce green hydrogen from water and renewable energy at global scale | Dec 2020 | USA |
| **Koloma** | Koloma has developed the technology to identify, access, and produce natural geologic hydrogen, resulting in clean, cost-effective energy worldwide. | Aug 2021 | USA |
| **H2Pro** | Alternative electrolyser technology to to Alkaline or PEM to produce ultra-low-cost hydrogen with higher energy efficiency | Feb 2021 | Israel |
| **H2Site** | Low-cost hydrogen transportation using existing pipeline infrastructure and transforming ammonia into pure hydrogen on site | Jun 2022 | Spain |

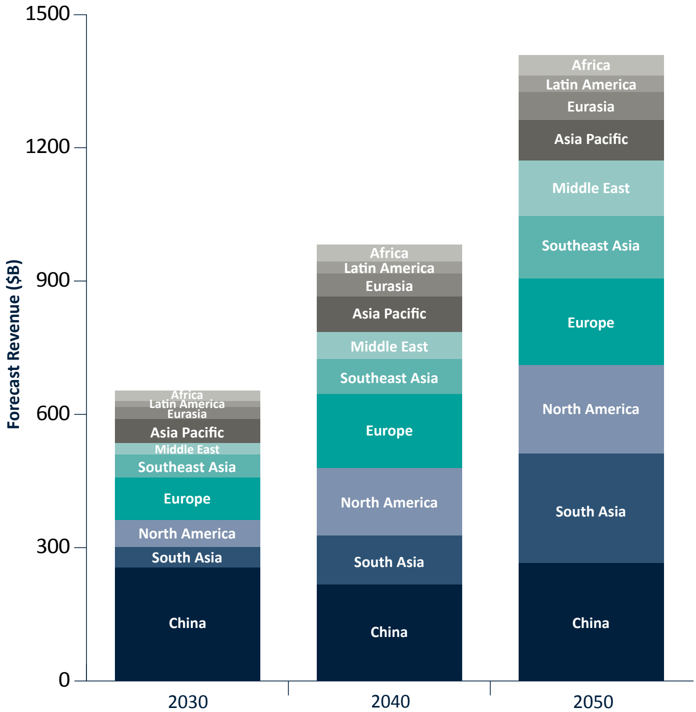
***Source:*** *Breakthrough Energy Ventures*

Before turning to our detailed discussion on specific investment opportunities, we put some dimensions here on the potential growth of the clean hydrogen market and the profit pools that emerge from that. The overall hydrogen market can grow substantially from global revenues of $160B in 2022, comprised of entirely carbon-intensive hydrogen, to more than $640 billion in 2030 and $1.4 trillion in 2050 as shown in Exhibit 50. These are Deloitte estimates which correspond with a very ambitious 2050 scenario of 600 Mt of hydrogen production. Our own estimates would see these estimates cut in half.

To achieve this market growth scenario, Deloitte estimates that $9.4T of cumulative investment will be needed by 2050 (see Exhibit 51), which translates into an annual figure of $350B per year of investment (assuming 27 year straight line average), or closer to $175B under our assumptions of a 300 Mt 2050 market. Note that half of this estimated investment is in the wind and solar capacity required to produce the green hydrogen, leaving something closer to $87B per year of investment, most in electrolysers with the remainder in transport, CCS, and conversion infrastructure. This market estimate ignores the retrofit equipment and

### Exhibit 50

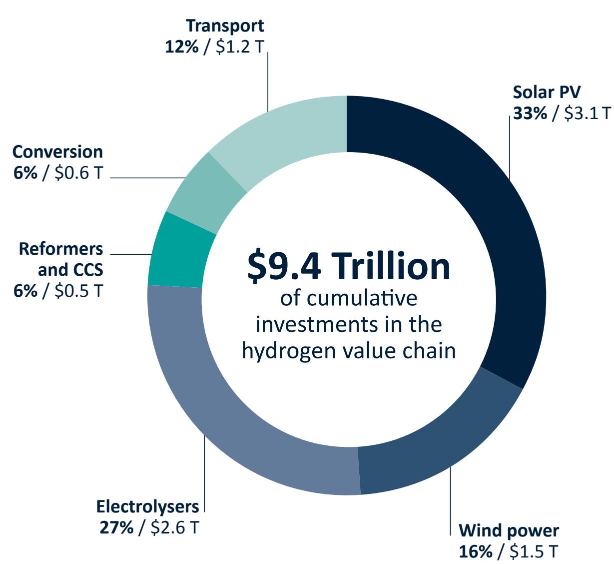
**Deloitte's analysis offers some of the largest market size assumptions, forecasting $642B by 2030, up from the present $160B (mostly grey) hydrogen market size**




***Source:*** *Deloitte analysis based on HyPE model*

### Exhibit 51

**Deloitte estimates that $9.4T of cumulative investment will be needed by 2050 which translates into an annual figure of $350B per year ignoring the end-use retrofit equipment and installation markets**




***Source:*** *Deloitte analysis based on HyPE model*

installation for hydrogen use in all of the end use markets, which could more than double this investment level.

The IEA estimates that investments in the electrolyser industry exceeded $600M globally in 2022, more than double that of 2021. Like so many other parts of the energy transition, hydrogen is at a very low starting point, forecast to grow many multiples of its current size.

We expect the 27-year Deloitte estimate of $2.6T of cumulative spend on electrolysers will translate into approximately $50B per year of electrolyser equipment purchases but skewed toward the next 15 of the 27 year build out period to 2050. Exhibit 52 is a more conservative estimate of the pace and scale of electrolyser capacity build out suggesting approximately 30 GW of new capacity additions per year on average between now and 2040. The average cost per KW of electrolyser capacity is between $1000 and $460. Assuming an average of $700/KW, we arrive at an annual investment of $21B.

We are writing at a key inflection point where the pace of new project announcements has rocketed up with the European directives and the IRA in the US, leaving us with heightened uncertainty about the pace of clean hydrogen penetration. Projects take 3 to 7 years from feasibility to commissioning, sourcing of solar and wind generated electricity post risks, and subsidies regulation can change in these time frames. Electrolyser manufacturers need to ramp their own capacity while having little certainty around how many of the projects in their feasibility stage will turn into actual contracts. The relatively slow rate of growth and the economics of blue and green hydrogen feature as implications for evaluating any investment in the overall hydrogen value chain. The primary observation for investors is precisely this, the creation of the hydrogen markets will be slow.

Our belief is that we will not see significant growth in profit pools for any companies or sectors until we enter the 2030-40 decade. Bain & Company's estimates of profit pool growth in and around the hydrogen economy is shown in Exhibits 53 and 54.

Turning to the investment implications, one framework for segmenting investment opportunities is to look at the overall value chain for the hydrogen industry as shown here in Exhibit 55.

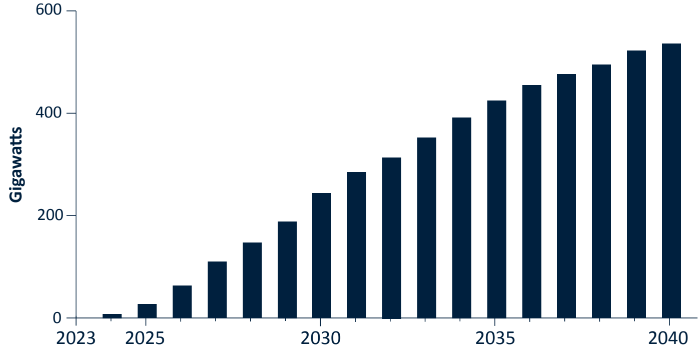
Simplifying this, and working from the end users on the right of this chart and then back, the investment segments fall into five groupings with these suggested investors:

1. End users – investing mostly via public companies

2. Transport, storage and distribution – via the oil majors early on, but eventually infrastructure funds

**Exhibit 52**

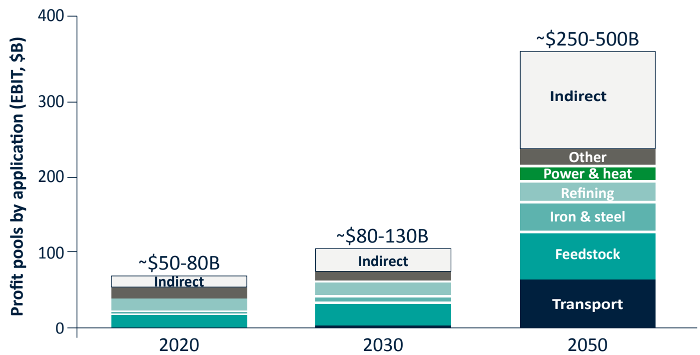
**Electrolyser installed capacity is expected to grow from near zero to 500 GW by 2040 translating into average electrolyser purchases of $50B per year**




***Source:*** *Rystad energy*
***Note:*** *as of July 2023*

**Exhibit 53**

**Profit pools from all hydrogen are expected to grow by 5% p.a. from $50-80B today to $80-130B by 2030 and then accelerate growth to approximately 6.6% p.a. from 2030 to 2050 reaching $250-500B in EBIT**

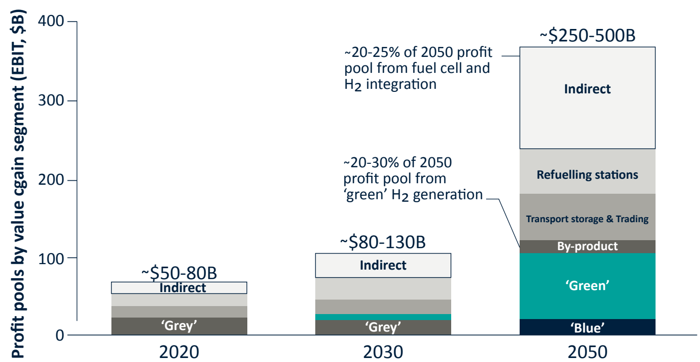



***Source:*** *Bain & Company*

***Note:*** *Indirect profit pools include supply of commodities, development of $H_2$-related technology (electrolysers, fuel cells), integration services (fuel cells and $H_2$ in processes), and advisory roles; (*) Hydrogen produced as waste from industrial electrochemical processes that is captured and consumed within the same facility or sold into the merchant market for use by others*

**Exhibit 54**

**Profit pool growth in the out years will come from three core parts of the values chain: $H_2$ generation, transportation applications and integrating $H_2$ into the energy complex**




***Source:*** *Bain & Company*

**Exhibit 55**

**Hydrogen value chain participants from electricity providers to electrolyser manufacturers, chemical companies producing hydrogen, and end users**

| Production | | Distribution & Transport | | | | Application | |
|---|---|---|---|---|---|---|---|
| $H_2$ Inputs | Generation | Transport | Storage | Distribution | Trading | Usage | |
| **Renewable power producer** | **'Grey' $H_2$ generator** (producer, by-product) | **Compressed gas transporter** | **$H_2$ Storage provider** (e.g., salt cavern operator) | **Pipeline distributor** | **$H_2$ Trader** | **Pure $H_2$ consumer** (refining, chemicals, industrial) | **Industrial $H_2$ user** (steel, chemicals) |
| **Other inputs producer** (natural gas, oil) | **'Blue' $H_2$ generator** (CCUS) | **Liquefied $H_2$ transporter** | | **Ground distributor** (rail, trucks) | | **$H_2$ dericative producer** (ammonia, SNG/synfuel) | **Transport company** (long-haul trucks, ships airlines) |
| **Electrolyser manufacturer** | **'Green' $H_2$ generator** (electrolysis) | | | **Maritime shipping distributor** | | **$H_2$ fuel staion operator** | |
| **Carbon capture equipment manufacturer** | | | | | | | |
| **Company examples by value chain segment** | | | | | | | |
| • HydrogenPro<br>• MHI<br>• NEL<br>• NextEra<br>• IOCs | • Air products<br>• LTM Power<br>• Linde<br>• Orsted<br>• Siemens<br>• IOCs | • Air Liquide<br>• Linde<br>• TotalEnergies<br>• Kawasaki Heavy<br>• Industries | • Air Liquide<br>• Engie<br>• Equinor<br>• MHI | • Fortescue Future Industries<br>• Fluxys<br>• Gascade<br>• Maersk | • Gunvor Group<br>• Linde<br>• Trafigura<br>• Vitol | • BASF<br>• Yara<br>•IOCs (i.e., Shell, BP, ExxonMobil) | • Arcelor<br>• SSAB<br>• Merck<br>• BA<br>• Toyota |

***Source:*** *Bain & Company and Partners Capital*

**3.** Electrolyser and CCUS equipment manufacturers – a blend of specialist small private and public companies and divisions of large engineering companies like Siemens and MHI

**4.** Producers of clean hydrogen – mostly large chemical companies like Air Products

**5.** Raw materials suppliers including fossil fuels for blue hydrogen and renewable electricity for green – the oil majors and electric utilities.

Venture capital investments cross almost all parts of the value chain, with the greatest focus on the equipment manufacturing stage. The vast majority of the investment in the hydrogen economy will be made by the leading corporate incumbents like those listed in the bottom half of Exhibit 55.

Bain & Company, strategy consultants, describe three business models to initiate successful hydrogen projects during this early phase of the industry's development, beyond the obvious initiatives to develop new technologies. This is the advice they provide to their corporate clients, as so is what we would expect to see embedded in the energy transition strategies of large public companies. These models tell us how important location is to successful clean hydrogen economics.

**1. Low LCOE (levelised cost of energy) supply hubs:** Large scale integrated projects using low-cost natural gas with CCS and low-cost off-grid renewable energy systems.

**2. Scale hydrogen clusters:** Integrated hubs around multiple use cases, connected to green / blue $H_2$ at scale, mostly to decarbonise industries. These can either be located next to low-cost hydrogen sources (e.g., offshore wind and $H_2$ production) or located in areas of concentrated industrial demand (e.g., co-firing gas power plants in Japan).

**3. Localised solutions:** Localised pilot projects or decarbonisation efforts around specific use cases, including decarbonisation-as-a-service models.

Critical for each business model is to understand which anchor customers and value chain partners are required to secure offtake and bring in the required capabilities.

**Current producers of grey hydrogen are likely to have a role in clean hydrogen, mostly blue hydrogen.** Most grey hydrogen is produced at the site of use such as at a refinery or a fertiliser plant. The major producers of grey hydrogen in this vein are oil majors including China National Petroleum Corporation, Exxon Mobil Corporation, Indian Oil Corporation Limited, Marathon Petroleum Corp, Reliance Industries, Saudi Aramco, and Shell plc. All of these companies' oil refinery operations have implemented some form of CCUS to produce blue hydrogen and are the leading, but small, producers of blue hydrogen.

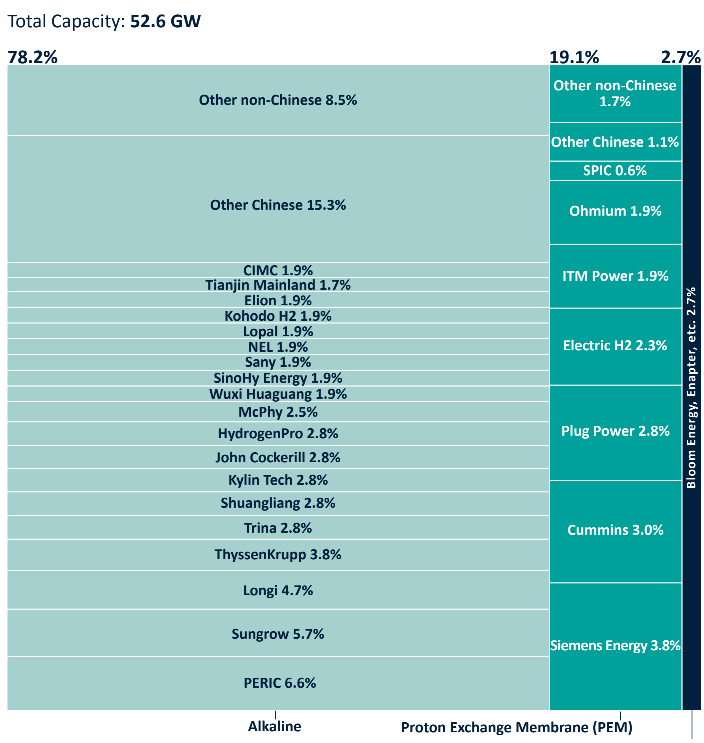
**The industrial gas industry also plays a role in the production and transport of off-site (grey) hydrogen.** It consists of a small oligopoly of global firms that tend to be vertically integrated. Air Products is a major US based seller of industrial gases and chemicals that has dominated the grey and blue hydrogen markets. In Port Arthur, Texas, Air Products created the first retrofit technology to capture carbon on a commercial scale. Air Liquide has a 60-year history in the hydrogen value chain across the space, aeronautics, and refining industries. It has been operating its Cryocap $H_2$ technology in Port Jerome, France since 2015. Linde is an American-German chemical company headquartered in the U.K. and Dublin, Ireland. It specialises in distributing and producing nitrogen, oxygen, acetylene, argon, and process gases, including hydrogen and helium.

**Investing in electrolyser manufacturers should be in those most likely to be strategically important to the largest hydrogen producers.** Exhibit 56 provides estimates of 2024 market share (global stack assembly capacity) and highlights how nascent this market is, where picking the likely leaders today is not easy. We can see the large presence of Chinese manufacturers which is not surprising as electrolysers have been targeted as yet another strategic priority in the energy transition space where they are expected to invest aggressively to create a dominant position not unlike what they have already achieved in solar panels and lithium-ion batteries.

The 52 GW of capacity translates into approximately 5 Mt of green hydrogen production capacity, so a fraction of the 24 Mt of approved projects in the hydrogen data base planned to be ready by 2030. This explains the ambitious growth announcements by electrolyser manufacturers shown in Exhibit 57.

In western markets, key players have embraced joint ventures and vertical

**Exhibit 56**
**Estimate of 2024 electrolyser stack assembly capacity by producer and technology**




***Source:*** *Company filings, BloombergNEF, industry sources.*

Exhibit 57

**Electrolyser manufacturers are announcing plans to increase capacity by 6x on average from current to 2025**

| Manufacturers | Headquarters | Technology | Capacity (MW) | | |
|---|---|---|---|---|---|
| | | | Current | Expansion plans | Growth |
| **ITM Power** | UK | PEM | 1,000 | 5,000 (by 2024) | 5x |
| **McPhy** | France | PEM. Alkaline | 100 | 1,300 (by 2024) | 13x |
| **Nel** | Norway | PEM. Alkaline | 500 | 10,000 (by 2025) | 20x |
| **John Cockerill** | Belgium | Alkallne | 350 | 8,000 (by 2025) | 22x |
| **Plug Power** | US | PEM | 75 | 3,000 (by 2025) | 40x |
| **Thyssenkrupp** | Germany | Alkaline | 1,000 | 5,000 (by 2030) | 5x |
| **Sunflre** | Germany | Alkaline, Solid oxide | 40 | 500 (by 2023)" | 12x |
| **Siemens Energy** | Germany | PEM | 125 | 1,000 (by 2030) | 8x |
| **Cummins** | us | PEM. Alkaline, Solid oxide | 38 | 3,500 (by 2025) | 92x |
| **Topsoe** | Denmark | Solid oxide | 75 | 5,000 (by 2030) | 66x |
| **Ohmlum** | US | PEM | 500 | 2,000 (by 2022) | 4x |
| **Enapter** | Italy | AEM | 30 | 300 (by 2023) | 10x |
| **Bloomenergy** | US | Solid oxide | 500 | 1,000 (by 2023) | 2x |
| **Green Hydrogen Systems** | Denmark | Alkaline | 75 | 400 (by 2023) | 5x |
| **Hyelrogen Pro** | Norway | Alkaline | 100 | 1,000 (by 2030) | 10x |
| **Elogen** | France | PEM | 160 | 1,000 (by 2025) | 6x |
| **Other manufacturers** | | PEM. Alkaline, Solid oxide | 1,000E | 12,000E (by 2030) | |
| **Total** | | | 5,600 | 37,000 (by 2025)<br>60,000 (next 10 years) | 6x<br>10x |

***Source:*** *EY analysis, Company press releases, Secondary sources*
***Note:*** *PEM: proton exchange membrane | AEM: anion exchange membrane*

integration which can reduce many of the risks, providing better control of supply, quality, and costs. Electrolyser OEMs are establishing partnerships in three directions:

1. Midstream operators, who play a crucial role in transporting, storing, and trading hydrogen, to bridge the gap between hydrogen production and end-user applications.

2. Tie-ups with key hydrogen producers across different industry segments. For example, ITM Power, which has expertise in manufacturing electrolyser systems, has taken this approach, announcing a joint venture with Linde to deliver green hydrogen to large scale industrial projects within Linde's existing customer base. ITM has also partnered with Shell to develop a 100 MW electrolyser at Shell's Rheinland Energy and Chemicals park, where Shell intends to produce SAF using the green hydrogen from that project.

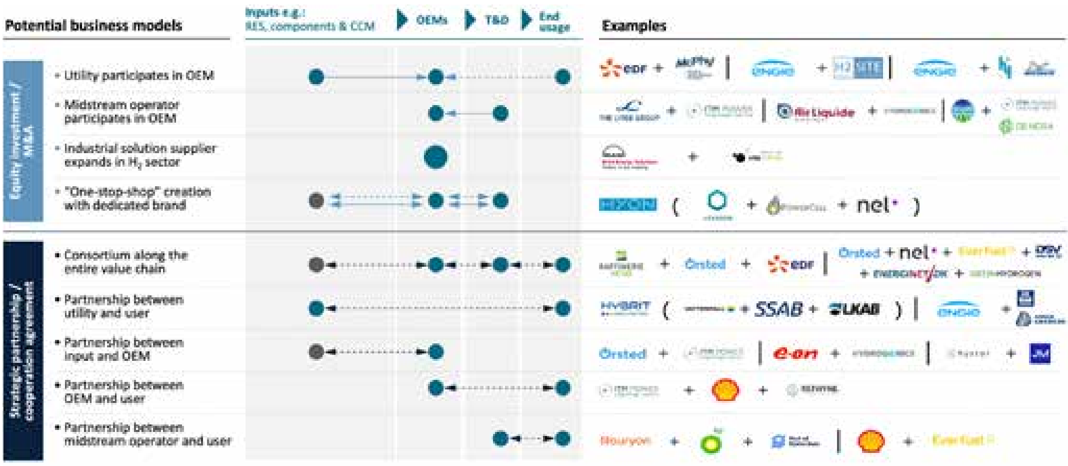
3. Partnerships with energy and utility players as renewable power hubs are inferred to be better suited for green hydrogen production due to access to renewable electricity.

Exhibit 58 is from Bain's analysis of M&A transactions (top half) and joint-ventures (bottom half) already in place. These partnerships are expected to support the development of a green hydrogen ecosystem.

Like so many investments in the energy transition space, we would expect large public companies including oil majors and chemical companies to make the most significant investments including acquisitions of the smaller specialist electrolyser manufacturers listed above. Accordingly, one potential investment theme would be to pick the likely winners among the electrolyser manufacturers who will be highly sought after as acquisition targets. One example could be Norway's NEL who is already in several corporate consortia shown in Exhibit 58. NEL's annual run rate revenue is approximately $140M and has a market cap of $1.1B, down from $2.2B at the beginning of the 2023.

## Exhibit 58

**Most participants in the H2 market have formed partnerships to de-risk entry**




***Source:*** *Market participant interviews, Lit. search*

**The most attractive and accessible investment opportunities we see are in the public equity market, in the form of well-resourced companies with long experience in dealing with the many challenges of hydrogen who are most determined to lead in its long-term development.** Within the still nascent green hydrogen economy, China's early dominance of electrolyser manufacturing has begun to fade as US and European governments provide stronger financial support for electrolysers. Bloomberg NEF estimates that the Americas, Europe, and EMEA regions will together account for c.45% of global electrolyser shipments in 2023, and c.60% in 2024. In China, global electrolyser stack assembly capacity is led by PERIC Hydrogen Technologies, Sungrow Power, and LONGi Hydrogen. These original equipment manufacturers (OEMs) provide capacity to state-owned energy companies that have started building green hydrogen projects in response to the Chinese central government's call for net-zero even without subsidies to justify the business case. Among the leading western electrolyser OEMs are Bloom Energy, ITM Power, John Cockerell, HydrogenPro, and Siemens Energy.

Air Liquide, HydrogenPro, Linde, Plug Power, Siemens, and ThyssenKrupp have used their size, reach, and balance sheets to emerge well-positioned to capitalise on the rapidly growing green hydrogen market. Air Liquide and Linde each have over 100 years of expertise in hydrogen and have publicly stated multi-billion dollar plans to invest in green hydrogen projects. Norway-headquartered HydrogenPro is to ship 220MW of alkaline stacks to the United States this year from its factory in China. By taking advantage of low costs in China and relatively higher prices in the international market, it is the first Western electrolyser maker to have positive EBITDA. Plug Power is a leading developer of fuel cell technology that has several large-scale green hydrogen projects in development and has partnered with Johnson Matthey to procure membranes for its PEM electrolysers. Siemens and ThyssenKrupp are multinational conglomerates that have used partnerships with leading companies in the green hydrogen space to share knowledge, resources, and expertise to help accelerate the development of the green hydrogen market. Their global supply chain capabilities allow them to source upstream materials such as copper busbar (for conductive electrical connection) and polymer hoses (for electrolyser inlet and outlet), from China and South Africa for use at domestic production facilities.

## Biggest unknowns:

- Will the massive scale of recent European and US government economic support for hydrogen drive progress past expectations? Or will changing political parties/leaders reverse this support?
- Will battery technology improve more rapidly than expected giving hydrogen more competition in the "hard to electrify" applications in transport?
- Will we be surprised by the advent of low-cost green hydrogen as a result of a surplus of low-cost renewable electricity in strong solar and wind markets?
- Will large well-funded corporations like Toyota surprise us with breakthroughs in ammonia or other versions of clean hydrogen penetrating automotive and other sectors?
- Will China dominate the global electrolyser market as they have with batteries and solar, driving costs down the curve to result in more rapid penetration?

# Conclusion

**Hydrogen is expected to play a major role in the global energy transition, but not as large as many experts or hydrogen industry leaders forecast. Clean hydrogen and derivative market development has monumentally accelerated in the last two years, with a 2.5x step up in the number of announced projects and announced project supply capacity. Governments of most large countries have reinforced their long-term commitments to clean hydrogen with targets and financial incentives. Broad commercial viability for clean hydrogen applications is expected to materialise this decade, with specific pockets of development opportunity opening now. But actual growth in revenue will be slow with acceleration only appearing as we enter the 2030's.**

Clean hydrogen is a technology that has the potential to transform the path to global net zero across a number of key emitting sectors and industries. Both green and blue hydrogen will be critical pillars to any net zero path. Policy, affordability, and scalability seem to be converging to create momentum for the clean hydrogen economy. That said, there are still challenges that must be addressed to unlock the potential of low-emission hydrogen.

The key constraint to adoption of clean hydrogen will be the cost. Green hydrogen's move towards cost parity with grey hydrogen is accelerating and we expect this to be reached just after 2030 ignoring subsidies. However, we note that the current macro dynamic of structurally higher commodity prices, in particular natural gas, combined with higher carbon prices is creating a unique green hydrogen cost parity dynamic in Europe. With most currently produced hydrogen being sourced from natural gas in the region, the notably higher natural gas price to which the region is currently exposed is tilting the scale in favor of green hydrogen from an economic standpoint.

Safe and cost-efficient transport, storage and distribution of hydrogen will be critical in setting the pace of its large-scale deployment. The low energy density of the fuel under ambient conditions, its high diffusivity in some materials including different types of steel and iron pipes, and its highly flammable nature present technological and infrastructure challenges to its large-scale adoption. Hydrogen's initial acceleration and use is likely to be more locally concentrated in hydrogen supply hubs while a large-scale globally integrated value chain is likely to take longer to emerge.

The IEA has recently lowered its 2050 NZE scenario target from 600 Mt to 420 Mt reflecting "slower technological and market development." This points to c.4 gigatons of carbon reduction, contributing to 8% of global decarbonisation.

Using the same hydrogen $Co_2$ abatement factor of 10 that we used for replacing the current grey hydrogen applications with clean $H_2$ (perhaps the maximum levels of abatement from each tonne of clean $H_2$ substituted), and the 500-600 Mt 2050 NZE scenarios hydrogen demand assumptions, they arrive at a maximum carbon abatement of 5 to 6 gigatons which is approximately 10-12% of total current GHG emissions. But using estimates that we believe will be more likely, specifically where clean $H_2$ usage reaches 300 Mt by 2050, and using the same abatement factor of 10, we arrive at our base case assumption of 3 gigatons of $Co_2$ abatement from hydrogen or 6% of total current GHG emissions.

Undoubtedly, high levels of uncertainty around the technology, subsidies/taxes, cost, and customer adoption, will stall the $150B to $300B a year of capital investment that experts estimate is needed to achieve the range of outcomes described above. The most viable opportunities will exploit location advantages that drive low natural gas and renewable energy input costs and hydrogen transportation costs. Large public companies have the greatest strategic advantages to pursue such investments and public equity investors with deep insights into the hydrogen economy will be best positioned to help asset owners generate outsized returns and drive the greatest decarbonisation from the deployment of clean hydrogen.

# DISCLAIMER



Within the United Kingdom, this material has been issued by Partners Capital LLP, which is authorised and regulated by the Financial Conduct Authority of the United Kingdom (the "FCA"), and constitutes a financial promotion for the purposes of the rules of the Financial Conduct Authority. Within Hong Kong, this material has been issued by Partners Capital Asia Limited, which is licensed by the Securities and Futures Commission in Hong Kong (the "SFC") to provide Types 1 and 4 services to professional investors only. Within Singapore, this material has been issued by Partners Capital Investment Group (Asia) Pte Ltd, which is regulated by the Monetary Authority of Singapore as a holder of a Capital Markets Services licence for Fund Management under the Securities and Futures Act and as an exempt financial adviser. Within France, this material has been issued by Partners Capital Europe SAS, which is regulated by the Autorité des Marchés Financiers (the "AMF").

For all other locations, this material has been issued by Partners Capital Investment Group, LLP which is registered as an Investment Adviser with the US Securities and Exchange Commission (the "SEC") and as a commodity trading adviser and commodity pool operator with the Commodity Futures Trading Commission ("CFTC") and is a member of the National Future's Association (the "NFA").

This material is being provided to clients, potential clients and other interested parties (collectively "clients") of Partners Capital LLP, Partners Capital Asia Limited, Partners Capital Investment Group (Asia) Pte Ltd, Partners Capital Europe SAS and Partners Capital Investment Group, LLP (the "Group") on the condition that it will not form a primary basis for any investment decision by, or on behalf of the clients or potential clients and that the Group shall not be a fiduciary or adviser with respect to recipients on the basis of this material alone. These materials and any related documentation provided herewith is given on a confidential basis. This material is not intended for public use or distribution. It is the responsibility of every person reading this material to satisfy himself or herself as to the full observance of any laws of any relevant jurisdiction applicable to such person, including obtaining any governmental or other consent which may be required or observing any other formality which needs to be observed in such jurisdiction. The investment concepts referenced in this material may be unsuitable for investors depending on their specific investment objectives and financial position.

This material is for your private information, and we are not soliciting any action based upon it. This report is not an offer to sell or the solicitation of an offer to buy any investment. While all the information prepared in this material is believed to be accurate, the Group, may have relied on information obtained from third parties and makes no warranty as to the completeness or accuracy of information obtained from such third parties, nor can it accept responsibility for errors of such third parties, appearing in this material. The source for all figures included in this material is Partners Capital Investment Group, LLP, unless stated otherwise. Opinions expressed are our current opinions as of the date appearing on this material only. We do not undertake to update the information discussed in this material. We and our affiliates, officers, directors, managing directors, and employees, including persons involved in the preparation or issuance of this material may, from time to time, have long or short positions in, and buy and sell, the securities, or derivatives thereof, of any companies or funds mentioned herein.

Whilst every effort is made to ensure that the information provided to clients is accurate and up to date, some of the information may be rendered inaccurate by changes in applicable laws and regulations. For example, the levels and bases of taxation may change at any time. Any reference to taxation relies upon information currently in force. Tax treatment depends upon the individual circumstances of each client and may be subject to change in the future. The Group is not a tax adviser and clients should seek independent professional advice on all tax matters.

Within the United Kingdom, and where this material refers to or describes an unregulated collective investment scheme (a "UCIS"), the communication of this material is made only to and/or is directed only at persons who are of a kind to whom a UCIS may lawfully be promoted by a person authorised under the Financial Services and Markets Act 2000 (the "FSMA") by virtue of Section 238(6) of the FSMA and the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) (Exemptions) Order 2001 (including other persons who are authorised under the FSMA, certain persons having professional experience of participating in unrecognised collective investment schemes, high net worth companies, high net worth unincorporated associations or partnerships, the trustees of high value trusts and certified sophisticated investors) or Section 4.12 of the FCA's Conduct of Business Sourcebook ("COBS") (including persons who are professional clients or eligible counterparties for the purposes of COBS). This material is exempt from the scheme promotion restriction (in Section 238 of the FSMA) on the communication of invitations or inducements to participate in a UCIS on the grounds that it is being issued to and/or directed at only the types of person referred to above. Interests in any UCIS referred to or described in this material are only available to such persons and this material must not be relied or acted upon by any other persons.

Within Hong Kong, where this material refers to or describes an unauthorised collective investment schemes (including a fund) ("CIS"), the communication of this material is made only to and/or is directed only at professional investors who are of a kind to whom an unauthorised CIS may lawfully be promoted by Partners Capital Asia Limited under the Hong Kong applicable laws and regulation to institutional professional investors as defined in paragraph (a) to (i) under Part 1 of Schedule to the Securities and Futures Ordinance ("SFO") and high net worth professional investors falling under paragraph (j) of the definition of "professional investor" in Part 1 of Schedule 1 to the SFO with the net worth or portfolio threshold prescribed by Section 3 of the Securities and Futures (Professional Investor) Rules (the "Professional Investors").

Within Singapore, where this material refers to or describes an unauthorised collective investment schemes (including a fund) ("CIS"), the communication of this material is made only to and/or is directed only at persons who are of a kind to whom an unauthorised CIS may lawfully be promoted by Partners Capital Investment Group (Asia) Pte Ltd under the Singapore applicable laws and regulation (including accredited investors or institutional investors as defined in Section 4A of the Securities and Futures Act).

Within France, where this material refers to or describes to unregulated or undeclared collective investment schemes (CIS) or unregulated or undeclared alternative Investment Funds (AIF), the communication of this material is made only to and/or is directed only at persons who are of a kind to whom an unregulated or undeclared CIS or an unregulated or undeclared AIF may lawfully be promoted by Partners Capital Europe under the French applicable laws and regulation, including professional clients or equivalent, as defined in Article D533-11, D533-11-1, and D533-13 of the French Monetary and Financial Code.

Certain aspects of the investment strategies described in this presentation may from time to time include commodity interests as defined under applicable law. Within the United States of America, pursuant to an exemption from the US Commodity Futures Trading Commission (CFTC) in connection with accounts of qualified eligible clients, this brochure is not required to be, and has not been filed with the CFTC. The CFTC does not pass upon the merits of participating in a trading program or upon the adequacy or accuracy of commodity trading advisor disclosure. Consequently, the CFTC has not reviewed or approved this trading program or this brochure. In order to qualify as a certified sophisticated investor a person must (i) have a certificate in writing or other legible form signed by an authorised person to the effect that he is sufficiently knowledgeable to understand the risks associated with participating in unrecognised collective investment schemes and (ii) have signed, within the last 12 months, a statement in a prescribed form declaring, amongst other things, that he qualifies as a sophisticated investor in relation to such investments.

This material may contain hypothetical or simulated performance results which have certain inherent limitations. Unlike an actual performance record, simulated results do not represent actual trading. Also, since the trades have not actually been executed, the results may have under- or over-compensated for the impact, if any, of certain market factors, such as lack of liquidity. Simulated trading programs in general are also subject to the fact that they are designed with the benefit of hindsight. No representation is being made that any client will or is likely to achieve profits or losses similar to those shown. These results are simulated and may be presented gross or net of management fees. This material may include indications of past performance of investments or asset classes that are presented gross and net of fees. Gross performance results are presented before Partners Capital management and performance fees, but net of underlying manager fees. Net performance results include the deduction of Partners Capital management and performance fees, and of underlying manager fees. Partners Capital fees will vary depending on individual client fee arrangements. Gross and net returns assume the reinvestment of dividends, interest, income and earnings.

The information contained herein has neither been reviewed nor approved by the referenced funds or investment managers. Past performance is not a reliable indicator and is no guarantee of future results. Investment returns will fluctuate with market conditions and every investment has the potential for loss as well as profit.

The value of investments may fall as well as rise and investors may not get back the amount invested. Forecasts are not a reliable indicator of future performance.

Certain information presented herein constitutes "forward-looking statements" which can be identified by the use of forward-looking terminology such as "may", "will", "should", "expect", "anticipate", "project", "continue" or "believe" or the negatives thereof or other variations thereon or comparable terminology. Any projections, market outlooks or estimates in this material are forward –looking statements and are based upon assumptions Partners Capital believe to be reasonable. Due to various risks and uncertainties, actual market events, opportunities or results or strategies may differ significantly and materially from those reflected in or contemplated by such forward-looking statements. There is no assurance or guarantee that any such projections, outlooks or assumptions will occur.

Certain transactions, including those involving futures, options, and high yield securities, give rise to substantial risk and are not suitable for all investors. The investments described herein are speculative, involve significant risk and are suitable only for investors of substantial net worth who are willing and have the financial capacity to purchase a high risk investment which may not provide any immediate cash return and may result in the loss of all or a substantial part of their investment. An investor should be able to bear the complete loss in connection with any investment.

All securities investments risk the loss of some or all of your capital and certain investments, including those involving futures, options, forwards and high yield securities, give rise to substantial risk and are not suitable for all investors.

*Image: 4maksym/Istock*

## Europe

5 Young Street
London
W8 5EH
United Kingdom
**T** +44 (0)20 7938 5200

82 avenue Marceau
75008 Paris
France
**T** +33 (0)1 7038 1054

## North America

Federal Reserve Plaza
600 Atlantic Avenue
30th Floor
Boston, MA 02210
United States
**T** +1 617 292 2570

640 Fifth Avenue
21st Floor
New York, NY 10019
United States
**T** +1 212 951 1288

3 Embarcadero Center
Suite 2360
San Francisco, CA 94111
United States
**T** +1 415 862 7100

## Asia

50 Raffles Place
Level 13
Singapore Land Tower
Singapore 048623
**T** +65 6645 3733

10/F Champion Tower
3 Garden Road
Central, Hong Kong
**T** +852 3614 0230