Goldman Sachs | Research

Carbonomics
The clean hydrogen revolution

Clean hydrogen has emerged as a critical pillar to any aspiring global net zero path, aiding the de-carbonization of **c.15% of global GHG emissions**, we estimate, with **TAM** for hydrogen generation alone having the potential **to double to c.US$250 bn by 2030** and reach **>US$1 tn by 2050.** We believe it is now time to revisit the clean hydrogen theme as **policy, affordability** and **scalability** seem to be **converging to create unprecedented momentum** for the clean hydrogen economy.

Policy support is strengthening globally, with **>30 national hydrogen strategies** and roadmaps pledging a **>400-fold increase in clean hydrogen installed capacity this decade** vs 2020 and supportive of a c.50-fold increase in the pace of annual average green hydrogen new builds. **Scalability** is already revolutionizing the green hydrogen projects pipeline, with scope for **average project sizes to increase 100x+,** from 2MW in 2020 to >200MW by 2025 and a GW scale by 2030, leading to **cost deflation of 40% for electrolyzer systems by 2025E**, similar to what has been observed for batteries over the past five years. **Affordability** is rapidly improving with green hydrogen likely to be at **cost parity with grey in advantageous regions by 2025E** (US$1.5/kg H2) and **hydrogen cost parity with diesel** in long-haul heavy road transport likely as early as **2027E.** We believe clean hydrogen can develop into a major global market, impacting geopolitical patterns in energy supply, and we examine the **case for international trade,** concluding that **30% of global hydrogen volumes** have the potential to be involved in cross-border transport, **higher than for natural gas.** Regions such as **MENA, LatAm, Australia and Iberia** could emerge as key clean hydrogen **exporters**, while Central Europe, Japan, Korea and East China could emerge as key importers.

With **US$5.0 tn cumulative investments required in the clean hydrogen supply chain**, on our estimates, we examine the hydrogen case for **11 industrial conglomerates with growing exposure to the theme** and also **initiate coverage on three leading hydrogen pure-plays.**

Zoe Clarke
+44 20 7051-2816
zoe.clarke@gs.com
Goldman Sachs International

Michele Della Vigna, CFA
+44 20 7552-9383
michele.dellavigna@gs.com
Goldman Sachs International

The Goldman Sachs Group, Inc.

Full list of authors inside

AUTHORS

Zoe Clarke
+44 20 7051-2816
zoe.clarke@gs.com
Goldman Sachs International

Michele Della Vigna, CFA
+44 20 7552-9383
michele.dellavigna@gs.com
Goldman Sachs International

Georgina Fraser, Ph.D.
+44 20 7552-5984
georgina.fraser@gs.com
Goldman Sachs International

Jerry Revich, CFA
+1 212 902-4116
jerry.revich@gs.com
Goldman Sachs & Co. LLC

Neil Mehta
+1 212 357-4042
neil.mehta@gs.com
Goldman Sachs & Co. LLC

Robert Koort, CFA
+1 713 654-8440
robert.koort@gs.com
Goldman Sachs & Co. LLC

Alberto Gandolfi
+39 02 8022-0157
alberto.gandolfi@gs.com
Goldman Sachs Bank
Europe SE - Milan branch

Chao Ji
+86 21 2401-8936
chao.ji@ghsl.cn
Beijing Gao Hua Securities
Company Limited

Ajay Patel
+44 20 7552-1168
ajay.patel@gs.com
Goldman Sachs International

Bepul Shahab
+44 20 7774-3694
bepul.shahab@gs.com
Goldman Sachs International

Table of Contents

The clean hydrogen revolution: Thesis in charts

Exhibit 1: Clean hydrogen is a critical pillar to any aspiring net zero path, aiding the de-carbonization of c.15% of global GHG emissions on our estimates..

Carbonomics cost curve with emissions abatement potential attributed to clean hydrogen indicated
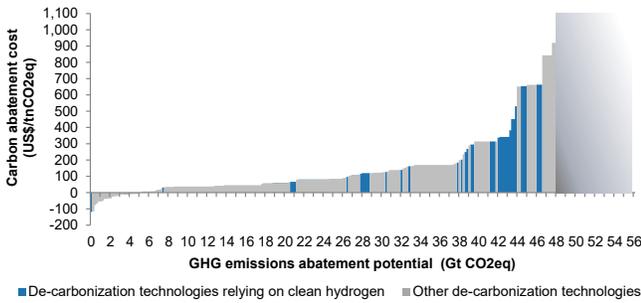
Exhibit 2: ..and our GS global net zero paths (one consistent with 1.5°C of global warming, one consistent with well below 2.0° and one consistent with 2.0°)...

GS global net zero models, CO2 emissions (incl. AFOLU)
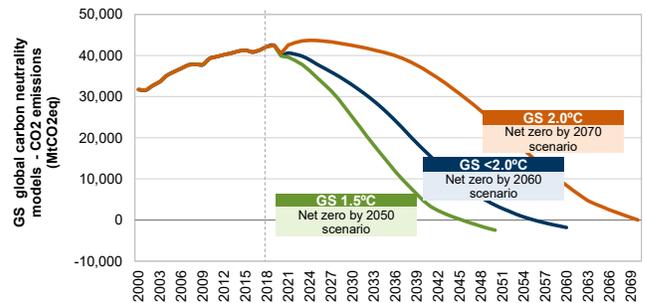
Exhibit 3: ..imply an up to 7-fold increase in the global hydrogen demand on the path to net zero across industries.

Global hydrogen demand (Mt H2) under the three GS net zero models
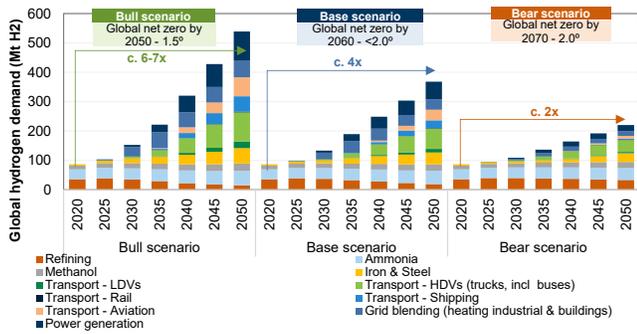
Exhibit 4: We estimate US$5.0 tn of investments will be required in the global clean hydrogen supply chain to net zero..

Investments required in the clean hydrogen supply chain for net zero
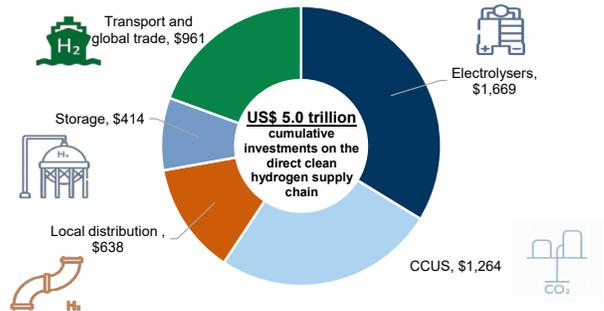
Exhibit 5: ..while TAM for hydrogen generation has the scope to double from US$125 bn to c.US$250 bn by 2030 and reach >US$1 tn by 2050 (bull scenario)

TAM for global hydrogen generation, transport and storage (US$bn)
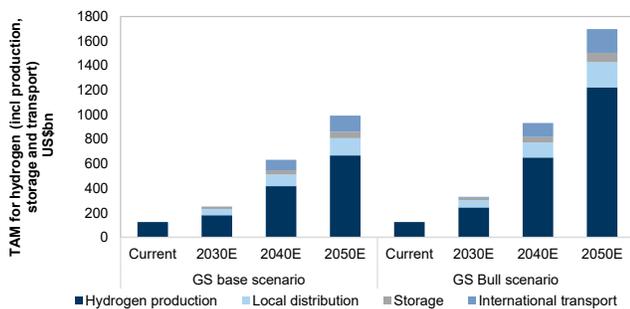
Exhibit 6: Policy support for clean H2 is strengthening globally with >30 national H2 strategies and roadmaps explicitly pledging c.130GW of capacity by 2030, >400x the 2020 level
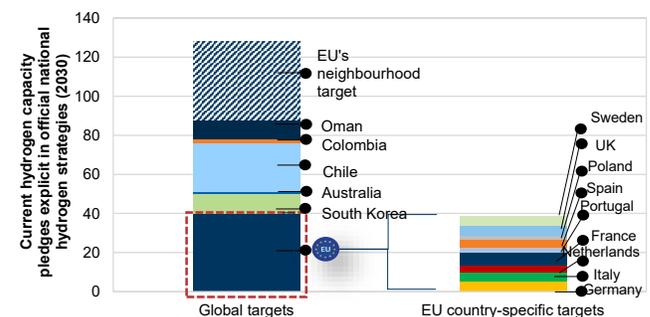
Exhibit 7: We see green hydrogen as the key de-carbonization solution, benefiting from the growth and cost deflation in renewable power…
Levelized cost of hydrogen production (US$/kg H2)

Source: Goldman Sachs Global Investment Research

Exhibit 8: ..and the industry is growing at a remarkable pace with announced green hydrogen projects across the globe trending above our base case..
Global installed green H2 electrolysis capacity from projects announced compared to GS scenarios
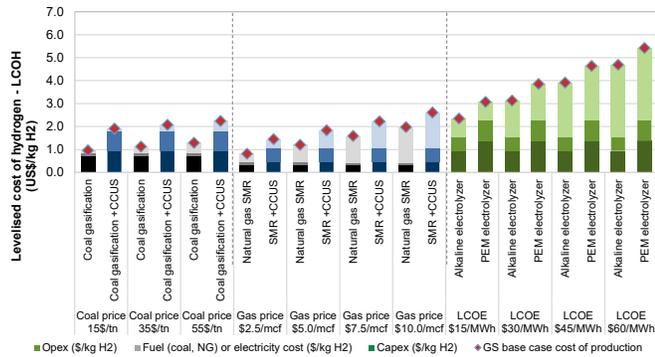
Source: Goldman Sachs Global Investment Research

Exhibit 9: ..representing a >200-fold increase to 2030, and a c.20%-30% CAGR to 2050
Global installed electrolyzer capacity under various scenarios and vs GS global hydrogen models (GW)

Source: BNEF, IEA, Hydrogen Council, Goldman Sachs Global Investment Research

Exhibit 10: Europe leads the planned green hydrogen projects pipeline in the near term, with Australia, LatAm and MENA scaling up notably post 2025E
Cumulative installed electrolysis capacity based on announced/planned green hydrogen projects
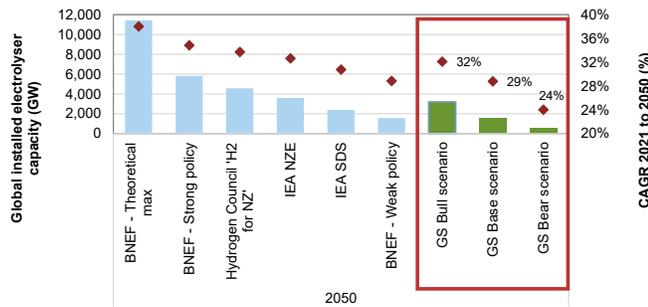
Source: Goldman Sachs Global Investment Research

Exhibit 11: Scale brings cost deflation and we estimate that the cost of electrolyzers can fall by c.40% by 2025E, similar to what we observed for batteries over five years..
Cost per kW capacity for electrolyzers, renewables, batteries (per kWh)
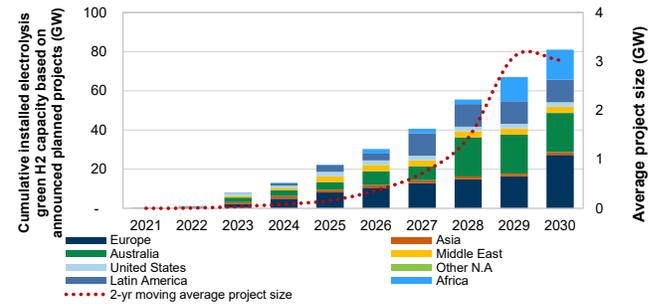
Source: Goldman Sachs Global Investment Research

Exhibit 12: ..unlocking cost parity of green with grey hydrogen as early as 2025-26E in advantageous regions (low RES cost)
Levelized cost of hydrogen (US$/kg H2) for grey, green and blue H2
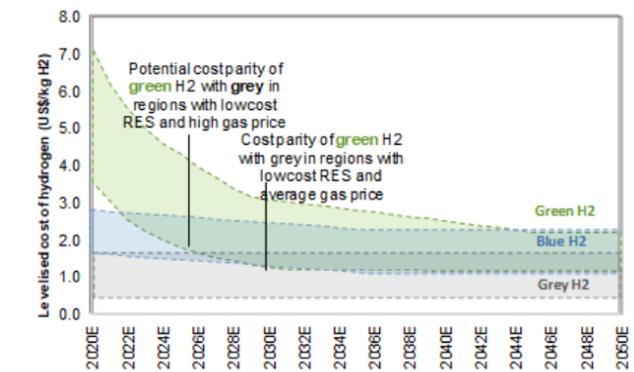
Source: Goldman Sachs Global Investment Research

Exhibit 13: The unique dynamic in Europe with historically high gas and carbon prices is already leading to green H2 cost parity with grey across key parts of the region (LCOE <US$50/MWh)
Levelized cost of hydrogen - LCOH (US$/kg H2)
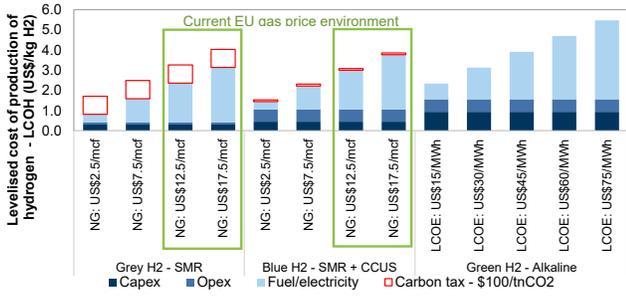
Exhibit 14: Clean hydrogen at the pump can reach cost parity with diesel for heavy duty long-haul trucks as early as 2027E on our estimates (TCO basis)
Hydrogen price at the pump for cost parity with diesel for HDTs
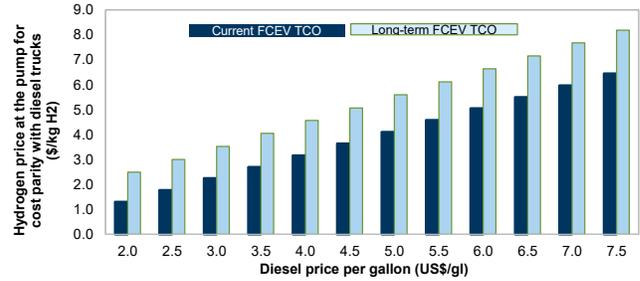
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 15: The rise of the green hydrogen economy calls for almost one third of global renewable capacity additions from 2030E..
Average annual RES capacity additions for green H2 and as a % of global annual average RES capacity additions
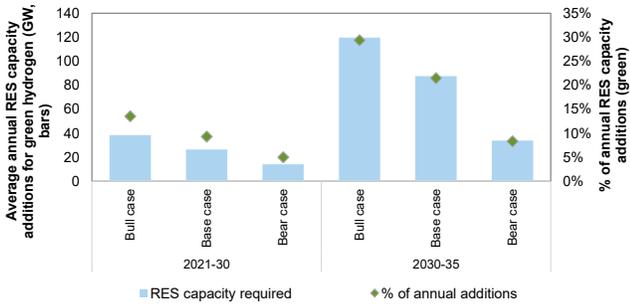
Source: Goldman Sachs Global Investment Research

Exhibit 16: ..and can cause up to c. 5%/18% growth in incremental average annual demand for nickel/PGMs and a multi-fold increase for iridium
Average annual incremental demand for specific metals and minerals used in electrolyzers
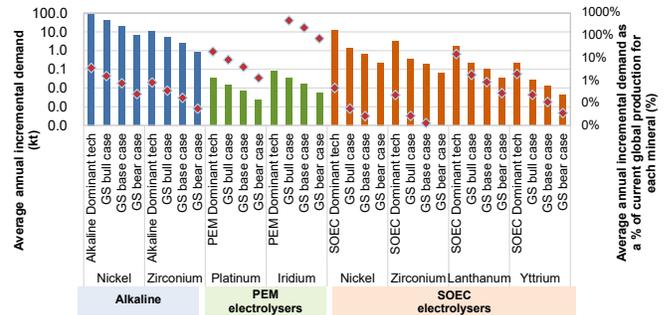
Source: Goldman Sachs Global Investment Research

Exhibit 17: We see potential for c.30% of the global hydrogen market to be involved in international trade
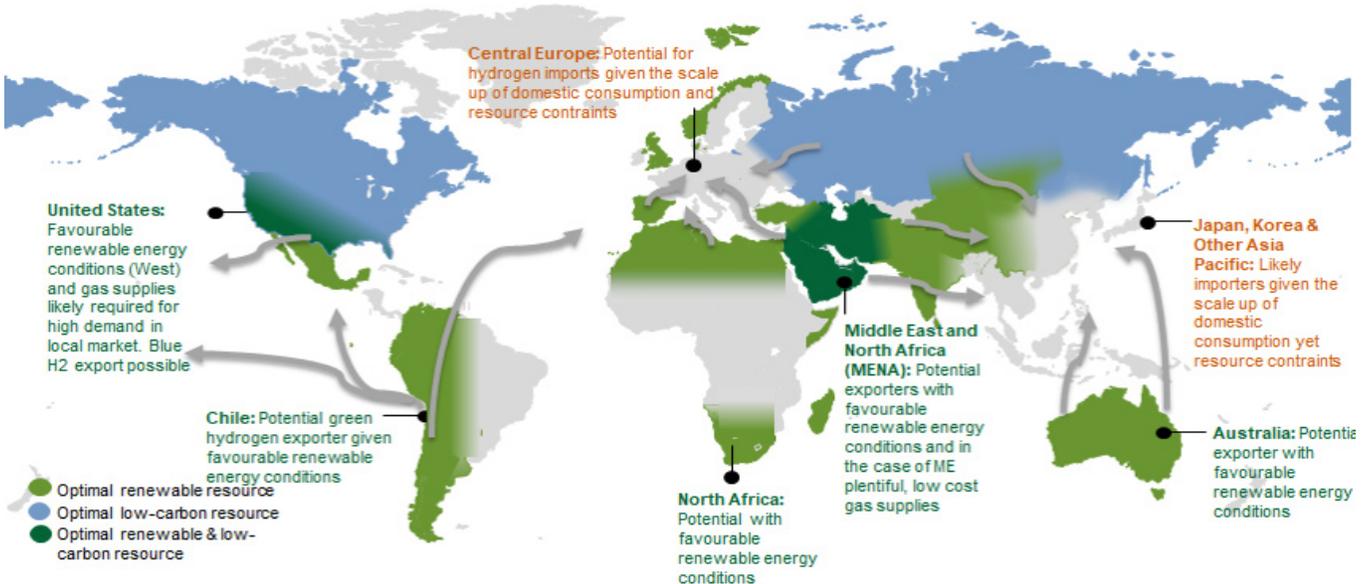
Source: Compiled by Goldman Sachs Global Investment Research

PM summary: The global clean hydrogen race

Clean hydrogen has emerged as a critical pillar to any aspiring net zero path, and policy, affordability, and scalability are converging to create unprecedented momentum for the clean hydrogen economy

Clean hydrogen has emerged as a critical pillar to any aspiring global net zero path, aiding the de-carbonization of **c.15% of global GHG emissions** on our estimates, and we leverage our global GS net zero models (one consistent with 1.5°C of global warming, one consistent with well below 2.0° and one consistent with 2.0°) and Carbonomics cost curve to construct **three global hydrogen scenarios.** Our global GS hydrogen models are developed on a sectoral basis, and include a modeling of the technological mix and activity for each of the potential hydrogen end markets on the path to net zero. **Under all three of the global hydrogen demand paths**, the bull, base and bear, **global hydrogen demand increases at least 2-fold on the path to net zero:** from 2-fold in the bear scenario to **7-fold in the bull scenario.** Meanwhile, **policy** support is strengthening across the globe, with **>30 national hydrogen strategies** and roadmaps released pledging a **>400-fold increase in clean hydrogen installed capacity this decade** compared to 2020 and supportive of a c.50-fold increase in the pace of annual average green hydrogen new builds.

Exhibit 18: Our GS global hydrogen models point to remarkable growth in the hydrogen market, with hydrogen demand increasing at least 2-fold and up to 7x on the path to net zero..
Global hydrogen demand (Mt H2) under the three GS net zero models
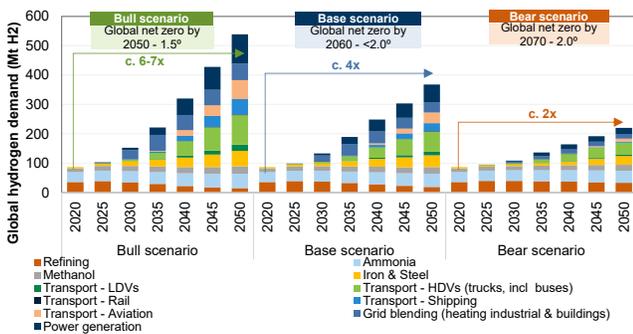
Source: Goldman Sachs Global Investment Research

Exhibit 19: ..and policy support is strengthening across the globe, with >30 national H2 strategies and roadmaps explicitly pledging c.130 GW of capacity by 2030, >400x the 2020 level
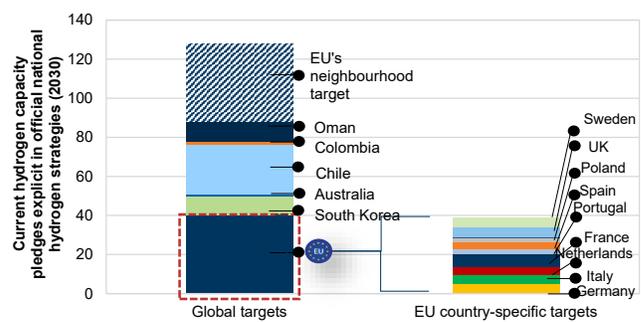
Source: European Commission, data compiled by Goldman Sachs Global Investment Research

We estimate US$5.0 trillion of cumulative investments in the clean hydrogen supply chain will be required for net zero, while the TAM for hydrogen generation alone has the potential to double by 2030E (to US$250 bn) and reach >US$1 tn by 2050E

Investments in the hydrogen industry have already started to inflect notably higher, particularly in production technology deployment. Focusing on the direct supply chain of clean hydrogen, encompassing investments required for its production (electrolyzers and CCUS for green and blue hydrogen, respectively), storage, distribution, transmission and global trade, we estimate that, in aggregate, **US$5.0 tn of cumulative investments in the direct clean hydrogen supply chain will be required to net zero.** We note this is solely capex investments in the direct supply chain of clean hydrogen

and does not include capex associated with end markets (industry, transport, buildings) or upstream capex associated with the power generation plants required for electricity generation for green hydrogen. Meanwhile, the **total addressable market (TAM) for hydrogen generation** alone has the potential to **double by 2030E**, from c. US$125 bn currently to **c.US$250 bn** by the end of this decade, and potentially reach **>US$1 tn by 2050E.**

Exhibit 20: We estimate US$5.0 tn of investments will be required in the global clean hydrogen supply chain to net zero..
Investments required in the clean hydrogen supply chain for net zero (US$bn)
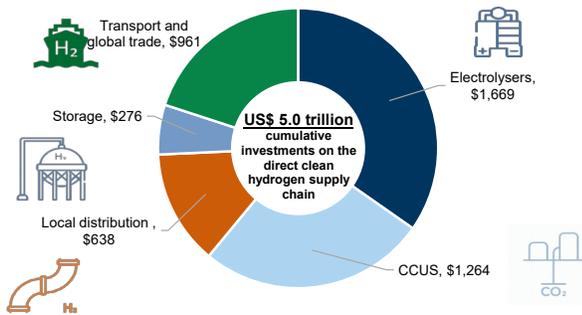
Source: Goldman Sachs Global Investment Research

Exhibit 21: ..while TAM for hydrogen generation has the scope to double from US$125 bn currently to c. US$250 bn by 2030 and reach >US$1 tn by 2050 (bull scenario)
TAM for global hydrogen generation, transport and storage (US$bn)
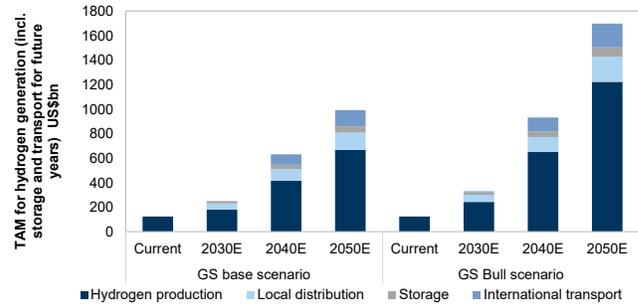
Source: Goldman Sachs Global Investment Research

Scalability unlocks affordability: Scalability is already revolutionizing the industry, unlocking economies of scale and cost deflation

Green hydrogen is the ultimate de-carbonization solution, in our view, benefiting from the growth and cost deflation in renewable power. The total installed electrolyzer capacity for green hydrogen production was only around 0.3 GW by the end of 2020 but **the industry is moving at a remarkable pace,** with the current projects pipeline suggesting an installed electrolysis capacity of close to 80 GW by end-2030, including projects currently under construction, having undertaken FID (final investment decision) and pre-FID (feasibility study), and assuming projects meet the guided start-up timeline. If we were to consider projects in earlier stages of development (pre-feasibility study stage, 'concept' projects), then this figure would go close to 120 GW, tracking our 'bull' hydrogen scenario in the near term. **Scalability** is already revolutionizing the green hydrogen projects pipeline, with scope for **average project sizes to increase 100x+,** from 2MW in 2020 to >200MW by 2025 and GW scale by 2030, leading to **cost deflation of c.40% for electrolyzer systems by 2025E**, similar to what has been observed for batteries over the past five years. **Affordability** is rapidly improving with green hydrogen at **cost parity with grey in advantageous regions by 2025E** ($1.5/kg H2) and **hydrogen cost parity with diesel** in long-haul heavy road transport achieved as early as **2027E,** on our estimates.

Exhibit 22: The industry is growing at a remarkable pace with announced green H2 projects across the globe tracking our bull and base scenarios in the near and medium term..

Global installed green H2 electrolysis capacity from projects announced compared to global GS scenarios (GW)

Source: Goldman Sachs Global Investment Research

Exhibit 23: ..and scalability is already revolutionizing the projects pipeline, with scope for average project sizes to increase 100x+, from 2MW in 2020 to >200MW by 2025 and a GW scale by 2030...

Cumulative installed electrolysis capacity from announced/planned projects and average project size
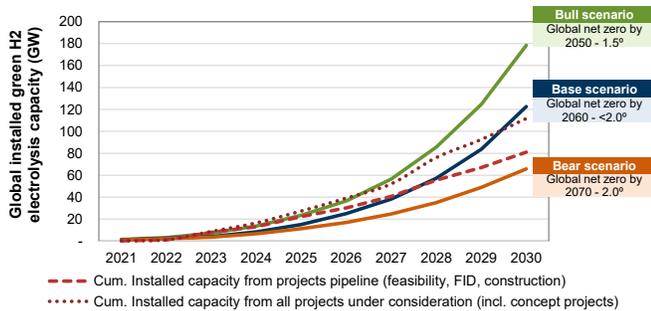
Source: Goldman Sachs Global Investment Research

Exhibit 24: ..leading to economies of scale and cost deflation, with electrolyzer costs falling c.40% by 2025E, similar to what was observed for batteries over the past five years...

Cost per kW for electrolyzers, renewables and per kWh for batteries
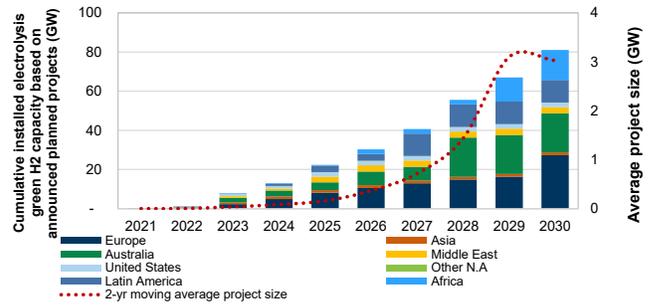
Source: Goldman Sachs Global Investment Research

Exhibit 25: ..and unlocking green hydrogen cost parity with grey in advantageous regions as early as 2025-26E (low RES cost)

Levelized cost of production of hydrogen (US$/kg H2)
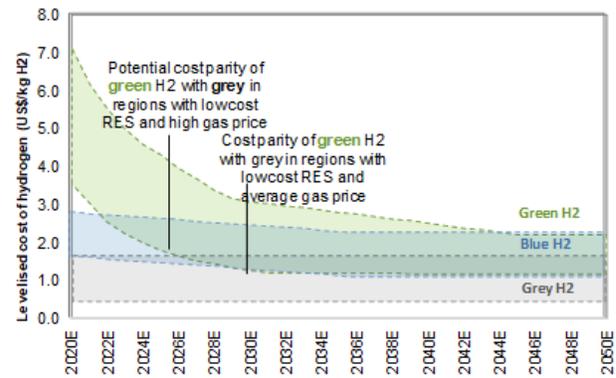
Source: Goldman Sachs Global Investment Research

The rise of the clean hydrogen economy calls for 1/3 of global average annual renewable power capacity additions and can cause incremental demand for metals such as nickel, PGMs and other minerals such as iridium

In the report, we also address the impact of the rise of the clean hydrogen economy on global demand for electricity, water, metals and minerals. Overall, we estimate that the **clean hydrogen revolution** can cause a 50+% increase in global power demand and **calls for 1/3 of global average annual installed renewable power capacity additions from 2030E** for the production of green hydrogen. Furthermore, we estimate that the **water requirement** for the production of clean hydrogen will likely reach **c.7 bcm by 2050,** while electrolyzers and fuel cells manufacturing can cause **up to c. 5%/18% incremental average annual demand for nickel and PGMs** (platinum) respectively, and a **multi-fold** increase for the more niche mineral **iridium**.

Exhibit 26: The rise of the green hydrogen economy calls for almost one third of global average annual renewable capacity additions from 2030...
Average annual RES capacity additions for green H2 and as a % of global annual average capacity additions
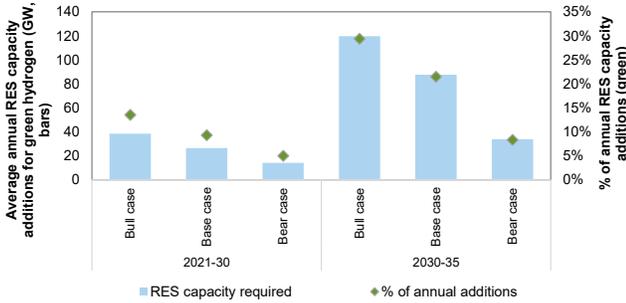
Exhibit 27: ..and can cause up to c. 5%/18% incremental average annual demand for nickel/PGMs and a multi-fold increase for iridium
Average annual incremental demand for specific metals and minerals used in electrolyzers

Source: Goldman Sachs Global Investment Research
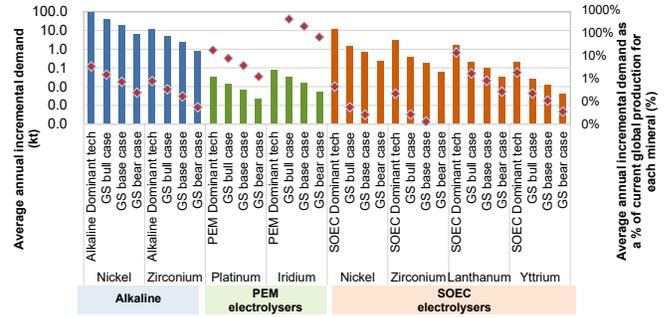
Source: Goldman Sachs Global Investment Research

We estimate that c.30% of global clean hydrogen volumes have the potential to be involved in long cross-border transport, impacting energy supply geopolitics

We believe clean hydrogen can develop into a major global market, impacting geopolitical patterns in energy supply, and we examine the **case for international trade,** concluding that **30% of global hydrogen volumes** have the potential to be involved in cross-border transport, **higher than for natural gas. MENA, LatAm, Australia and Iberia** could emerge as key clean hydrogen **exporting** regions, while Central Europe, Japan, Korea and parts of East China could emerge as key importing regions.

MENA, Chile (and other LatAm), Australia and Iberia could emerge as key clean hydrogen exporting regions while Japan, Korea, Central Europe and potentially parts of East China could become key clean hydrogen importing regions, depending on the scale and importance of clean hydrogen in their respective economies
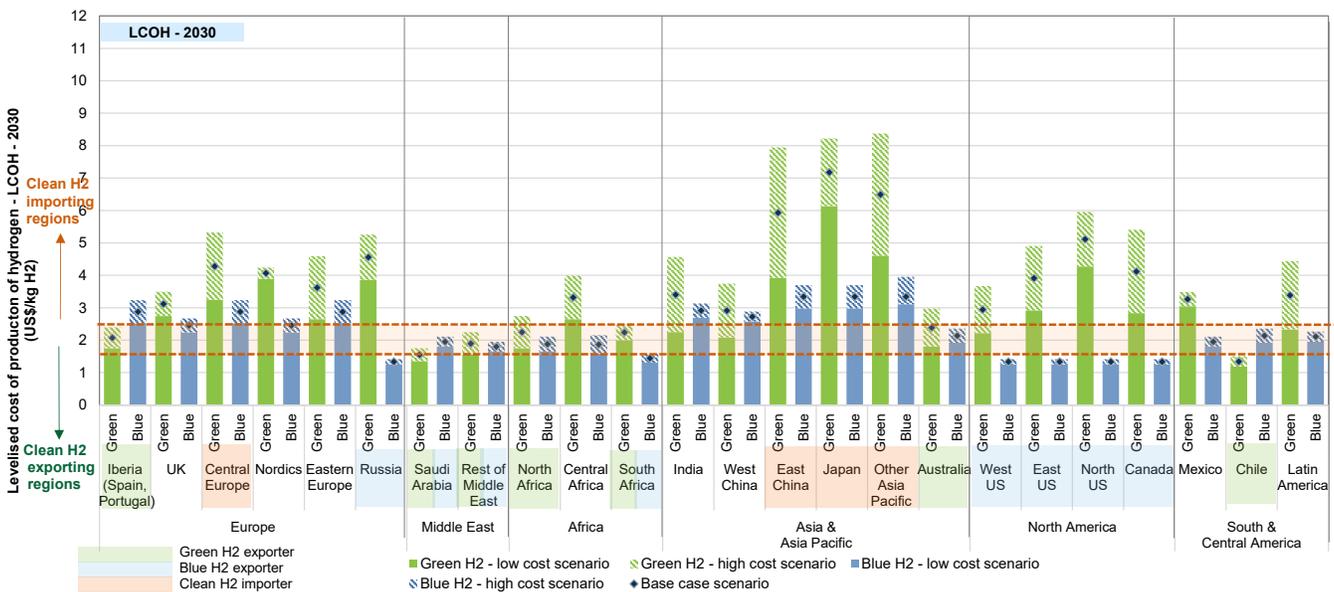
Source: Goldman Sachs Global Investment Research

The emergence of a multi-dimensional clean tech ecosystem

The de-carbonization process is evolving from one dimensional (renewable power) to a multi-dimensional ecosystem as capital markets, corporates and governments expand their sustainability focus to encompass a wider range of clean technologies

In our global net zero paths report, _Carbonomics: Introducing the GS net zero carbon models and sector frameworks_, we present our modeling of the paths to net zero carbon, with three global models of de-carbonization by sector and technology, leveraging our _Carbonomics cost curve of de-carbonization_. The Carbonomics cost curve shows the reduction potential for anthropogenic GHG emissions relative to the latest annual reported global GHG emissions. It comprises de-carbonization technologies that are currently available at commercial scale (commercial operation & development), presenting the findings at the current costs associated with each technology's adoption. We include conservation technologies and process specific sequestration technologies (process specific carbon capture) across all key emission-contributing industries globally: power generation, industry and industrial waste, transport, buildings and agriculture.

In our report, _Carbonomics: The dual action of Capital Markets transforms the Net Zero cost curve_, we present the latest update of our Carbonomics cost curve of de-carbonization, encompassing >100 different applications of GHG conservation technologies across all key emitting sectors globally. Looking at the ongoing transformation of our Carbonomics cost curve of de-carbonization, we argue that the **de-carbonization process is evolving from one dimensional (renewable power and electrification) to a multi-dimensional ecosystem** as **capital markets, corporates and governments expand their sustainability efforts and focus to encompass a wider range of clean technologies (the next frontier of clean tech)** that are required to unlock the path to global net zero. **Four technologies are emerging as transformational**, having a leading role in the path to carbon neutrality: renewable power, clean hydrogen, carbon sequestration and battery energy storage.

Exhibit 28: We have constructed three global carbon neutrality models: one consistent with 1.5°C of global warming, one consistent with well below 2.0° and one consistent with 2.0°..
GS global net zero models, CO2 emissions (incl. AFOLU)
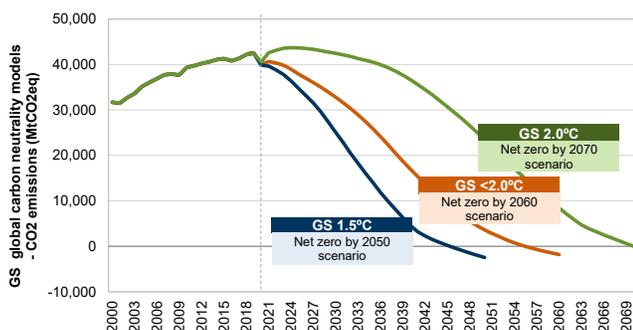
Exhibit 29: ...leveraging our global Carbonomics cost curve of de-carbonization
2021 Carbonomics carbon abatement cost curve for anthropogenic GHG emissions, based on current technologies and current costs

Source: Emission Database for Global Atmospheric Research (EDGAR) release version 5.0, FAO, Goldman Sachs Global Investment Research
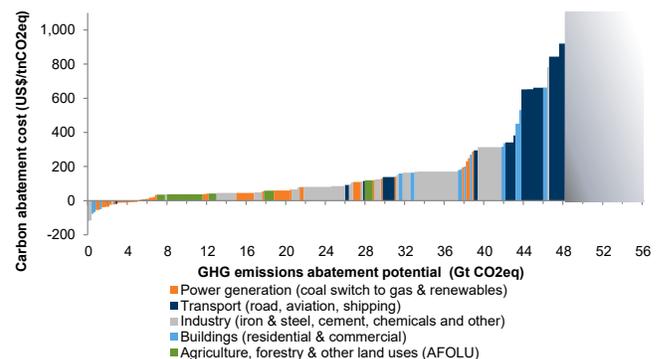
Source: Goldman Sachs Global Investment Research

The next frontier of clean tech: Four interconnected technologies are emerging as transformational, having a leading role in the evolution of the cost curve and the path to net zero

We identify four technologies which are emerging as transformational, having a critical role in the path to net zero: renewable power, clean hydrogen, carbon sequestration and battery energy storage as summarized in the infographic below. Notably, all of these technologies are interconnected:

(1) Renewable power: This is a technology that dominates the 'low-cost de-carbonization' spectrum today and has the potential to support the de-carbonization of c.40% of total global anthropogenic GHG emissions, supporting a number of sectors that require electrification, as well as being critical for the production of clean hydrogen longer term ('green' hydrogen). This is the first transformational clean technology that attracted the interest of investors, corporates and regulators given its critical importance.

(2) Clean hydrogen: This is a transformational technology for long-term energy storage enabling an increasing uptake of renewables in power generation, as well as aiding the de-carbonization of some of the harder-to-abate sectors (iron & steel, long-haul transport, heating, petrochemicals). We estimate that clean hydrogen can aid the de-carbonization of c.15% of global GHG emissions (c.20% of CO_2 emissions) while becoming a key pillar of the energy mix.

(3) Battery energy storage: It extends energy storage capabilities, and is critical in the de-carbonization of road transport through electrification.

(4) Carbon capture technologies: They are vital for the production of clean ('blue') hydrogen, while also aiding the de-carbonization of industrial sub-segments with emissions that are currently non-abatable under alternative technologies.

In this report, we primarily address the clean hydrogen and carbon capture technologies, providing a deep-dive into the relevant technological innovation, economics, policy, potential global addressable markets and project pipelines.

Renewable power | Clean hydrogen | Battery energy storage | Carbon sequestration

Source: Goldman Sachs Global Investment Research

National net zero pledges worldwide continue to gain momentum, currently covering >80% of global CO2 emissions

The commitment to achieving net zero is what calls for the development of a broader set of technologies beyond direct electrification to facilitate the energy transition. Over the past two years, we have seen a rapid acceleration in the number of national net zero and climate neutral pledges made by national jurisdictions globally, as well as corporates, embedding a net zero target. COP 26 has seen a number of key emitting regions joining the global net zero ambition, with India, Saudi Arabia, and Australia notable examples. By end-2021, we calculate that c.63% of the global CO_2 emissions (2020) were covered by national net zero and climate neutral pledges which are included in law, in proposed legislation and in policy documents. Another c.20% of the global CO_2 emissions were covered by declared net zero/climate neutral pledges that are not in law, legislation or policy documents at present. Around half of the emissions covered by these national pledges (c.35% of global CO2 emissions) are embedded in net zero/carbon neutrality targets for 2050 or earlier with the rest mostly aiming for net zero by 2060 or later (China and India notable examples). A global net zero scenario would require transformational changes across all key parts of the global energy ecosystem and broader economy and therefore calls for technological innovation that extends beyond renewable power and touches the next frontier of clean technologies including clean hydrogen, battery energy storage and carbon sequestration. While renewable power remains the commercial, scalable technology that currently occupies the lower end of the Carbonomics cost curve, alone it can only de-carbonize up to around half of the global CO2 emissions, with the Carbonomics cost curve becoming much steeper for the second half of global de-carbonization.

Exhibit 30: The rapidly rising number of national net zero/climate neutral pledges (including those in law, legislation and policy documents) worldwide by YE2021 covered c.83% of the global CO2 emissions, of which around half have a timeline for net zero by 2050 or sooner (the key exception being China)
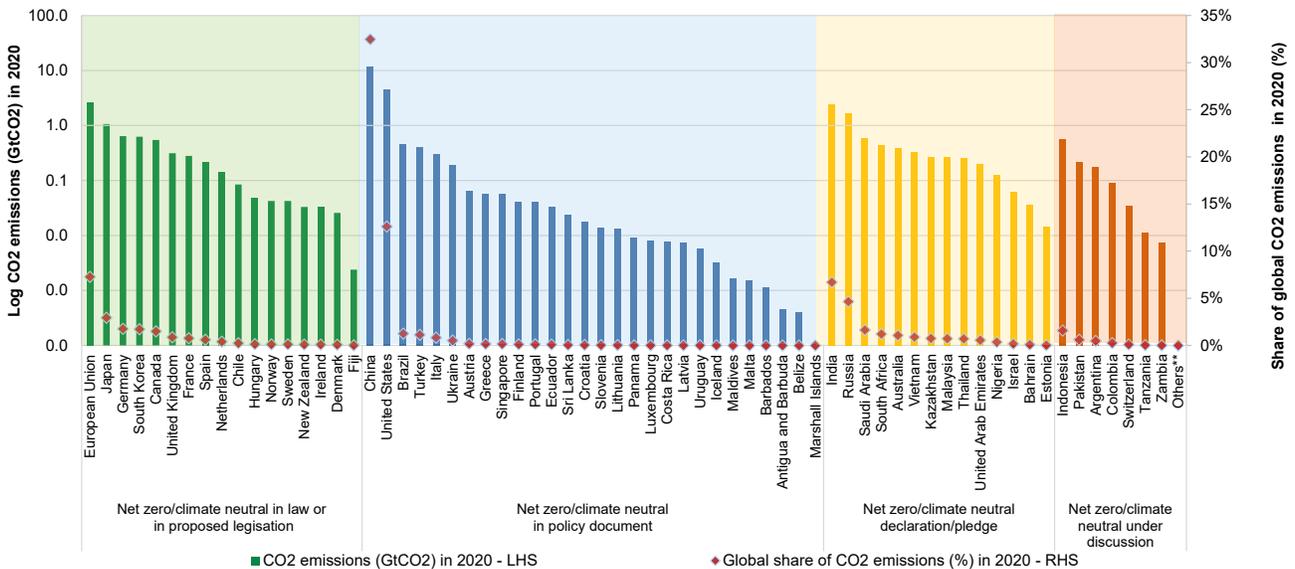
** Others under consideration include many countries and regions (list not exhaustive)

Source: Net Zero Tracker, Emission Database for Global Atmospheric Research (EDGAR) release version 5.0, Goldman Sachs Global Investment Research

The rise of the clean hydrogen economy

Clean Hydrogen

Clean hydrogen plays a critical role on the global path to net zero and forms a key interconnecting pillar between other key clean technologies

Clean hydrogen has a major role to play in the path towards net zero carbon, providing de-carbonization solutions in the most challenging parts of the **_Carbonomics_** cost curve - including long-haul transport (buses, rail, long-haul heavy trucks), steel, chemicals (ammonia, methanol), heating (hydrogen boilers, grid blending) and long-term energy storage (hydrogen turbines, fuel cells in power generation).

We noted previously that despite the wealth of relatively low-cost de-carbonization opportunities, the abatement cost curve is steep as we move beyond 50% de-carbonization, calling for technological innovation and breakthroughs to unlock the net zero carbon potential. Examining the emerging technologies that could meaningfully transform the de-carbonization cost curve, it becomes evident to us that **clean hydrogen** is currently at the forefront of this technological challenge: based on our analysis, it has the potential to **transform 15%/20% of the total global GHG/CO2 emissions in our cost curve** and can be attractively positioned in a number of transportation, industrial, power generation and heating applications. Clean hydrogen's cost competitiveness is also closely linked to cost deflation and large scale developments in renewable power and carbon capture (two key technologies to produce it), creating three symbiotic pillars of de-carbonization.

Exhibit 31: Clean hydrogen has emerged as a key technology, required to de-carbonize c.15%/20% of global GHG/CO2 emissions across sectors
2021 Carbonomics cost curve with technologies relying on clean hydrogen indicated

Source: Goldman Sachs Global Investment Research

The revival of hydrogen: A new wave of support and policy action

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. While hydrogen has gone through several waves of interest in the past 50 years, none of these translated into sustainably rising investment and broader adoption in energy systems. Nonetheless, the recent focus on de-carbonization and the scale up and accelerated growth of low carbon technologies such as renewables have sparked a new wave of interest in the properties and the supply chain scale-up of hydrogen. **We believe that this is not another false start for clean hydrogen.** Over the past two years, the intensified focus on de-carbonization and climate change solutions has begun to translate into **renewed policy action aimed at the wider adoption of clean hydrogen. By end-2021, more than 30 governments had released national hydrogen strategies or official roadmaps,** including Japan, Korea, Australia, Canada, Chile, Czech Republic, France, Germany, Hungary, the Netherlands, Norway, Portugal, Russia, Spain, Poland, United Kingdom, Colombia, Finland, and Belgium among others. Across hydrogen strategies, the vital role of hydrogen for industrial applications and transportation is highlighted. 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. **Policy support and economic considerations, with the acceleration of low-cost renewables and electrification infrastructure, seem to be converging to create unprecedented momentum for the clean hydrogen economy**.

Exhibit 32: The past two years have seen a new wave of policy interest and support for clean hydrogen across the globe, reflected through a rapid increase in national hydrogen strategies and roadmaps

Source: Various sources; data compiled by Goldman Sachs Global Investment Research

From ambition to policy action: Reflecting on hydrogen strategies across the globe

The Appendix provides an overview of the key quantitative deployment and production targets from various hydrogen strategies announced by countries across the globe. Asian countries such as Japan, South Korea and Australia have all been early movers in the industry with their respective hydrogen strategies all announced before the 2020 wave of hydrogen policy announcements. Both Japan and South Korea have developed strategies that largely focus on the wider domestic adoption of hydrogen across end markets and the creation of a hydrogen economy, including an emphasis on transport. Australia's hydrogen strategy on the other hand largely focuses on the country's prospect and ambition of becoming a major hydrogen export hub leveraging its vast natural gas and low cost renewable power resources for blue and green hydrogen production, respectively.

While Asia had dominated the hydrogen debate over 2017-19, the 2020 wave of hydrogen policy announcements that followed was rather Europe-centric, with the EU Hydrogen Strategy at the epicenter. The EU's 2x40 GW electrolyzer capacity target by 2030 (40 GW in Europe and 40 GW in Europe's neighborhood) is to date the largest regional green hydrogen capacity target globally and is backed by the subsequent launch of various country-specific hydrogen strategies, roadmaps and targets from most key European countries. Adding the country-specific targets announced, these make up c.39GW of the 40 GW targeted by the EU Hydrogen Strategy (including the UK and Sweden's proposed targets) with c.1GW remaining, as shown in Exhibit 33. Overall, while what qualifies as 'clean' hydrogen varies by regions, several countries have announced **explicit capacity ambitions embedded in these official strategies which, on our estimates, amount to c.130GW of capacity by 2030** (including the 40 GW neighboring countries' target from EU), **>400x the 2020 level.**

Exhibit 33: Several countries, as well as the European Union, highlight explicit clean hydrogen capacity ambitions in their hydrogen strategies. We estimate that these pledges together result in a total capacity of c.130 GW by 2030, >400x the 2020 level of installed electrolysis capacity, with the majority linked to the targets of the European Union (2x40 GW) and Chile (25 GW)
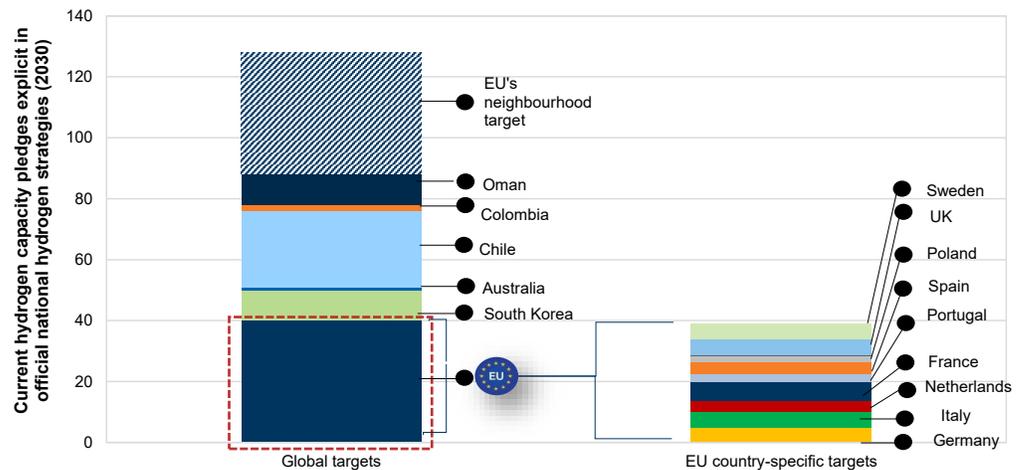
Source: Various sources; data compiled by Goldman Sachs Global Investment Research

On the other side of the Atlantic, both North and South America have started to show clear signs of acceleration of policy initiatives on the topic with Chile and Canada the first to publish national hydrogen strategies. Chile's strategy in particular stands out in terms of scale, with the country having laid out its ambition to have 25GW of capacity in projects with committed funding by 2030 (while the actual installed capacity will likely be lower than this as the target includes projects under development at the time, this represents the largest single-country target), leveraging on the country's vast, low-cost renewable energy resource. Canada's hydrogen strategy, published around the same time, presents a goal of c.30% of total final energy consumption by 2050 attributed to hydrogen and acknowledges a broader range of low-carbon hydrogen production routes including any fossil fuel-produced ones which comprise CCUS retrofitting (natural gas, oil, biomass), as well as electrolytic green hydrogen and hydrogen produced as a by-product.

The US enters the hydrogen policy wave with a milestone US$9.5 bn for the development of hydrogen as a clean energy source as part of the US Infrastructure Investments and Jobs Act

While the US has not yet released an official nation-wide hydrogen strategy, the Department of Energy (DoE) has published the *Hydrogen Program Plan* and *Hydrogen strategy* documents that provide the strategic framework for the wider deployment and growth of the hydrogen economy in the country. We see scope for a nation-wide hydrogen strategy nonetheless following the bipartisan Infrastructure Investments and Jobs Act. Relevant sections of the Infrastructure Bill with respect to hydrogen include the following:

- **Section 40313** of the infrastructure plan focuses on the **establishment of the clean hydrogen research and development plan** to (1) advance research and development and commercialize the use of clean hydrogen in the transportation, utility industrial, commercial, and residential sectors; and (2) demonstrate a standard of clean hydrogen production in the transportation, utility, industrial, commercial, and residential sectors by 2040.

- **Section 40314** recognizes additional clean hydrogen programs including five important provisions to the Energy Policy Act:

  (1) Regional Hydrogen Hubs - provides **$8 billion over four years** for the creation of Regional Hydrogen Hubs;

  (2) National Energy Strategy for Hydrogen - **requires the Secretary of Energy to develop a technologically and economically feasible national energy strategy and roadmap to facilitate widescale production, processing, delivery, storage and use of clean hydrogen**;

  (3) Grants for Research and Development - provides **$500 million over four years** to award multi-year grants and contracts for research, development, and demonstration projects to advance new clean hydrogen production, processing, delivery, storage and use of equipment manufacturing technology and techniques;

  (4) Clean Energy Electrolysis Program – provides **$1 billion to fund a grant program for research, development, demonstration, commercialization, and**

deployment for the purpose of commercialization, and to improve the efficiency, increase the durability, and reduce the cost of producing clean hydrogen using electrolyzers. Grants will be awarded to eligible entities that can achieve the following goals of the program: (i) reduce the cost of hydrogen produced using electrolyzers to less than $2 per kilogram of hydrogen by 2026; and (ii) any other goals the Secretary of Energy determines are appropriate;

(5) Coordination of the National Laboratories - establishes a mechanism for the coordination of the work of the National Energy Technology Laboratory (NETL), the Idaho National Laboratory, and the National Renewable Energy Laboratory (NREL) and institutions of higher education, and research institutes.

■ **Section 40315 addresses the clean hydrogen production qualification.** The Bill defines 'clean hydrogen' as hydrogen produced with a **carbon intensity equal to or less than 2 kilograms of carbon-dioxide equivalent per kilogram (kgCO2eq/kg H2).** The Secretary of Energy will develop an initial standard for the carbon intensity of clean hydrogen production that will support clean hydrogen production from a variety of sources and take into account technological and economic feasibility. No later than five years after the date under which the standard is developed, the Secretary in consultation with the Administrator of the Environmental Protection Agency, shall determine whether the definition of clean hydrogen should be adjusted and if so, the Secretary shall carry out the adjustment.

Exhibit 34: The agreed US Infrastructure Investment and Jobs Act allocates US$9.5 bn in clean hydrogen initiatives
United States Infrastructure Investment and Jobs Act selected energy R&D programs (US$mn) with a focus on clean hydrogen
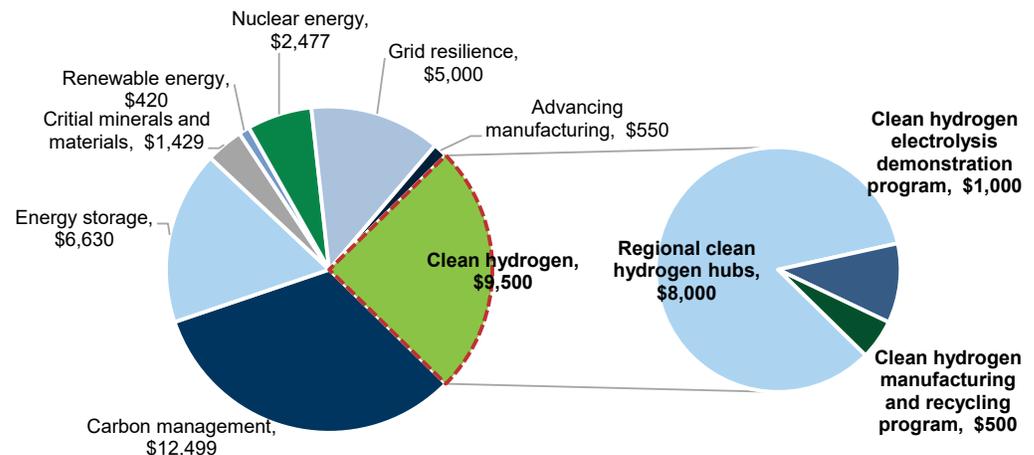
Source: United States Infrastructure Investment and Jobs Act, data compiled by Goldman Sachs Global Investment Research

Moreover, recently, **a ten-year tax credit worth up to $3 per kilogram** of "clean hydrogen" was approved by the US House of Representatives as part of President Joe Biden's Build Back Better Bill (BBB). However, the Build Back Better Bill **still requires to be passed by the US Senate and our economists believe this looks unlikely in its current form.**

The House version of the Bill stated that only hydrogen with lifecycle greenhouse gas emissions of less than 0.45kg of carbon dioxide equivalent (CO_2e) per kg of H2 would be eligible for the full $3 credit. Production of hydrogen with higher emissions would be eligible for smaller percentages of the clean hydrogen production tax credit rates as follows: 0.45-1.5kg CO_2e per kg of H2: 33.4% of the full tax credit (i.e., $1/kg of hydrogen), 1.5-2.5kg CO_2: 25% ($0.75/kg), 2.5-4kg CO_2: 20% ($0.60/kg), 4-6kg CO_2: 15% ($0.45/kg). Projects would need to have begun construction before 2029 to claim the tax credit, while facilities in the 4-6kg CO_2/kgH2 category would have had to be placed into service before 2027. While the BBB in its current form looks unlikely to be passed as mentioned earlier, **this does provide a glimpse into the potential incentives and frameworks that could further encourage and improve the economic viability of clean hydrogen.**

Other key regions to watch on the policy front: The UAE, rest of MENA, Latin America and India

While Asia Pacific was initially the front-runner in the clean hydrogen strategy race, followed by the EU, with currently a large portion of the region having already announced national hydrogen strategies and roadmaps, we believe the **clean hydrogen policy focus could start to shift towards the MENA and LatAm regions**. In particular, Oman, the UAE and Saudi Arabia all seem to have taken majors steps on the clean hydrogen economy front with large-scale projects (both for green and blue hydrogen) moving ahead. In terms of policy, **Oman** has a national hydrogen strategy due, with press/industry reports (e.g. S&P) suggesting targets of 1GW by 2025, 10GW by 2030 and around 30GW by 2040. The **UAE** has revealed at COP26 the Hydrogen Leadership Roadmap aiming to support domestic de-carbonization through hydrogen while also becoming a key global export hub of the clean energy carrier by targeting a 25% market share by 2030. In LatAm, Paraguay has followed Chile and Colombia in developing a hydrogen roadmap while Uruguay is also currently developing its own green hydrogen strategy. Finally, **India** appears to have joined the global hydrogen race with the release of its National Hydrogen Mission and with growing interest coming from the region.

Hydrogen primer: An introduction to hydrogen, the most abundant element in the universe

An introduction to hydrogen, the lightest and most abundant element in the universe

Hydrogen's role in the energy ecosystem is not new and has a long history in transport and industrial applications, used as a fuel since the 18th century to lift blimps and in the production of key industrial chemicals, which is still relevant today, for instance, in the case of ammonia. Looking at the chemistry of the molecule itself, hydrogen is the **lightest element in the universe**, with the most common isotope (protium, which represents 99% of hydrogen in terms of abundance) having an atomic nucleus of just a single proton. Under standard, ambient conditions, hydrogen is a gas of diatomic molecules having the formula H_2 (we refer to hydrogen using this chemical formula extensively in this report), consisting of two hydrogen atoms bonded together with a covalent bond. It is colorless, odorless, non-toxic, and highly combustible.

Hydrogen is the **most abundant chemical substance** in the universe, constituting roughly 75% of all normal matter. Nonetheless, most of the hydrogen on Earth exists in molecular forms such as in water and in organic compounds (primarily hydrocarbons). As such, pure H2 requires energy processes to be produced in that form, therefore leading to it being mostly considered an energy vector as opposed to an energy source.

Exhibit 35: Hydrogen is the most abundant and lightest element in the universe, and has three distinct isotopes

^1_1H ^2_1H ^3_1H

Protium   **Deuterium**   **Tritium**
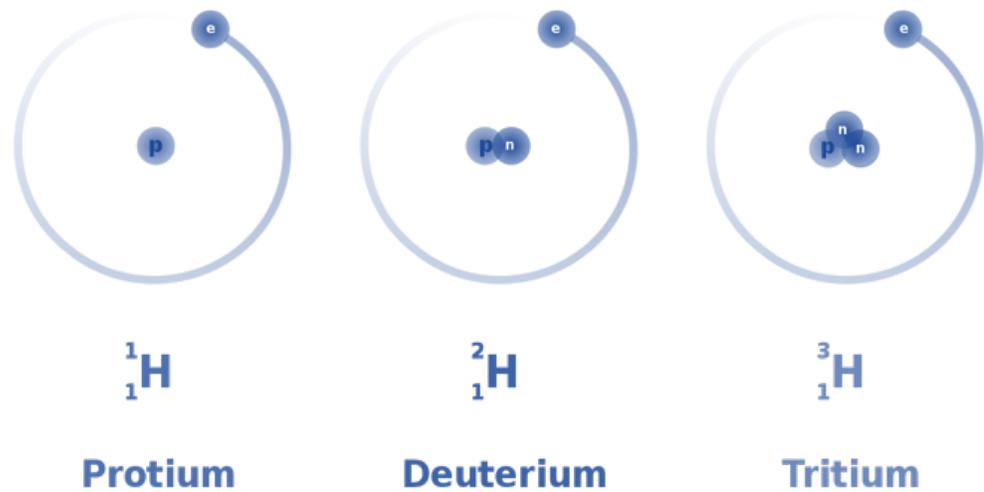
Source: Company data

Hydrogen's versatility in production, high energy content per unit mass and no emissions at the point of use (combustion) explain its attractiveness as an energy vector and fuel

Hydrogen has a number of valuable attributes that make it screen attractively relative to other fuels in the era of de-carbonization and climate change. These include the versatility in its production pathways, offering flexibility along the supply chains, its very high specific energy per unit mass (c.2.6x that of gasoline and c. 2.3x that of natural gas)

which implies the ability to release vast amounts of energy without contributing meaningfully to the weight of various applications, and, finally, the ability to be stored and used as a clean fuel without releasing any direct emissions at the point of use. During its combustion process, hydrogen only releases oxygen and water as products. Exhibit 36 shows how the properties of hydrogen compare to those of other commonly used fuels.

Despite the characteristics that make hydrogen attractive for energy ecosystems (fuel, vector, feedstock), hydrogen in its ambient form is a highly reactive (combustible) gas with very low energy density (energy content per unit volume), implying the need for careful handling, transport and distribution as well as the use of high pressure systems typically for final applications. Moreover, while it does not contribute to GHG emissions at the point of use, the current dominant production pathways for hydrogen (which is rarely found in its pure form) are carbon intense as they primarily rely on the use of fossil fuels (typically natural gas and coal in specific regions). The combustible nature of hydrogen implies very low ignition energy and large energy release when it expands in air. Nonetheless, its lighter-than-air property to some extent reduces the risk as it implies it can dissipate rapidly when in contact with air. Despite the outlined risks, we note that the risk of combustibility and lack of containment is not new and is frequently the case for other current widely adopted fuels such as gasoline, diesel, natural gas.

Exhibit 36: Hydrogen has >2x the energy content per unit mass compared to natural gas and gasoline yet its very low weight implies much lower energy density per unit volume in its gaseous form at ambient conditions

Fuel properties	Energy per unit mass (MJ/kg)	Density (kg/m3)	Energy density (MJ/L)	Specific energy - per unit mass (kWh/kg)	Energy density - per unit volume (kWh/L)	Physical conditions
Gasoline	46.4	737.1	34.20	12.89	9.5000	Ambient, 1 bar, 25 ºc
Natural gas (ambient)	53.6	0.7	0.04	14.89	0.0101	Ambient, 1 bar, 25 ºC
LNG	53.6	414.2	22.20	14.89	6.1667	Liquefaction temperature: -160 ºC
Hydrogen (ambient)	120.1	0.09	0.01	33.36	0.0028	Ambient, 1 bar, 25 ºC
Liquid hydrogen	120.1	70.8	8.49	33.36	2.3586	Liquefaction temperature: -253 ºC, 1 bar

Abbreviations: MJ = megajoules, m3 = cubic meters, L = litre, kWh= kiloWatt hour, kg= kilograms

Source: EIA, IEA, Goldman Sachs Global Investment Research

Exhibit 37: Hydrogen has very high gravimetric energy density but lower volumetric energy density compared to other conventional fuels widely used today...
Volumetric vs gravimetric density of commonly used fuels compared to hydrogen
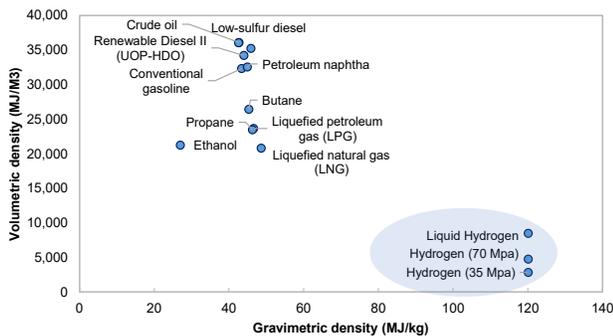
Source: EIA, US DEO, data compiled by Goldman Sachs Global Investment Research

Exhibit 38: ..and can have a critical role in the energy transition as it does not emit any GHG emissions at the point of use (combustion) and it is very versatile in terms of production
Carbon intensity at the point of consumption vs gravimetric density of commonly used fuels compared to hydrogen

Source: EIA, US DEO, data compiled by Goldman Sachs Global Investment Research

A glimpse into the current hydrogen market: A feedstock for key industrial processes - refining, production of ammonia, methanol and steel

Currently, H2 is primarily used as a feedstock in a number of key industrial processes, therefore playing a very limited role in the energy transitio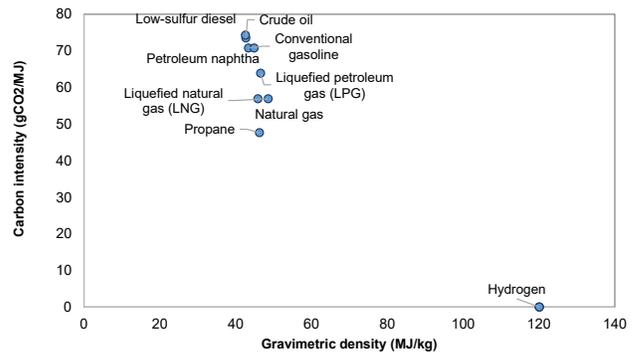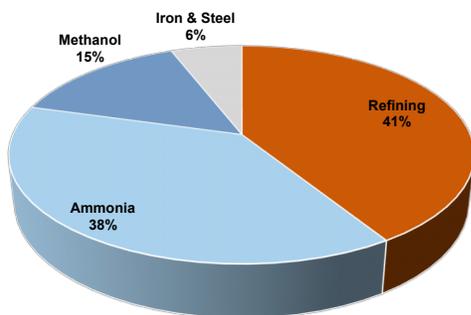n as we are still to unlock hydrogen's potential as an energy vector and fuel. According to the IEA, global hydrogen demand was around 90 Mt in 2020. This includes more than 70 Mt H2 used as pure hydrogen, primarily in oil refining and ammonia production, and less than 20 Mt H2 mixed with carbon containing gases primarily for methanol production and steel manufacturing. This excludes around 20 Mt H2 that is present in residual gases from industrial processes used for heat and electricity. Oil refining is the largest consumer of hydrogen currently, accounting for c.41% of global hydrogen demand in 2020. In oil refining, hydrogen is primarily used in hydrosulfurization to remove sulphur contents in crude and in hydrocracking processes to upgrade heavy residual oils into higher-value products. Around half of this demand is met with hydrogen produced as a by-product from other processes in the refineries or from other petrochemical processes integrated in refining plants while the remaining demand is met by dedicated on-site hydrogen production or merchant hydrogen sourced externally. The chemicals industry consumes about c.53% of global hydrogen, primarily as a feedstock for ammonia and methanol production, each requiring around 180 and 130 kg of hydrogen per tonne of product, respectively. The remaining c.6% of hydrogen is used in the steel industry and stems specifically from the DRI-EAF steelmaking process route used to reduce iron ore to sponge iron (in a mixture with carbon monoxide).

Hydrogen demand from these three key industries (refining, chemicals and steel) has been growing steadily over the years, as shown in Exhibit 40, yet we believe climate change and the increasing focus of investors, corporates and regulators on the topic of de-carbonization and sustainability is likely to unlock new end markets for hydrogen, which we discuss in the next sections of this report.

Exhibit 39: Hydrogen demand currently stems from its use as a feedstock across key industrial processes including refining, ammonia, methanol production and steel...
2020 Global hydrogen demand split (%)

Exhibit 40: ..and currently exceeds 80 Mt H2 pa, an already large and established industry at the onset of transformation
Global hydrogen demand (MT H2)

Source: IEA, data compiled by Goldman Sachs Global Investment Research
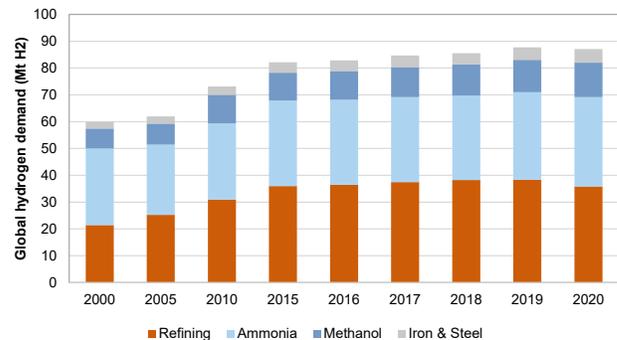
Source: IEA, Goldman Sachs Global Investment Research

The role of hydrogen in the energy transition: The key tool for harder-to-de-carbonize sectors

The role of clean hydrogen in the energy transition: Unlocking c.20% of global CO$_2$ emissions abatement across key hard-to-abate sectors

As we mention earlier in this report, net zero has become the new normal, with >80% of global CO2 emissions currently covered by global net zero national pledges worldwide. The path to net zero emissions requires transformational changes to the current energy ecosystem which we believe calls for a substantially wider use of hydrogen and hydrogen-based fuels across industries. Increasing the use of hydrogen as a new energy vector is a long-term endeavor, implying a multi-decade long process to significantly penetrate the energy mix. **This decade is therefore a decisive one in laying the foundations for the role of clean hydrogen in the energy transition.**

Exhibit 41: Hydrogen could have a critical role in aiding de-carbonization across a wide variety of sectors, including long-haul transport, industry, energy storage in power generation and heating in buildings

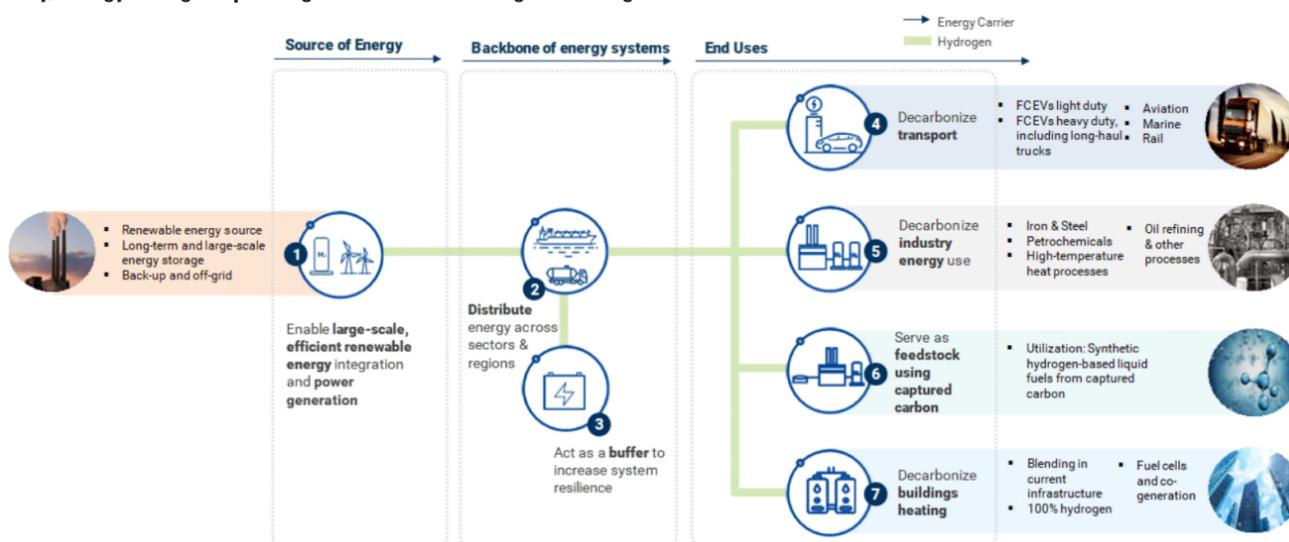Source: Hydrogen Council, Goldman Sachs Global Investment Research

While access to renewable power and direct electrification is the first step of de-carbonization, potentially aiding the abatement of around half of global emissions, as we move to harder-to-abate sectors including long-haul heavy transport, heavy industry, and high temperature industrial heat, direct electrification faces several hurdles and clean hydrogen could be the dominant technology in these industries. As shown in matrix presented in Exhibit 43, the preferred de-carbonization technology varies depending on whether direct electrification and clean hydrogen are possible and achievable for different sectors.

In general, we view that where direct electrification is currently available for the de-carbonization of an industry, and has been developed at scale, it is likely to be the preferred de-carbonization route owing to its overall lower cost, later stage of development, already formed supply chains and higher energy efficiency at the point of use. Examples of this include de-carbonization of light-duty vehicles where the

commercialization of battery technology has unlocked the direct electrification potential, particularly for short haul routes. On the contrary, for industries where current direct electrification technologies have not yet reached commercial scale, or where electrification technologies face notable hurdles, clean hydrogen is likely to be the dominant technology, assuming it is applicable in that industry. This is consistent with the industries we view to be the key addressable end markets dominating growth in global hydrogen demand longer term. Among these are long-haul heavy transport (where the current state of battery technologies faces hurdles in terms of weight and refueling times), high-temperature industrial heat (for heavy industries such as steel, glass and cement), steel and petrochemicals. Finally, for industries where neither direct electrification nor clean hydrogen are applicable currently, we view the need for other clean technologies, namely bioenergy and carbon sequestration (carbon capture).

Exhibit 42: Access to clean renewable power is the first step to net zero, potentially unlocking c.50% abatement of GHG emissions on our estimates across sectors..
2021 Carbonomics cost curve with technologies relying on access to renewable power indicated
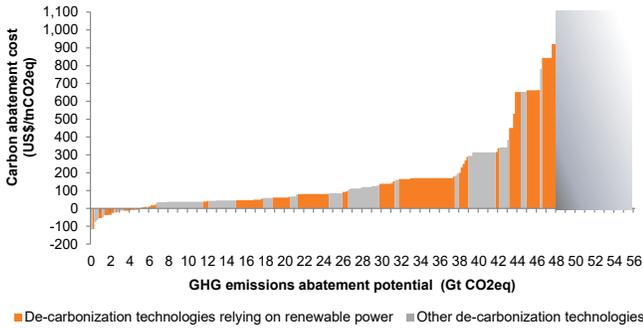
Source: Goldman Sachs Global Investment Research

Exhibit 43: ..yet is not sufficient to achieve global net zero across all sectors, with the key industries for hydrogen's potential addressable market being the ones where direct electrification based on today's technologies is currently not possible

		Hydrogen technology applicable	
		Yes	**No**
Direct electrification applicable	**Yes**	Competition possible yet overall cost and energy efficiency could benefit direct electrification *Examples: Light-duty road transport, buildings heat, low-temperature industrial heat, power generation*	Electrification dominance
	No	Hydrogen dominance *Examples: Long haul heavy-transport, shipping, high temperature industrial heat, petrochemicals, steel*	Other clean technologies and innovation required such as bioenergy and carbon capture *Examples: Cement*

Source: Goldman Sachs Global Investment Research

Introducing the GS global hydrogen demand models: 7-fold increase in the potential addressable market for hydrogen for global net zero

We adopt a sectoral approach to construct our global GS hydrogen demand models, each consistent with a different path to net zero and resulting temperature rise

In our report, _Carbonomics: Introducing the GS net zero carbon models and sector frameworks_, we introduced our global paths to net zero carbon, with global models of de-carbonization by sector and technology, leveraging our Carbonomics cost curve. Our three paths to global net zero, as shown in Exhibit 44, are:

- **GS 1.5°:** An emissions path for **global net zero carbon by 2050,** which would be **consistent with limiting global warming to 1.5°C**, with limited temperature overshoot. For this scenario, we assumed a carbon budget for remaining net cumulative CO_2 emissions from all sources from 2020 to be c.500 $GtCO_2$, in line with estimates from the IPCC AR6 WGI Summary for Policymakers, and consistent with a 50% probability of limiting warming to 1.5°C by 2100.

- **GS <2.0°:** A more achievable global net zero model which is **consistent with the Paris Agreement's aim to keep global warming well below 2°C and achieving global net zero around 2060.** We define the carbon budget for our GS <2.0° model to be one with a cumulative remaining amount of 750 $GtCO_2$, consistent with around 1.65°C global warming with a 50% probability.

- **GS 2.0°:** A **less aspirational scenario** that aims for global carbon neutrality by 2070 and is consistent with a 50% probability of **2.0°C global warming to 2100**, and with a cumulative carbon budget from 2020 of 1,350 $GtCO_2$, in line with the carbon budgets outlined in the IPCC AR6 WGI Summary for Policymakers.

In this report, we introduce our GS global hydrogen demand models, leveraging on our global GS net zero carbon models and frameworks to **assess the potential global addressable hydrogen market under three district de-carbonization scenarios, as shown in Exhibit 45.**

Exhibit 44: We leverage our three global GS net zero carbon models, each consistent with a specific carbon budget and resulting temperature rise..
GS net zero global models, CO2 emissions (incl. AFOLU)
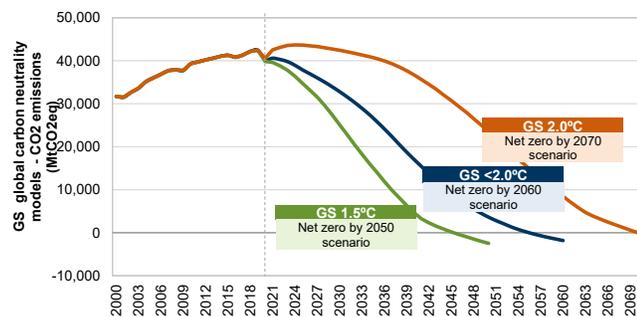
Exhibit 45: ..to construct our three global GS hydrogen demand models, representing three distinct scenarios to 2050
Global hydrogen demand (Mt H2) under the three GS net zero models
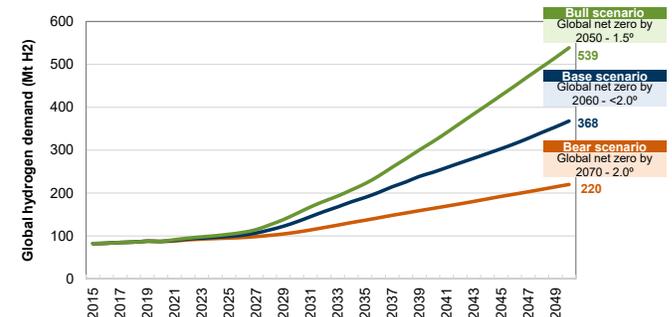

Source: Emission Database for Global Atmospheric Research (EDGAR) release version 5.0, FAO, Goldman Sachs Global Investment Research

Source: Goldman Sachs Global Investment Research

The rise of the clean hydrogen economy could see global demand for hydrogen increasing 7-fold to >500 Mt H2 pa under a global net zero by 2050 scenario

Our global GS hydrogen demand models are developed on a sectoral basis, and include a modeling of the technological mix and activity for each of the potential hydrogen end markets on the path to net zero. We present in Exhibit 46 and Exhibit 47 global hydrogen demand resulting from the various hydrogen end markets under the three scenarios. **Under all three of the global hydrogen demand paths**, the bull, base and bear, **global hydrogen demand increases at least 2-fold on the path to net zero: 2-fold in the bear scenario** (which is in line with 2 degrees of global warming and global net zero by 2070) **to 7-fold in the bull scenario** (which is in line with 1.5 degrees of global warming and global net zero by 2050). This includes hydrogen demand associated with the production of hydrogen-based fuels including ammonia for shipping and synthetic fuels for aviation.

Global hydrogen demand has contributions across industries, both existing end markets, such as refining and ammonia and methanol production, and new emerging markets including long-haul heavy road transport, shipping, aviation, rail, grid blending for heating, power generation for energy storage, and steel. Our sectoral framework follows the matrix logic shown in Exhibit 43 with the dominant emerging hydrogen demand markets being ones where direct electrification is facing hurdles in its current technological state. Moreover, the pace of rising hydrogen penetration in each of these industries is determined by the current positioning of the respective hydrogen technology on our Carbonomics cost curve, as shown in Exhibit 49.

Exhibit 46: Under all three GS global hydrogen demand scenarios, the addressable market for hydrogen increases substantially to 2050, from a doubling in demand under the bear scenario to a 7-fold increase under the bull scenario
Global hydrogen demand for the three scenarios, split by industry (Mt H2)
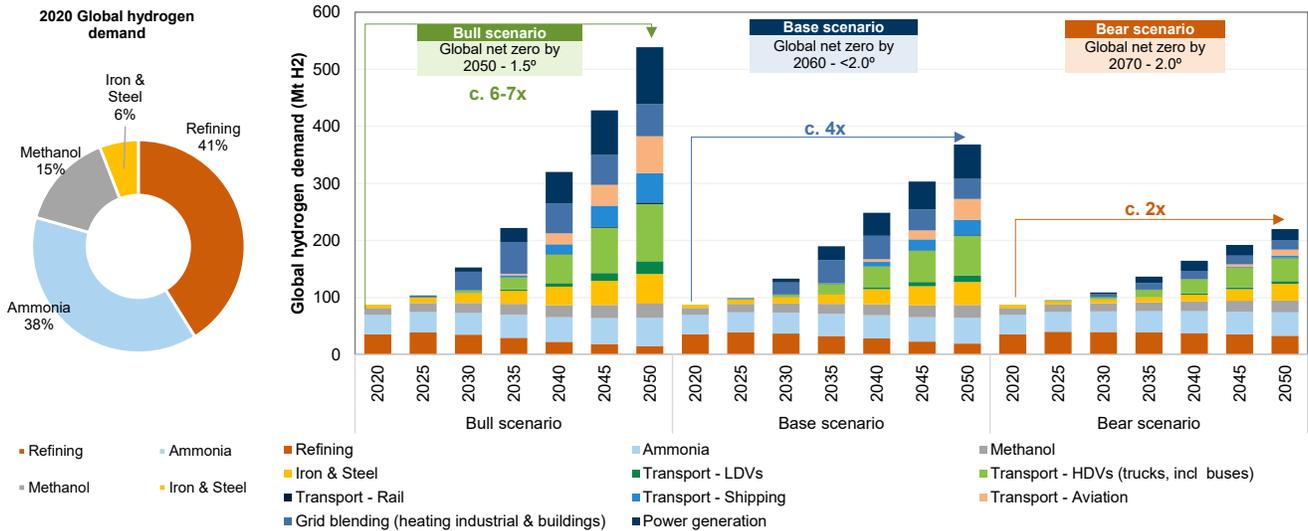
Source: Goldman Sachs Global Investment Research

Exhibit 47: The path to net zero emissions requires transformational changes to the current energy ecosystem and calls for a substantially wider use of hydrogen and hydrogen-based fuels . We summarize in this table the key addressable markets for clean hydrogen in the era of de-carbonization under our three GS global hydrogen demand models

End-use market	% of global CO2 emissions (direct, 2019)	Key competing de-carbonization technologies			Potential role for hydrogen	GS global hydrogen demand models – Hydrogen potential demand in 2050		
		Bioenergy	Electrification (renewable power & storage)	Carbon Capture	Hydrogen stage of development	GS Bull case	GS Base case	GS Bear case
Refining	1.3 GtCO2, c. 3%	●	◐	◐	●	15 MtH2	19 MtH2	33 MtH2
Primary chemicals	0.9 GtCO2, c. 3%	◐	◐	◕	◔	74 MtH2	68 MtH2	62 MtH2
Iron & Steel	2.6 GtCO2, c. 7%	○	◐	◐	◐	52 MtH2	40 MtH2	29 MtH2
Road transport Light-duty vehicles (LDVs)	3.9 GtCO2, c. 10%	●	●	○	◔	22 MtH2	12 MtH2	5 MtH2
Road transport Heavy-duty vehicles (HDVs, incl. trucks and buses)	2.3 GtCO2, c. 6%	●	◕	○	◔	100 MtH2	68 MtH2	40 MtH2
Rail	0.2 GtCO2, <1%	◔	●	○	◔	3 MtH2	2 MtH2	1 MtH2
Shipping	0.9 GtCO2, c.2%	◔	◕	○	◕	52 MtH2	27 MtH2	4 MtH2
Aviation	1.0 GtCO2, c.3%	◔	◕	○	◔	64 MtH2	36 MtH2	10 MtH2
Power generation	13.8 GtCO2, c.36%	●	●	◕	◐	100 MtH2	60 MtH2	20 MtH2
Buildings (incl. space and water heating)	3.5 GtCO2, c.9%	●	●	○	◐	56 MtH2	35 MtH2	16 MtH2

Source: Goldman Sachs Global Investment Research

Comparing our global hydrogen demand models to other available global climate scenarios

There exist a wide range of potential hydrogen demand scenarios, released by a number of agencies and organizations including, among others, the International Energy Agency (IEA Sustainable Development and Net Zero scenarios), the Hydrogen Council, Bloomberg New Energy Finance (BNEF), and IRENA. In Exhibit 48, we show how the GS global hydrogen demand scenarios screen against these various other global scenarios.

Our bull scenario (which assumes global net zero by 2050 is reached with a carbon budget in line with 1.5 degrees of global warming) results in 2% higher 2050 hydrogen demand compared to IEA's NZE scenario, owing to a more moderate assumed step-up in efficiency and smaller role of behavioral energy consumption changes leading to higher demand for hydrogen in power generation seasonal energy storage, aviation, heavy road transport and steel. Nonetheless, our 'bull' scenario is c. 18%/23% lower than what is estimated by the more optimistic Hydrogen Council's 'H2 for NZ' and BNEF's Strong Policy scenarios which assume larger and broader global policy coordination on achieving global carbon neutrality than is currently observed. Overall, we remain very bullish on the clean hydrogen economy and **view clean hydrogen as a necessary pillar to any aspiring net zero path.**

Exhibit 48: Different global hydrogen demand scenarios show a wide range of estimates for the potential global hydrogen market given the difference in the pace and extent of hydrogen penetration assumed across the various end markets
Global hydrogen demand under different scenarios (Mt H2)
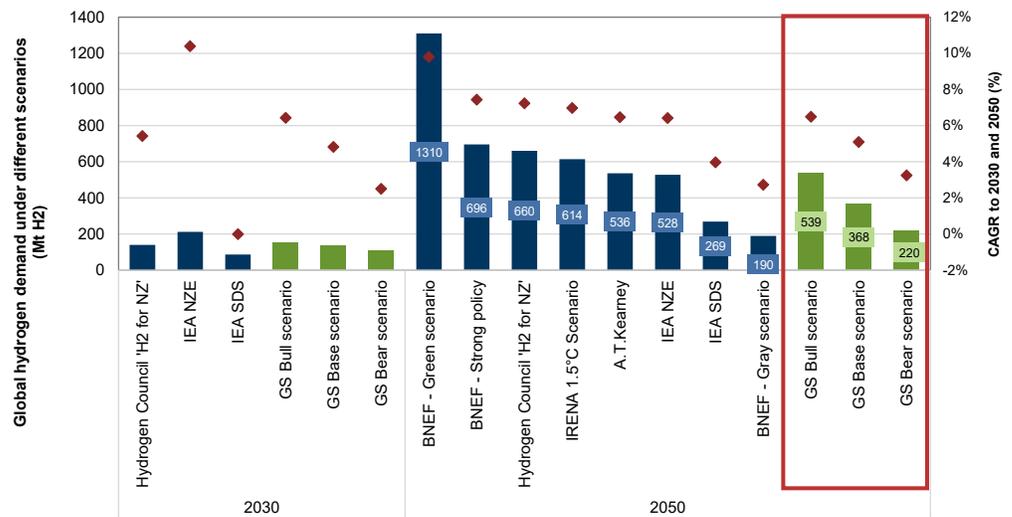
Source: BNEF, IEA, Hydrogen Council, AT Kearney, Goldman Sachs Global Investment Research

**In our GS global hydrogen demand models, the pace and ultimate penetration of clean hydrogen technologies in each industry is correlated to the carbon abatement cost and technological readiness of these technologies on our Carbonomics cost curve**

Given the broad range of end uses and potential markets for hydrogen, the scenarios reflect a broad range of estimates, with the key difference primarily stemming from different hydrogen penetration rates assumed across these markets. We believe the two key factors that ultimately influence the penetration of hydrogen in these industries are (a) the level of policy support and (b) the cost associated with hydrogen adoption compared to alternative technologies in each of these industries.

In our GS global hydrogen demand models, the pace and ultimate penetration of clean hydrogen technologies in each industry is therefore correlated to the carbon abatement cost and technological readiness of these technologies as addressed by our Carbonomics cost curve. Exhibit 49 demonstrates the high correlation between the penetration of clean hydrogen across various end markets and the carbon abatement cost of these technologies both in our 'base' and 'bull' scenarios. The only exception to this trend is steel, where despite the comparatively lower implied carbon abatement cost associated with the switch from existing coal BF-BOF plants to H2 DRI-EAF plants, the very young existing plant fleet, particularly in China, coupled with the long useful life of these assets implies a relatively slower pace of penetration increase in that industry.

Exhibit 49: For our global GS hydrogen demand models, we assume that the pace of clean hydrogen technologies' penetration in each industry is related to the current positioning on our Carbonomics cost curve
Clean hydrogen penetration by industry in 2040 vs abatement cost (blue for the Base scenario and green for the Bull scenario)
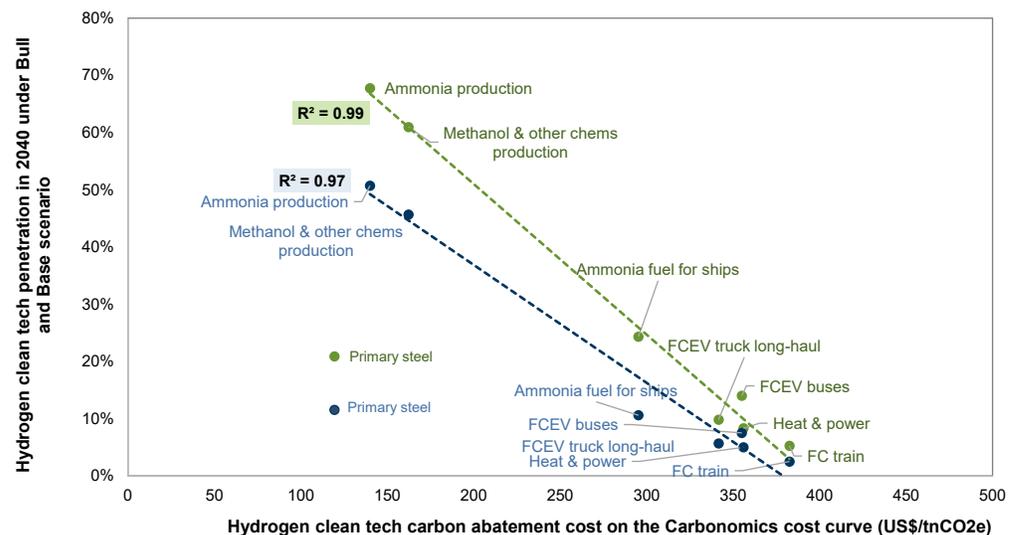
Source: Goldman Sachs Global Investment Research

# Decoding the hydrogen rainbow: A colorless gas with a wide color spectrum

Hydrogen has a number of valuable attributes as we laid out in an earlier section of this report, two of which make it unique in the age of climate change: (1) its ability to be stored and used as a clean fuel without direct emissions of GHG gases and/or air pollutants and (2) the wide variety of clean production pathways that could be adopted in its production (versatility), offering flexibility along supply chains. There are six well-defined colors of hydrogen, depending on the production route and technology: brown, grey, blue, green, pink, and turquoise. This is what we refer to in this report as the hydrogen production rainbow.

Exhibit 50: Summary of the key hydrogen shades, including process technology description and key metrics

Hydrogen colour		Hydrogen production process technology			Direct carbon intensity	Efficiency		Scalability	Conditions	
		Process	Feedstock	Process description	kgCO2e/kg H2	kWh/kg H2	% LHV	Typical plant size	Temperature ºC	Water
Thermochemical	**Brown**	Gasification	Coal, Biomass, Oil, Solid waste	Coal is heated in a pyrolysis process to 400 degrees, vaporising volatile components of feedstock in H2,CO, CO2, CH4. Then oxygen is added in the combustion chamber and char undergoes gasification releasing gases, tar vapors, solid residues (CO and H2). Water-gas shift reaction converts CO into CO2 and H2 and then purification through methanation or PSA occurs.	19.5 kgCO2e/kg H2	41-47	70-80%	500,000 kgH2 pd	80-1,800	9 L/kg H2
	Turqoise	Pyrolysis	Natural gas	Hydrocarbons undergo heating without air combustion splitting into hydrogen and solid carbon black. There are four types: slow, flash, fast and microwave pyrolysis.	-	47-66	50-70%	10,000-50,000 kg H2 pd	200-760	n.a.
	Grey	Steam methane reforming (SMR)	Natural gas	Natural gas (methane) and high-temperature steam are mixed with nickel catalyst to produce hydrogen, CO and a small amount of CO2. Heat is typically provided by burning fuel gas. A water-gas shift reaction occurs where CO and steam are then reacted further to produce CO2 and more hydrogen. In the final step, hydrogen is separated from the tail gas through selective adsorption.	9-11 kgCO2e/kg H2	52	64%	200,000-500,000 kgH2 pd	750-1,100	4.5 L/kg H2
		Autothermal reforming (ATR)		ATR combines the endothermic reaction of steam reforming and exothermic reaction of oxidation. Feedstock natural gas, steam, or sometimes CO and dioxygen are mixed before pre-heating. In the combustion zone partial oxidation occurs producing a mixture of CO2 and hydrogen. In the catalytic zone gases leaving the combustion zone reach equilibrium. A water-gas shift reaction happens post ATR reacting CO with steam to produce more hydrogen and CO2.	9 kgCO2e/kg H2	40-42	78-82%	up to 1,500,000 kg H2 pd	980-1,200	n.a.
	Blue	Steam methane reforming (SMR) + CCUS	Natural gas	Similar process to SMR above but with an integrated carbon capture system added. CO2 capture can be done on three streams: on the shifted syngas with MDEA, on the PSA tailgas with MDEA or from the SMR fuel gas using MEA.	0.9-2.5 kgCO2e/kgH2	lower end of range	lower end of range	200,000-500,000 kgH2 pd	750-1,100	4.5 L/kg H2
		Autothermal reforming (ATR) + CCUS	Natural gas	Similar process to ATR above. Carbon capture is typically more effective in ATR compared to SMR given the higher concentration of CO2 in the stream.	0.5-1.35 KgCO2e/kg H2	lower end of range	lower end of range	up to 1,500,000 kg H2 pd	980-1,200	n.a.
Electrolysis	**Green**	Alkaline electrolysis (AE)	Renewable Electricity, Water	For all of these electrolysis routes direct current passes through an ionic substance producing chemical reaction at the electrodes. Electrodes are immersed in electrolyte and separated by a medium where Hydrogen ions move towards the cathode to form H2 and receivers collect this hydrogen and oxygen (other electrode) in gaseous forms	-	48-64	52-69%	Scale-up ongoing	60-80	9-15 L/kg H2
		Proton-exchange membrane electrolysis (PEM)			-	43-60	60-75%	Scale-up ongoing	50-80	9-15 L/kg H2
		Solid oxide electrolyzer cell (SOEC)	Renewable Electricity, Steam		-	40-45	74-81%	Research/ Pilot	650-1,000	9-15 L/kg H2
	Pink	Nuclear electrolysis	Nuclear energy, Water	Pink hydrogen is generated through electrolysis powered by nuclear energy. Nuclear-produced hydrogen can also be referred to as purple hydrogen or red hydrogen.	-	n.a.	n.a.	Research/ Pilot	n.a	n.a
Microbial	**Other**	Microbial electrolysis	Electricity, Water	Combines electrical energy with microorganism (such as bacteria) activation to produce hydrogen.	-	47	c.70%	Research	n.a	n.a
		Biomass dark fermentation	Biomass, Water	Dark fermentation converts organic matter to hydrogen through biochemical reactions (typically using bacteria to trigger series of reactions)	-	>70	30-40%	Research	25-40	n.a
		Photoelectrical synthesis	Sunlight, Water	Photolytic technologies focus on directly converting sun energy into hydrogen. This process typically involves the use of microorganisms.	-	n.a	n.a	Research	n.a	n.a

Source: Kearney Energy Transition Institute, data compiled by Goldman Sachs Global Investment Research

Exhibit 51: While brown and grey hydrogen technologies are the most mature, both green electrolysis and carbon capture for blue hydrogen continue to move further down the hydrogen technological maturity curve. Storage and transportation, as well as new novel hydrogen production routes have also started to make an entry
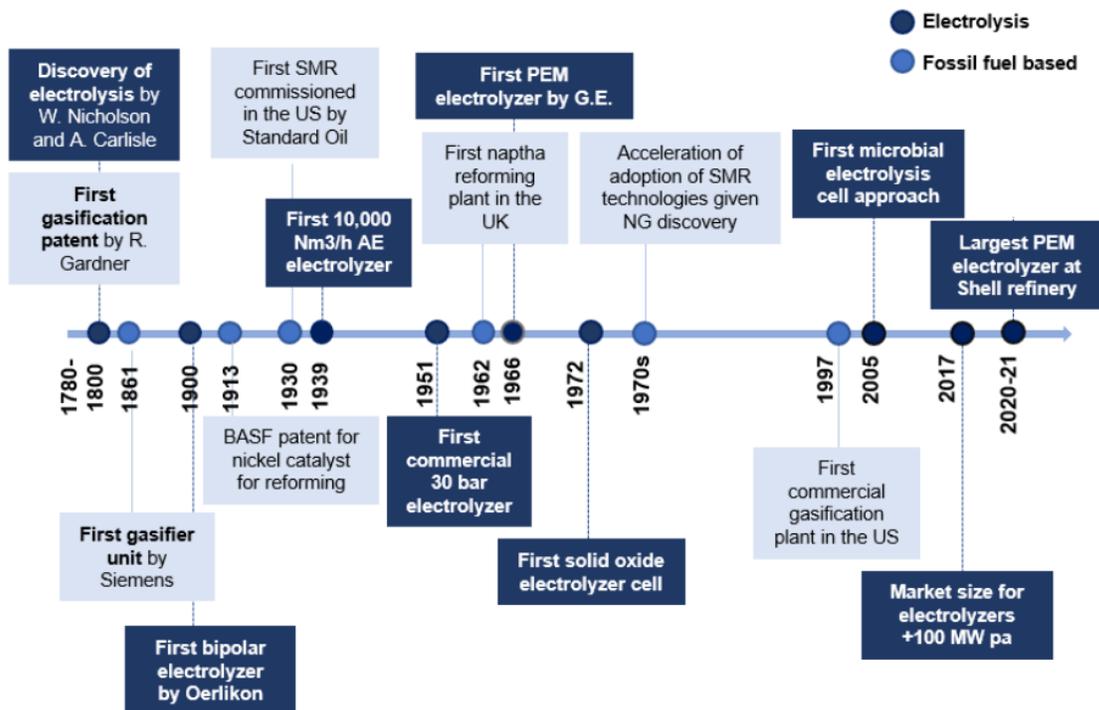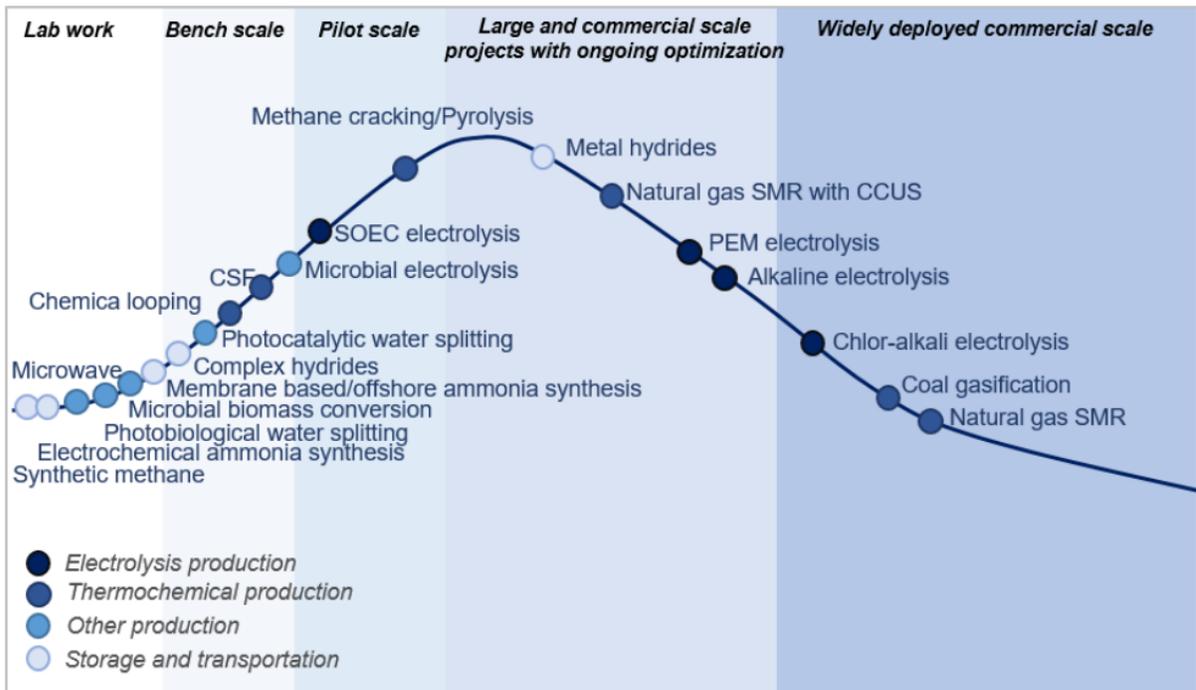
Source: Company data, Kearney Energy Transition Institute, compiled by Goldman Sachs Global Investment Research

Fossil-fuel hydrogen supply dominance at present but the hydrogen rainbow expansion is gaining momentum with 'blue' and 'green' hydrogen setting the scene for de-carbonization

Global hydrogen demand of around 90 Mt H2, as outlined earlier in this report, was almost entirely met with hydrogen supply relying on fossil fuels, with 72 Mt H2 coming from dedicated hydrogen production plants and the remaining produced as a by-product in facilities that were designed primarily for the production of other products (such as refineries, according to the IEA).

Today, over c.60% of hydrogen is produced from natural gas, c. 19% from coal, and c. 21% as a by-product. Less than c.1%-2% of hydrogen production is currently produced via electrolysis, the least carbon intense hydrogen production pathway. While electrolysis is not new, and has in fact been around for nearly a century, as shown in Exhibit 51, production of hydrogen through low carbon electricity (green hydrogen) is not currently carried out on a large commercial scale and still shows a wide range of variability, including the capital expenditure requirements associated with electrolyzers, operating time, conversion efficiency and the cost of electricity. In our view, this is a key area in the de-carbonization debate that calls for innovation and technological progress and that could potentially unlock the 'green' hydrogen scale-up opportunity. Similarly, carbon capture, utilization and storage technologies (CCUS) for blue hydrogen, while developed at scale, have been largely under-invested over the past decade compared to other clean technologies and have not enjoyed the economies of scale that other technologies have, yet are critical in the low-carbon, low-cost transition to clean hydrogen.

We believe the **technological and fuel mix of hydrogen production is likely to undergo a revolutionary change in the coming decades on the path to global carbon neutrality.** We show in Exhibit 52 below how we anticipate the hydrogen production mix to evolve in the coming decades based on our three global hydrogen scenarios.

Exhibit 52: While fossil-based hydrogen production dominates global H2 supply, we expect 'green' and 'blue' hydrogen to set the stage for de-carbonization in the coming years with material growth under even the GS bear case scenario, from just about c.1% today
Global hydrogen supply by source
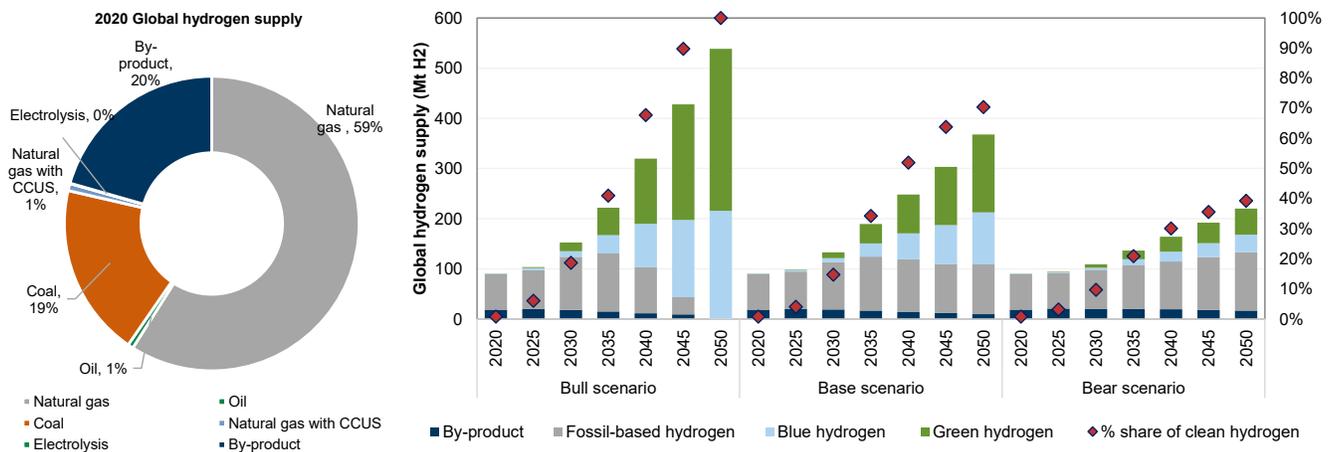
As shown in the above exhibit, **we primarily focus on the 'blue' and 'green' clean hydrogen production routes** for the purpose of this report and paths to net zero. These two routes are not only the low-carbon intensity pathways that have reached commercial scale for hydrogen production today, but they also make hydrogen **uniquely positioned to benefit from two key technologies in the clean tech ecosystem - carbon capture and renewable power generation.** 'Blue' hydrogen refers to the conventional natural gas-based hydrogen production process (SMR or ATR) coupled with carbon capture while 'green' hydrogen refers to the production of hydrogen from water electrolysis where electricity is sourced from zero carbon (renewable) energies. In a later section of this report, we go into further details on the technologies, costs and outlook for these two colors of hydrogen as we believe they are likely to set the stage for de-carbonization in the coming decades.

Exhibit 53: Clean hydrogen forms a key connecting pillar between two key de-carbonization technologies - renewable power and carbon capture, each interconnected with one another
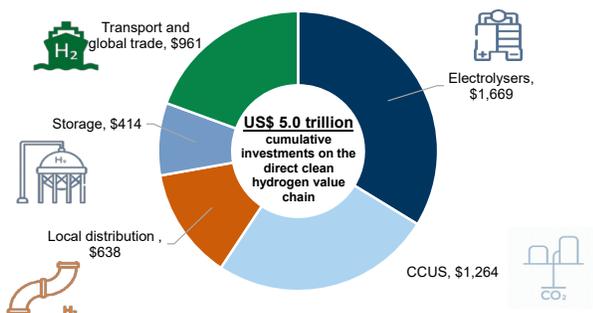

Source: Goldman Sachs Global Investment Research

We estimate that US$5.0 tn of investments will be required in the hydrogen supply value chain for net zero by 2050

Investments in the hydrogen industry have already started to inflect notably higher, particularly in production technology deployment. Nonetheless, we estimate that a lot more investment will be required to set us on a path consistent with net zero by 2050 ('bull' hydrogen demand scenario). Government action will be critical for this, and we address the wide range of tools available for policy support to encourage the wider deployment of clean hydrogen and de-risk the investment proposition in a later section of this report ('Policy Toolbox'). Government action more broadly has started to notably gain momentum, as demonstrated by the more than 20 newly launched national hydrogen strategies over the past two years alone, which we see spurring the strong pace needed for investments. For instance, as part of its national hydrogen strategy, Germany announced a EUR9 bn package, which, according to the German government, will likely lead to an additional EUR33 bn of private investments. We expect that, just as we have observed in the solar and wind industries, public investments will likely lead to ever higher private investments fueling an acceleration of the industry.

Focusing on the direct supply chain of clean hydrogen, encompassing investments required for its production (electrolyzers and CCUS for green and blue hydrogen, respectively), storage, distribution, transmission and global trade, we estimate **that a net zero by 2050 scenario calls for US$5.0 tn of cumulative investments in the direct clean hydrogen supply chain to 2050, and c.US$0.6 tn to 2030**. We view these as solely capex investments (not including opex or other costs) in the direct supply chain of clean hydrogen (as outlined) and not including capex associated with end markets (industry, transport, buildings) or upstream capex associated with the power generation plants required for electricity generation for green hydrogen. This corresponds to **an annual average of c.US$55/165 bn pa required to 2030/50E, respectively.**

Exhibit 54: We estimate that c. US$5.0 tn of investments in the direct supply chain of clean hydrogen will be needed for a scenario consistent with net zero by 2050...
Investments required in the clean hydrogen supply chain (excl. upstream RES and end markets) for net zero by 2050

Source: Goldman Sachs Global Investment Research

Exhibit 55: ..with c.US$55 bn pa annually required in the 2020s
Average annual hydrogen investment requirements for net zero by 2050 (US$bn)

Global average annual hydrogen investment requirements for the net zero by 2050 scenario (US$bn)

■ Electrolysers ■ CCUS ■ Local distribution ■ Storage ■ Transport and global trade
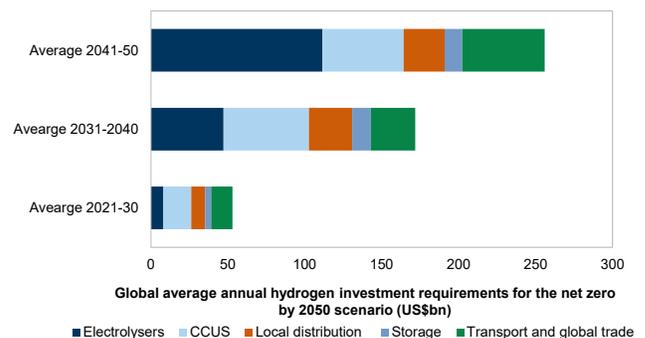
Source: Goldman Sachs Global Investment Research

Championing sustainable innovation: The economics of clean hydrogen

As mentioned earlier in this report, there are many types (colors) of hydrogen, depending on the production pathway in consideration. However, the low-carbon intensity pathways for hydrogen production and what makes the fuel uniquely positioned to benefit from two key technologies in the clean tech ecosystem - carbon capture and renewable power generation - are '**blue**' and '**green**' hydrogen. These are also currently the commercialized routes of clean hydrogen production.

While 'blue' and 'green' hydrogen are the lowest carbon intensity hydrogen production pathways, both of these technologies are currently costly when compared to the traditional hydrocarbon-based 'grey' hydrogen production method, based on our hydrogen cost of production analysis, as shown in Exhibit 56, calling for further technological innovation and wider adoption that would unlock the benefits of economies of scale. We note that the costs presented below are **based on current cost estimates** for electrolyzer ('green') and carbon capture & storage ('blue').

Exhibit 56: 'Blue' and 'green' hydrogen set the stage for de-carbonization, yet both are more costly than traditional 'grey' hydrogen - thus there is a need for technological innovation and investment in both carbon capture and electrolyzer technologies
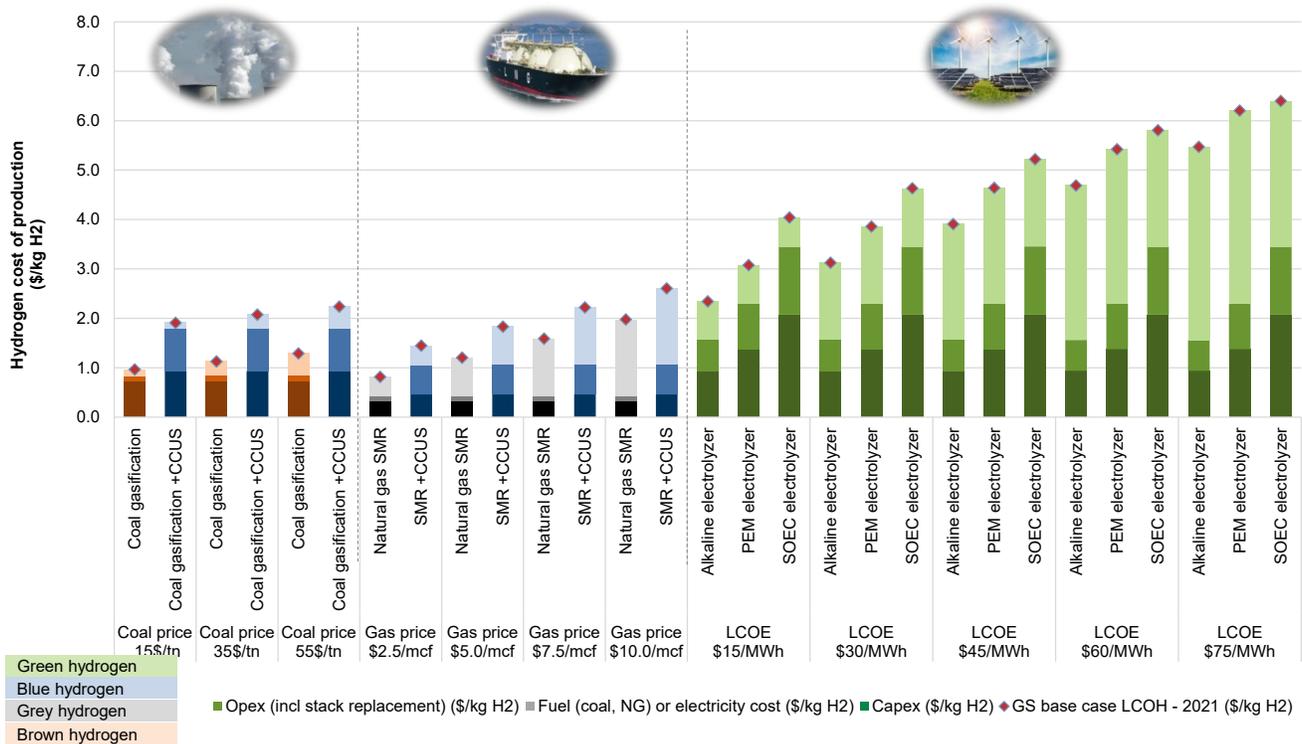
Source: Goldman Sachs Global Investment Research

1) 'Blue' hydrogen and the critical role of sequestration in supporting the low carbon hydrogen transition

'Blue' hydrogen refers to the production of hydrogen from **natural gas** through either steam-methane reforming (SMR) or autothermal reforming (ATR) whereby emissions are captured through **carbon capture technologies (CCUS).** The production of 'blue' hydrogen for de-carbonization offers several advantages in the near to medium term as it utilizes the current conventional, large-scale commercial hydrogen production pathways and infrastructure, with c.60% of global hydrogen production relying on natural gas SMR plants.

The most widespread method for hydrogen production is natural gas-based steam-methane reforming, which is a process that uses water (steam) as an oxidant and a source of hydrogen. Natural gas in SMR acts as both a fuel (c.30%-45% of it is combusted to fuel the process giving rise to a diluted CO_2 stream) and feedstock. The typical steps of the process involve: (1) a feedstock pre-treatment unit (desulfurization) where sulphur and chlorine is removed from the natural gas feedstock; (2) the stream subsequently enters the steam-methane reformer unit where natural gas is combined with pressurized steam to produce syngas (a blend of carbon monoxide and hydrogen); (3) the syngas outlet stream, mostly consisting of carbon monoxide and hydrogen, undergoes a 'water-gas shift' reaction where carbon monoxide and water are reacted using a catalyst to produce carbon dioxide and more hydrogen; and (4) the final process step removes carbon dioxide and other impurities from the hydrogen stream, increasing its purity in what is referred to as 'pressure-swing adsorption' (PSA).

Adopting CCUS technologies to SMR and ATR plants for hydrogen production **can result in a c.90% reduction in carbon emissions** in aggregate according to industry studies. While 30%-40% of emissions arise from using natural gas as a fuel to produce steam and heat, giving rise to a diluted CO2 stream, the rest of the natural gas used in this process is split into hydrogen and a more concentrated CO2 stream, where c.60% of capture can occur. Combining carbon capture across both streams can achieve 90% reductions or higher. An alternative process to SMR is a partial oxidation process (using oxygen as the oxidant), yet more typically a combination of both processes is used - known as autothermal reforming (ATR). ATR carbon capture is considered easier to achieve given the higher concentration of CO_2 in the syngas stream. However, the vast majority of natural gas hydrogen production facilities globally adopt the SMR technology. The schematic of a typical SMR process with CCUS is shown in Exhibit 57, which indicates the three potential carbon capture locations (SMR flue gas, shifted syngas and PSA tail gas) with the SMR flue gas being the stream with the highest CO_2 concentration and highest carbon capture potential.

Exhibit 57: Schematic diagram presenting the steps of a typical 'blue' hydrogen production process combining SMR with carbon capture
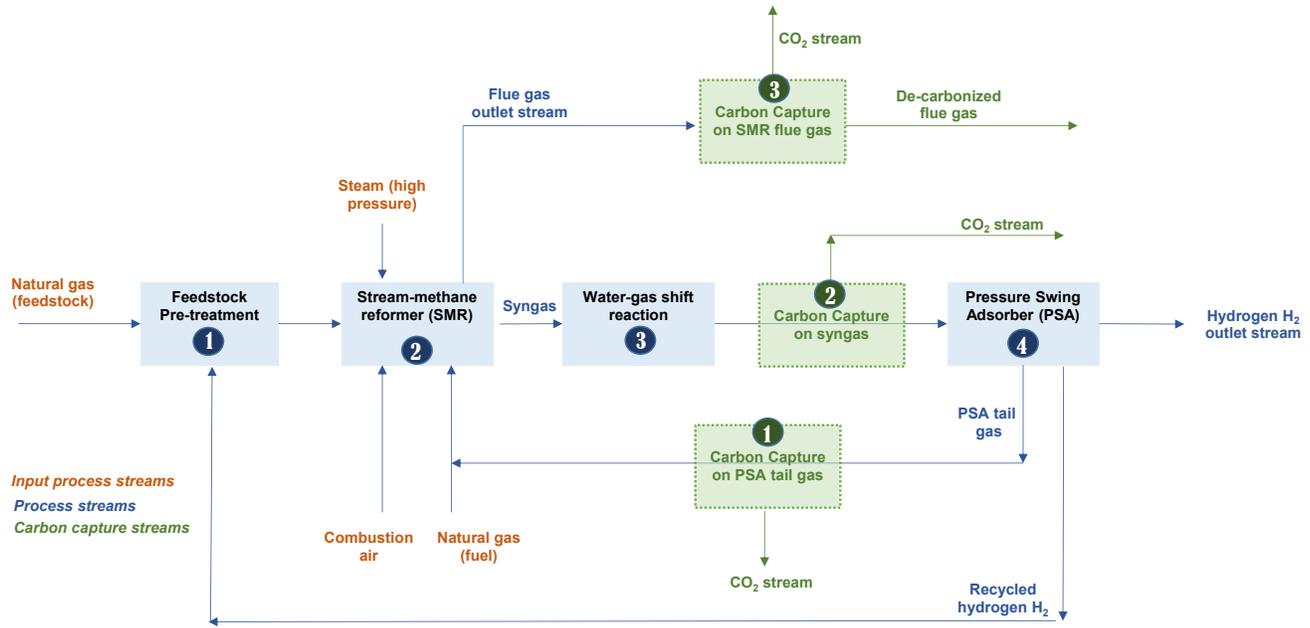
Carbon capture stream		Process description	Capture rate
1	Capture of CO_2 from PSA tailgas with mdea	$MDEA + CO_2 + H_2O = MDEAH^+ + HCO_3^-$	50-55%
	Capture of CO_2 from PSA tailgas using low temperature and membrane separation	CO_2 liquefied and purified	50-55%
2	Capture of CO_2 from shifted syngas with MDEA	$MDEA + CO_2 + H_2O = MDEAH^+ + HCO_3^-$	50-55%
	Capture of CO_2 from shifted syngas with MDEA with H_2^- rich burners	$MDEA + CO_2 + H_2O = MDEAH^+ + HCO_3^-$	60-70%
3	Capture of CO_2 from SMR fuel gas using MEA	$MEA + CO_2 = H_2O + C_3H_5NO_2^- + N_2$	85-90%

Source: Company data, Goldman Sachs Global Investment Research

The scale-up of 'blue' hydrogen is solely reliant on the wider adoption and integration of carbon capture, utilization and storage technologies, which resemble the incremental cost for the production of 'blue' hydrogen vs 'grey'. As we have highlighted in our global net zero models Carbonomics report, sequestration is likely to play a vital role in aiding de-carbonization efforts, particularly in harder-to-abate sectors and in achieving net zero anthropogenic (i.e. related to human activities) emissions. We present more details around this technology and address the current pipeline of carbon capture projects in a later section in this report.

The two key variables determining the levelized cost of blue hydrogen (LCOH) are (a) the price of natural gas since each kg of hydrogen typically requires 2.5-4 kg of methane and (b) the cost of CCUS (including both capex and opex). Both of these parameters vary significantly between regions globally, including the ability and cost to store the captured CO2 (with onshore storage being more cost competitive than offshore storage, with regions with vast amounts of storage potential in depleted oil & gas fields screening better than others in that aspect). In the table below, we present the sensitivity of the LCOH to the natural gas price and CCUS cost.

Exhibit 58: The price of natural gas and the cost of carbon capture and storage are the two key determinant factors for the blue LCOH

Levelized cost of blue hydrogen (LCOH), US$/kg H2

		Carbon capture and storage cost - US$/tnCO2					
		50	75	100	125	150	175
Natural gas price US$/mcf	2.5	1.2	1.4	1.6	1.8	2.0	2.2
	5.0	1.6	1.8	2.0	2.2	2.4	2.6
	7.5	2.0	2.2	2.4	2.6	2.8	3.0
	10.0	2.4	2.6	2.8	3.0	3.2	3.4
	12.5	2.8	3.0	3.2	3.4	3.6	3.8
	15.0	3.2	3.4	3.6	3.8	4.0	4.2
	17.5	3.5	3.7	3.9	4.2	4.4	4.6

Source: Goldman Sachs Global Investment Research

Exhibit 59: Below we present the results of a sensitivity analysis for the cost of production of blue hydrogen under different natural gas prices and carbon capture cost assumptions

Levelized cost of blue hydrogen (LCOH), US$/kg H2
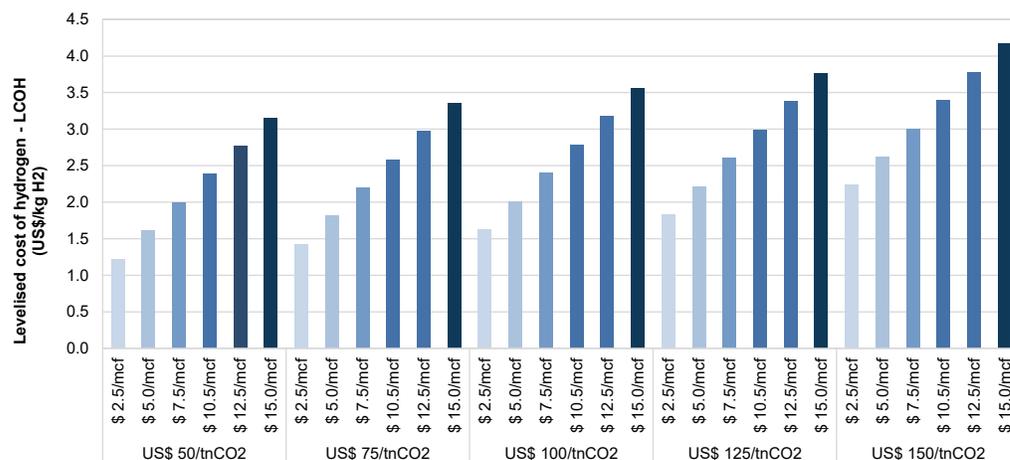
Source: Goldman Sachs Global Investment Research

2) 'Green' hydrogen: The ultimate de-carbonization tool
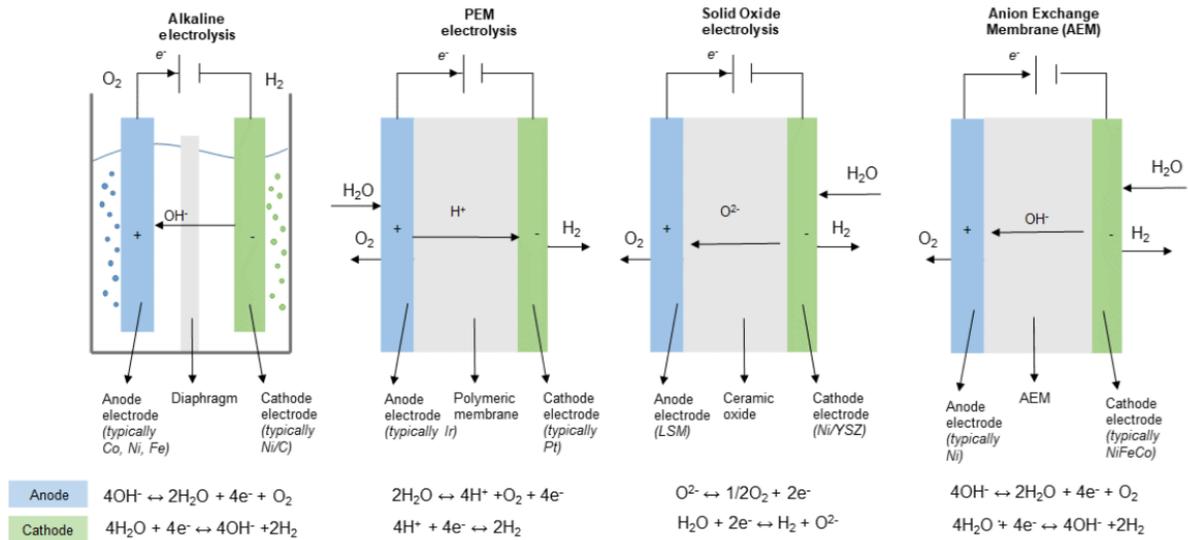
'Green' hydrogen is typically produced via water electrolysis, an electrochemical process in which water is split into hydrogen and oxygen. Dedicated 'green' hydrogen production electrolysis remains a very niche part of global hydrogen production today (<1%); yet with renewable energy sourced electricity costs having reduced substantially over the years (solar PV, onshore and offshore wind), and with de-carbonization focus from investors, corporates and policy makers accelerating, we see growing interest in the space. The key underlying technology for green hydrogen production is electrolyzer, which uses electricity to produce hydrogen, and there are three distinct types that have reached commercialization: **alkaline** electrolysis, **proton exchange membrane** electrolysis (PEM) and **solid oxide electrolysis cells** (SOECs).

Exhibit 60: Simplified schematic of the three currently commercialized electrolysis technologies for the production of 'green' hydrogen

| Anode | $4OH^- \leftrightarrow 2H_2O + 4e^- + O_2$ | $2H_2O \leftrightarrow 4H^+ + O_2 + 4e^-$ | $O^{2-} \leftrightarrow 1/2O_2 + 2e^-$ | $4OH^- \leftrightarrow 2H_2O + 4e^- + O_2$ |
| Cathode | $4H_2O + 4e^- \leftrightarrow 4OH^- + 2H_2$ | $4H^+ + 4e^- \leftrightarrow 2H_2$ | $H_2O + 2e^- \leftrightarrow H_2 + O^{2-}$ | $4H_2O + 4e^- \leftrightarrow 4OH^- + 2H_2$ |

	Alkaline electrolyser	PEM electrolyser	SOEC electrolyser	AEM electrolyser
Development status	Commercial	Commercial	Demonstration/Pilot	Research
System cost (US$/kW)	600-1,100	800-1,250	>1,850	n.a.
Electrical efficiency	52-70%	55-75%	74-85%	40-70%
Operating temperature (ºC)	60-80	50-85	600-1000	40-60
Opearing pressure (bar)	1- 30	30 to 80	c. 1	<35
Current density (A/cm2)	0.2-0.6	1.0-3.0	0.5-1	n.a.
Response time	Start: 1-10 mins Shut: 1-10 mins	Start: 1 sec - 5 mins Shut: few seconds	High (n.a.)	n.a.
Load range (% of nominal load)	10-110%	20-160%	20-100%	5-100%
Stack lifetime (hours)	60,000 - 90,000	30,000 - 80,000	10,000 - 40,000	5,000-9,000

Source: The Fuel Cells and Hydrogen Joint Undertaking (FCH JU), Company data, compiled by Goldman Sachs Global Investment Research

Alkaline and PEM technologies dominating the electrolyzer market today, yet innovation is ongoing, with new technologies making an entry

- **Alkaline electrolysis:** The most widely adopted and mature technology is alkaline electrolysis, characterized by relatively low electrolyzer capital cost (less expensive metals typically used compared to other electrolysis technologies) and relatively high efficiencies - typically varying from 55% to 70%. The reaction occurs in a solution comprised of liquid electrolyte (typically potassium hydroxide) between two electrodes. When sufficient voltage is applied between the electrodes, the oppositely charged ions (OH- and H+) are attracted to the oppositely charged electrodes. The anode accumulates water (through the combination of OH- ions) while the cathode gives hydrogen. While the technology is the most mature and has been around for over a century thanks to its use in the chlorine industry, the comparatively low current density, longer response time (lower flexibility) and lower operating pressure vs other technologies present key challenges for the adoption of this technology across the entire clean hydrogen application spectrum.

- **PEM electrolysis:** This technology is based on the principle of using pure water as the electrolyte solution and therefore overcomes some of the issues associated with hydroxide solutions (used for alkaline electrolysis). The process involves the use of a conductive solid polymer membrane. When voltage is applied between the two electrodes, oxygen in the water molecules creates protons, electrons and O_2 at the anode while the positively charged hydrogen ions travel through the proton conducting polymer towards the cathode where they combine to form hydrogen (H_2). The electrolyte and two electrodes are sandwiched between two bipolar plates whose role is to transport water to the plates, transport product gases away from the cell, conduct electricity and circulate a coolant fluid to cool down the process. PEM electrolyzers typically require the use of expensive electrode catalyst materials (such as platinum and iridium) and membrane materials, resulting in overall higher costs vs alkaline at present. Nonetheless, they tend to be more compact, have a better response time, and operate at higher pressures resulting in a competitive advantage compared to alkaline for several applications.

- **Solid oxide electrolysis cells (SOEC):** This type of electrolysis technology is much less widely adopted and has not reached large scale commercialization to date. Principally, this uses ceramics as the electrolyte and operates at very high temperatures (>500°C) using steam as opposed to water. Its key benefit is the potential to reach efficiencies >70% and the need for lower electricity consumption and therefore reduced electricity cost. Key challenges include the high temperature required, limited flexibility and low ceramic membrane durability due to extreme operating conditions.

- **Anionic exchange membrane (AEM):** This is an emerging technology that uses an exchange membrane similar to PEM, yet, unlike PEM, the reaction occurs under alkaline conditions implying no requirement for expensive platinum group metals as catalysts and expensive titanium bipolar plates to survive the highly corrosive acidic environments. In the mild alkaline environment of the AEM electrolyzer, the remaining hydroxide ion (OH–) from the reaction will return to the anode half-cell via the membrane.

Breaking down the cost of production of 'green' hydrogen: Renewable electricity cost and availability, electrolyzer capex, efficiency the key determining drivers

Electrolysis across both alkaline and PEM electrolyzers (the two most widely adopted at present) have efficiencies that typically require between 50-55 kWh of clean electricity per kg of hydrogen, with the theoretical maximum potential efficiency still resulting in 33 kWh per kg of hydrogen. This makes the cost of electricity the single most important determinant of the cost of production of green hydrogen currently, accounting for over half of the LCOH, as shown in Exhibit 62. This is followed by the cost of the electrolyzer system, accounting for around one fourth of the total cost, on our estimates, at present, as well as the cost of stack replacement (typically required after 7-10 years). Finally, while water is the only key raw material, its cost has a relatively small contribution to the total LCOH, along with the remaining other operating cost.

Exhibit 61: The current electrolyzer market is dominated by alkaline and PEM technologies..
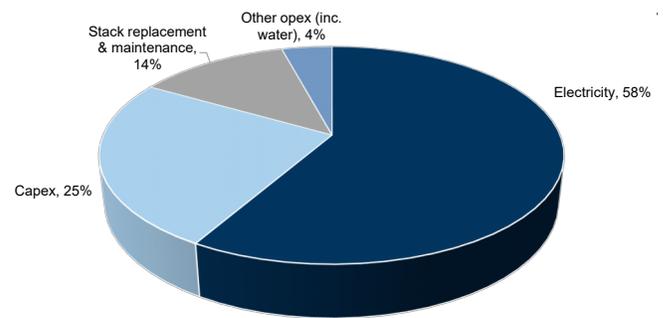Global installed electrolyzer capacity (MW)
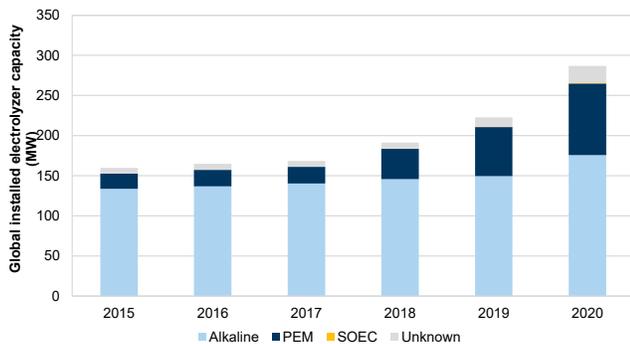
Source: IEA

Exhibit 62: ..for which the cost of renewable power and electrolyzer capex are the two key contributors of the LCOH
LCOH split by cost contributor

Assumes US$750/kW electrolyzer capex, stack replacement after 8 years, $35/MWh electricity cost and 52 kWh/kg efficiency, 8% IRR
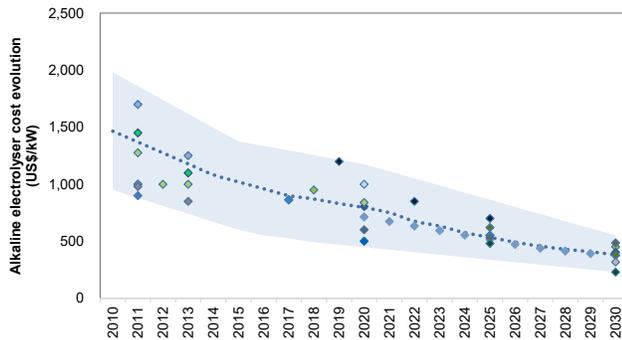
Source: Goldman Sachs Global Investment Research

1) Electrolyzer capex: The area of greatest potential for cost reduction, benefiting from ongoing technological innovation and economies of scale

Following the cost of electricity, the cost of the electrolyzer system is the second most important determinant of the levelized cost of hydrogen. The cost varies depending on the electrolyzer technology, as shown in Exhibit 60, with different technologies currently at different stages of technological maturity and readiness. For the purpose of this analysis, we primarily focus on the cost of alkaline and PEM electrolyzers, which are the two electrolysis technologies found further down the hydrogen technological maturity curve, as shown in Exhibit 51. The costs of both types of electrolyzers have been trending downwards over time, with PEM electrolyzers currently considered more costly based on quoted system prices given the younger, less mature state of the technology. The exhibits below show the wide range of electrolyzer cost estimates for alkaline and PEM electrolyzer systems estimated by hydrogen manufacturing companies and energy agencies globally. The different dots represent projections from electrolyzer manufacturing companies and agencies.

Exhibit 63: There exist a wide range of estimates for both the historical and future trajectory of electrolyzer system costs..
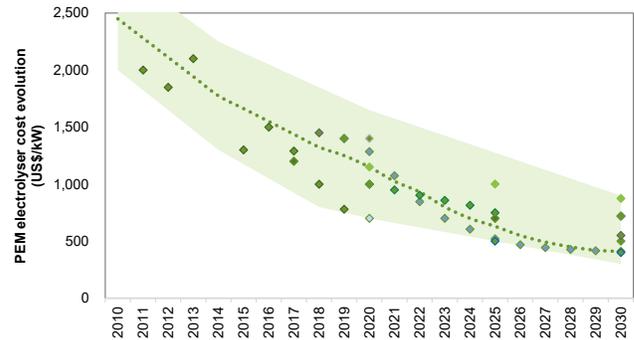Alkaline electrolyzer system cost (US$/kW)

Exhibit 64: ..with PEM electrolyzer systems costs currently screening higher than the competing alkaline technology costs owing to PEM's more recent technological development
PEM electrolyzer cost evolution (US$/kW)

Technological innovation and economies of scale: In the exhibits that follow, we show what constitutes fixed electrolyzer costs for alkaline and PEM systems. For both technologies, the cost can be split into two key components: the electrolyzer stack and the balance of plant, each making around half of the full system cost (as the module size increases the cost split between the balance of plant and stack may deviate from that). The processes included in the balance of plant cost component are typically industrial and chemical processes, which are well understood and widely deployed across industrial applications and therefore have, in our view, lower technological innovation potential compared to the **stack where we believe the largest opportunity for technological innovation lies.**

Looking at PEM electrolyzer full systems, the stack cost is itself split into various components, including the cost and design of the bipolar plants, the catalyst material coating the membrane, the porous transport layer and other smaller components. All these are key areas of ongoing research and technological development and optimization, with perhaps the catalyst coating the membrane having attracted the most focus and interest, given the precious metals involved (iridium and platinum) and the benefits of lower cost, higher performance and higher durability that could be unlocked. While the precious metals overall make up just about c.10% of the total system cost for small scale electrolyzers, securing supply for these metals may be a key constraint longer term as the industry scales up. For alkaline electrolyzers, the cost split at the full system level is similar between the stack and the balance of plant. The diaphragm makes a substantial proportion of the stack cost (more than 50%) yet the electrodes form a smaller component given the use of simpler designs and cheaper materials (mostly nickel-based).
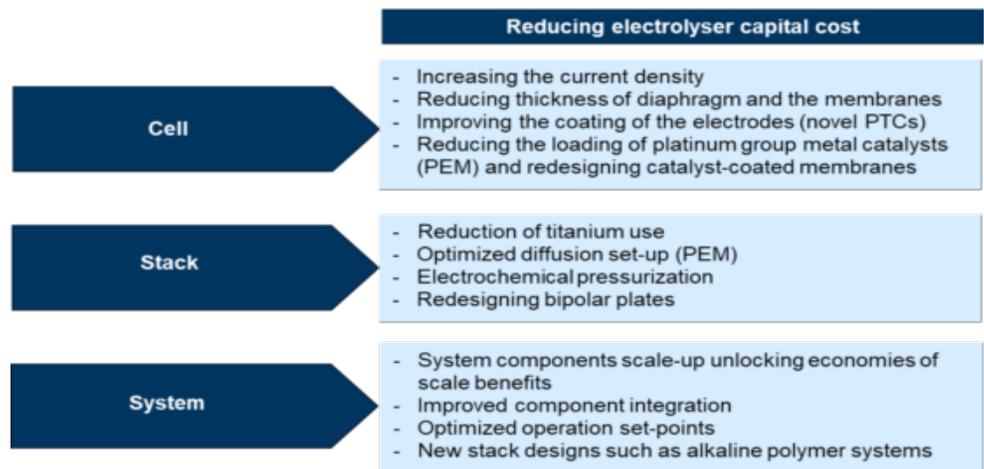
Exhibit 65: Cost breakdown for a typical 1 MW PEM electrolyzer (top) and alkaline electrolyzer (bottom)
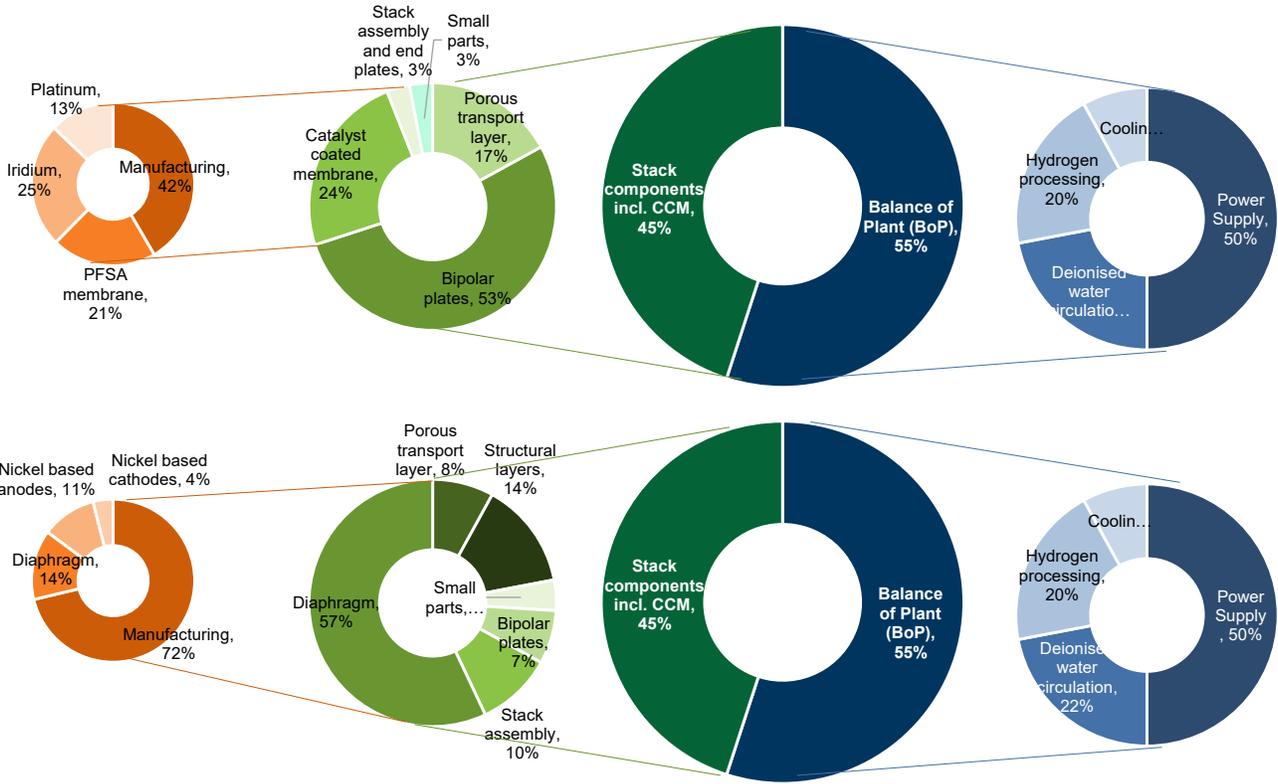
Source: IRENA

Overall, the two key areas of ongoing technological innovation that can unlock cost reduction for both electrolyzer systems are **(1) stack design and cell composition and (2) economies of scale and increase in module size, which are likely to improve the cost positioning of both technologies**. In Exhibit 66, we show the key areas where we see the greatest scope for technological and cost reduction breakthroughs in the coming years for both electrolyzer technologies.

Exhibit 66: Key areas of technological innovation and ongoing optimization for electrolyzer systems

| Reducing electrolyser capital cost |
|---|
| **Cell** | - Increasing the current density
- Reducing thickness of diaphragm and the membranes
- Improving the coating of the electrodes (novel PTCs)
- Reducing the loading of platinum group metal catalysts (PEM) and redesigning catalyst-coated membranes |
| **Stack** | - Reduction of titanium use
- Optimized diffusion set-up (PEM)
- Electrochemical pressurization
- Redesigning bipolar plates |
| **System** | - System components scale-up unlocking economies of scale benefits
- Improved component integration
- Optimized operation set-points
- New stack designs such as alkaline polymer systems |

Source: Goldman Sachs Global Investment Research

Our global GS hydrogen scenarios all show stellar growth of the clean hydrogen economy. We assume that both blue and green hydrogen play a critical role in each of these paths and assume a long-term split between the two technologies of 40% and 60%, respectively. Assuming a utilization rate, this enables us to estimate the global installed electrolyzer capacity required to meet green hydrogen demand in these scenarios. The outcomes are shown in Exhibit 67 and Exhibit 68 below. Overall, we estimate that between 65 and 180 GW of electrolyzer capacity will need to be installed by 2030 and 500-3,200 GW by 2050 under the three scenarios. This represents a stellar 200-570-fold increase to 2030, given the very low starting base of around 0.3-1.0 GW (2021), and a 20%-30% CAGR to 2050 depending on the scenario considered.

With the industry likely to experience substantial growth, we believe that the cost of these electrolyzer units (in US$/kW) has the potential to decrease by 50%/65% by 2030 for alkaline and PEM electrolysis systems, respectively. We **expect that, longer term, the cost of alkaline and PEM electrolyzers is likely to converge** to around US$300-400/kW (2030E), with **PEM enjoying a higher learning rate compared to alkaline given its higher starting point and earlier stage of development.** We see the industry's scale-up as the primary contributor to this reduction with the scale-up coming in three distinct forms: the scale-up of individual modules' size, the scale-up and further automation of the factories that manufacture them (larger-sized gigafactories), and the scale-up of the projects in which these electrolyzer systems are deployed. In Exhibit 69, we compare the cost evolution for electrolyzers to that for other clean energy technologies, including solar PV, onshore and offshore wind, and batteries (rebased to 2010 for renewable power and 2015 for batteries). **We estimate that electrolyzer system costs will have a learning rate between 10%-15% this decade, but note that this learning rate could be even higher if we use the rates observed in the renewable power industry as a proxy.** Overall, we assume a **compounded annual reduction of c. 7%/10% pa for alkaline and PEM electrolyzers, respectively** (higher for PEM given ultimate convergence around 2030 yet a higher cost starting point).

Exhibit 67: Total installed electrolyzer capacity increases >200-fold and >1000-fold under all three GS global hydrogen demand models to 2030 and 2050, respectively..
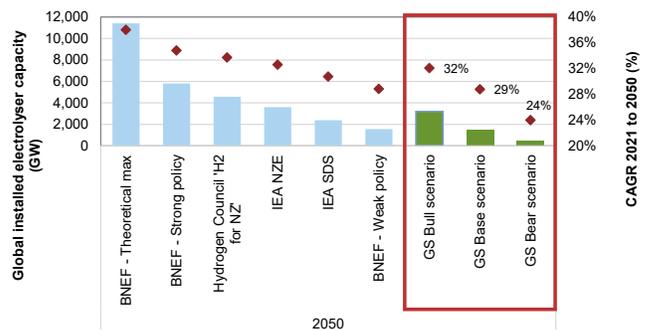Global installed electrolyzer capacity based on our GS global hydrogen demand models (GW)
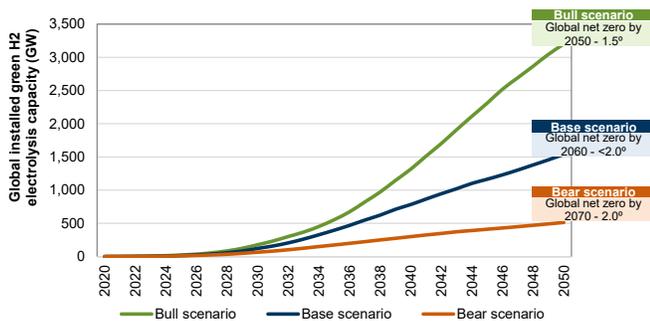
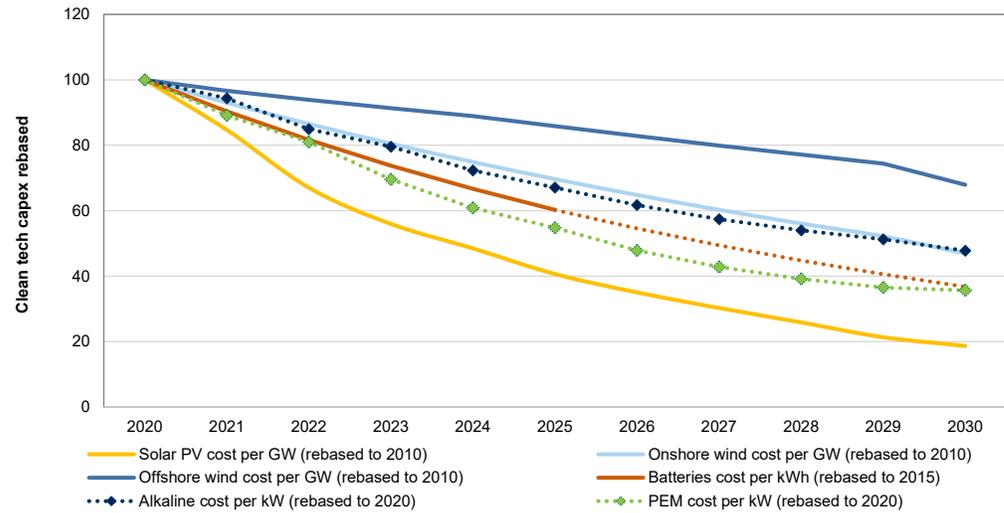Source: Goldman Sachs Global Investment Research

Exhibit 68: ..resulting in a c.20%-30% CAGR to 2050, a substantial scale-up for the industry
Global installed electrolyzer capacity under various scenarios and vs GS global hydrogen models (GW)

Source: BNEF, Hydrogen Council, IEA, Goldman Sachs Global Investment Research

Exhibit 69: We expect electrolyzer system costs to more than halve by the end of the decade (2030), tracking the trajectory of technologies such as onshore wind and batteries
Cost per kW electrolyzer capacity, per kW of renewable power capacity and per kWh of battery

Source: Goldman Sachs Global Investment Research

Exhibit 70: Based on our estimates of the evolution of alkaline and PEM electrolyzer costs, the implied learning rate is lower than the one observed in solar and onshore wind over 2010-20 as well as batteries in 2015-20, but more in line with the learning rate of offshore wind, leaving us with further upside to potential cost reduction
Cost index per unit capacity of various clean technologies compared to the cumulative capacity installed (in MW or MWh)
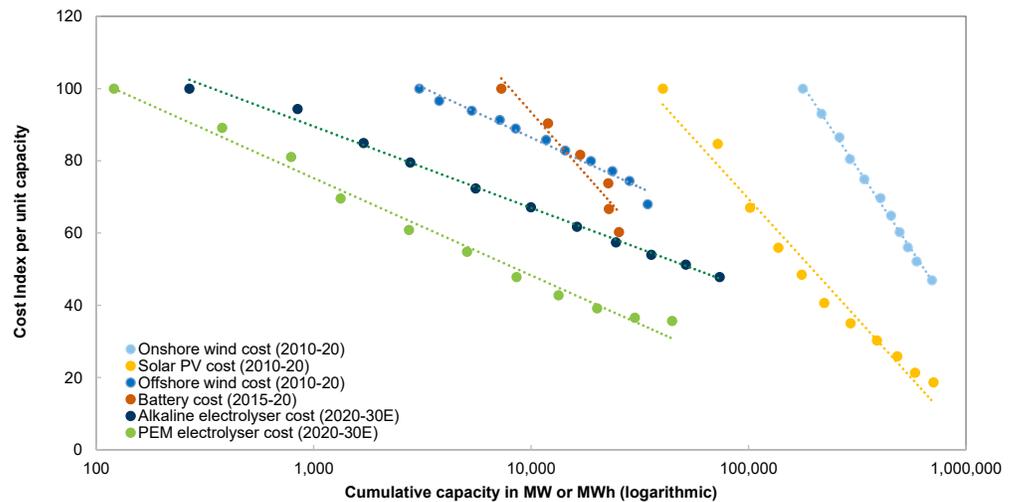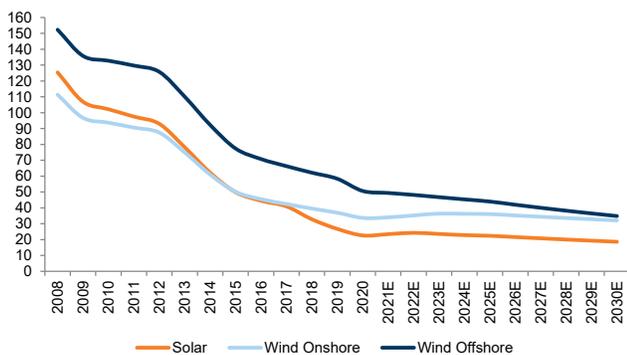

Source: IRENA, Goldman Sachs Global Investment Research

2) Renewable power: The reduction in the cost of renewable power a key enabler of the rise of the clean hydrogen economy

As mentioned earlier in the report, clean hydrogen forms a key interconnecting pillar between other critical de-carbonization technologies. In the case of green hydrogen, this refers to renewable power, with the two technologies inter-linked; green hydrogen requires renewable energy for its production and at the same time the energy storage capabilities (incl. seasonal) offered by green hydrogen could enable the larger uptake of renewables in the global power system. The reduction in the levelized cost of electricity (LCOEs) observed over the past decade is a key enabler of the emergence of the clean hydrogen economy. Solar PV LCOEs have fallen c.80% since 2010 while wind LCOEs have fallen by around 60% in a similar timeframe. This was driven by both ongoing operational cost reduction from economies of scale and a reduction in the cost of capital for these clean energy developments, contributing, on our estimates, c.1/3 of the cost reduction since 2010.

Exhibit 71: The LCOE for renewable power has reduced by c.80/60% for solar and wind, respectively, since 2010..
Levelized cost of electricity (LCOE, EUR/MWh)

Source: Goldman Sachs Global Investment Research

Exhibit 72: ..on the back of ongoing operational cost reduction from economies of scale and a reduction in the cost of capital for these clean energy developments, contributing c.1/3 of the cost reduction since 2010
Renewables LCOE % reduction from 2010 base, split between operational and financial (cost of capital)
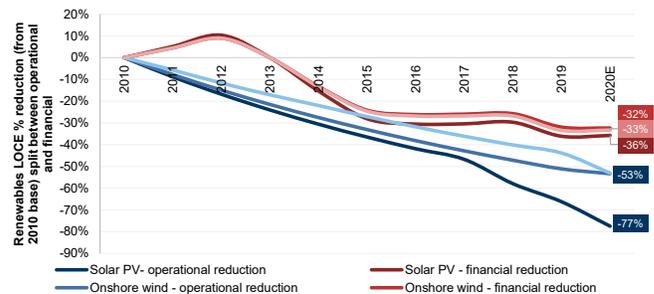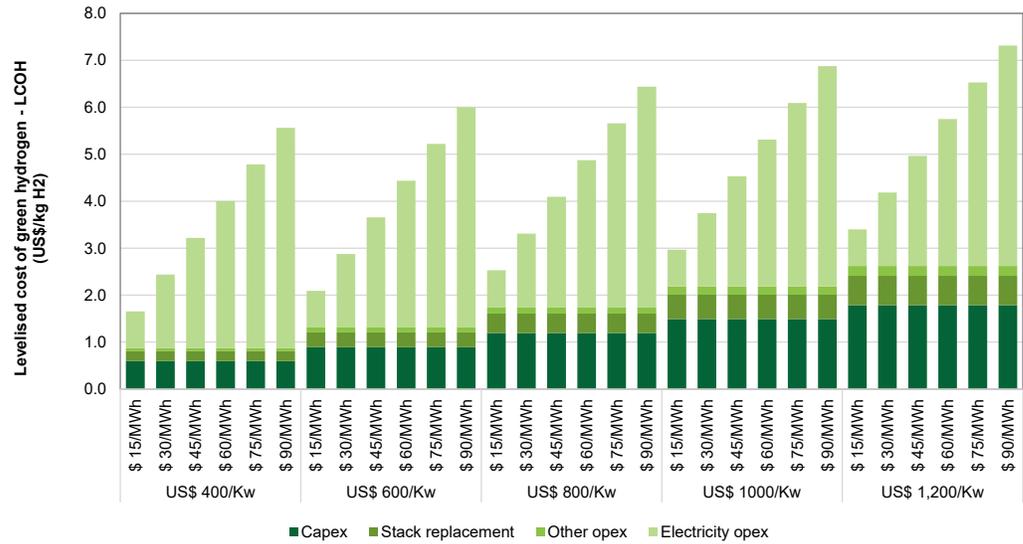

Source: Goldman Sachs Global Investment Research

In the exhibits that follow, we present our sensitivity analysis of the impact of the cost of power and the cost of the electrolyzer system on the resulting levelized cost of hydrogen (LCOH). As shown below, the cost of electricity has the potential to materially influence the resulting cost of 'green' hydrogen. Overall, we estimate that for an electrolyzer of an efficiency of 64% operating for 5,000 full load hours, an LCOE that is lower than c.US$30/MWh is required to be at cost parity with 'blue' hydrogen, and lower than c.US$20/MWh to be at cost parity with 'grey' hydrogen. This can be improved by a reduction in the cost of electrolyzer as well as an improvement in the electrolyzer efficiency and higher utilization, which we will address in a later section.

Exhibit 73: The LCOE and electrolyzer capex are the two key contributing factors to the levelized cost of 'green' hydrogen, which we estimate can vary from US$2-7/kg H2 currently

Levelized cost of 'green' hydrogen (US$/kg H2)

Source: Goldman Sachs Global Investment Research

Exhibit 74: Overall, we estimate that for an electrolyzer of an efficiency of 64% and operating for 5,000 full load hours, an LCOE that is lower than c.US$30/MWh is required to be at cost parity with 'blue' hydrogen, and lower than c.US$20/MWh to be at cost parity with 'grey' hydrogen

Levelized cost of green, blue and grey hydrogen under different electrolyzer capex assumptions
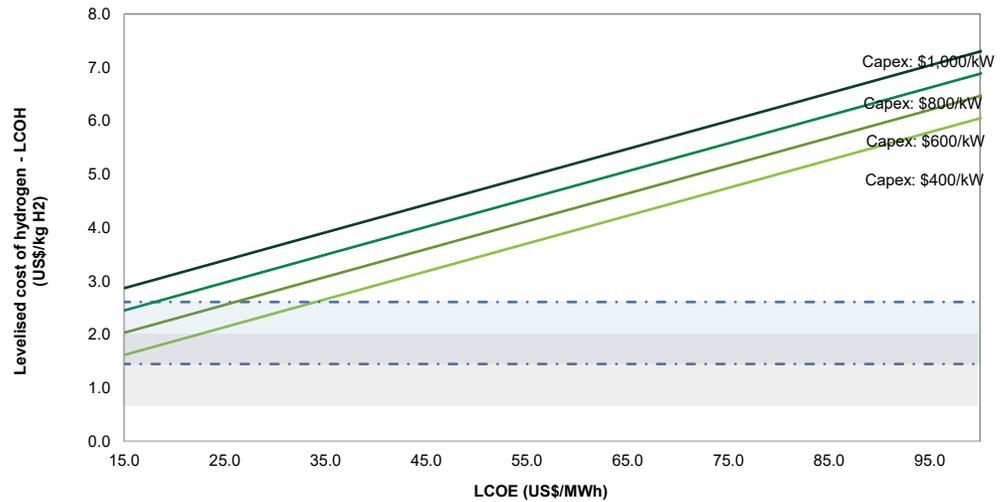
Source: Goldman Sachs Global Investment Research

3) Higher utilization and improved efficiency have the potential to drive further cost reduction

In addition to the cost of electricity and the electrolyzer system, the full load hours of operation (load factor) of the electrolyzer as well as the electrolyzer efficiency (which ultimately determines the amount of electricity to be used per kg produced) are two other relevant parameters that can influence the overall cost as the industry grows and ongoing investment and technological innovation enhances system optimization. In the exhibits below, we present how the levelized cost of hydrogen (LCOH) varies with LCOE for different utilization levels and electrolyzer efficiencies.

Overall, as shown in Exhibit 75, higher utilization of the electrolyzer reduces the LCOH, yet the reduction becomes less significant once utilization exceeds 4,000 full load hours (c.46% load factor), and as the capex of electrolyzer reduces (as shown by the lower curve steepness for a $750/kW electrolyzer compared to a $1,100/kW one). Nonetheless, the ultimate utilization depends on the final electrolyzer system owner and the nature of the project (higher utilization levels typically for ones connected on the grid compared to distributed renewable power). Similarly, higher efficiency reduces the operating electricity cost, as expected, resulting in lower LCOH.

Exhibit 75: Higher utilization can contribute to LCOH reduction yet it becomes less important once this exceeds 45% and as the cost of electrolyzer reduces..
Levelized cost of hydrogen for different utilization and electrolyzer capex levels (US$/kg H2)
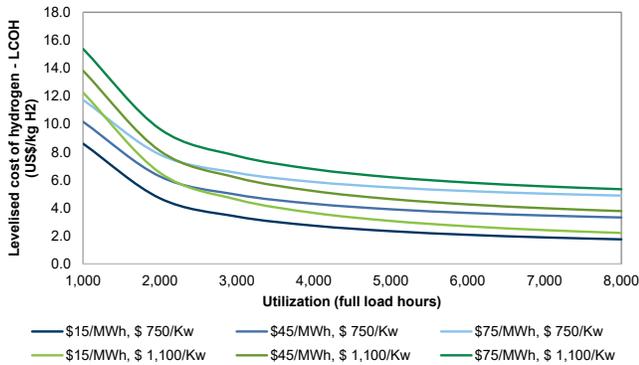
Source: Goldman Sachs Global Investment Research

Exhibit 76: Efficiency improvements can reduce the operating cost associated with electricity use, yet its impact on the LCOH is less when compared to the LCOE or cost of the electrolyzer
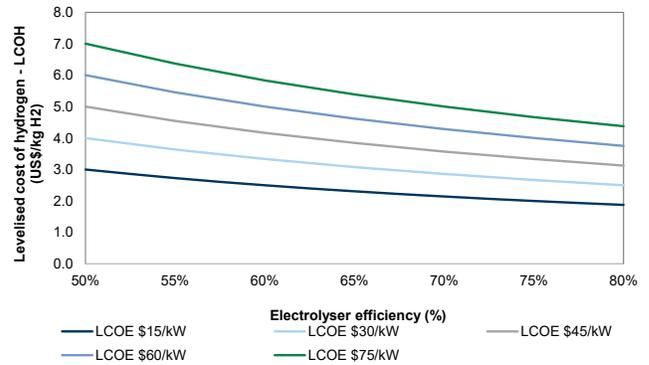Levelized cost of hydrogen for different electrolyzer efficiencies (US$/kg H2)

Source: Goldman Sachs Global Investment Research

Unlocking green hydrogen cost parity with grey hydrogen before 2030

As outlined earlier in the report, our global GS hydrogen scenarios all show stellar growth of the clean hydrogen economy with scope for between 65 and 180 GW of electrolyzer capacity to be installed by 2030. This represents **a remarkable 200-600 fold increase**, **making this decade a critical one for the development of the clean hydrogen economy.** 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 utilization is likely to increase too as the de-carbonization process unfolds. 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. Exhibit 77 presents our estimates for the evolution of green and blue hydrogen over time, in the absence (top) and presence (bottom) of global carbon pricing.

Exhibit 77: Green hydrogen can achieve cost parity with grey hydrogen before the end of this decade, depending on the regional gas price. As global carbon prices increase, the path towards cost parity accelerates
Levelized cost of grey, blue and green hydrogen over time (US$/kg H2)
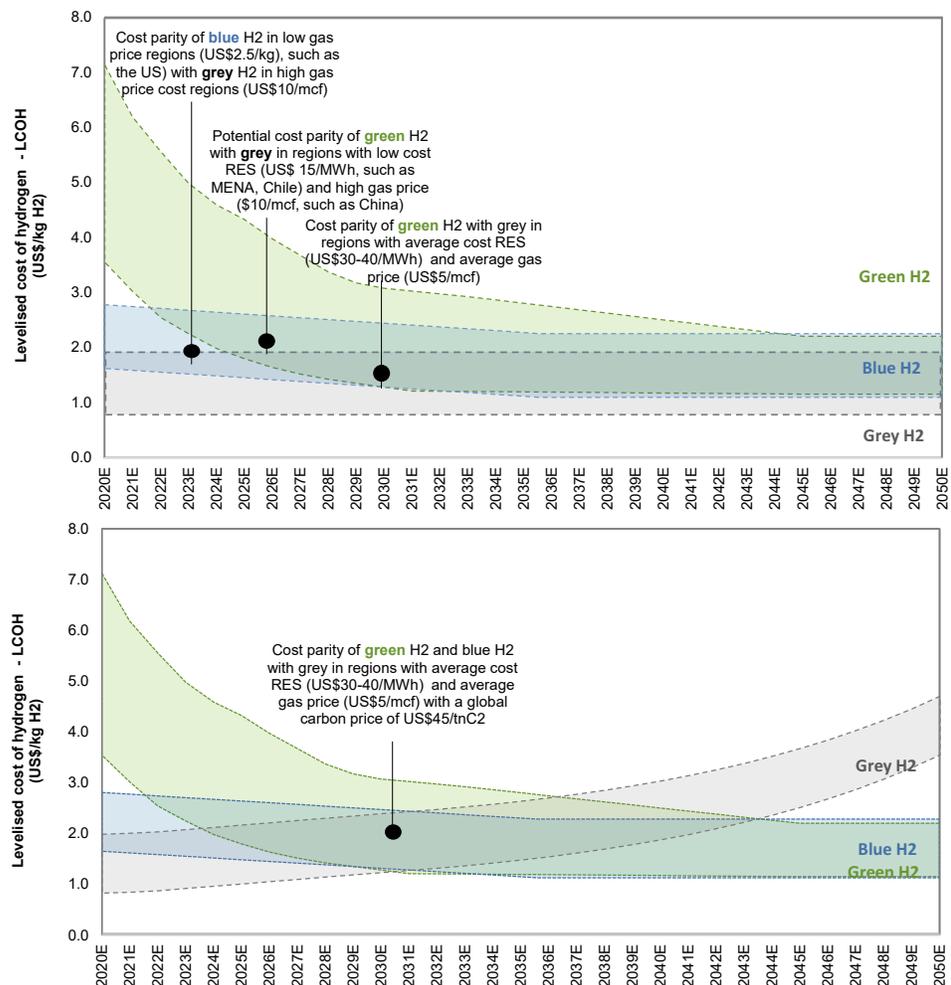
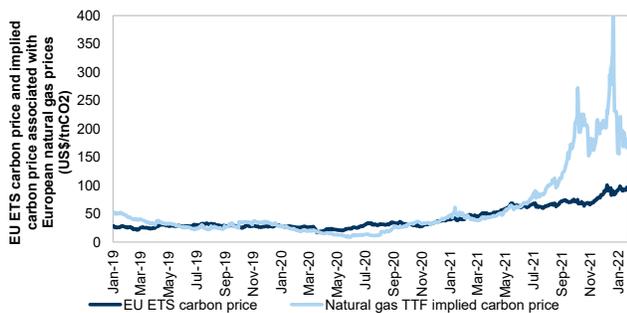Source: Goldman Sachs Global Investment Research

The case of Europe: Higher natural gas and carbon prices tilt the scale in favor of green hydrogen with cost parity already achieved in key parts of the region

Higher natural gas prices and carbon prices are creating a unique dynamic, with green hydrogen already reaching cost parity with grey across key parts of the region..
While green hydrogen's move towards cost parity with grey hydrogen is accelerating, and we expect this to be reached before 2030 across regions of low renewable power costs, **we note that the current macro dynamic of structurally higher commodity prices, and 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. We estimate that the carbon price implied by the current higher natural gas price environment in the region is equivalent to >US$150/tnCO2eq (when accounting for the scope 1,2,3 carbon intensity of natural gas) while European ETS carbon prices also continue to edge higher, currently approaching US$100/tnCO2eq. This is sufficient to bridge the cost of grey hydrogen with green across regions of Europe with a renewable power LCOE lower than US$50/MWh.

Exhibit 78: Higher European carbon and natural gas prices are already creating a unique dynamic in the region..
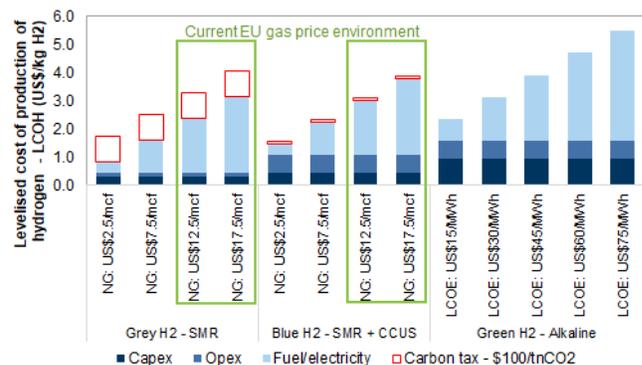EU ETS carbon prices and carbon prices implied by natural gas prices in Europe (TTF) in US$/tnCO2eq

Source: Thomson Reuters Datastream, Goldman Sachs Global Investment Research

Exhibit 79: ..with green hydrogen reaching cost parity with grey for regions with renewable power availability <US$50/MWh
Levelized cost of production of hydrogen - LCOH (US$/kg H2)

Source: Goldman Sachs Global Investment Research

..providing an incentive for the region to escalate its efforts in clean hydrogen
The current natural gas price situation in Europe is encouraging the acceleration of efforts to scale up the clean hydrogen economy. In particular, the Energy Networks Association announced in a statement in January that the UK's gas grid could be ready to blend up to 20% hydrogen into the gas networks across the country from 2023, a more than doubling of the current blending. Germany is also expanding its efforts here, approving in December EUR900 mn (around US$1 bn) into a funding scheme to support green hydrogen. In December 2021, the EU Commission has also proposed a new EU framework to de-carbonize gas markets, promoting hydrogen.

Scaling-up: The clean hydrogen projects pipeline is expanding at an unprecedented pace, tracking the GS 'bull' scenario to 2025

Global installed capacity of 'green' hydrogen projects is accelerating with Europe, Australia, Latin America, and the Middle East leading project pipeline growth..

We have addressed the global hydrogen demand opportunity and evolution under our three GS global hydrogen models as well as the key technological developments in the space in previous sections of the report. In this section, **we utilize our clean hydrogen projects database** to look at the current supply and project pipeline trends that have started to emerge. We track the development of >600 clean hydrogen projects across all key regions globally.

While, as highlighted previously, the **total installed electrolyzer capacity was only around 0.3 GW by the end of 2020, the current projects pipeline would suggest this grows to close to 80 GW by end-2030,** including projects currently under construction, having undertaken FID (final investment decision) and pre-FID (feasibility study), and assuming projects meet the guided start-up timeline. If we were to consider projects in earlier stages of development (pre-feasibility study stage, 'concept' projects), then this figure would go close to 120 GW. While this would appear to trend in line with our 'Bull' case scenario to 2025, we note that not all of these projects are likely to materialize in line with their guided timeline, with projects under construction and those that have reached final investment decision (FID) only accounting for c.7 GW. On the other hand, while our projects database is comprehensive and captures, we believe, the vast majority of near-term projects (to 2025E), we note that given the lead project times many of the projects for the second half of this decade (2026-30E) have not yet been announced and are therefore not captured here, implying further upside in the second half of this decade and explaining the flattening of the red line in the exhibit below post 2028E.

Exhibit 80: The current projects pipeline suggests installed capacity growth in the near term that could track our bull scenario..

Global installed electrolyzer capacity (GW) under the three GS scenarios compared to installed capacity implied by planned projects (red line)
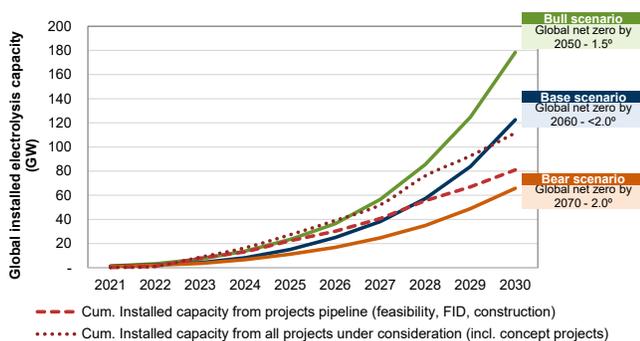
Exhibit 81: ..but with the vast majority of these projects not yet reaching a final investment decision (in feasibility study stage)

Installed electrolyzer capacity additions split by project status (MW)

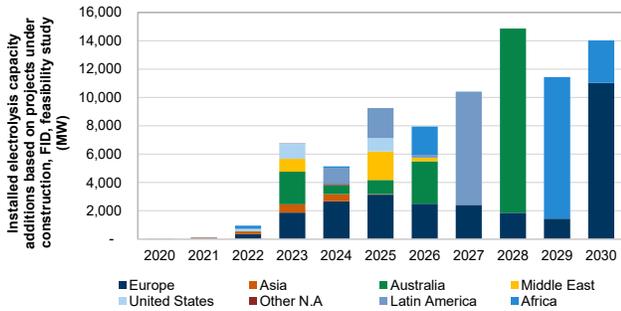Source: Goldman Sachs Global Investment Research
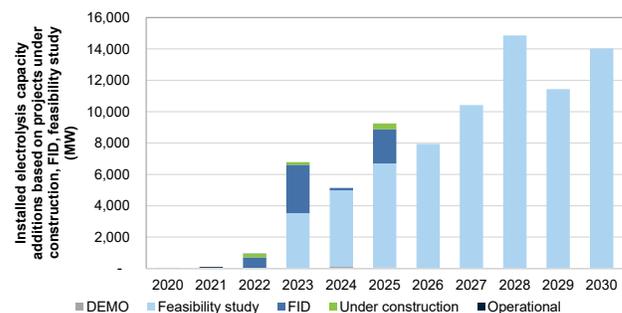
Source: Goldman Sachs Global Investment Research

From a regional perspective, we see the majority of capacity additions stemming from Europe and the Middle East in the near term (2021-25E) and from Australia, Europe, Latin America and Africa post 2025E. Europe, in particular, is leading planned electrolyzer capacity additions with c.27GW cumulative to 2030E, followed by Australia (c.20 GW), Latin America (c.13 GW), Africa (15 GW) and the Middle East (c.3 GW). Capacity additions by key region and cumulative annual installed capacity are presented in Exhibit 82 and Exhibit 83.

Exhibit 82: Europe, Australia, Latin America and the Middle East lead the green hydrogen projects pipeline this decade..
Installed electrolyzer capacity additions based on projects under construction, FID, feasibility

Source: Goldman Sachs Global Investment Research

Exhibit 83: ..with global installed electrolyzer capacity reaching c.80 GW by 2030, a >250-fold increase if the projects currently planned materialize in line with their guided timeline
Cumulative installed electrolyzer capacity by year-end (GW)
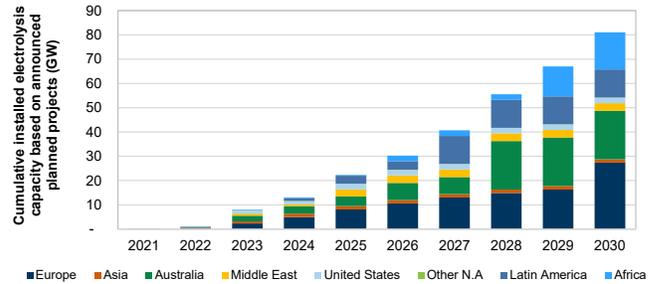
Source: Goldman Sachs Global Investment Research

..with project sizes entering a GW scale and unlocking benefits associated with economies of scale that would aid electrolyzer systems' cost reduction

The industry is not only scaling up in terms of the number of projects currently in the pipeline but also in terms of the average size of these projects. We estimate the average size of projects increasing from c.2 MW in 2020 to c.200 MW by 2025 and a GW scale by 2030 with a number of GW-scale projects currently in the pipeline as well, particularly post 2024, as shown in Exhibit 85. Among these are the NEOM project in Saudi Arabia (2 GW), the Central Queensland CQ-H2 project (3 GW) in Australia, the H2 Magallanes project of TotalEnergies in Chile (8 GW), the main green hydrogen project (14 GW), and the NortH2 project in the Netherlands (4 GW).

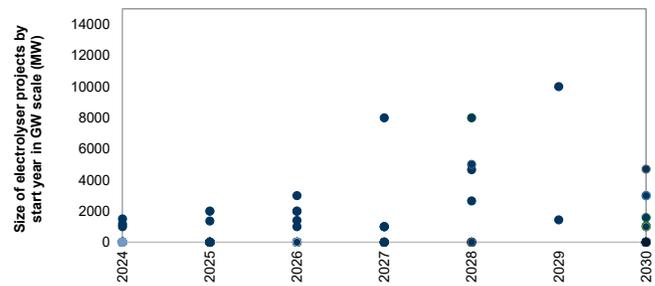**Exhibit 84: The average size of projects is rapidly increasing...**
Size of electrolyzer projects by project start year (MW)
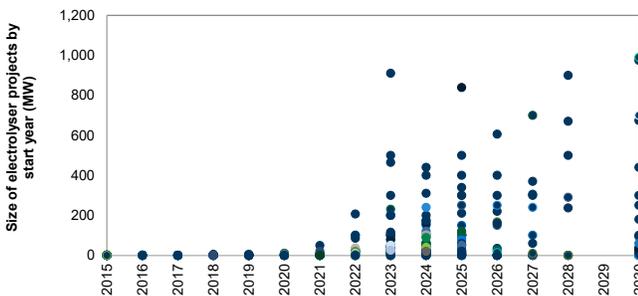
Source: Goldman Sachs Global Investment Research

Exhibit 85: ..reaching GW scale before the middle of this decade
Size of electrolyzer projects by start year, focusing on projects with >1 GW capacity

Source: Goldman Sachs Global Investment Research

Europe and Australia offering greater support (in terms of funding) for clean hydrogen projects

This new generation of hydrogen projects is primarily focused in regions such as Europe and the Middle East in the near term (2021-25E) and in Australia, Europe, Latin America and Africa post 2025E. Europe and Australia are the two regions in particular which are leading planned electrolyzer capacity additions with c.27/20GW cumulative to 2030E, respectively (from projects in feasibility study stage, FID, and under construction but excluding concept projects). This is not surprising to us given the two regions offer among the greatest availability of funding for green hydrogen projects, as shown in the exhibit below. Germany, in particular, has been key to unlocking Europe's green hydrogen potential, having approved at the end of last year EUR900 mn for green hydrogen projects (as part of the innovative funding instrument H2Global).

Exhibit 86: Europe and Australia are the two regions offering the greatest hydrogen project support and therefore dominating the near-term project pipeline
Average annual funding potentially available for hydrogen projects (US$bn, as of mid-2021)
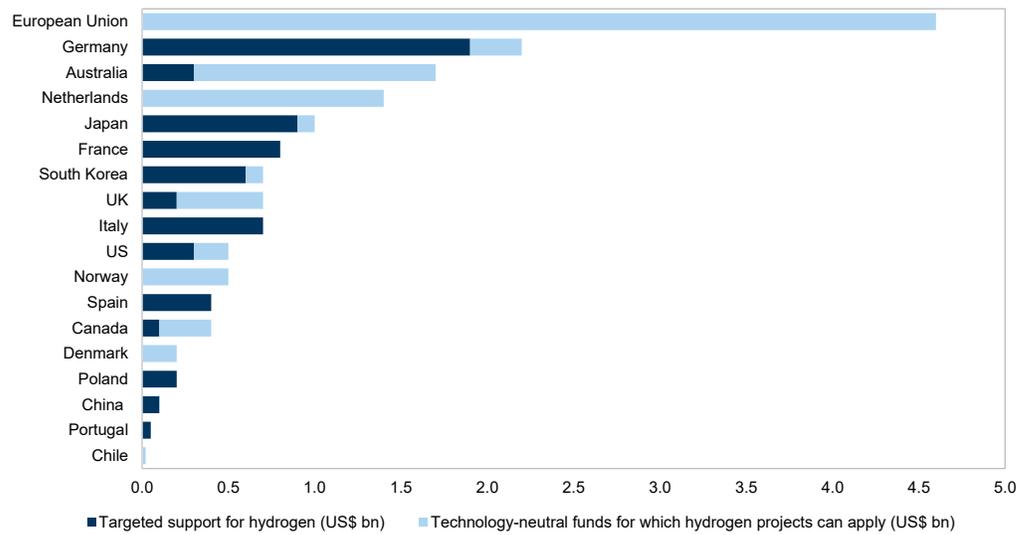
Source: IRENA adopted from BNEF

## Blue hydrogen projects are also gaining momentum, typically occurring at larger scale compared to green and more regionally concentrated

While green hydrogen projects are accelerating at an extraordinary pace, as outlined above, the blue hydrogen project pipeline is also gaining momentum. Hydrogen production methods using the natural gas reforming process and from coal using gasification are well-established technologies and currently dominate existing global hydrogen supply and hydrogen production plant assets. However, both are carbon intensive routes for hydrogen production, making carbon capture technologies necessary for emissions abatement in these plants. CCUS is important in the production of low-carbon hydrogen from fossil fuel sources for three important reasons: (1) it can aid the reduction of up to 90% of emissions from the existing hydrogen plants across refining, ammonia, methanol and other chemical plants, (2) its application does not require the retirement of existing assets, avoiding therefore the debate around stranded assets, particularly in regions of the world where industrial plants are still relatively young compared to their useful life, and (3) it can offer the potential for scale-up of low-carbon hydrogen production in regions of the world where renewable power resource availability may be constrained or unreliable. We go into further detail on the various carbon capture technologies and current state of the market in a later section of the report.

Out of the current c.40 MtCO2 pa global carbon capture capacity in operation, around two-thirds is attributed to natural gas processing facilities, given the high carbon dioxide concentration in the resulting stream that ultimately reduces the cost of carbon capture. Based on our compiled projects database, we estimate that around 16 projects are currently producing hydrogen from fossil fuel routes combined with CCUS, with annual production of around 0.7 MtH2 in 2020 (according to the IEA), which also captures close to 10 Mt CO2 (c. one-fourth of the total global carbon capture operating capacity).

Exhibit 87: The pipeline of blue hydrogen projects is also gaining momentum, particularly in Europe and North America (the US and Canada)..
Cumulative operating capacity of blue hydrogen projects split by key region (MtCO2 captured)
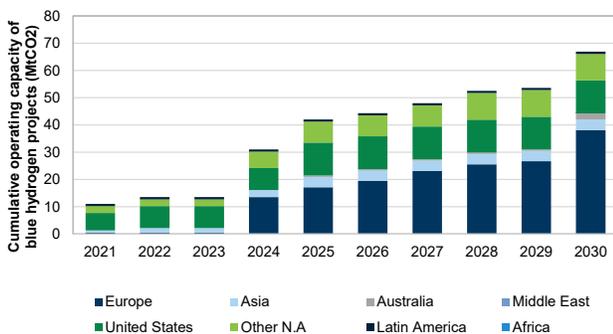
Source: Global CCS Institute, Goldman Sachs Global Investment Research

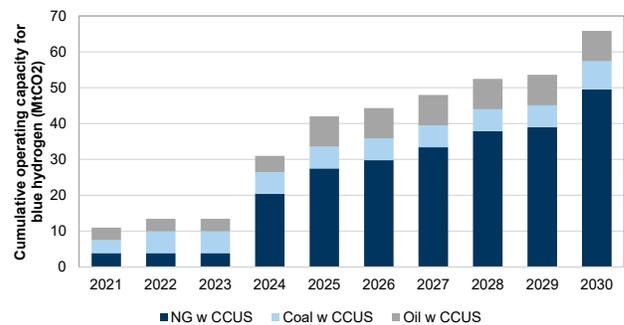**Exhibit 88: ...where the majority of the existing fossil-based hydrogen producing plants are natural gas SMR/ATR plants**
Cumulative operating capacity for blue hydrogen split by source (MtCO2 captured)

Source: Global CCS Institute, Goldman Sachs Global Investment Research

Addressing the remaining hydrogen value chain: Hydrogen conversion, transport and storage unlock a new infrastructure opportunity

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 (low MIE) present important technological and infrastructure challenges to its large-scale adoption. If natural gas was used as a direct comparable for the development of the hydrogen value chain, it would be expected that hydrogen's initial acceleration and use is likely to be more locally concentrated (hydrogen hubs) while a large-scale globally integrated value chain is likely to take longer to emerge. We note, however, that there are key differences between the two gases, which may alter the trajectory and pace of development of hydrogen from a local to a global market. Its nature (from a chemical and physical perspective) may imply that global market emergence is more challenging, while, on the other hand, the extraordinary engagement and focus of corporates and investors on the theme of de-carbonization and hydrogen's necessity for net zero aspirations may accelerate its development leading to the emergence of a global market faster than what has been observed for natural gas.

Exhibit 89: Hydrogen has very high energy gravimetric density compared to other fuels..
Gravimetric energy density (MJ/kg)
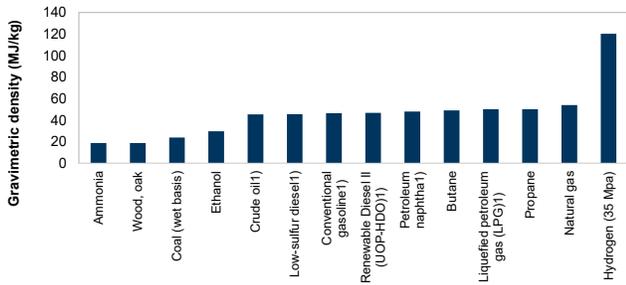
Source: DOE, EIA, Goldman Sachs Global Investment Research

Exhibit 90: ..yet it has very low density in its ambient gaseous form, making conditioning a necessity for effective transportation
Hydrogen and hydrogen carriers' density (kg H2/m3)
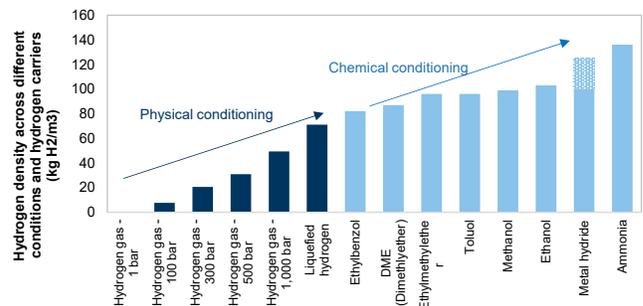
Source: H2Tools, DOE, Goldman Sachs Global Investment Research

Exhibit 91: The very low liquefaction point of hydrogen makes liquefaction more energy intense/costly compared to natural gas..
Liquefaction temperature of different fuels
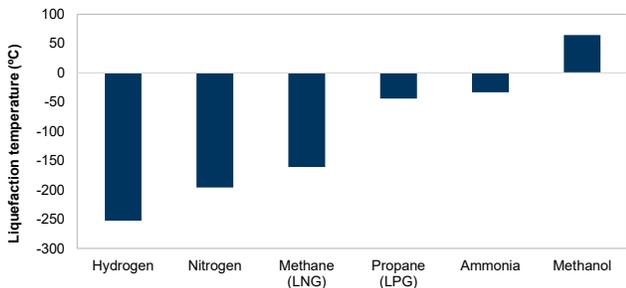
Source: US DOE, Goldman Sachs Global Investment Research

Exhibit 92: ..and its low MIE (high flammability) makes the fuel more challenging to handle
Minimum Ignition Energy, MIE (MJ)
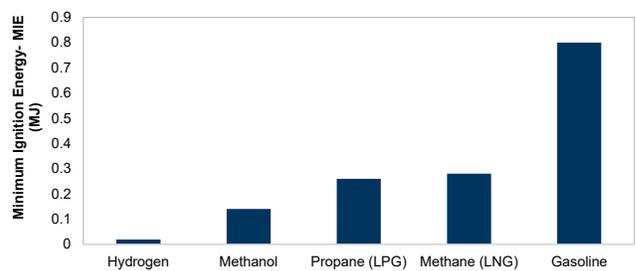
Source: EIA, H2Tools, Goldman Sachs Global Investment Research

Hydrogen conditioning a prerequisite before hydrogen transport and storage to increase energy density

As shown in Exhibit 90, while hydrogen has very high energy density per unit mass, it has very low density per unit volume, making transportation, distribution and storage challenging. As such, hydrogen conditioning is a prerequisite and not an option. Hydrogen conditioning is broadly classified into two categories, physical and chemical conditioning; physical conditioning encompasses all processes which change the physical conditions of hydrogen but do not interfere with its chemical properties. These include the change of pressure (pressurized hydrogen) as well as changes in the physical state, such as liquefaction or cryo-compression. Chemical conditioning on the other hand entails the transformation of hydrogen into a different chemical compound for which hydrogen is a constituent element, a hydrogen carrier such as ammonia, methanol, liquid organic hydrogen carriers (LOHCs), and metal hydrides.

We summarize the key routes of hydrogen conditioning (conversion and re-conversion) in Exhibit 93 and Exhibit 94, including key considerations of each route, overall efficiency of conversion and re-conversion, the resulting energy density of hydrogen, the stage of development, and key advantages and disadvantages of each. While the intention is not to take a view on the likelihood of the most successful hydrogen transport and storage technology, we highlight that the end market and its location are ultimately likely to determine the chosen conditioning (as well as the cost and availability of necessary infrastructure), and further note that compression appears to be an attractive option for local handling, while ammonia, methanol and LOHCs appear a more suitable solution for long-haul, seaborne transportation compared to liquefied hydrogen.

Exhibit 93: Hydrogen conditioning either through physical transformation or chemical combination is required for the storage, transport, distribution of hydrogen, unless consumed directly onsite post production
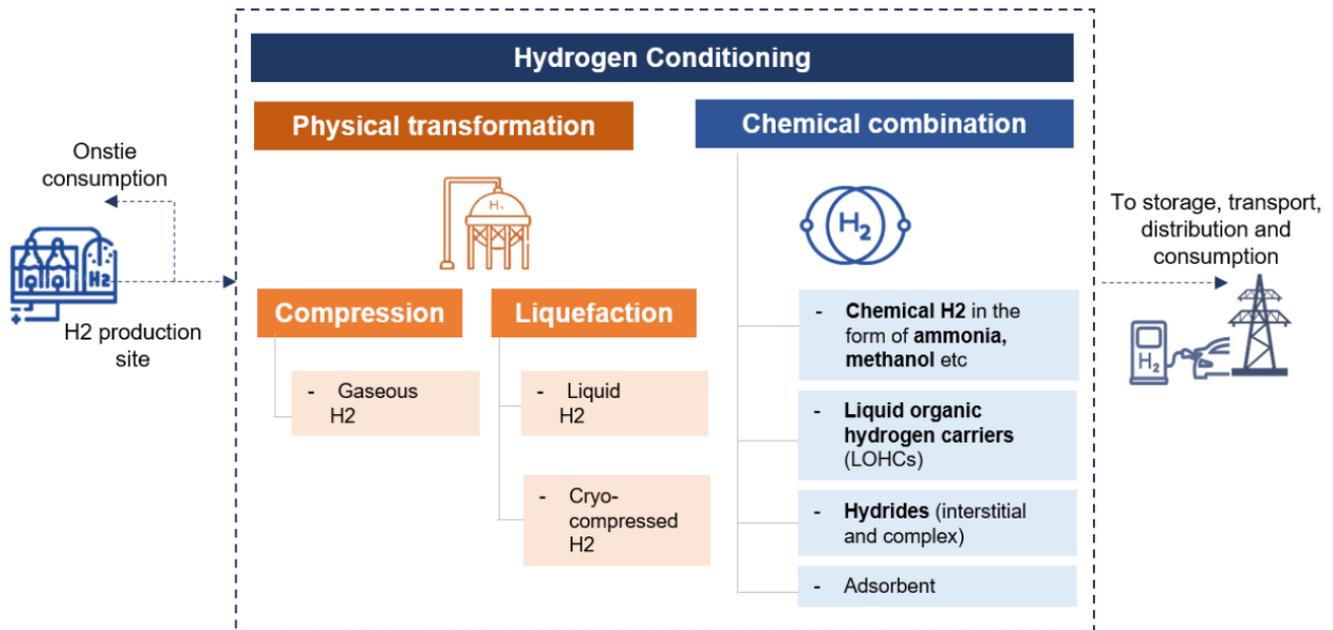
Source: US Department of Energy, Goldman Sachs Global Investment Research

Exhibit 94: Summary of key hydrogen conditioning pathways (conversion and reconversion)

Hydrogen conditioning		Process description	Process maturity	Energy requirement		Density	Pros	Cons
				kWh/kg h2	% LHV	kg H2/M3		
Physcial	Gas at 150 bar	Compression of H2 gas to desired pressure increasing density		c. 1	>90%	11	Relatively efficient, mature technology occuring at ambient temperature. PEM technologies already produce high pressure hydrogen	Hydrogen gas is flammable and more challenging to handle at high pressures
	Gas at 350 bar			c. 4	>85%	23		
	Gas at 700 bar			c. 6	80%	38		
	Liquefied H2	Cooling at -253 through cryo-compression		c. 9	65-75%	71	Could unlock global trade potential and could be economically viable in regions of high demand with limited space	Higher enery intensity, cost and energy losses compared to LNG conversion
Chemical	Ammonia, NH3	Reaction with nitrogen for conversion and then reconversion back to H2		c. 3 for conversion and c. 8 for reconversion	82-93% for conversion and c. 80% for reconversion	121	Could unlock global trade potential with a mature industry that has the potential to leverage existing infrastructure	High energy requirement (and therefore lower efficiency) for reconversion, toxicity and air pollution
	Methanol, MeOH	Hydrogen with carbon monoxide (syngas) react to form methanol		NA, GS assumption for similar to ammonia		99	Could unlock global trade potential with a mature industry that has the potential to leverage existing infrastructure	Relatively lower toxicity compared to ammonia
	Liquid organic hydrogen carriers (LOHC)	Mixing with a LOHC such as MCH and convert back to H2		Conversion exothermic, c. 12 for reconversion	c. 65% for reconversion	110	Conversion is exothermic	Low efficiency at reconversion, toxicity, flammability and availability of toluene
	Metal hydrides	Chemical bonding with metals and then reheating back to H2		c. 4	88%	80-100	Higher efficiency than most alternatives	Storage unit can be heavy with long response times and lifetime

Source: Kearney Energy Transition Institute, IEA, Company data, Goldman Sachs Global Investment Research

Transportation and distribution of hydrogen: A function of volume, distance and type/form of hydrogen carrier

Transportation and distribution costs for hydrogen are a function of the **volume** transported, the **distance** and the **type of hydrogen carrier** (hydrogen conditioning pathway). For the purpose of this analysis, we therefore categorize transport and distribution into three areas: local distribution (<500 km), short transmission (<1000 km) and long-distance transmission (>1,000 km). The transport and distribution methods for hydrogen include pipelines, trucking and shipping, using a range of potential carriers. While the optimal distribution and transportation method will depend on the targeted end use and terrain to be covered, in general, the following conclusions could be reached depending on the distance considered.

- **Local distribution:** For local distribution, pipelines can achieve very low hydrogen transportation costs, particularly for retrofitted infrastructure utilizing existing assets, and therefore could be the preferred option for transportation. The exact cost depends on the availability of existing networks and suitable retrofitting (typically, gas pipelines made of steel would need a polymer retrofit to avoid hydrogen leakage and, given the higher leakage and ignition range which is about seven times that of methane, an upgrade to leak detection and flow control systems may be required), demand for high volumes of hydrogen and high utilization. Newly built hydrogen pipelines will require higher upfront capital expenditure than retrofitting, including the necessary network planning permits. Analysis by the European Hydrogen Backbone study and the Hydrogen Council suggests conversion costs are typically 10%-40% of the cost of a new hydrogen pipeline making retrofitting a more economically attractive solution. Overall, according to the IEA, depending on the pressure of hydrogen transported and the amount, the capital cost associated with hydrogen pipelines can be in the range of US$0.3-1.0 mn per km for local distribution (c.>10% higher than natural gas equivalent pipelines). Hydrogen pipelines today

cover around 5,000 km with the mast majority located in Europe and the US. Hydrogen pipelines, according to the Hydrogen Council, are notably cheaper compared to electricity transmission lines, and can transport 10x the energy at 1/8th the cost.

■ **Short-distance transmission:** For short-distance transmission (defined for the purpose of this report as transmission of distances up to 1,000 km), both onshore pipelines (which can cost c.US$0.6-1.2 mn for retrofitted and c.US$2.2-4.5 mn per km for new), as described above, and trucks appear to be competitive solutions, especially for distances above 500km. Today, hydrogen distribution mostly relies on compressed gas trailer trucks. Trucks and trailers using liquefied hydrogen or ammonia are also feasible.

In the exhibit that follows, we perform a simplified levelized cost of hydrogen transport analysis that compares different costs of transportation/distribution of hydrogen for local distribution and short-distance transmission (i.e. up to 1,000 km). Exhibit 95 presents solely the cost of transport, while Exhibit 96 includes the conversion (important for liquefaction) and reconversion costs incurred (for ammonia, LOHCs), providing a fairer representation of costs for comparison purposes. When looking at this exhibit, it is evident that the most economical distribution solution for hydrogen is retrofitted pipelines for distances <1,000 km, where those are available. Trucks (ammonia, LH2) only start to look more compelling at larger distances, while the cost of trucking gaseous hydrogen increases notably with distance.

Exhibit 95: The cost of transportation in the absence of conversion/reconversion costs would suggest that both trucking (ammonia, LH2, LOHCs) and pipelines appear competitive routes of transportation...
Levelized cost of transport of hydrogen (US$/kg H2)
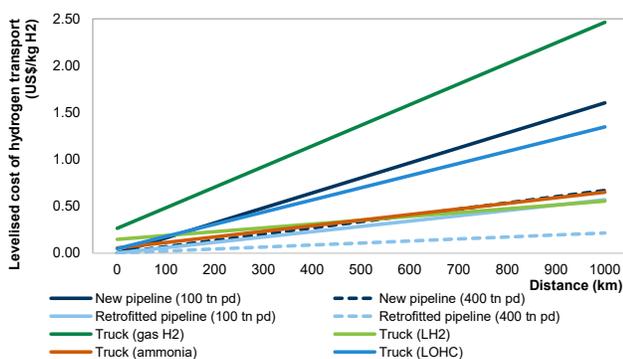
Source: Hydrogen Council, Goldman Sachs Global Investment Research

Exhibit 96: ..but pipelines (especially retrofitted) are the most economical solution for local and short-distance distribution/transmission once conversion/reconversion costs are considered
Levelized cost of hydrogen transport including conversion/reconversion cost (us$/kg H2)
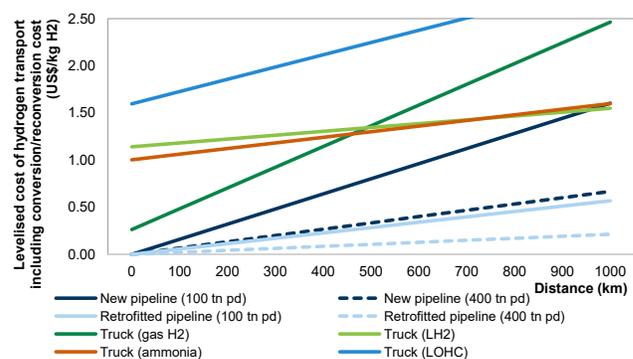
Source: Hydrogen Council, Goldman Sachs Global Investment Research

■ **Long-distance transmission:** For long-distance (>1,000km) transmission, pipelines (onshore and subsea) as well as shipping (in various forms such as ammonia, methanol, LOHCs and LH2) both appear to be feasible solutions, similar to the way natural gas mostly moves worldwide through pipelines or as LNG in ships. We note that for the global scale-up of the hydrogen economy, including international trade, developing solutions and the supply chain for long-distance and cross-sea transport

will be essential.

Pipelines for long-distance transmission, both onshore and subsea, depending on the terrain and distance, could be the most economical solution for distances up to 2,000-3,000 km, in particular retrofitted onshore pipelines. Subsea pipelines can cost 1.3-2.3x the cost of onshore ones, according to the Hydrogen Council. As the transmission distance increases, the cost of transporting gaseous hydrogen through pipelines increases at a faster pace than shipping in a liquid form (LH2, ammonia, LOHC) since a greater number of compressor stations are required. Similar to natural gas, shipping liquefied hydrogen could form a potential solution longer term, yet given the very low liquefaction point of hydrogen (-253°C), technological innovation is necessary to enhance the feasibility and economics (currently, it is a very energy intensive process and has relatively low efficiency, consuming about 1/3 of the energy of hydrogen). The expectation would be that these ships will be fueled by the hydrogen that boils off during the journey. Ammonia, methanol and LOHCs (such as toluene) for hydrogen transport by ship are the preferred options, as per industry players, as they do not require cryogenic conditions for liquefaction or handling and are some of the commonly used methods for long-distance transport today. These solutions appear more economic than pipelines and gaseous transport for distances >2,500 km. Efficiency, energy losses and costs associated with the conversion and reconversion processes are a key drawback of this route (in addition to toxicity for ammonia).

Exhibit 97: When considering the cost of long-distance transmission alone (excl. conversion and reconversion costs but incl. storage), transporting in the form of ammonia or LOHC appears particularly attractive...
Levelized cost of hydrogen long-distance transmission excluding conversion/reconversion cost (US$/kg H2)

Exhibit 98: ..but once conversion/reconversion costs are considered, this is only the case for distances >2,500 km
Levelized cost of hydrogen long-distance transmission including conversion/reconversion cost (US$/kg H2)

Source: Hydrogen Council, IEA, Goldman Sachs Global Investment Research

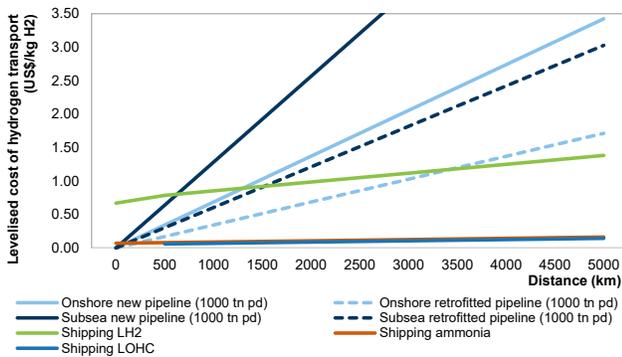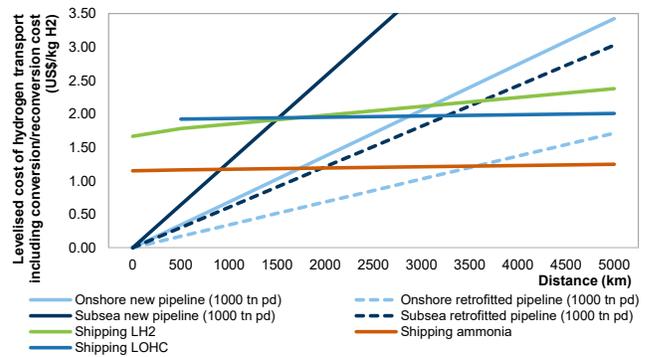Source: Hydrogen Council, IEA, Goldman Sachs Global Investment Research

Storage: Multiple options with storage duration, volume and geographical availability being the key determining parameters

Hydrogen storage is another core part of the hydrogen value chain with the scale-up of the clean hydrogen economy likely to increase the need for a wide variety of storage options suitable for different levels of volumes, duration of storage, and required speed of discharge as well as differing geographical availability.

Short-term, small-scale storage: For short-duration storage, typically required on a small-scale, daily basis, the use of pressurized containers is already a mature, widely adopted and economic storage solution. The costs associated with this are already below US$0.2/kg H2, making negligible contribution to the total cost of hydrogen delivery. These tanks tend to have high discharge rates and efficiencies (around 98%-99%). If the required storage extends beyond a couple of days, the capital costs of these vessels and compressors becomes a drawback given the high operational recycling rate required to make them economically feasible.

Medium and long-term storage (seasonal), large-scale: For large-scale, long-term storage, a variety of options exists, including salt caverns, depleted gas fields, rock caverns, and aquifers. These storage options are used for natural gas currently and could provide benefits associated with economies of scale, high efficiency and low operational costs. Of these options, salt caverns appear to be the most economically attractive (according to a report by BNEF, the levelized cost of storage of these can be below US$0.3/kgH2) while having around 98% efficiency and low risk of hydrogen contamination. Depleted oil & gas fields are typically larger compared to salt caverns, but they also tend to be characterized by higher permeability and may contain contaminants which would imply the need for their removal and purification of hydrogen before use, adding to the additional cost of storage. Worth noting that the feasibility and cost of storing hydrogen in depleted fields and in aquifers are largely still unproven, as these means of storage remain in early stages of development. Nonetheless, once viability is established, these options could offer the large-scale storage benefits required for seasonal energy storage, particularly useful in locations without salt caverns.

Exhibit 99: The cost of storage for hydrogen depends on the required volume, duration and geographical availability. Pressurized containers appear the cheapest option for small-scale, short-duration storage while caverns appear the most economically attractive solution for long-term, large-scale storage. Other liquid forms of storage exist with low storage cost but high conversion and reconversion costs associated with them (as well as comparatively lower efficiency)
Levelized cost of storage (inc. conversion/reconversion for liquid states) - US$/kg H2
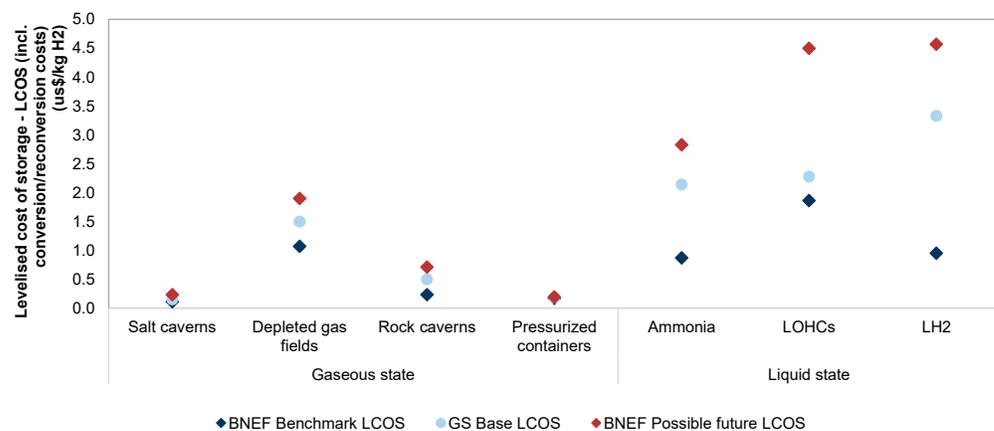
Source: BNEF, Goldman Sachs Global Investment Research

From a local to a global market: We see scope for c.30% of global clean hydrogen to be involved in international trade (cross-border transport)

International trade and potential key exporting and importing regions as hydrogen evolves into a global market

As the energy transition unfolds and hydrogen demand growth accelerates, international trade will likely be an important part of the clean hydrogen economy. While we believe that clean hydrogen is likely to first develop locally before becoming a global market, similar to what happened with natural gas and LNG, as demand more than doubles in the coming decades under all three of our GS global hydrogen demand scenarios, we believe that **an international hydrogen trade market is likely to emerge**. In this section, we therefore attempt to compare the levelized cost of clean hydrogen (considering both 'blue' and 'green') across key regions in the world, both under current costs (2021) and the potential 2030 outlook.

Overall, we identify two critical parameters that determine a region's ability to develop into a major clean hydrogen export hub: (1) The availability and cost of the required resources, renewable power in the case of 'green' hydrogen and the availability and cost of natural gas and carbon capture and storage capabilities in the case of 'blue' hydrogen; (2) the ability to produce beyond the quantity that is required to meet local regional demand, particularly important for the largest global hydrogen demand hubs (the US, Europe, Japan, Korea and China).

We present the outcome of our analysis in Exhibit 100 below for both 2021 and 2030. These exhibits present the levelized cost of hydrogen production (LCOH) across regions, with the wide variability in renewable power availability and costs (therefore LCOEs) as well as gas pricing and availability of carbon storage resulting in the observed differences of LCOHs across regions. While we present here simply the cost of production, the orange band is representative of the average global cost of transportation and conversion for hydrogen. The implication of this would be that regions with a LCOH below the lower bound of the orange band could export to regions with a LCOH above the upper bound of the orange band, as, even when the cost of transportation is considered, exported hydrogen cost would still below that of what is regionally produced. The colors for each region are representative of its potential role in international hydrogen trade, with green representing regions with potential to be green hydrogen exporters, blue for regions with potential to be blue hydrogen exporters and orange for regions with potential to be clean hydrogen importers. **Overall, we estimate that c.30% of the global hydrogen market could end up being involved in international trade (cross-border transportation).** This compares to c.25% for natural gas.

Exhibit 100: MENA, Chile, and Australia (among others) could emerge as key clean hydrogen exporting regions while Japan, Korea, Central Europe and potentially parts of East China could become clean hydrogen importing regions, depending on the scale and importance of clean hydrogen in their respective economies

Levelized cost of green and blue hydrogen (LCOH) in US$/kg under 2021 and 2030 assumptions
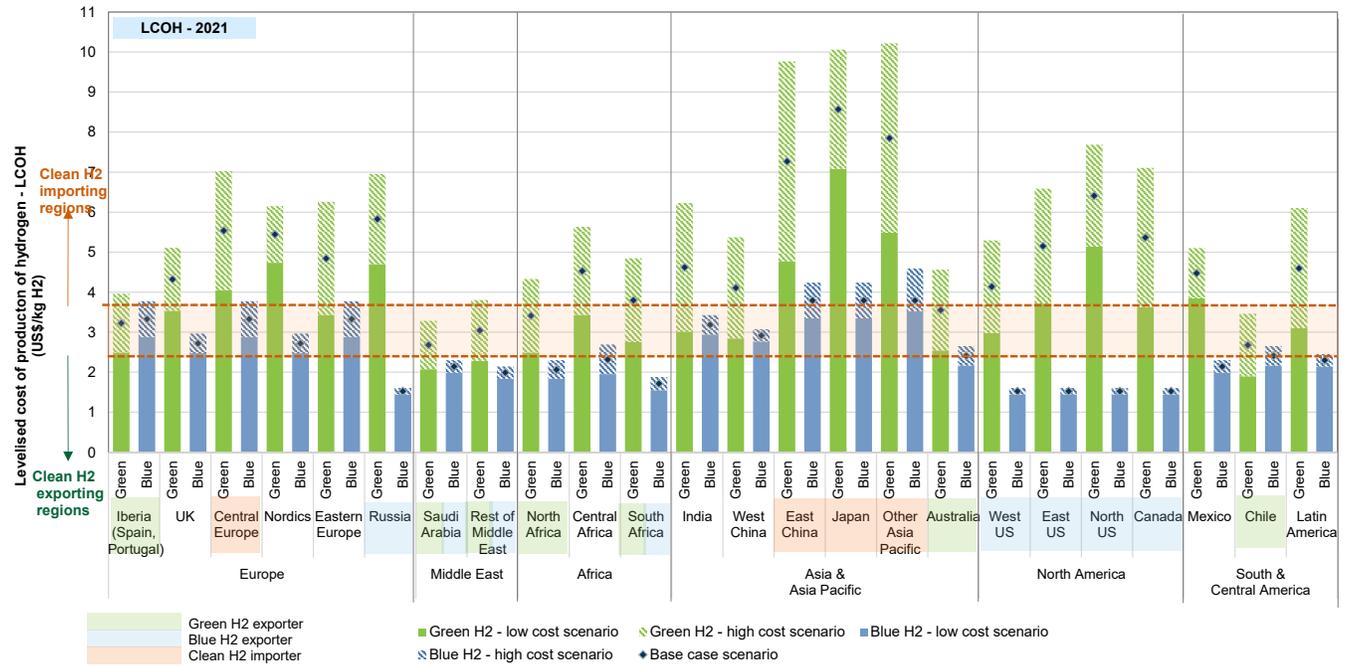
Source: Goldman Sachs Global Investment Research
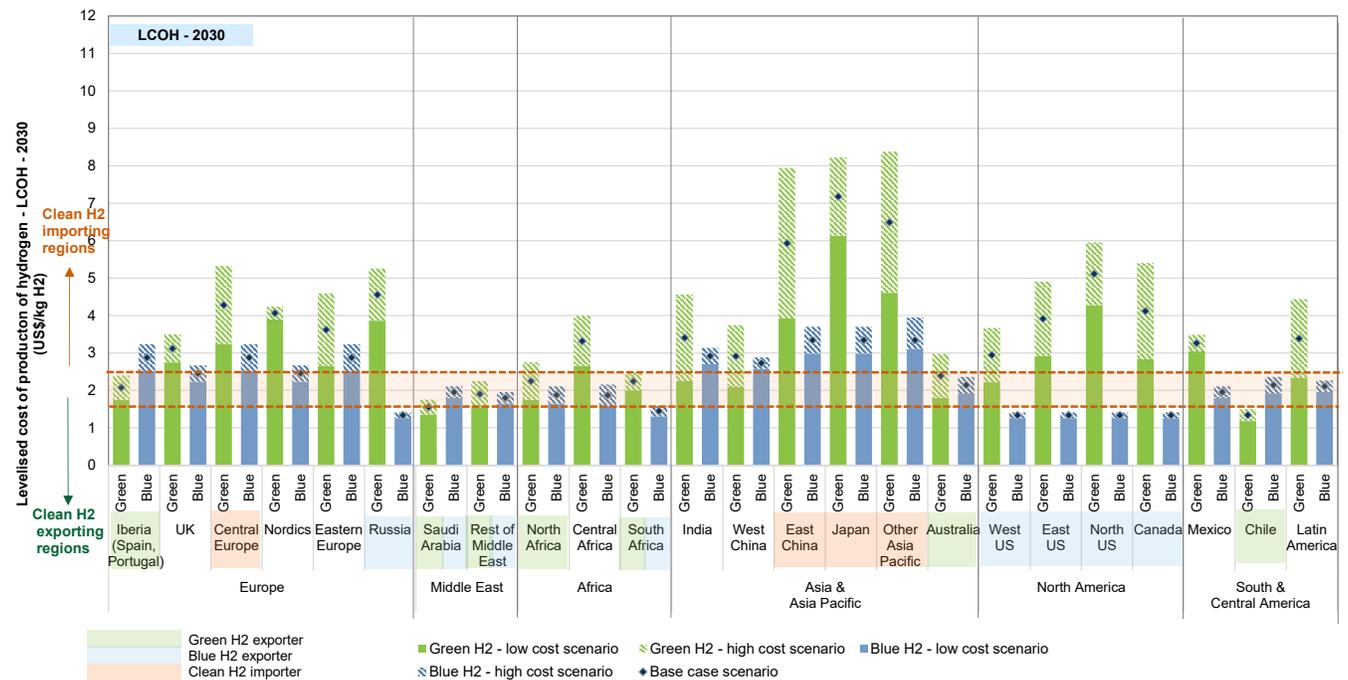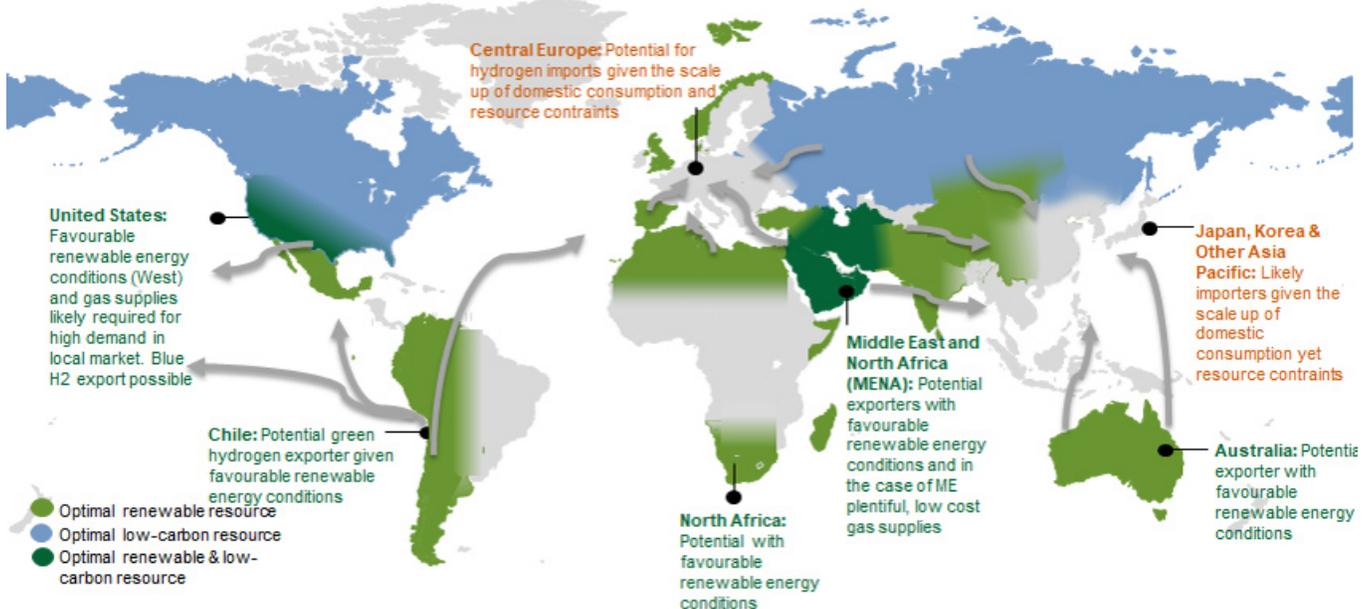

Source: Goldman Sachs Global Investment Research

MENA, Australia, Chile could emerge as the key clean hydrogen exporting regions among others

As shown in Exhibit 100, we believe the regions that have potential to become key exporters of clean hydrogen, especially once the seaborne market is considered, would be those that (a) have a vast availability of low cost renewable power resource or natural gas and carbon capture storage and, (b) will likely be able to supply clean hydrogen quantities larger than what is required to support their domestic demand. Three key regions appear to fulfill both of these criteria: the Middle East & North Africa, Australia and Chile and other LatAm. Australia, Chile and North Africa owe this to their vast, low-cost renewable power resource potential while the Middle East can rely on both its low cost solar power resource and its natural gas supplies and carbon capture and storage capabilities. While the US also fulfills the first criterion, we believe the domestic hydrogen economy may develop to a scale that is large enough to consume supply.

Japan, Korea and potentially Central Europe (among others) could emerge as clean hydrogen importing regions depending on the pace of hydrogen penetration in their local economies

Japan and Korea are two of the economies having potential clean hydrogen demand hubs, owing to the strong policy support (both regions have pledged net zero by mid-century) and appetite for the development of clean hydrogen as a key pillar of their domestic energy ecosystem and energy transition. Depending on the pace of hydrogen penetration in these regions, we see scope for both countries to become clean hydrogen importers longer term. Central Europe could also become a clean hydrogen importer, with the EU's Hydrogen Strategy aiming for 40 GW of domestically installed green hydrogen capacity by 2030, and another 40 GW from neighboring countries.

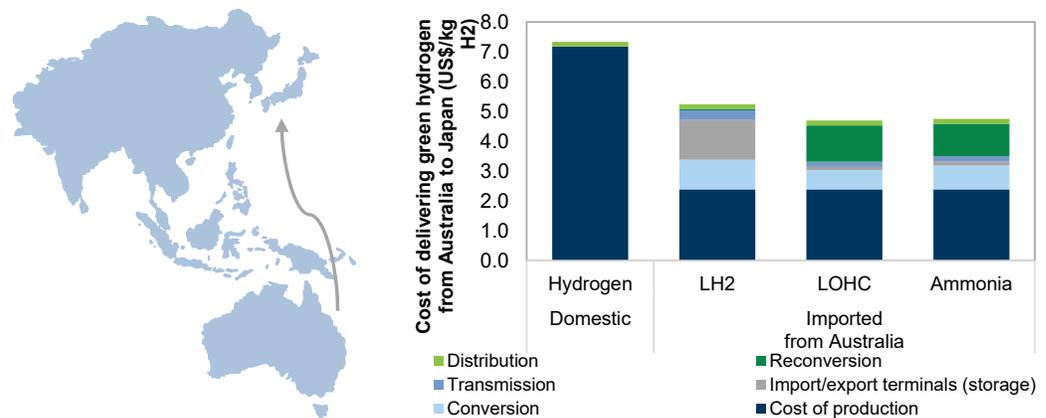**Exhibit 101: Potential evolution of an international clean hydrogen market**

Source: Compiled by Goldman Sachs Global Investment Research

Demonstrating an example of all-in costs for exporting green hydrogen from Australia to Japan

As demonstrated by our analysis above, we see potential for Japan to be a key importing region for clean hydrogen. While a number of regions could be suppliers, we demonstrate the all-in costs of importing green hydrogen from Australia as an example. We perform this analysis by comparing the domestic cost of production of green hydrogen and distribution to the end use in Japan to the all-in cost of importing it in the form of liquefied hydrogen, ammonia and LOHC from Australia. Our analysis indicates that even under the more costly liquefied green hydrogen route, imported green hydrogen from Australia is likely to be delivered at a lower cost than what is produced domestically, reaffirming our analysis presented earlier that Japan could emerge as a key clean hydrogen importer.

Exhibit 102: A summary of all-in costs of Japan importing green hydrogen from Australia under various forms

Source: Goldman Sachs Global Investment Research

Demonstrating an example of all-in costs for exporting green hydrogen from the Middle East to Europe

In the exhibit below, we perform a similar analysis for exporting green hydrogen (in various forms) from Saudi Arabia to the port of Rotterdam through the Suez Canal. We note that this example is specific to North-West and Central Europe (and particularly the Port of Rotterdam), acknowledging that the cost of renewable power and therefore the cost of production of green hydrogen can be higher or lower (in the case of Iberia for example) than indicated depending on the region. Our analysis indicates that North-West Europe would indeed benefit from importing green hydrogen from the Middle East or North Africa, even when the cost of transportation and conversion/reconversion are included. This is consistent with our analysis above and also with the EU's strategy to develop 40GW of installed electrolyzer capacity by 2030 but to also source hydrogen from another 40GW of installed capacity from nearby regions.

Exhibit 103: A summary of all-in costs for North-West Europe importing green hydrogen from Saudi Arabia under various forms
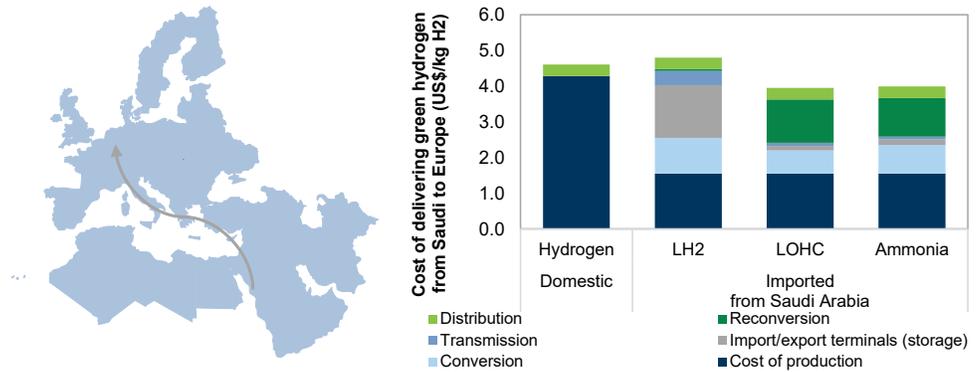

Source: Goldman Sachs Global Investment Research

Demonstrating an example of all-in costs for exporting green hydrogen from Chile to Europe

In 2021, the Ministry of Energy of Chile and the Port of Rotterdam Authority signed a Memorandum of Understanding (MoU) on the potential export of green hydrogen. In the year, the Chilean Ministry of Energy also signed a MoU with the ports of Antwerp and Zeebrugge to work together to make green hydrogen flows between Chile and Europe a reality. In the exhibit below, we present the potential all-in costs for the export of green hydrogen from Chile to Europe, and, more specifically, from Puerto Valparaiso, Chile, to the Port of Rotterdam, Netherlands. Indeed, exporting in the form of ammonia or other LOHC would provide a lower hydrogen delivery cost vs the cost of domestic production. Liquefied hydrogen costs, however, increase substantially with longer distances (in this case, we assume 17,900 km for the route between the two ports), making it a less attractive option economically.

Exhibit 104: A summary of all-in costs of North-West Europe importing green hydrogen from Chile under various forms
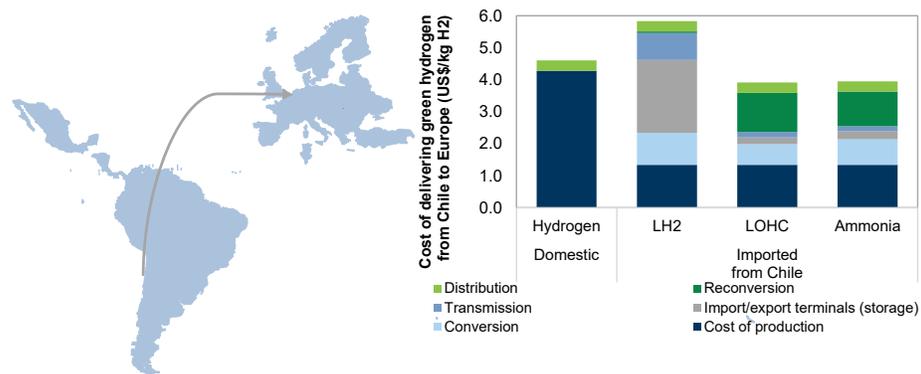
Source: Goldman Sachs Global Investment Research

Policy Toolbox: In search of a constructive hydrogen policy and pricing framework to move from ambition to action

While cost parity of clean with fossil-fuel hydrogen is nearing reality (supported by the higher commodity price environment and carbon prices), there is still a major need for a constructive hydrogen policy and pricing framework for harder-to-de-carbonize end markets

The current higher commodity price environment (particularly for natural gas) is helping achieve green hydrogen cost parity with fossil fuel-based hydrogen (grey) already across several regions of the globe. Even under normalized commodity prices, we estimate the carbon price required to bring green hydrogen production cost at parity with grey in a range of US$70-250/tnCO2 on average (for US$2/kg H2 grey hydrogen price), implying that current carbon prices observed in the EU ETS could already be sufficient to bridge the cost of production gap in low-renewable power cost regions in Europe. Similarly, we estimate that a carbon price in a range of US$50-120/tnCO2 is required to bridge the gap between the cost of production of blue hydrogen and that of grey across the globe (to compensate for the cost of CCS).

Despite the achievable carbon prices (implicit or explicit) required to bring clean hydrogen at cost parity with grey at the point of production, when considering the final delivered price of hydrogen (including costs across the value chain) and its use in new harder-to-abate end markets, our Carbonomics cost curve suggests a much higher range of carbon prices is required to incentivize clean hydrogen adoption and compete with current fossil fuel-relying technologies across the industry, transport, heating, and power generation.

Exhibit 105: While the European ETS carbon price has increased to record levels over the past year..
EU ETS carbon price (EUR/tnCO2eq)
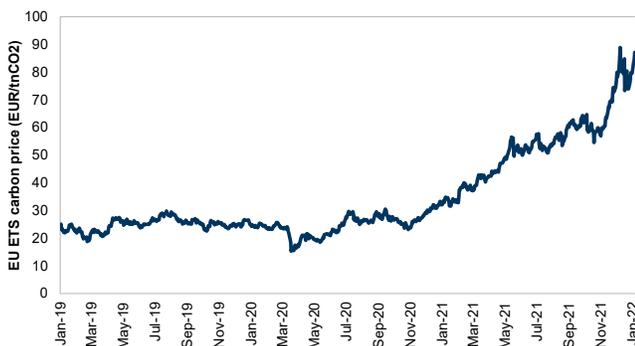
Source: Thomson Reuters Eikon

Exhibit 106: ..carbon prices associated with global national and sub-national carbon price initiatives (carbon taxes & ETS) show a wide regional variability..
Carbon prices through taxes and ETS (mid-2021)
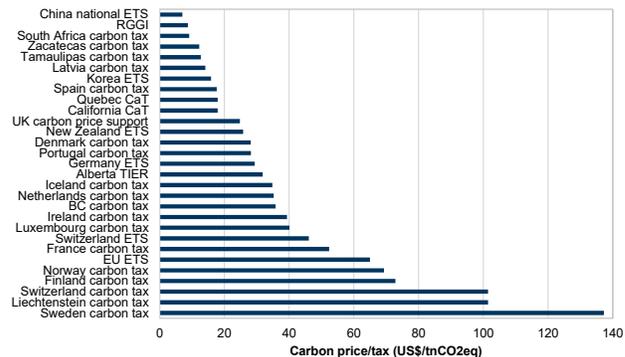
Source: World Bank Group

Exhibit 107: ..and carbon pricing initiatives cover only up to 25% of global GHG emissions, even with the addition of China, by 2021
Carbon pricing initiatives' share of global GHG emissions covered (%)

Source: World Bank Group, Goldman Sachs Global Investment Research

Exhibit 108: As such, not only higher ETS carbon prices but also higher carbon prices implied by commodity benchmarks are aiding the economic competitiveness of clean hydrogen
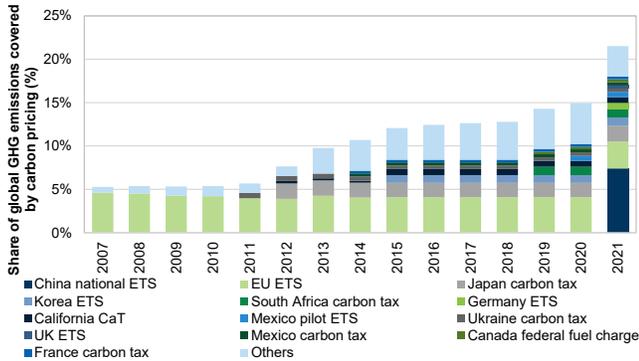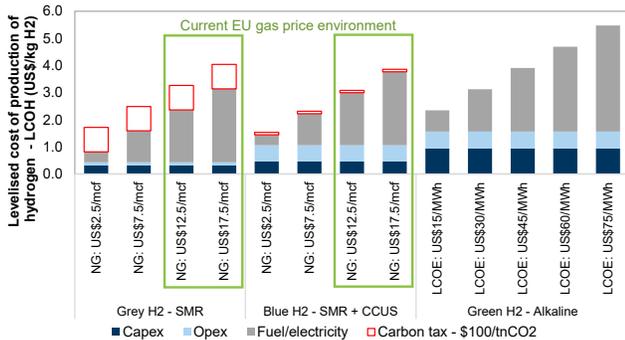Carbon price implied by various commodity benchmarks and carbon ETS scheme (US$/tnCO2eq)

Source: Thomson Reuters Eikon, Bloomberg, Goldman Sachs Global Investment Research

Exhibit 109: While the combination of higher carbon and commodity prices brings both blue and green (at LCOEs <$45/MWh) at cost parity with grey hydrogen in Europe at the point of production..
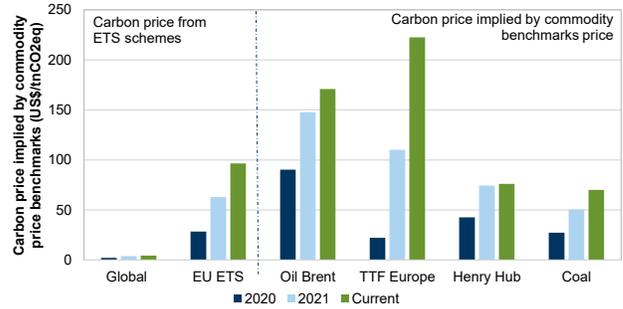Levelized cost of production of hydrogen - LCOH (US$/kg H2)

Source: Goldman Sachs Global Investment Research

Exhibit 110: ..higher carbon prices are required at the point of use to encourage large-scale adoption and penetration of clean hydrogen in the hard-to-de-carbonize end markets
Carbonomics cost curve carbon abatement price (US$/tnCO2eq) for clean hydrogen applications
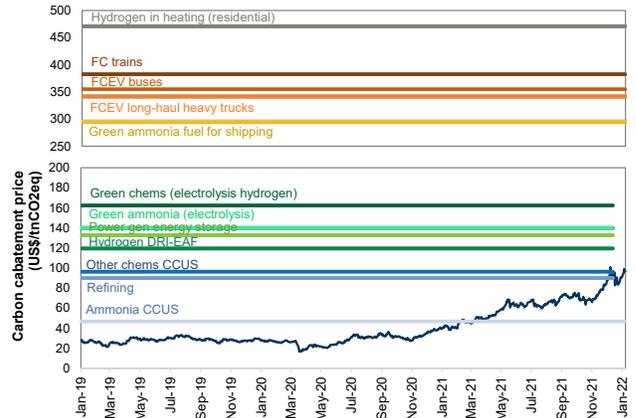
Source: Thomson Reuters Eikon, Goldman Sachs Global Investment Research

In search of a constructive policy framework: We see the need for new explicit and implicit carbon pricing and support mechanisms to encourage large-scale hydrogen adoption across harder-to-abate sectors and new applications

Given that the existing carbon prices, both in the EU ETS (as shown in Exhibit 110 by the blue line) and globally, are below the carbon abatement prices required for clean hydrogen to become economically competitive in the harder-to-abate sectors and new end markets (as estimated as part of our Carbonomics cost curve), we see the need for additional mechanisms and policy instruments to bridge that gap and encourage rising penetration of clean hydrogen in these markets. A number of key regions globally are working on developing policy frameworks and support schemes that would provide corporates and investors with an appropriate risk profile and cost of capital to invest in these technologies. Among these regions are the EU, which is examining options to

utilize a number of mechanisms such as carbon contracts for difference (CCfDs), grants, and purchase agreements similar to what has been achieved in the renewable power industry, as well as the US, with a tax credit recommendation included in the Build Back Better plan (BBB) that nonetheless is pending approval. In the table below, we summarize examples of some of the key market and non-market, direct and indirect mechanisms that could encourage a wider adoption of clean hydrogen (utilizing our own knowledge and policy suggestions by the Hydrogen Council).

Key policy mechanism	Potential instruments	Description
Emission Trading Schemes (ETS)	ETS, including any expansion to existing schemes for additional coverage	A central authority caps carbon emissions and allocates a set number of permits to emitters, who can buy permits in the market to cover their excess emissions or sell their excess permits to generate revenue.
Carbon taxes	Carbon tax	Levies tax on carbon emissions generated by economic activities in order to internalize the societal cost of those emissions and their global impact.
Direct support mechanisms (which include competitive auctions)	Carbon Contracts for difference (CCfDs), Contracts for Difference (CfDs), Feed-in Tariffs (FiTs), tax incentives (such as tax credits)	Various forms of subsidies to guarantee investors a higher revenue stream or lower operational costs, increasing profitability, visibility and reducing risk.
Direct financial support mechanisms	Monetary support including grants or loans	Financial support could be provided directly by the government or authorities to projects that meet specific threshold requirements, lowering upfront investment costs.
Alternative revenue streams	Payments given for added grid flexibility (buffering and storage) etc.	Tools aimed at providing secondary revenue streams alongside main business revenue generation.
Guaranteed offtake	Long-term contracts	Long-term commercial contracts which include an agreement for set volumes of hydrogen and hydrogen-based products to be guaranteed to be sold to an entity at a set price for the length of the contract. This would de-risk the projects, guaranteeing demand and providing revenue certainty.
Investment de-risk mechanisms	Balance sheet support tools such as debt guarantees and equity	Public-private collaboration that could be used to finance, build and operate projects, therefore reducing the upfront investment construction and technology risk.
Return on investment de-risk	Regulated Asset Base Model (RABM), availability payments, minimum revenue guarantee, future purchase commitment	Tools used to secure return on investment for developers by passing down costs to consumers, increasing revenue certainty.
Quotas, targets and standards	Direct regulatory intervention with quotas, emission performance standards, targets (directly on installed hydrogen capacity or on emission reduction or emission intensity), targets for specific sectors (penetration rates and sales), midstream targets (blending requirements of hydrogen in the grid)	Mandatory emission reduction or clean hydrogen capacity targets could be reached through legislation, either economy/country-wide or for specific sectors. Direct quotas and performance standards can also be used.

Guarantees of origin: Guarantees of origin will likely be a vital component for the sourcing of hydrogen as the clean hydrogen economy continues to gain scale. Guarantees of Origin (GOs) is a credit-based chain of custody system that is already widely used in the EU to guarantee the source of electricity is renewable. The revised EU Renewable Energy Directive (2018/2001/EU) extended the scope of GOs also to hydrogen and mandated European Standard Organisations CEN/CENELEC to review the standard EN 16325, which is currently under revision to support the new provision of the Directive. The GO system aims to provide greater transparency and credibility to the clean hydrogen value chain. We believe such a system will be vital across the globe as the clean hydrogen revolution unfolds.

The impact of the rising hydrogen economy on electricity, water and natural resources demand

Green hydrogen could be the next transformational driver for power demand, with potential for over 50% increase on the path to net zero

For electrolysis-produced hydrogen to qualify as 'green' and aid the global energy transition on the path to net zero, it has to be sourced from clean electricity (renewable electricity for 'green', nuclear power for 'purple' hydrogen). This will therefore contribute to the rising need of further renewable power installed capacity, beyond power generation demand growth for the ongoing direct electrification of other sectors such as road transportation, low-temperature industrial processes and manufacturing, and buildings energy. In this section, we present the results of our analysis of likely power demand to meet the three GS hydrogen demand scenarios.

Assuming a technological split between alkaline, PEM, SOEC electrolysis technologies over time, and incorporating the efficiency of each technology and how this is likely to improve over time, our analysis concludes that production of green electrolysis hydrogen can lead to 15,000 TWh of incremental power demand by 2050 (under our 'bull' scenario which is consistent with net zero by 2050 globally and 1.5 degrees). **This is equivalent to the entire non-OECD power demand (2020) and represents c.57% of the 2020 global power demand,** even after having incorporated electrolyzer efficiency improvements and an increasing penetration of high-efficiency SOEC electrolyzer units. Our 'base' GS hydrogen model still suggests substantial growth in power generation demand, larger than the entire power generation of North America. We note that this analysis assumes a blue/green hydrogen split of 40/60 and therefore any ratio that substantially differs from that in favor of green hydrogen leaves further potential upside to the power generation demand scenarios presented below.

Exhibit 111: Green hydrogen could be the next transformational driver of power demand growth..
Green hydrogen production power demand (TWh) under our three GS hydrogen scenarios
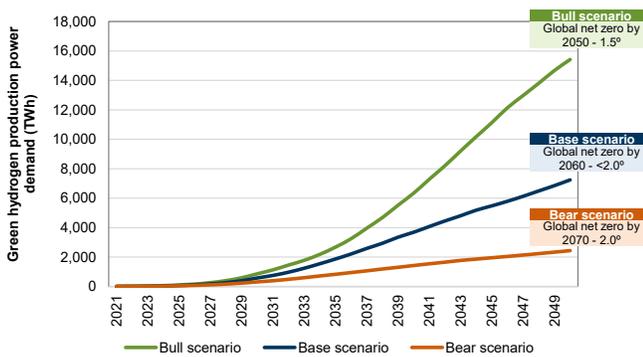
Source: Goldman Sachs Global Investment Research

Exhibit 112: ..leading to incremental power generation demand equivalent to entire non-OECD generation in 2020 (bull case) and higher than the entire power generation of North America (base case)
Power generation across regions (2020) vs required generation of green hydrogen implied by global GS hydrogen models (TWh)
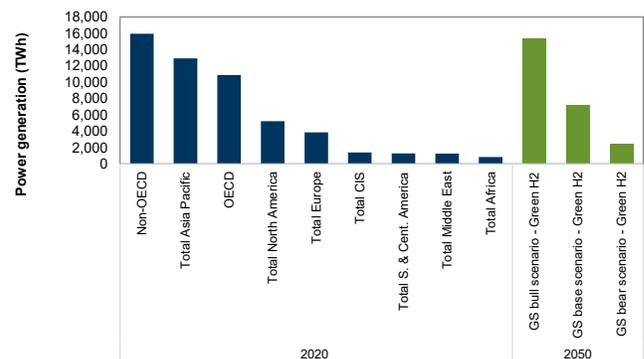
Source: BP Statistical Review, Goldman Sachs Global Investment Research

Assuming average load factors for renewable power of c.30% (weighted average of solar PV, onshore and offshore wind, as we expect the renewable power energy mix to evolve over time), our 'bull' case scenario suggests a **need for at least 5,000 GW of additional renewable installed capacity by 2050 (for global net zero - 'bull' case scenario) to satisfy incremental power demand for the production of green hydrogen.** To put this into perspective, looking into this decade, we estimate that the required average annual renewable capacity additions for the production of green hydrogen could represent 5%-15% of the total global average annual capacity additions (with the low end of 5% representing the 'bear' and the upper end of 15% representing the 'bull' scenarios). As we move further out in time, over 2030-35, **we estimate that up to 1/3 of global average annual RES capacity additions will be needed for the production of green hydrogen.** While not out of reach, this is a significant portion, leading to a rising focus on the availability of renewable capacity.

Exhibit 113: Assuming a 40/60 blue/green hydrogen split and an average load factor of 30%, we estimate that the required installed renewable capacity for green hydrogen production would be close to 5,000 GW by 2050 ('bull')..
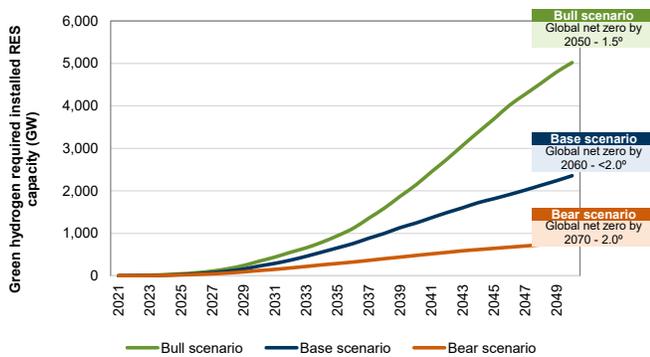
Green hydrogen required installed RES capacity (GW)

Source: Goldman Sachs Global Investment Research

Exhibit 114: ..with the average annual capacity additions in 2021-30 and 2030-35 required for green hydrogen representing c.5%-15%/8%-30% of the total global average RES capacity additions in those periods, respectively

Average annual RES capacity additions required for green hydrogen and % of total global average RES capacity additions
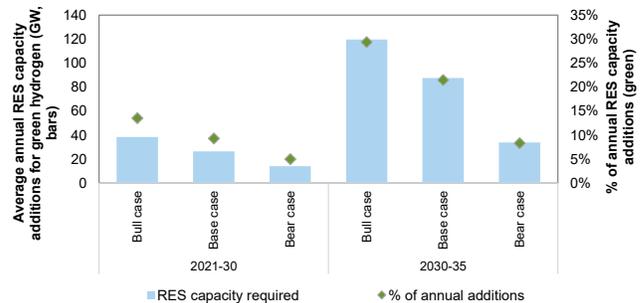
Source: Goldman Sachs Global Investment Research

Water availability and cost manageable on a global basis but could be a regional constraint for locations prone to water supply stress

In addition to energy, water is the next key requirement for which global availability and the resource need to be considered as the clean hydrogen economy scales up. Water demand for hydrogen production via electrolysis, as well as reforming or gasification is considered marginal in absolute amounts. In the case of water electrolysis, about 9-10 kg of water per kg of hydrogen ('green') is needed, with the electricity-based technology for which the requirement is significantly higher being electrolysis via nuclear electricity ('purple' hydrogen), which uses, according to the Hydrogen Council, more than 200 kg of cooling water per kg of hydrogen due to nuclear power production. For SMR/ATR, specific water demand is higher than for 'green' electrolytic hydrogen with 13-18 kg of water per kg of hydrogen required, while coal gasification uses around 40-85 kg of water per kg of hydrogen produced ('brown').

Exhibit 115: Water demand for hydrogen production via electrolysis, as well as reforming or gasification is considered marginal in absolute amounts, yet can be significant in regions prone to water supply stress
Gross water consumption factors for hydrogen production pathways (kg H2O/ kg H2, LHV)
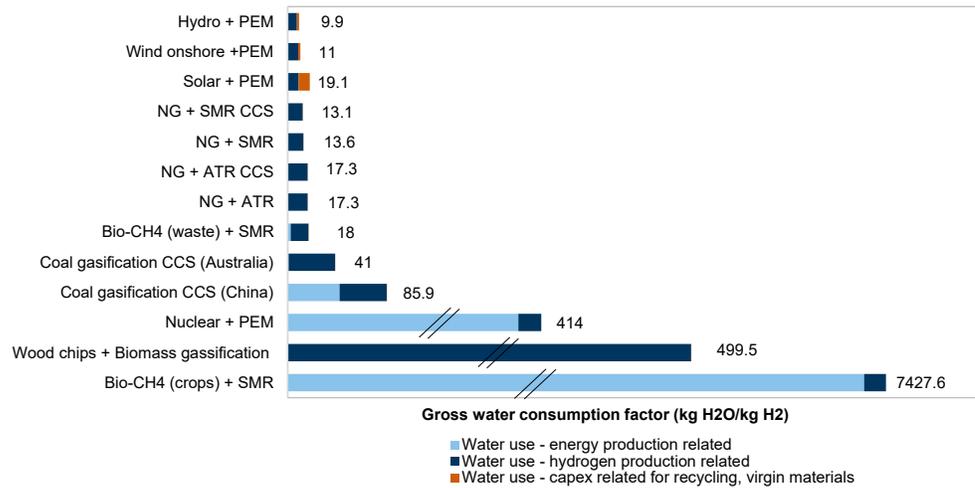
Source: Hydrogen Council, LBST

Leveraging our global GS hydrogen demand models, we estimate the total water requirement for the scale-up of the clean hydrogen industry (both 'green' and 'blue' hydrogen considered here given their comparable water consumption) at c.7/3.3 bcm by 2050 under our 'bull and 'base' hydrogen demand scenarios, respectively. To put this into perspective, the energy sector's water consumption globally was estimated to be around 47 bcm (IEA) in 2016 while the energy sector's total water withdrawal was estimated to represent around 10% of the global level. As such, water consumption for hydrogen production is estimated to reach up to 15% of the global energy sector's water consumption under our 'bull' scenario.

We therefore conclude that, **from a global perspective, the availability of water to support the rise of the clean hydrogen economy is not likely to be a key constraint, especially if clean hydrogen is replacing highly water-consuming and energy intensive fossil-fuel extraction processes, which account for the majority of the energy sector's water consumption today. Nonetheless,** with a growing pipeline of GW-scale projects, which could be significant water consumers locally, there could be **regional supply challenges in areas prone to water supply stress. For these locations, sea water desalination technologies may be required.** Most hydrogen electrolysis technologies today require high-purity water and as such already have an integrated de-ionizer as part of their system, making desalination (reverse osmosis)-sourced water a possibility. While this adds little incremental electricity needs for electrolysis projects, it requires the environmentally benign management of the effluent brine. From a cost perspective, we estimate the **total cost for water desalination** at around $0.5-3.0/cm (requiring around 3-4 kWh per cm), which would imply an additional cost to the LCOH of around **US$0.01-0.05/kg H2**, **a negligible level**.

Exhibit 116: Water requirement for the production of clean hydrogen will likely reach c.3.3-7 bcm by 2050 (under our 'base' and 'bull' scenarios)...
Clean hydrogen production water consumption (bcm)
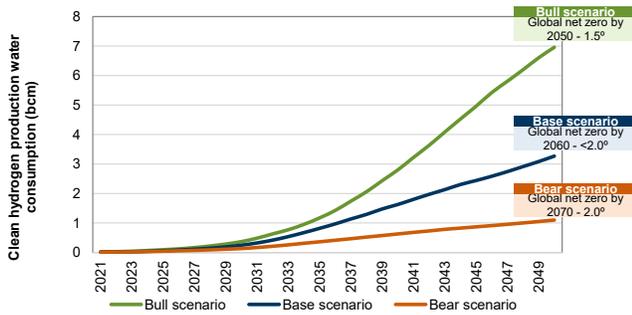
Exhibit 117: ...which, from a global perspective, is not very material, representing c.15% of the total energy sector's water consumption
Water withdrawal (left) and consumption (right) for the energy sector and for clean hydrogen production under our GS hydrogen models (bcm)

Source: Goldman Sachs Global Investment Research
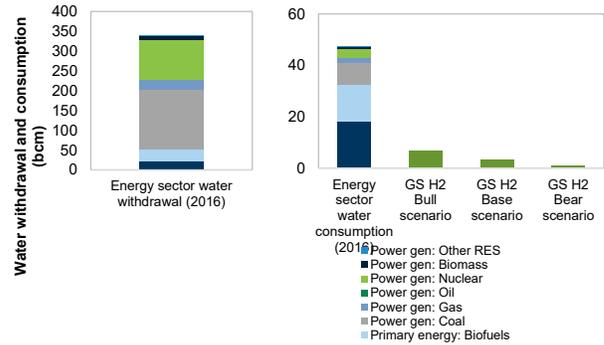
Source: IEA, Goldman Sachs Global Investment Research

Water availability is a regional challenge and both economic and social factors have to be taken into consideration when addressing the water resource locally. We utilize FAO's Global Information System on Water and Agriculture, including the geospatial database and AQUAMAPS, which summarizes the proportion of water resources withdrawn (pressure on water resources) across regions. MENA appears to be the key region with water supply stress, yet also a region of vast, low-cost renewable power availability, which we believe suggests potential for it to become a key 'green' hydrogen exporting region (as outlined in a section earlier). Water availability and desalination technologies are therefore likely to be critical for the clean hydrogen economy scale-up.

The impact of the rise of clean hydrogen on metal and mineral resources: Nickel, Platinum, Iridium in focus

Demand for natural resources, in particular, metals and minerals, is one of the prime considerations of any aspiring path to net zero and for any energy transition scenario. In this section, we aim to assess the potential incremental demand that could result from the rise of the hydrogen economy leveraging our three GS global hydrogen demand scenarios. The natural resources (metals and minerals) required to facilitate the scale-up of the clean hydrogen economy will largely depend on the ultimate penetration of the various technologies. For instance, looking at the 'green' hydrogen economy in particular, different electrolysis technologies (alkaline, PEM, SOEC, and AEM as outlined previously) will require different types and quantities of metals for the manufacture of the electrolyzer systems.

Exhibit 118: Different minerals and metals are required for the manufacture of different types of electrolysis technologies, with PEM in general being more precious metals-reliant while alkaline and SOEC are nickel, steel and potentially zirconium dependent
Demand for specific metals and minerals per MW electrolyzer capacity (kg/MW)
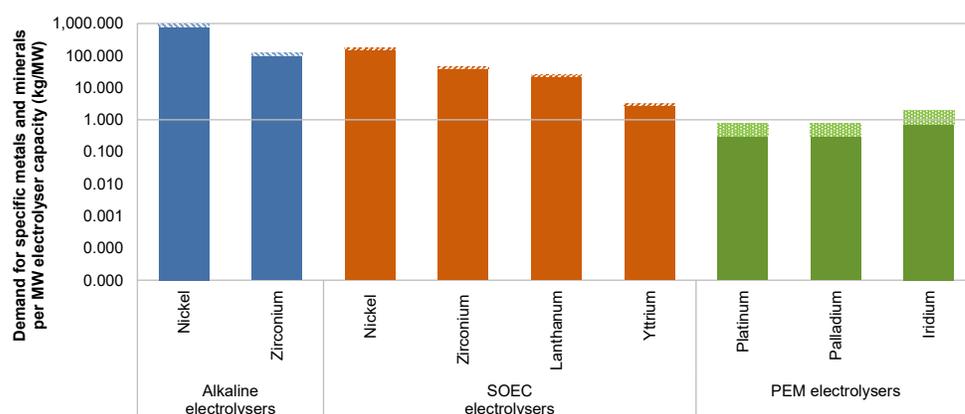
Source: IEA, IRENA, Goldman Sachs Global Investment Research

Alkaline electrolysis relies on the availability of nickel, which potentially places it in competition for the mineral with technologies such as batteries (despite the much lower nickel intensity of electrolyzers)

Alkaline electrolyzers have low capital costs compared to some other technologies, primarily due to the avoidance of precious metals. However, current designs do require nickel in quantities of more than one tonne per MW of electrolyzer capacity. Nickel is required to resist the highly caustic environment while some chlor-alkali designs also include small amounts of platinum and cobalt. For the purpose of this analysis, we assume a typical alkaline electrolyzer system which relies on nickel and steel in the absence of note-worthy quantities of platinum and cobalt (which is required only for a specific class of alkaline electrolyzers). We could see a reduction in nickel demand for alkaline electrolyzers as metal loadings reduce and are subject to further optimization over time, but not requiring it at all is unlikely. Using the latest electrolyzer designs, which require around 800 kg per MW, and assuming c.44% long-term penetration in the market by 2050 (based on our global GS hydrogen models) with full recycling, we estimate average annual incremental nickel demand for electrolyzers amounts to 39 kt

and represents just 1.5% of current global nickel production.

Even if alkaline electrolyzers become the dominant electrolyzer market technology (which would imply average annual incremental nickel demand of 89 kt pa for electroyzers, c.4%-5% of current global production, on our estimates), nickel demand for electrolyzers would remain much lower than that for batteries and marginal, in our view. However, competition for nickel supplies with battery manufacturers could emerge as a challenge, which could see the price of nickel structurally move higher over time. In addition to nickel, 1 MW of alkaline electrolyzer could require around 100 kg of zirconium today, half a tonne of aluminium and more than 10 tonnes of steel, along with smaller amounts of cobalt and copper catalysts, according to the IEA.

PEM electrolysis the key technology facing mineral availability constraints, with iridium and PGMs at the forefront but with rapidly reducing loading

The use of critical minerals is considered a bigger challenge for the PEM electrolyzer technology, albeit we note that coatings of electrodes for alkaline electrolyzers often contain small quantities of these minerals. The anode is typically coated with iridium, a scarce mineral that is nonetheless required, given the high oxidizing potential of the anode in this system with not many materials available to withstand these conditions. Additionally, the porous transport layer typically requires titanium-based materials coated with PGMs (typically platinum or palladium). The cathode itself is typically coated with platinum. Assuming a long-term penetration rate for PEM electrolyzers of 44% (similar to alkaline), full recycling and a platinum requirement of 0.3 kg per MW (the 2030 EU target for precious metals in electrolyzers is 0.4kg/MW with PEM manufacturing companies such as ITM already having met this target), we estimate annual average incremental platinum demand to be around 15 tonnes pa for the path to net zero by 2050. This represents c.8% of global annual production currently. If PEM were to be the dominant technology, accounting for the entire capacity by 2050, this would lead to average annual incremental platinum demand of c.18%, which, while a considerable increase, is likely to be partly offset by (a) additional platinum capacity resulting from higher recycling rates and (b) reduced demand for platinum required for catalytic reformers that are used in internal combustion engine vehicles as the energy transition unfolds and electric and fuel cell vehicles increase their penetration in the global sales mix. However, we do note that when fuel cells also enter the PGM demand equation, it is likely to see higher demand overall, given the higher platinum intensity of fuel cells relative to combustion engines. This leads us to conclude that beyond the cost associated with PGMs, there is not a major availability constraint as far as electrolysis is concerned, but such a constraint could emerge when fuel cells are also considered.

The use of iridium in PEM electrolyzers, on the other hand, could be an important cause for concern. Assuming a long-term penetration rate for PEM electrolyzers of 44% (similar to alkaline), full recycling and a need for 0.7 kg of iridium per MW, we estimate average annual incremental demand for iridium can increase >4-fold on the path to net zero. **If we assume PEM becomes the dominant technology,** this can lead to a **10-fold increase in annual iridium demand.** We therefore **highlight the importance of reducing iridium content in PEM electrolyzers.** We note that the companies currently involved in the manufacturing of this type of technology are already laying out

targets to substantially reduce the content of both PGMs and iridium longer term and therefore we view this as a key area of innovation in the coming years. Industry bodies such as IRENA and EU Commission have suggested the scope for reducing the dependence on critical materials, and we identify the below measures which could help achieve this: (1) material substitution where possible and a reduction in material quantity requirement per unit capacity through higher surface area supported catalysts, the use of thinner coating layers, and innovative technologies including AEM, which combine alkaline with PEM (or different alloys, nanoparticles, or a change in morphology of electrodes), (2) an extension of the useful life of equipment or an increase in efficiency, which would imply the need for a smaller area, (3) recycling, with our estimates for mineral demand outlined above already assuming full recycling.

Finally, looking at the SOEC technology, given the relatively early stage of development and absence of large, commercial scale production currently, at least not to the extent observed for alkaline and PEM technologies, we note that there is a wide variability in the quantities of minerals required for these designs. For the purpose of our analysis, we utilize IEA's estimates which include nickel (150-200 tn/GW), zirconium (40 tn/GW), lanthanum (20 tn/GW), and yttrium (<5 tn/GW). Under these assumptions, even when considering SOEC's technological dominance long term where the entire electrolyzer capacity would rely on this technology, by 2050, the impact on average annual incremental demand for these metals would be marginal, in our view, owing to the higher efficiency of SOEC electrolyzers, which inherently implies a lower quantity of installed electrolyzer capacity required to meet hydrogen demand. We note that given the earlier stage of development of SOEC technologies, a number of different designs have emerged, including, for instance, Ceres' SteelCell technology, which relies primarily on steel as opposed to niche materials.

Exhibit 119: Alkaline electrolyzers' impact on demand for its constituent minerals is likely to be marginal even under an 'alkaline technology dominance' scenario; for PEM electrolyzers, the reliance on iridium in particular (and PGMs to a lesser extent) could be a major constraint that may need to be addressed through ongoing technological innovation and loading optimization.
Average annual incremental demand for specific minerals under alkaline and PEM electrolyzer technologies (LHS), and as a % of current global production (RHS)
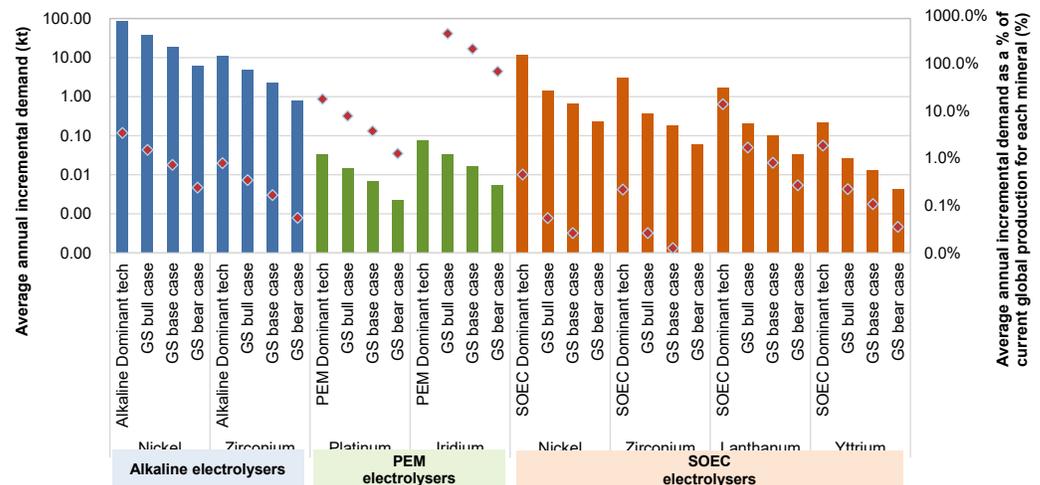

Source: Goldman Sachs Global Investment Research

Overall, we conclude that both alkaline and SOEC technologies are likely to have only a marginal impact on demand for the minerals and metals used in their manufacturing. PEM is the technology that is most likely to face constraints from an availability and cost perspective, given its reliance on iridium and PGMs. Having said that, we highlight that the loading of precious metals and iridium has been trending downwards and is likely to continue to come down substantially in the coming years as companies focus on ongoing loading optimization and technological innovation. We view this as necessary, not only because of the resource availability (iridium) and cost (PGMs) issues, but also given both platinum and iridium are two of the most carbon-intensive materials typically used in electrolyzers (from a lifecycle GHG and energy intensity perspective), as shown in Exhibit 120. Nonetheless, given the high energy intensity of the electrolyzer systems, the energy required to produce the metals upstream is still minimal in comparison. Finally, looking at the supply of the minerals required for the manufacture of electrolyzers, as shown in Exhibit 121, it is evident that the supply of critical materials such as platinum and iridium are both concentrated geographically in just a few regions globally, namely South Africa, Zimbabwe and Russia. This could be a key supply consideration as PEM electrolyzer manufacturing is likely to be linked to a few regions with limited short-term alternatives. For alkaline electrolyzers, on the other hand, while design options that use platinum and cobalt exist, the new commercial designs exclude these and primarily rely on nickel and steel for which supply is much more diversified geographically. Finally, SOEC electrolyzer manufacturing could face a similar geographical supply concentration issue, since most of the supply of critical minerals used in this system is currently concentrated in China. Nevertheless, we highlight the uncertainty associated with SOEC designs and their material loadings given the earlier stage of development of this technology.

Exhibit 120: Platinum and iridium typically used in PEM electrolyzer systems have among the highest energy and lifecycle GHG intensities compared to other important materials used across electrolyzer technologies..
Lifecycle global warming potential and cumulative energy demand for materials typically used in electrolyzer systems
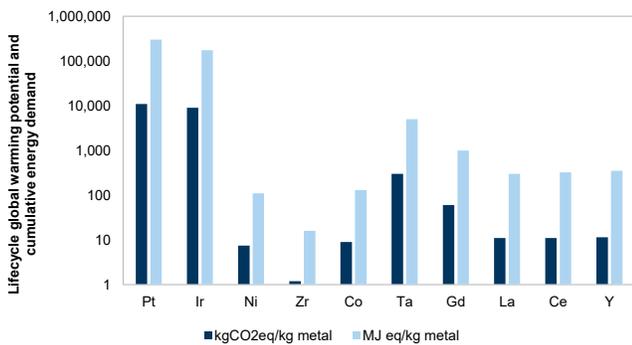
Source: IRENA, Nuss and Matthew (2014)

Exhibit 121: ..while supply is also highly concentrated geographically (e.g. South Africa), similar to what is seen for scarce minerals such as yttrium and lathanium used in SOEC systems (China)
Global production geographical share for materials typically used in electrolyzer systems (%)
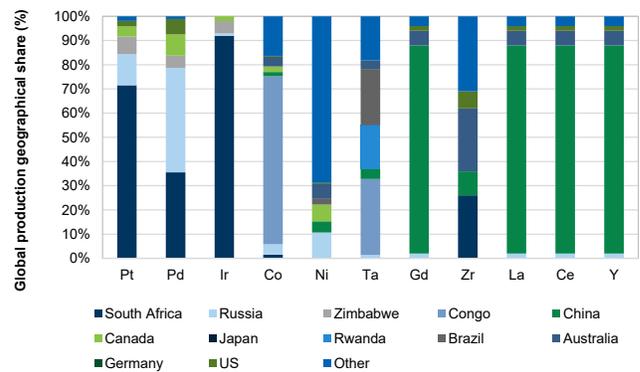
Source: European Commission (2020), USGS, IRENA, Goldman Sachs Global Investment Research

Moreover, beyond supply concentration geographically for most of the more niche metals involved in electrolyzer manufacturing (particularly PEM), the situation of relatively constrained supply and underinvestment that has led to a structural bull market across many commodities (energy and natural resources) in 2021 has already started to translate into notable inflation in prices of these metals. In the exhibits below, we show prices of the four key materials used in alkaline and PEM electrolyzers; nickel and zirconium for the former and platinum/palladium and iridium for the latter. The prices of all commodities shown have been very volatile and mostly been on an upward trajectory in 2021. Iridium, in particular, stands out, with its price having quadrupled since 2018 (and risen significantly in particular in 2021). This is reflective of the trends outlined earlier, with iridium being the key material that could face supply constraints given the potential demand from its use in PEM electrolyzers.

Exhibit 122: Prices of the materials typically used in the manufacture of electrolyzers can be very volatile and have in general started to trend upwards in 2021 (with the exception being platinum)...
Commodity prices in US$/tn or US$/oz for key materials used in electrolyzers (alkaline and SOEC top chart, PEM bottom chart)
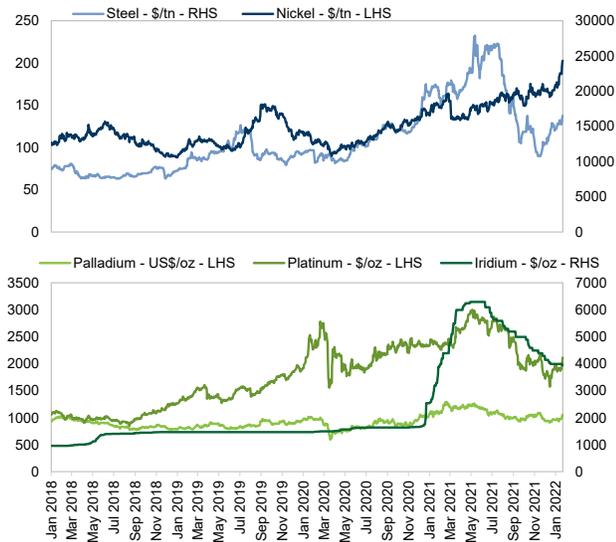
Exhibit 123: ..with iridium in particular having exhibited an extraordinary increase in price in 2021
Commodity prices (of materials used in electrolyzers) rebased to 1 Jan 2018
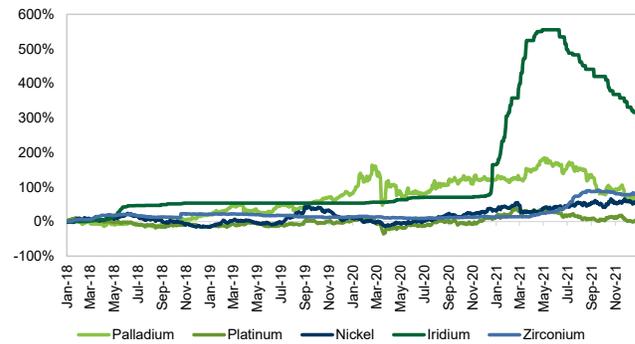
Source: Thomson Reuters Datastream, Bloomberg, Goldman Sachs Global Investment Research

Source: Thomson Reuters Datastream, Bloomberg, Goldman Sachs Global Investment Research

Clean hydrogen end markets: The revolution starts with the transformation of the existing hydrogen economy

We believe the start of the clean hydrogen revolution begins with the de-carbonization of existing hydrogen end markets, including refining and chemicals

Currently, H2 is primarily used as a feedstock in a number of key industrial processes and therefore plays a very limited role in the energy transition as we are still to unlock hydrogen's potential as an energy vector and fuel. According to the IEA, global hydrogen demand was around 90 Mt in 2020. This includes more than 70 Mt H2 used as pure hydrogen, primarily in oil refining and ammonia production, and less than 20 Mt H2 mixed with carbon containing gases, primarily in methanol production and steel manufacturing. This excludes around 20 Mt H2 that is present in residual gases from industrial processes used for heat and electricity. **We believe the clean hydrogen revolution begins with the de-carbonization of existing hydrogen end markets.** Therefore, we see the starting point of the clean hydrogen economy as the de-carbonization of the 70 Mt pa of current dedicated fossil fuel-based hydrogen production. Even in the absence of further hydrogen penetration into new end markets, this presents a remarkable opportunity for clean hydrogen to grow from <1 Mtpa currently to over 70Mtpa in a net zero world.

As pointed earlier, in the 'Policy Toolbox' section, while higher carbon and commodity prices (particularly natural gas) are making cost parity of clean hydrogen with grey a reality, higher implied carbon abatement prices and more technological innovation and cost deflation are required to achieve cost parity across hydrogen's end markets and final applications. The lowest carbon abatement price seems to be for existing hydrogen end markets, in particular refining, ammonia and methanol, supporting our thesis that the clean hydrogen revolution begins with the de-carbonization of existing hydrogen markets.

Exhibit 124: The existing end markets for hydrogen are the ones requiring lower carbon abatement prices and therefore areas where we see the beginning of the clean hydrogen revolution
Carbonomics cost curve carbon abatement price (US$/tnCO2eq) for clean hydrogen applications
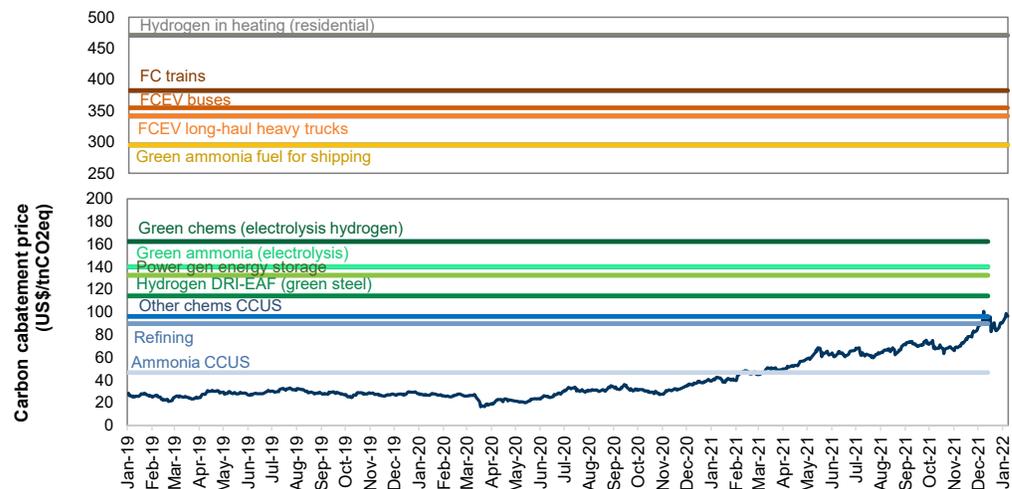
Source: Thomson Reuters Eikon, Goldman Sachs Global Investment Research

Oil refining: The only hydrogen end market facing structural decline, yet with biofuels and synthetic fuels offering support

Oil refining is the largest consumer of hydrogen currently, accounting for c.41% of global hydrogen demand in 2021 (GS estimates). In oil refining, hydrogen is primarily used in hydrosulfurization to remove sulphur contents in crude and in hydrocracking processes to upgrade heavy residual oils to higher-value products. The ongoing rising focus on air quality has led to the reduction of sulphur content in final refined products, as shown in Exhibit 126, while hydrocracking is becoming more important as demand for light and middle distillate products is growing at the expense of heavy residual oils. Around half of this demand is met with hydrogen produced as a by-product from other processes in the refineries or from other petrochemical processes integrated in refining plants while the remaining demand is met by dedicated on-site hydrogen production or merchant hydrogen sourced externally.

Overall, under all three of our GS global net zero scenarios, oil demand enters a period of structural decline post 2030, implying lower hydrogen demand for refining. Nonetheless, in the near term, a combination of tightening sulphur regulations and rising oil demand can be supportive for hydrogen demand in this end market. Longer term, increasing demand for biofuels and synthetic fuels can provide further support as hydrogen is required for biofuels' hydrotreatment to remove oxygen and improve the quality of vegetable oils and animal fats processed into diesel substitutes. Production of advanced biofuels can be even more hydrogen intense than traditional oil refined products, leaving potential for further hydrogen demand upside there. Given the relatively tight refining margins globally, higher refining margins, higher carbon taxes and lower clean hydrogen costs will all likely be required to achieve cost parity with existing grey (Europe and US) and brown (China) hydrogen use, as shown in Exhibit 129. We primarily focus on the US, Europe and China's refining economics as these three regions are the largest consumers of hydrogen in refining, making up around half of the global refining hydrogen demand.

Exhibit 125: While our three global net zero models all suggest structurally declining oil demand post 2030, implying lower demand for hydrogen in refining..
Oil demand in EJ and kbpd under three GS net zero carbon models
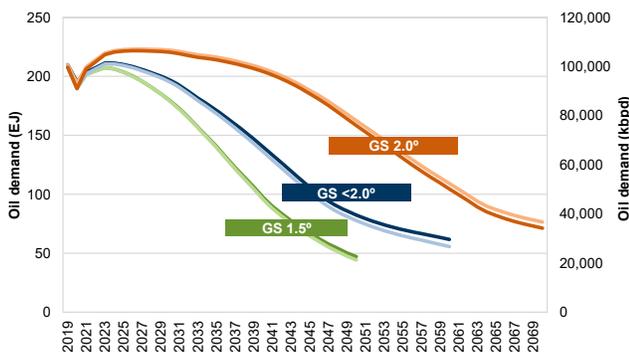
Source: Goldman Sachs Global Investment Research

Exhibit 126: ..ongoing tightening of sulphur standards could lead to higher hydrogen demand per unit of refined product for the desulphurization process in the near term...
Allowed sulphur content in refined products (Mtpa, LHS) vs global oil supply (kbpd, RHS)
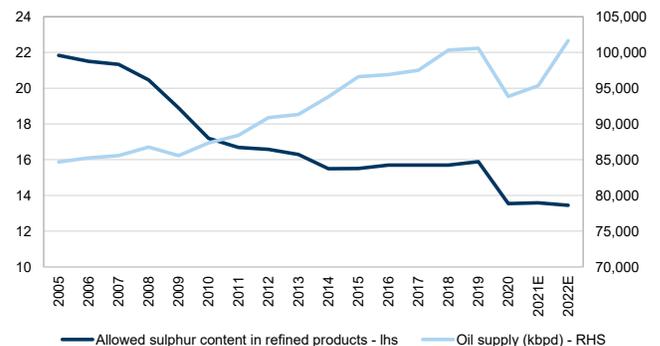
Source: IEA, Goldman Sachs Global Investment Research

Exhibit 127: ..while advanced biofuels and synfuels could offer support for refining hydrogen demand longer term, according to our GS global net zero models
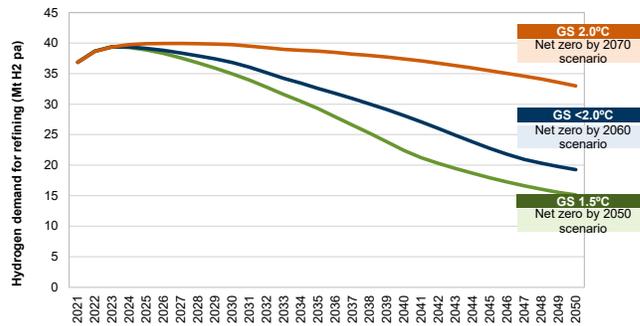Advanced biofuels and synfuels demand under two GS global net zero scenarios (kbpd)
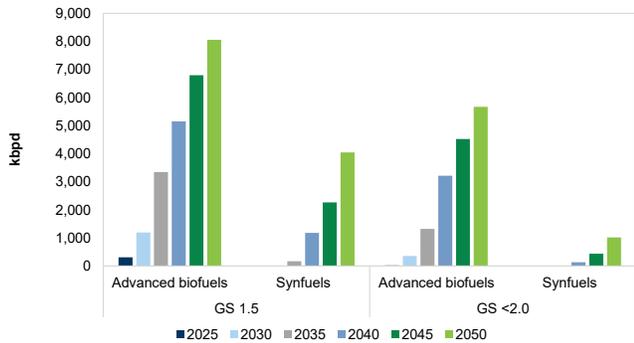
Source: Goldman Sachs Global Investment Research

Exhibit 128: A such, while we expect global demand for hydrogen from refining to decline over time, we do not expect it to diminish
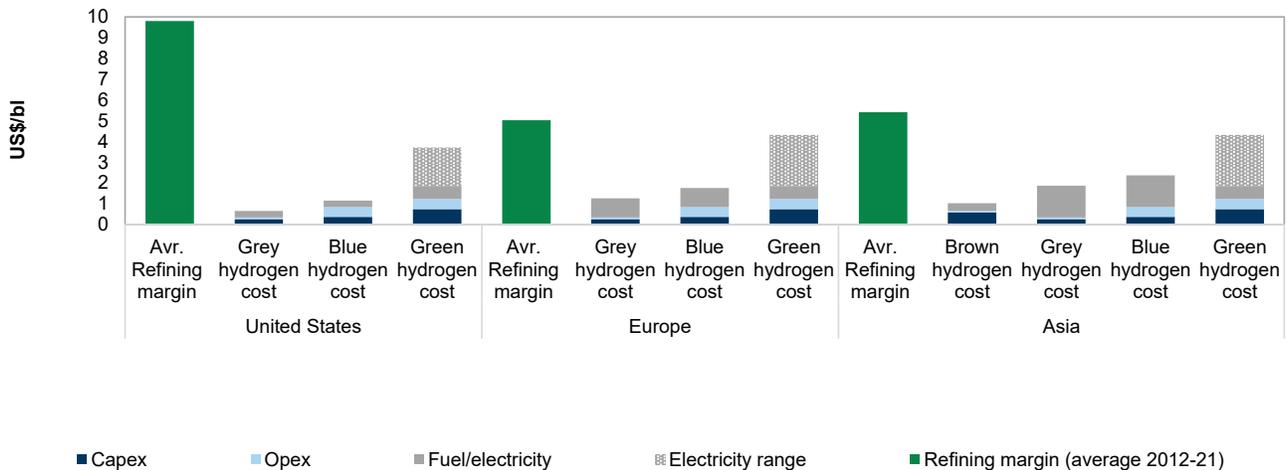Hydrogen demand for refining (Mt H2)

Source: Goldman Sachs Global Investment Research

Exhibit 129: Clean hydrogen production costs could form a large portion of refining margins, making higher carbon prices and clean hydrogen tech cost deflation essential for increasing clean hydrogen penetration
Refining margin and hydrogen cost per barrel (US$/bl)

Source: Thomson Reuters Eikon, Goldman Sachs Global Investment Research

Chemicals: Ammonia and methanol production, key end markets, both likely to see solid growth in the coming years and decades

The chemicals industry consumes about c.53% of global hydrogen, primarily as a feedstock for ammonia and methanol production, with both requiring around 180 and 130 kg of hydrogen per tonne of product, respectively. Chemicals is a broad sub-sector including a very large variety of commodity petrochemicals, specialty chemicals and products including plastics, fertilizers, pharmaceuticals, explosives, paints, solvents and more. In this section, we primarily focus on bulk commodity chemicals, namely ammonia and methanol, and much less on high-value-chemicals (HVCs, including ethylene, propylene, benzene and other olefins and aromatics). While hydrogen is a part of the molecular structure of almost all chemicals, a few key primary chemicals require
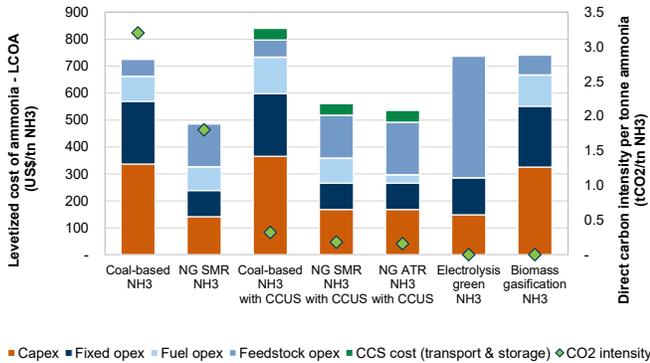
large quantities of dedicated hydrogen production for use as feedstock, notably ammonia and methanol.

Fossil fuels have historically been the most economic and mature method of producing ammonia and methanol, primarily natural gas (except in Asia and, in particular, China, where a lot of production still relies on the more carbon intensive coal). This results in relatively high carbon intensities for both chemicals (around 2.4 tnCO2eq/tn for ammonia and c. 2.3 tnCO2eq/tn for methanol), which need to be addressed for any aspiring path to global net zero. Therefore, not only is there a need to implement new process routes and feedstocks to de-carbonize the existing production facilities for ammonia and methanol, but also to facilitate strong growth in demand for both chemicals. Ammonia is primarily used as a feedstock for the manufacture of fertilizers such as urea and ammonium nitrate while the remainder is used for industrial applications such as synthetic fibers and other specialty chemicals, which are becoming an increasingly important component for ammonia demand. Methanol, on the other hand, is used in a wide range of industrial applications including the manufacture of formaldehyde and various solvents. The development of methanol-to-olefins and methanol-to-aromatics technologies has also opened up a demand opportunity for the manufacture of plastics. Our scenarios assume a c.1%-1.5% CAGR for ammonia and methanol demand to 2050. We note that this does not include additional demand for both chemicals that would stem from their use as established energy carriers for the transport and transmission as well as storage of clean hydrogen, or demand that could emerge if they were to be used as fuels on their own. We discuss this incremental demand from their use as fuels later in this section, addressing their potential use as a fuel in the shipping industry.

Alternative process technologies and feedstocks will be required to meet growing demand for dedicated hydrogen production for both chemicals while reducing the carbon footprint. In our global net zero models, we focus on three key process routes: (a) utilizing existing fossil fuel-based production routes but including carbon capture (CCUS) to reduce emissions (blue hydrogen equivalent), (b) using electrolysis-derived hydrogen with renewable power, (c) using biomass feedstocks assuming sustainable sourcing and handling. All of these options are currently more costly than the traditional fossil fuel-based routes, as shown in Exhibit 130 using our levelized cost of ammonia analysis, and therefore call for technological innovation and a constructive policy framework to bridge the US$80-160/tnCO2 implied carbon abatement price (as shown in Exhibit 124). CCUS appears to be the cheapest clean production route, given the relatively high concentration of CO2 in the stream for the ammonia process, with electrolysis the next available option. We have performed a similar analysis for the production of methanol, as shown in Exhibit 131, and reached similar conclusions.

Exhibit 130: CCUS and electrolysis appear to be the most cost competitive routes to de-carbonize ammonia production..
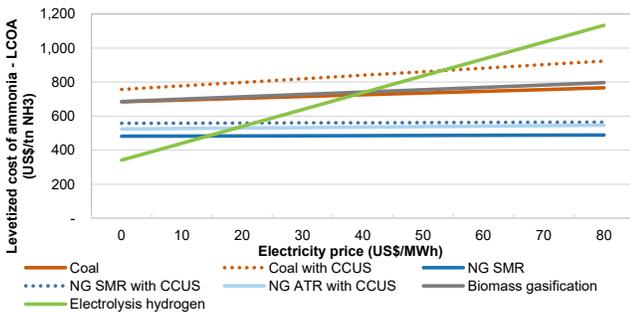Levelized cost of ammonia - LCOA (LHS, US$/tn NH3) and direct carbon intensity per tonne of ammonia (RHS, tnCO2/tnNH3)

Source: Goldman Sachs Global Investment Research

Exhibit 131: ..and methanol production, albeit the clean production routes for both appear more expensive than the fossil fuel alternative routes, calling for technological innovation and a constructive policy framework
Levelized cost of methanol - LCOM (LHS, US$/tn MeOH) and direct carbon intensity per tonne of methanol (RHS, tnCO2/tn MeOH)

Source: Goldman Sachs Global Investment Research

Exhibit 132: Electrolysis for ammonia manufacturing becomes competitive at renewable power prices below US$25/MWh..
Levelized cost of ammonia - LCOA vs electricity price

Source: Goldman Sachs Global Investment Research

Exhibit 133: ..similar to methanol electrolysis, with such prices, while lower than the global average, being achievable in certain regions
Levelized cost of methanol - LCOM vs electricity price

Source: Goldman Sachs Global Investment Research

Exhibit 134: CCUS appears to be a more economically competitive technology for the de-carbonization of ammonia and methanol manufacturing...
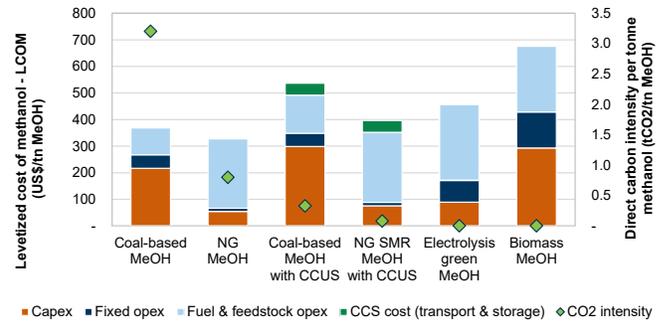Levelized cost of ammonia - LCOA vs CO2 price
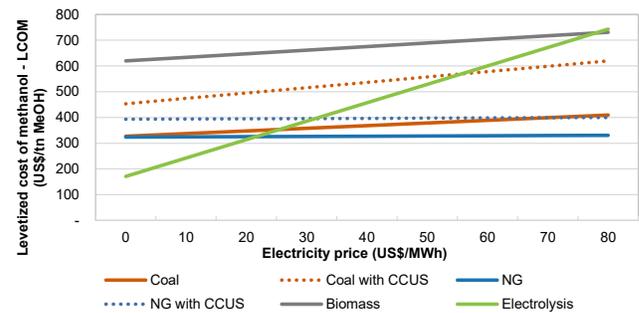
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 135: ..but heavily relies on the availability of storage or utilization optionality for CO2
Levelized cost of methanol - LCOM vs CO2 price
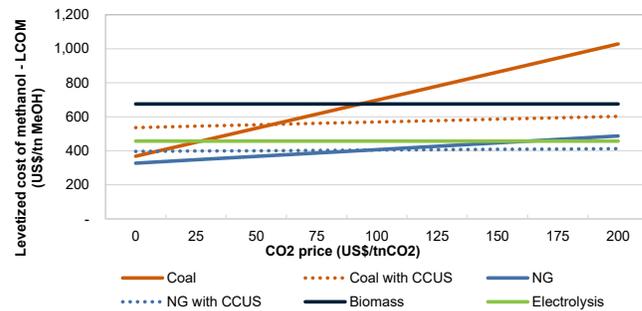
Source: Goldman Sachs Global Investment Research

Steel: An existing end market that has the potential to transform into one of the key emerging clean hydrogen opportunities as it embarks on its own de-carbonization journey

Around c.7% of current hydrogen demand (fourth largest single source) comes from the steel industry and stems specifically from the DRI-EAF steelmaking process route used to reduce iron ore to sponge iron (in a mixture with carbon monoxide). Currently, around three-quarters of total global steel demand is met through primary production methods, while the rest utilize scrap supplies. As far as primary production routes are concerned, the blast furnace-basic oxygen furnace (BF-BOF) routes account for around 90% of current global primary steel production, given the large steel production base of China, which primarily relies on coal for such high energy processes. It produces hydrogen as a by-product (rather than requiring dedicated hydrogen production). The direct reduction of the iron-electric arc furnace (DRI-EAF) route accounts for around 7% of primary steel production globally and utilizes a mixture of carbon monoxide and hydrogen as a reducing agent. This hydrogen is produced by dedicated production routes and not as a by-product, making up hydrogen demand from the steel industry today.

The iron & steel industry accounts for c.2.6 $GtCO_2$ of total emissions (2019) (GS estimates), the single highest emitter among industrial sub-sectors. However, a combination of fuel switches and innovative process routes can aid the low-carbon transition path for these ferrous alloys. Our GS 1.5° scenario sees a radical technological transformation of the iron & steel sub-sector, largely based on the ongoing shift from coal blast furnace routes (conventional BF-BOF) to electric arc furnace routes (either through natural gas, clean hydrogen or scrap). Iron & steel is a highly energy-intensive industry, accounting for c.15% of global primary coal demand (IEA). By 2050, in our GS 1.5° path, electricity and non-fossil fuels account for c.70% of the tonnes of steel produced, while the remaining fossil fuel-reliant plants are retrofitted with CCUS. CCUS and the switch from coal BF-BOF to natural gas DRI-EAF and scrap are the key near-term de-carbonization tools for steel, we believe, before the rapid uptake of the clean hydrogen process (H2 DRI-EAF) post 2030. **We therefore see incremental hydrogen demand coming not only from the increasing share of the current conventional DRI-EAF process but also from the emergence and scale-up of the hydrogen DRI-EAF production route, forming a key emerging clean hydrogen end market on the path to net zero.** Over the past few years, we have seen a number of innovative alternative clean steel production processes being developed, primarily focusing on the increasing use of electricity and clean hydrogen.

Our GS 1.5° model's architecture for heavy industries consists of three main components: **activity projections**, **technology mix modeling** (the selection of technologies and mix required to meet these activity levels) and, finally, **emissions modeling**, largely relying on the technology mix and incorporating energy and material efficiency where appropriate.

Exhibit 136: Final energy consumption of the steel industry is dominated by coal, which accounts for c.70% of the sub-sector's energy mix...
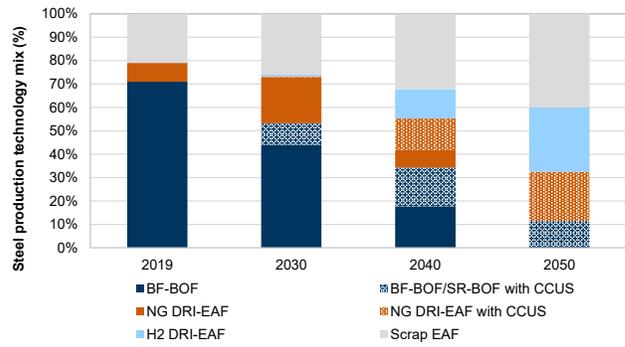
Final energy demand of key heavy industry sub-sectors and the share of fossil fuels (2019)
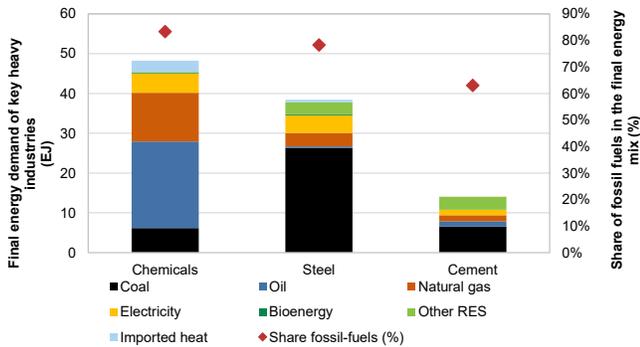
Exhibit 137: ...and our GS 1.5 degrees path assumes a radical transformation of the sector with c.70% of global steel produced in 2050 sourced from non-fossil fuel processes with the remaining largely retrofitted with CCUS

Steel production technology mix (%)

Exhibit 138: Our GS 1.5 degrees path assumes a combination of technologies in the steel sector will contribute to the sector almost being entirely carbon-free by 2050

Iron & steel sector emissions bridge to net zero by 2050 (MtCO2)
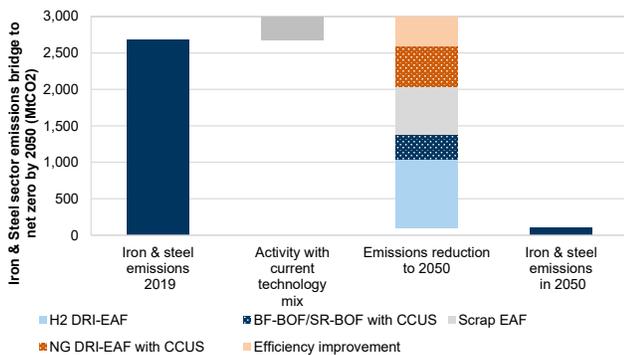
Exhibit 139: ..leading to a notable reduction in overall direct carbon intensity over time

Steel direct emissions carbon intensity (tnCO2/tn steel)
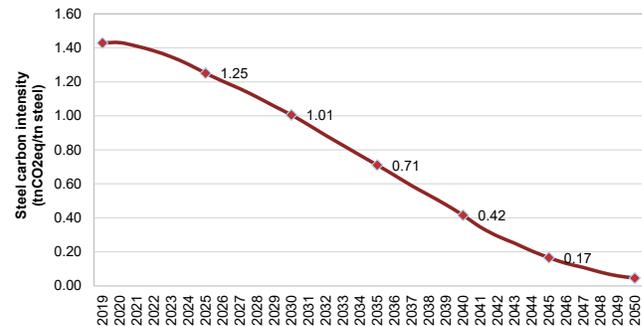
Similar to the analysis of levelized cost of ammonia and methanol by production route we presented earlier in the report on chemicals demand for hydrogen, we present here our levelized cost of steel analysis across the key clean production pathways currently available and in pilot or commercial scale, as shown in Exhibit 140. The clean production pathways for steel production are currently less cost competitive with the traditional BF-BOF process or gas-based DRI-EAF. In the absence of further cost reduction, technological innovation and a compelling carbon price framework, we estimate the cost of the switch to clean hydrogen to replace natural gas in the DRI-EAF process or the traditional BF-BOF process to be c.45%/60% higher, respectively (on a per tonne of steel basis). Given the relatively tight margins of the steel industry, such a differential is a substantial increase in the cost base of existing steel producers. Overall, we believe a combination of increasing secondary production and CCUS retrofitting could be the most economical solution near term (particularly for the existing plant base in Asia, given the very young average life of these assets, around 13 years compared to an average

useful life of 30-40 years) until technological innovation and cost deflation make clean hydrogen the most attractive carbon-free production route.

We estimate that for the clean hydrogen DRI-EAF production route to reach cost parity with the natural gas DRI-EAF route, an electricity price below US$25/MWh and ongoing capex reduction and improving electrolyzer efficiencies are required. This analysis is heavily reliant on assumed commodity prices as well. For the purpose of the exhibit shown below, we assume a natural gas price of US$8/mcf, coal price of US$100/tn, and electricity price of US$40/MWh (with the clean hydrogen DRI-EAF route relying entirely on renewable electricity), a discount rate of 8%.

Exhibit 140: Hydrogen DRI-EAF could be a key emerging de-carbonization technology for the steel industry, yet its current economics call for further technological innovation, scale and higher carbon pricing
Levelized cost of steel - LCOSS (US$/tn steel) vs carbon intensity of steel (tnCO2/tn steel)
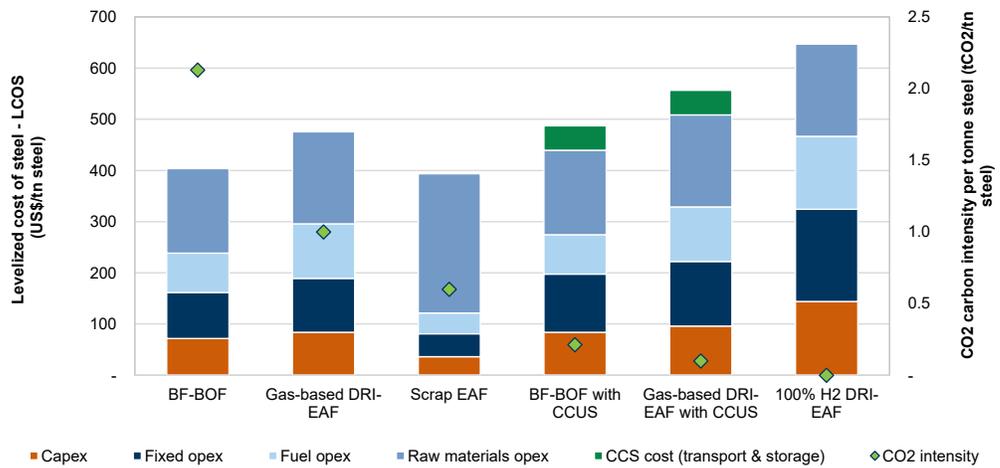
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 141: Very low renewable power prices would be needed today to bring hydrogen DRI-EAF processes at cost parity with alternatives in the absence of technological innovation, scale, cost reduction...
Levelized cost of steel - LCOS (US$/tn steel) vs electricity price (US$/MWh)
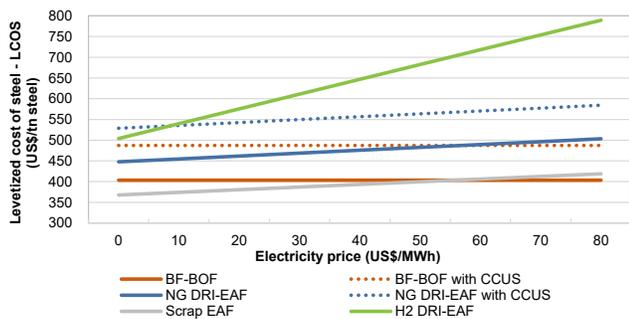
Source: Goldman Sachs Global Investment Research

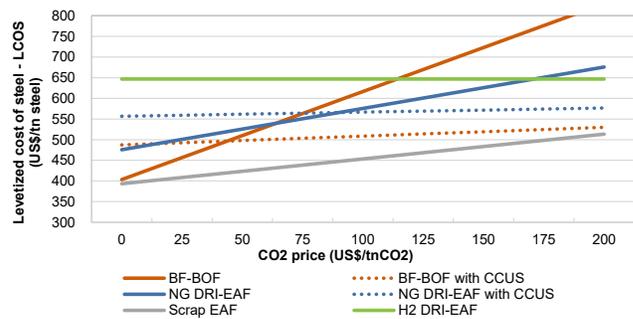**Exhibit 142: ..and a higher CO2 price, with the implied carbon abatement price for the switch at around US$120/tnCO2 on our estimates**
Levelized cost of steel - LCOS (US$/tn steel) vs CO2 price (US$/tnCO2)

Source: Goldman Sachs Global Investment Research

Clean hydrogen and its role in the de-carbonization of steel

As we highlight in the section above, a key industrial application of clean hydrogen, and one that has recently attracted industry interest, is the production of net zero carbon steel, to help meet growing global steel demand with lower emissions.

Exhibit 143: Schematic summary of possible steel manufacturing routes and associated emissions intensity (tnCO2eq/tn steel)
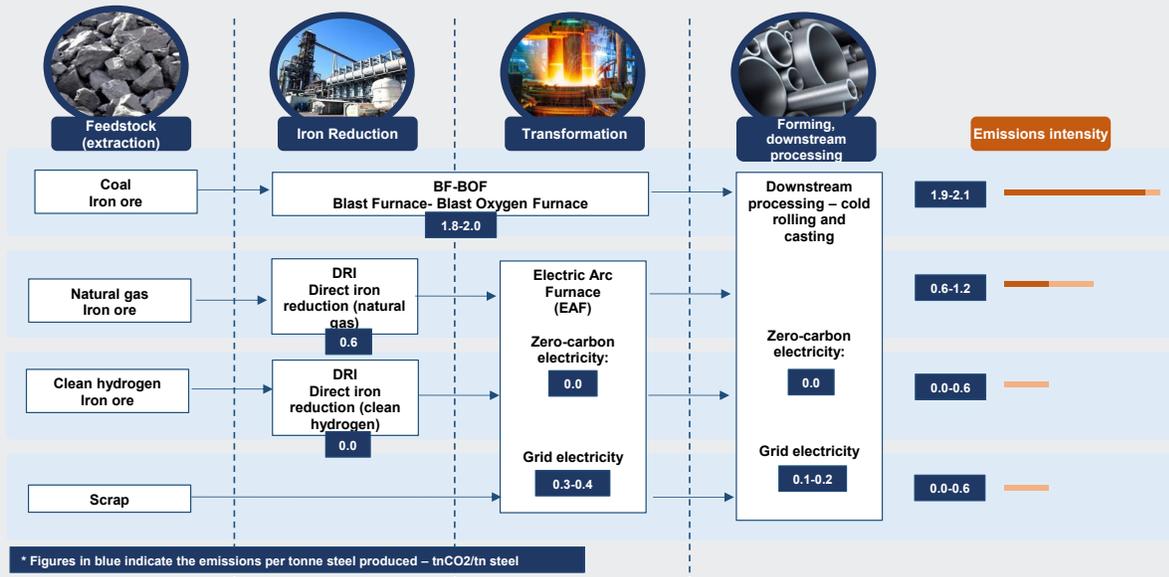
Source: Energy Transitions Commission, Goldman Sachs Global Investment Research.

A number of projects are currently underway to develop these processes and move towards commercialization, as outlined below.

- **SALCOS:** An initiative undertaken by **Salzgitter AG** and the Fraunhofer Institute to develop a process for hydrogen-based reduction of iron ore using the DRI-EAF route. The process initially involves the reduction of iron ore to iron with the aid of natural gas and a higher volume of hydrogen in a direct reduction reactor. Based on this method, a reduction of iron of up to 85% can be achieved according to the operators, with CO_2 savings of initially up to 50% theoretically possible.

- **ΣIDERWIN:** A research project by **ArcelorMittal** which is in the pilot phase. It utilizes an electrochemical process supplied by renewable sources to transform iron oxides into steel plate with a significant reduction of energy use. ArcelorMittal also announced that its Sestao plant in Spain will become the world's first full-scale zero carbon-emissions steel plant. According to the company, by 2025, the Sestao plant will produce 1.6 million tonnes of zero carbon-emissions steel.

- STEAG and Thyssenkrupp's hydrogen project: STEAG, Duisburg-based steel producer thyssenkrupp Steel and Dortmund-based thyssenkrupp Uhde Chlorine Engineers, specializing in electrolysis technology, are working on a joint feasibility study for the construction of a water electrolysis plant at the STEAG site in Duisburg-Walsum.

- **HYBRIT:** In 2016, **SSAB, LKAB and Vattenfall** formed a partnership for the de-carbonization of steel through a modified DRI-EAF process, aiming at producing the first fossil-free steel making technology with a net zero carbon footprint. During 2018, a pilot plant for fossil-free steel production in Luleå,

Sweden, started construction. The total cost for the pilot phase is estimated at Skr1.4 bn. The Swedish Energy Agency will contribute more than Skr500 mn towards the pilot phase and the three owners, SSAB, LKAB and Vattenfall, will each contribute one third of the remaining costs. The Swedish Energy Agency earlier contributed Skr60 mn to the pre-feasibility study and a four-year research project. In November 2021, The HYBRIT initiative was granted support from the European Union, as one of the seven large-scale innovative projects, under the Innovation Fund. The project will produce approximately 1.2 Mt crude steel annually, representing 25% of Sweden's production.

Exhibit 144: HYBRIT process route schematic diagram
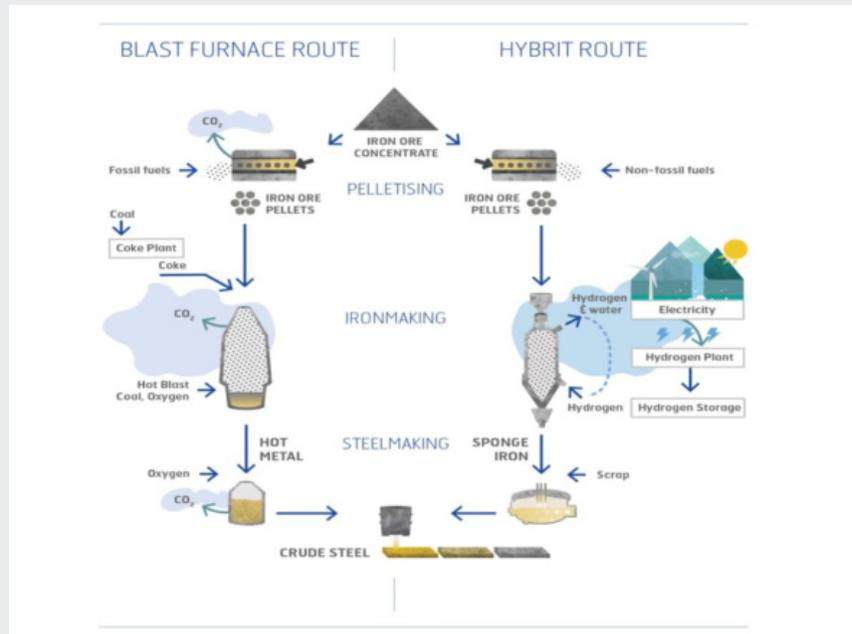
Source: HYBRIT, Company data

- **H2FUTURE:** A pilot plant for carbon-neutral production of hydrogen successfully commenced operation in 2019 at the **Voestalpine** site in Linz, as part of the EU-funded H2FUTURE project, with partners including VERBUND, Siemens, Austrian Power Grid, K1-MET and TNO.

- **COURSE 50:** An initiative from the Japanese Iron and Steel Federation which aims to reduce the carbon footprint of steel production through the use of a higher proportion of hydrogen for iron ore reduction, as well as capturing the CO_2 content of the process streams.

- **HIsarna:** In 2004, a group of European steel companies (including **Tata Steel**) and research institutes formed ULCOS, which stands for Ultra-Low Carbon Dioxide Steelmaking. Its mission is to identify technologies that might help reduce carbon emissions of steelmaking by 50% per tonne by 2050. HIsarna is one of these technologies and is a process involving an upgraded smelt reduction that processes iron in a single step. The process does not require the manufacturing of iron ore agglomerates such as pellets and sinter, nor the production of coke, which are necessary for the blast furnace process.

Transportation: A key emerging hydrogen demand opportunity, spanning across models (heavy-road, shipping, aviation, rail)

Transportation mostly sits in the 'high-cost' area of the de-carbonization cost curve, with the sector responsible for c.22% of the global anthropogenic CO_2 emissions (2019, incl. AFOLU) (EU EDGAR database). As part of our GS net zero models, we lay out the path to net zero emissions for transportation, as shown in Exhibit 148, addressing all key transportation modes: short and medium-haul road transport, heavy long-haul transport, rail, aviation and shipping. The speed of de-carbonization varies depending on the transport mode, and is largely driven by the difference in costs and technological readiness of the available clean alternatives required for each sub-sector. Light-duty vehicles and rail (which is already largely de-carbonized through electrification) are the two transport modes with faster relative de-carbonization, given the readiness and notable cost deflation of clean technologies for both (electrification). Conversely, aviation and shipping are de-carbonizing at a slower pace, given the still largely undeveloped or early stage de-carbonization alternatives for both (sustainable aviation fuels, synthetic fuels, clean hydrogen and ammonia), which we expect to enjoy a large uptake in adoption and account for a notable part of the fleet only post 2030. We further address the evolution of the fuel mix of energy consumption of transport over time in our GS 1.5 scenario and present the results both in aggregate and by key transport mode in Exhibit 147. Overall, we see electricity's share increasing in total transport energy consumption to c.50% by 2050, while fossil fuel's share declines from >95% at present to just 3%. Bioenergy, clean hydrogen & synthetic fuels, and ammonia all emerge as important energy sources for transportation, accounting for c.20%/ 23%/6%, respectively.

Exhibit 145: Transportation is emerging as a key industry for clean hydrogen demand long term, which could reach close to 250Mt H2 by 2050 ('Bull' scenario), c.3x the current global demand for hydrogen...
Transportation hydrogen demand (Mt H2 pa) under the three GS global hydrogen models
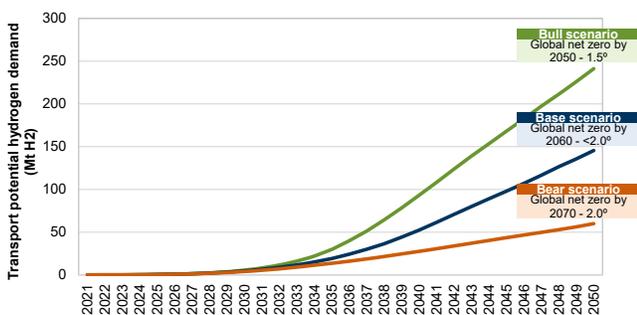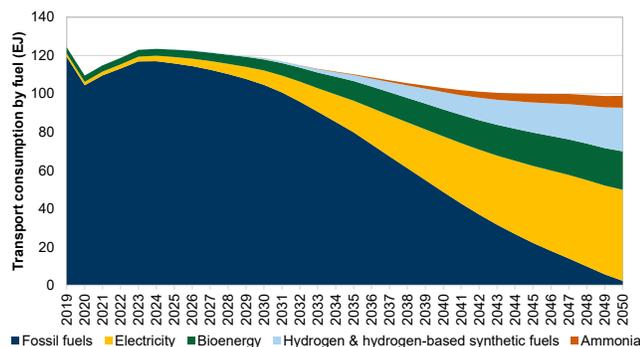

Source: Goldman Sachs Global Investment Research

Exhibit 146: ..with contribution across transport modes, including heavy long-haul road transport, aviation, shipping, and rail, with growth across all accelerating post 2030
Global hydrogen demand from transportation for the GS 'Bull' scenario (Mt H2)
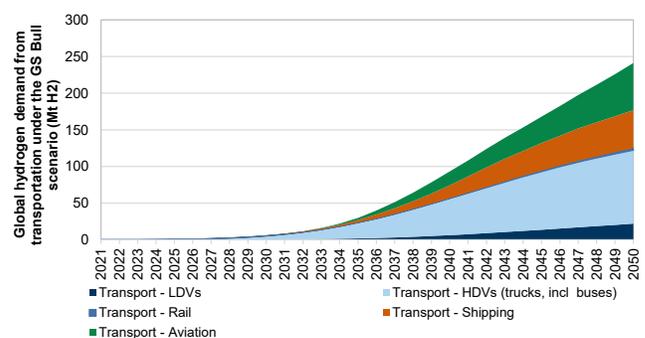
Source: Goldman Sachs Global Investment Research

Exhibit 147: We expect the energy mix of the transport sector to evolve dramatically over time for a path consistent with net zero...
Transport energy consumption by fuel (EJ)

Source: Goldman Sachs Global Investment Research

Exhibit 148: ..and we model the emissions from all key models of the transport sector in our GS 1.5°path to global net zero by 2050
Transport sector emissions (MtCO2) split by key transport mode
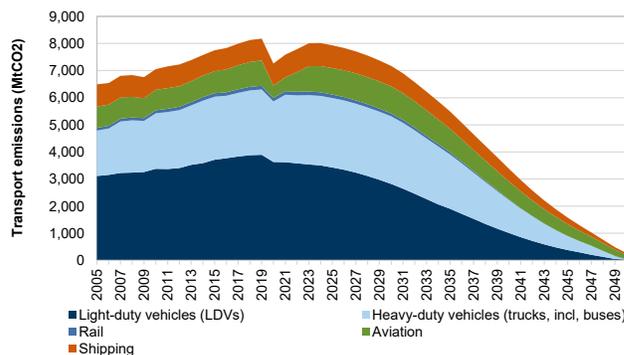
Source: Emission Database for Global Atmospheric Research (EDGAR) release version 5.0, FAO, Goldman Sachs Global Investment Research

Road transport: Long-haul heavy-duty road transport the sweet spot for clean hydrogen and alternative fuels, electrification likely to be the most attractive technology for passenger transport

We believe road transport is at the start of its most significant technological change in a century, with electrification, autonomous driving and clean hydrogen at the core of the de-carbonization challenge. For light duty vehicles (LDVs) (primarily constituting passenger vehicles, commercial vehicles and short/medium-haul trucks), we consider **electrification the key de-carbonization technology.** For **long-haul heavy trucks**, we **consider clean hydrogen a competitive option**, owing to its faster refueling time, lower weight and high energy content. Overall, we estimate that the total LDV road fleet (including passenger vehicles and short and medium-haul trucks) will increase almost two-fold to 2050 (from a 2019 base), with new energy vehicles – NEVs (including all of BEVs, PHEVs and FCEVs) – reaching almost 100% penetration in the road transport fleet, for a path consistent with net zero emissions globally by 2050 and peak emissions before 2030 in our global net zero model by 2050 (1.5 degrees).

While we believe that electric vehicles screen as the most attractive de-carbonization solution for LDVs, including short and medium-haul transport, we believe **that clean hydrogen could be a key competing technology when long-haul heavy transport is considered (HDVs), given its high energy content per unit mass (lighter) and faster refueling time.** Although the FCEVs (fuel cell electric vehicles) global stock was estimated to have exceeded only 40,000 in 2021 (IEA), owing to a limited product offering, non-competitive price points and little infrastructure, we see the recent policy drive towards de-carbonization as a reason to reconsider the potential for FCEVs. Currently, FCEV deployment has been concentrated largely on passenger LDVs, which is contrary to where we believe the true hydrogen opportunity lies, i.e. in heavy-long-haul transport (trucks, buses and forklifts) where, despite small absolute volumes, growth of FCEVs could accelerate notably. Overall, our net zero path by 2050 (GS 1.5°) calls for a sales mix that evolves notably in the coming years, with FCEVs and EVs making up c.22%/100%% of total HDV sales by 2030/40E.

Exhibit 149: Global FCEVs deployment has surpassed 40,000 in 2021, largely concentrated in Asia (China, Korea, Japan) and the US..
FCEVs stock by region (k units)
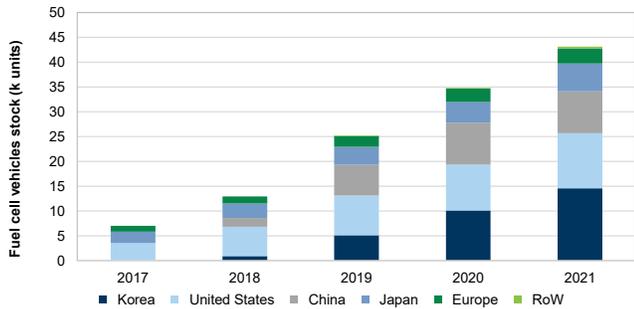
Source: IEA, AFC TCP, Goldman Sachs Global Investment Research

Exhibit 150: ...with infrastructure development and availability being a key constraint
HRSs vs FCEVs per HRS
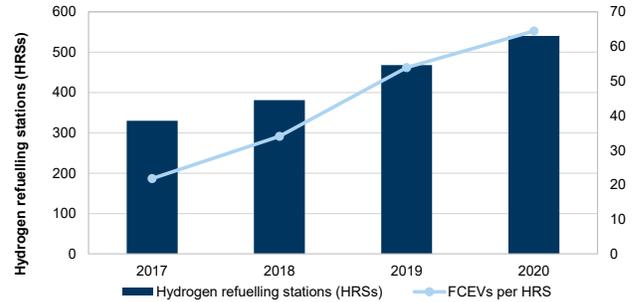
Source: IEA

Exhibit 151: Hydrogen outperforms significantly when we compare the refueling times of FCEVs versus BEVs at different kW charging levels...
mins to refuel/recharge
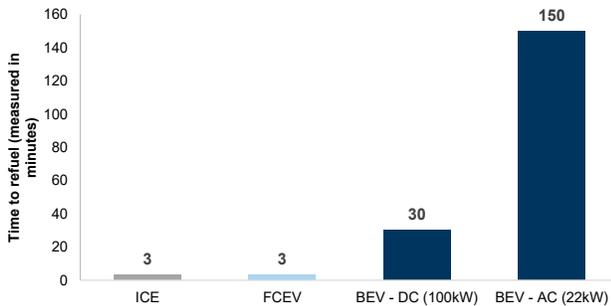
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 152: ...and also provides a range advantage for passenger vehicles, albeit other models meet the average weekly threshold too...
BEV/FCEV model range overview
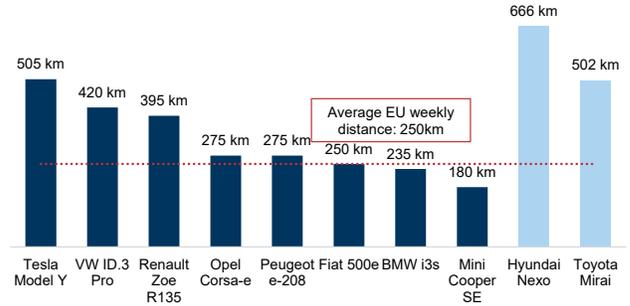
Source: Company data, compiled by Goldman Sachs Global Investment Research

Exhibit 153: ...making the application where the range advantage is most important, i.e. long-haul trucks and buses
ZEV Class 8 trucks and range (km)
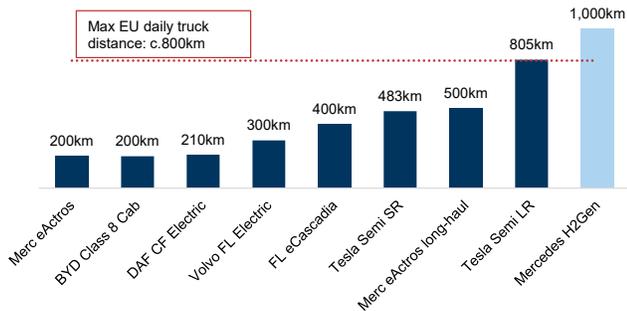
EU max daily driving time at 9 hours (assuming average speed of 90km/h)

Source: Transport & Environment, EU, compiled by Goldman Sachs Global Investment Research

Exhibit 154: FCEVs using compressed hydrogen screen attractively on a weight per unit of output energy basis when compared with BEVs
Weight per unit of output energy (tank-to-wheel basis, kg/MJ) for average passenger vehicle and % increase in average vehicle weight
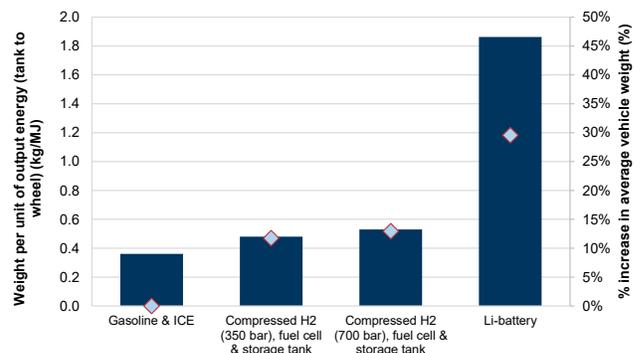
Source: US Department of Energy, EIA, Goldman Sachs Global Investment Research

In the exhibits below, we compare the total cost of ownership for ICE, BEV and FCEV, both for passenger vehicles and trucks. It is clear that the technological and cost competitive advantage of battery electric vehicles for passenger and short-haul transport make battery the preferred technology for this road transport segment. However, as we look into heavy-road long-haul transport, we find the hydrogen proposition competitive, with a TCO that is similar to that of BEV but benefiting from lower weight and faster refueling times. While both options remain more costly than conventional diesel ICE trucks, we expect technological innovation and cost deflation that generally comes on the back of economies of scale to reduce the costs of both technologies over time.

Exhibit 155: 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 refueling times, longer ranges and lower weight
Total cost of ownership of a Class 8 truck (15 years assumed useful life)
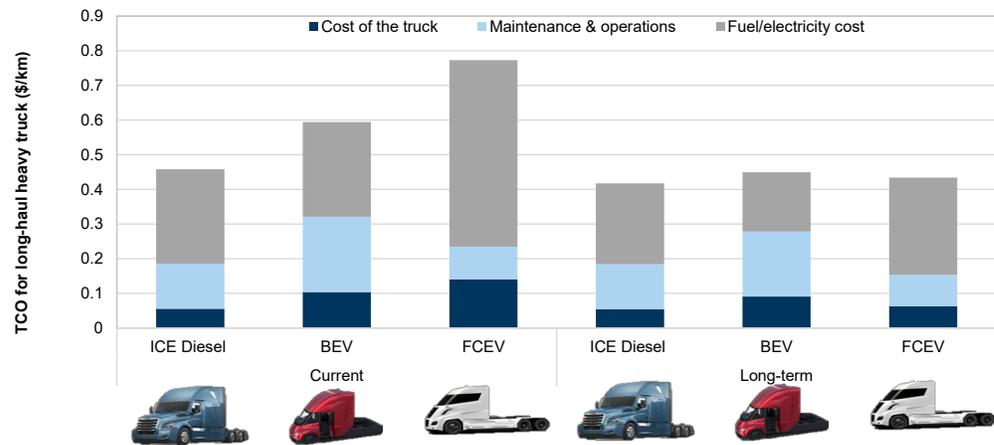
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 156: Longer term, we estimate a hydrogen price around US$4-4.5/kgH2 would be sufficient for cost parity with diesel (normalized diesel prices), while at current FCEV costs a hydrogen price of US$3-3.5/kg H2 would be needed for cost parity, well below c.$8-12/kgH2 at the pump currently
Hydrogen price at the pump required for cost parity with diesel
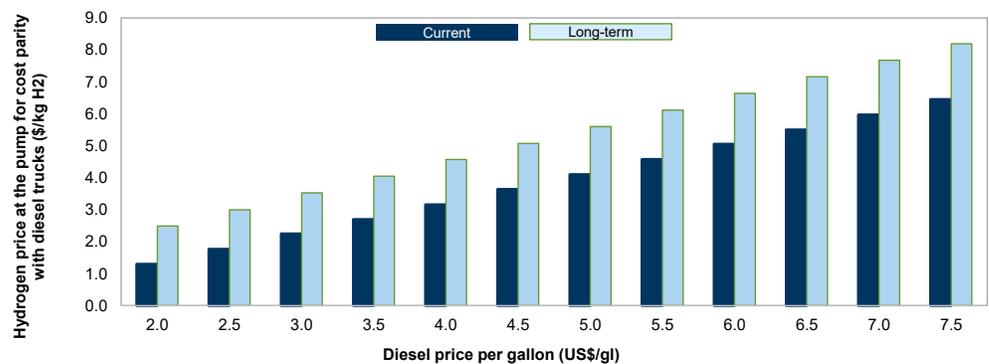
Source: Goldman Sachs Global Investment Research

Exhibit 157: Hydrogen has low efficiency, on a comparative basis, with electric vehicles being twice as efficient on a well-to-wheel/power-to-wheel basis
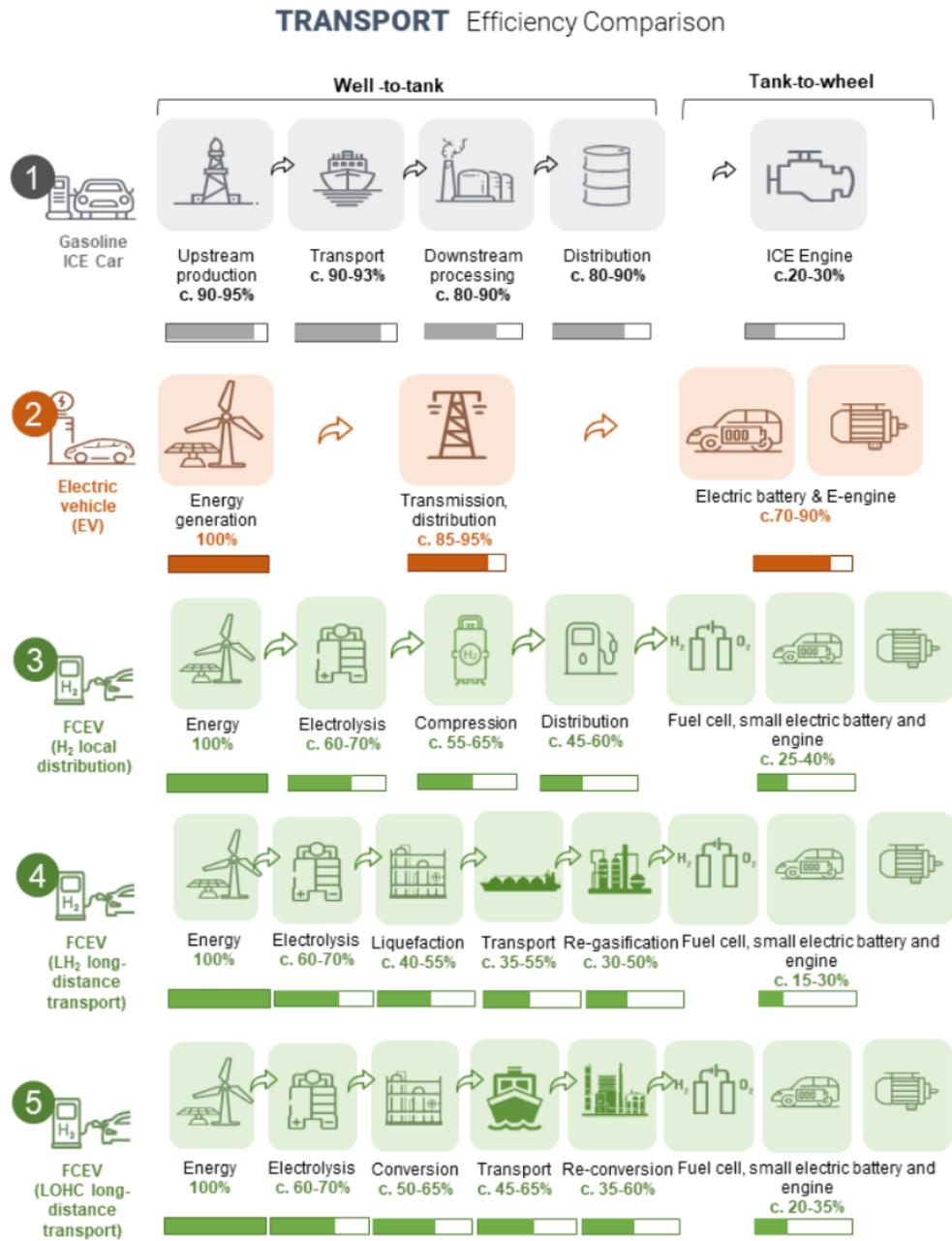
Source: Goldman Sachs Global Investment Research

Shipping & Aviation: A long-term opportunity for clean hydrogen, either in pure form or in the form of alternative fuels such as ammonia, methanol, and synthetic fuels to de-carbonize two of the hardest-to-abate industries

Shipping: Maritime shipping is responsible for c.0.9 GtCO2eq of emissions (2019) (GS estimates), accounting for a similar share of the global CO2 emissions as aviation. Shipping is another sector with hard-to-abate emissions, given a lack of widespread adoption of available low-carbon de-carbonization technologies at scale, and the relatively long operating life of vessels. Similar to aviation, we do not expect gross emissions in shipping to reach absolute zero in 2050, yet we do model a notable reduction in emissions, as alternative fuels become more widely adopted. These include liquefied natural gas (LNG), which while not a zero-emitting fuel, can play a key role as a transition fuel for the shipping sector. **Longer term, we expected advanced biofuels, and clean ammonia and hydrogen to play a larger role as the ultimate de-carbonization technologies for the sector.** Internal combustion engines for ammonia-fueled vessels are currently being developed, and we expect they can be made readily available to the market by 2030 (according to guidance from companies). **Methanol has also been demonstrated as a fuel for the maritime shipping sector** and is relatively more mature than hydrogen and ammonia while also being potentially compatible with existing maritime engines, we believe.

In our GS 1.5° path, consistent with our 'bull' global hydrogen scenario, we assume clean ammonia accounts for c.69% of the total energy in shipping in 2050 and sustainable biofuels provide c.20% of total shipping energy needs, with the remaining energy provided by fossil fuels (oil and LNG). However, we note that the vast majority of demand for ammonia, methanol or hydrogen-based fuels for the shipping sector is likely to come post 2030.

Exhibit 158: Our 'bull' scenario, consistent with net zero by 2050, calls for a radical fuel mix in the shipping sector to alternative fuels including bioenergy, LNG and ammonia (or methanol)...
Shipping energy consumption by fuel (EJ)
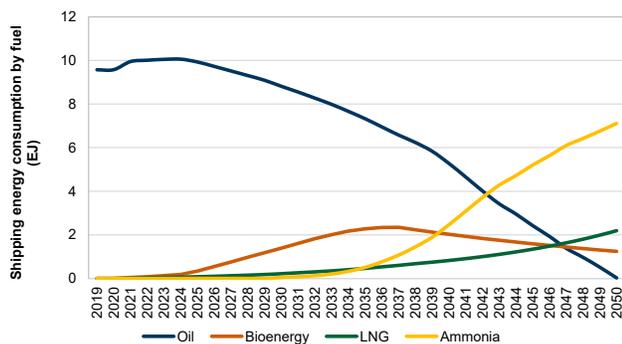
Source: Goldman Sachs Global Investment Research

Exhibit 159: ..potentially resulting in 52 Mt H2 pa long-term demand in a net zero by 2050 scenario ('Bull' scenario), yet with growth occurring almost entirely post 2035 under all three of our scenarios
Potential H2 demand for the shipping industry (Mt H2 pa)
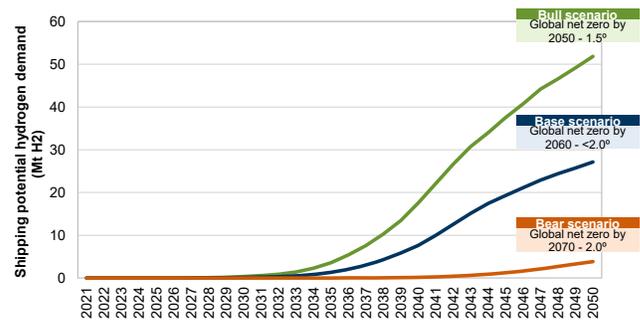
Source: Goldman Sachs Global Investment Research

Aviation: Aviation sits at the top of our Carbonomics cost curve, and is one of the toughest sectors to de-carbonize. Sustainable aviation fuels (SAFs), synthetic fuels and improved aircraft efficiency are, in our view, all key parts of the solution. In the near term, we view the new generation of aircraft and fleet renewal as likely to achieve the lowest-cost aviation emissions abatement. The potential role of hydrogen in this industry longer term could come in two forms: (a) its pure form with the use of fuel cells (short and potential medium-haul flights) or direct combustion (longer flights) and (b) in the form of synthetic fuels, whose production involves combining clean hydrogen with captured CO2. Technically, hydrogen combustion (instead of fuel cells) could be used for long-haul flights with notably lower fuel requirements (given the much higher energy content of hydrogen compared to conventional jet fuel), yet NOx emissions would need to be addressed. Moreover, using hydrogen in its pure form would require novel aircraft engine designs for both direct combustion and fuel cell options. Therefore, we use liquid fuels such as biofuels and synthetic fuels primarily in our models to net zero which do not require substantial innovation beyond existing aircraft engine designs. Synthetic fuels do, however, rely on the availability and cost competitiveness of clean hydrogen and captured CO2, implying it is likely to have a longer-term horizon given the need for the emergence and scale-up of the clean hydrogen and carbon capture industries first. As such, we see any penetration of synthetic fuels in aviation really accelerating post 2040 under all scenarios. Airbus is currently exploring various aircraft concepts with the aim of having a commercial aircraft available by 2035.

Exhibit 160: Alternative fuels such as hydrogen, bioenergy and synthetic fuels are likely to be necessary in an industry where direct electrification is not considered a technological option such as aviation...
Energy mix evolution for the transport sector by mode, under our GS 1.5 net zero by 2050 scenario (%)
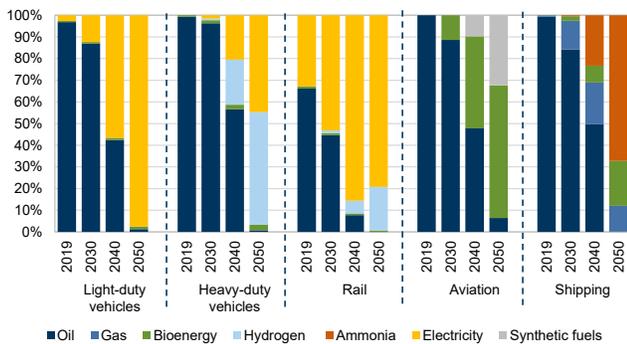
Source: Goldman Sachs Global Investment Research

Exhibit 161: ..with the opportunity for hydrogen, while large (c. 65 MT H2 by 2050 in our 'bull' scenario), only coming through post 2035 in this industry, under all our scenarios, given the lack of technological readiness
Aviation potential hydrogen demand (Mt H2 pa) under the three GS global hydrogen scenarios
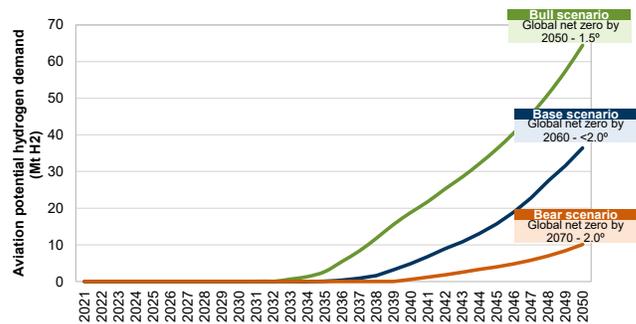
Source: Goldman Sachs Global Investment Research

Rail: An opportunity to contribute to the last piece of the de-carbonization puzzle in a front-runner sector in the energy transition

While the rail industry is already a front-runner in the energy transition, c.20% of rail traffic and 40% of the network is still under the diesel regime. Within this context, we believe that hydrogen trains will help to reduce further the emissions and noise levels caused by the industry. Fuel Cells and Hydrogen (FCH) trains have become a focus for rail OEMs in recent years. While FCH technology tests started in 2005, the first commercial trains were presented in 2016 by Alstom, and entered operation in Germany in 2018. While still in early development and, according to Alstom, >25% higher in terms of upfront costs, its environmental, technical and economic profile makes hydrogen trains attractive to replace the diesel-powered fleet. According to the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) and the Shift2Rail Joint Undertaking (S2R JU), the technology could form up to 20% of new European trains by 2030, replacing c.30% of diesel trains.

Synthetic hydrogen-based fuels and feedstocks

Synthetic fuels are another means of dealing with the de-carbonization challenge for industries such as aviation. An acceleration of large-scale hydrogen adoption in long-haul transport could materialize on the back of its ability to form ammonia and other liquid organic hydrogen carriers (LOHCs), but also its ability to combine with CO_2/CO to produce synthetic hydrocarbons/liquid fuels such as synthetic methanol, diesel and jet fuel. In our view, the former (ability to form ammonia and LOHCs) has the potential to enhance the pace of hydrogen adoption by aiding storage and transportation, while the latter (ability to combine with CO_2/CO) acts as a CO_2 utilization route with a wide range of applications. Some hydrogen-based synthetic feedbacks and fuels developed include:

- **Synthetic methane:** This is the most commonly produced synthetic hydrogen-based fuel, and the production pathway involves a methanation process (mostly catalytic but biological routes are also possible) that utilizes the direct reaction between hydrogen and CO_2 to produce methane, with water the main reaction by-product.

- **Synthetic methanol**: Methanol has c.80% higher energy density than hydrogen, and its production route from syngas (through hydrogen) is well developed commercially. The first CO_2-to-methanol facility, known as George Olah Renewable Methane Plant, is located in Iceland and was commissioned in 2012 with a capacity of 1,000 tpa of methanol before its expansion to 4,000 tpa in 2015. The CO_2 feedstock is captured from a nearby power plant while hydrogen is produced via electrolysis and used to directly hydronate the captured CO_2. The 'Vulcanol' product is then sold for use as a gasoline additive and feedstock for biodiesel production.

- **Synthetic diesel, kerosene and other fuels:** Synthetic diesel or kerosene is the result of a reaction occurring between carbon monoxide (CO) and hydrogen. Carbon monoxide could be obtained from captured CO_2, with the resulting syngas, CO_2 and hydrogen converted into synthetic fuels via the Fischer Tropsch synthesis route.

Exhibit 162: Clean hydrogen can be used in CO2 utilization processes for the production of synthetic hydrogen-based fuels
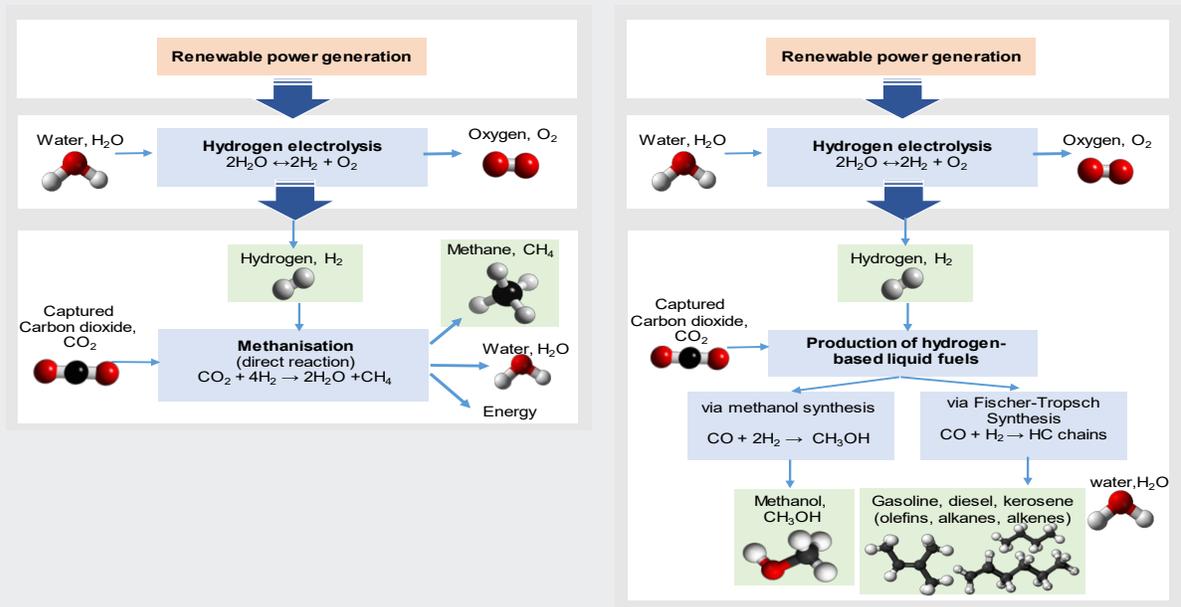
Source: The Royal Society, compiled by Goldman Sachs Global Investment Research

Buildings heating: Limited scope for large market share given the lower efficiency and availability of more efficient, cost competitive alternatives

Buildings' water and space heating accounts for almost 55% of global buildings' energy use and is responsible for almost all of buildings' direct CO_2 emissions, which, in 2019, accounted for c.9% of global CO_2 emissions (EU EDGAR). While we continue to see global activity continuing in the sector, with the global floor area increasing from 240 bn meters squared to c. 410 bn meters squared by 2050, the transformational energy shift away from fossil fuels to cleaner alternatives, coupled with an acceleration of energy efficiency improvements could bring the carbon intensity of buildings to close to zero. While the key technologies that govern the de-carbonization of buildings in the near and medium term are readily available, including electric heat pumps (air and ground source) and residential solar, geothermal, and bioenergy, the long lifespan of buildings makes the need for comparatively costly retrofits essential to achieve net zero emissions by 2050, particularly for residential buildings where the switch is largely reliant on consumer preference. As such, any aspiration for gross zero emissions in buildings has to come with an accelerated pace of retrofits.

While hydrogen's prospects for buildings specifically remains limited, reflecting the high efficiency of electricity-based de-carbonization options including heat pumps and the comparatively low efficiency of hydrogen, particularly when transportation and conversion is considered, it could aid the path to net zero particularly where gas infrastructure already exists and where the existing building stock is very difficult to retrofit for electricity-based solutions. Co-existence of hydrogen and other heat production technologies can also add flexibility to the grid to facilitate demand-driven responses, particularly in cold climates. The IEA identifies four main groups of technologies which could operate on hydrogen for buildings: hydrogen boilers, fuel cells that co-generate heat and electricity, hybrid heat pumps, and gas-driven heat pumps.

Exhibit 163: The prospects for hydrogen to be used in direct buildings' heating are fairly limited in places where heat pump technology can be successfully deployed, given the relatively low efficiency (high primary energy factor)..
Primary energy factor of heat production across technologies and fuels
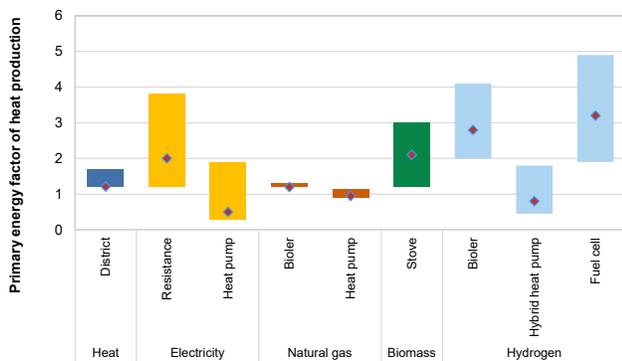
Exhibit 164: ...and therefore we assume a low share in buildings' energy
Buildings total final energy consumption fuel mix evolution (%)

Source: IEA

Source: Goldman Sachs Global Investment Research

Grid blending: A major potential addressable market for hydrogen that is important for various existing natural gas end-users and benefiting from existing infrastructure

We believe that, **in the near term, grid blending** is likely to be the **key driver of hydrogen demand for heating** and offers a unique **opportunity to utilize existing assets that face the risk of becoming stranded in a net zero world.** Furthermore, grid blending can **aid the de-carbonization of a broader range of natural gas customers**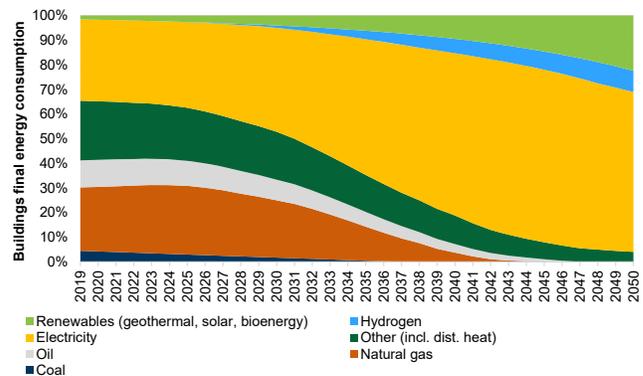 currently, including **industry**, **buildings** and **power generation,** leading to a much larger addressable market than buildings' heating alone would suggest. Blending clean hydrogen in existing natural gas infrastructure would avoid significant capital costs associated with developing new transmission and distribution infrastructure, as explained earlier in the report. Overall, on our estimates, hydrogen blending in existing infrastructure would likely increase costs by around US$0.2-0.5 $/kg H2 on top of the costs of hydrogen production due to the need for injection stations on the transmission and distribution grids as well as higher operational costs. Even small blending volume rates of hydrogen can have a major impact on its addressable market; for instance, we estimate that a 15% global hydrogen blend rate can lead to c. 60Mtpa of additional hydrogen demand. However, a number of challenges have to be addressed: (a) the low energy density per unit volume of hydrogen compared to gas (around a third) which would imply greater required gas volumes, (b) the smaller size of hydrogen molecules, which would imply higher risk of leakage through steel pipeline networks, suggesting the need for polymer-based retrofitting at blending rates that exceed 20%-30%, (c) the increased risk of flammability and the odorless, colorless nature of the gas leading to rising need for flame detectors and monitoring, (c) variability of the volume of hydrogen blended into the stream, which could have an adverse impact on the operation of the equipment, which often is designed with a narrow range of adaptability to different gases.

Europe is one of the leading countries when it comes to setting the regulatory framework for hydrogen blending. Germany, for instance, specifies a maximum of 10% provided there are no CNG filling stations connected to the network. There are currently many projects in Europe examining the potential for hydrogen blending in existing gas networks including GRHYD in France, and HyDeploy, H21 and Hy4Heat in the UK. The 'European Hydrogen Backbone' dedicated hydrogen infrastructure study published in 2020, authored by eleven gas infrastructure players, described the vision of how dedicated hydrogen infrastructure can be created in a significant portion of Europe. This describes a 6,800 km pipeline network by 2030 and its further scale-up to 23,000 km by 2040, requiring an estimated EUR27-64 bn based on the assumption of 75% natural gas pipelines converted and 25% new pipeline stretches. Assuming the backbone is equipped with a robust compression system, the proposed network should be able to meet 1130 TWh annual hydrogen demand in Europe by 2040.

More recently, in December 2021, the **European Commission proposed a new EU framework to de-carbonize gas markets, promote hydrogen and reduce methane emissions.** The market rules will be applied in two phases, before and after 2030, and notably cover access to hydrogen infrastructure, separation of hydrogen production and transport activities, and tariff setting. A new governance structure in the form of the European Network of Network Operators for Hydrogen (ENNOH) will be created to

promote dedicated hydrogen infrastructure, cross-border coordination and interconnecting network construction, and elaborate on specific technical rules. The new rules will make it easier for renewable and low-carbon gases to access the existing gas grid, by **removing tariffs for cross-border interconnections and lowering tariffs at injection points.** They also create a certification system for low-carbon gases, to complete the work started in the Renewable Energy Directive with the certification of renewable gases.

Exhibit 165: The potential hydrogen demand we estimate from grid blending could reach close to 60 MtH2 pa in our 'bull' scenario, consistent with global net zero by 2050..
Grid blending potential hydrogen demand (Mt H2 pa)
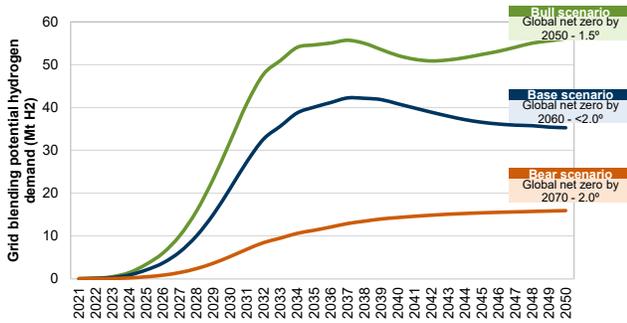
Source: Goldman Sachs Global Investment Research

Exhibit 166: ..yet would require further testing and an upgrade of global hydrogen blending limits
Hydrogen blending limits in natural gas grid by volume (%)
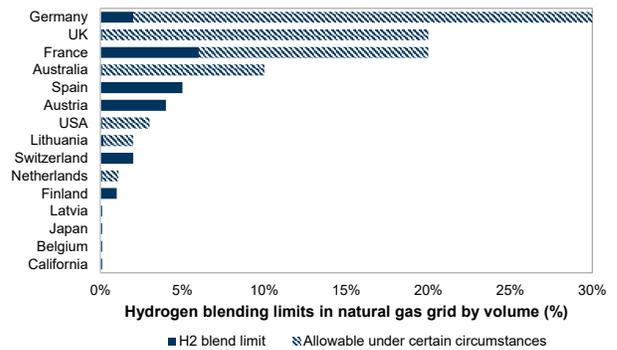
Source: S&P Global Platts

Power generation: Hydrogen necessary as a source of flexibility in power generation and for long-term seasonal energy storage

Hydrogen currently has a very niche and immaterial role in power generation. However, as power generation undergoes a complete transformation on the path to net zero, this may change and hydrogen could emerge as a key interconnecting pillar in this industry. Power generation is the most vital component for any net zero scenario, with the sector contributing to c.32% of global anthropogenic CO_2 emissions (incl. AFOLU) (EU EDGAR), making it the most critical area of focus to tackle the net zero challenge. The role of power generation is, in our view, only likely to increase in the coming decades, as the penetration and pace of electrification rapidly increases across sectors (including road transport, building heating, industrial manufacturing processes and low-temperature industrial heat) as they progressively follow their own de-carbonization path. Overall, we expect total demand for power generation in a global net zero scenario by 2050 to increase three-fold (vs. that in 2019) and surpass 70,000 TWh as the de-carbonization process unfolds.

Based on our Carbonomics cost curve analysis, power generation currently dominates the low end of the carbon abatement cost spectrum, with renewable power technologies already developed at scale and costs having fallen rapidly over the past decade, making them competitive with fossil fuel power generation technologies in many regions globally. However, renewable power generation suffers from two key problems that need to be addressed: intermittency and seasonality. Hydrogen can help with both of these problems.

Exhibit 167: Based on our global net zero by 2050 path, power generation demand increases three-fold to 2050...
Global electricity generation (TWh)
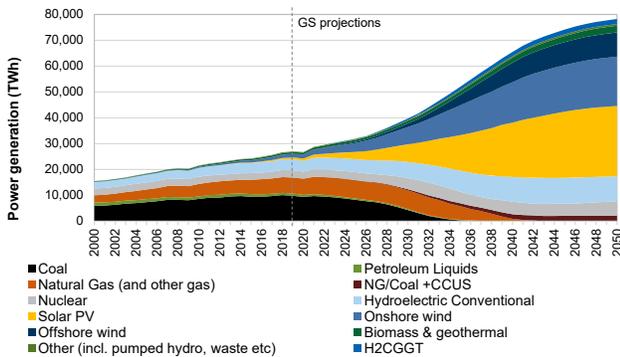
Source: BP Statistical Review, Goldman Sachs Global Investment Research

Exhibit 168: ...while the global power generation mix undergoes transformational changes, with the non-fossil fuel share in our net zero path rising from c.36% currently to >95% by 2050..
Global power generation fuel mix (%)
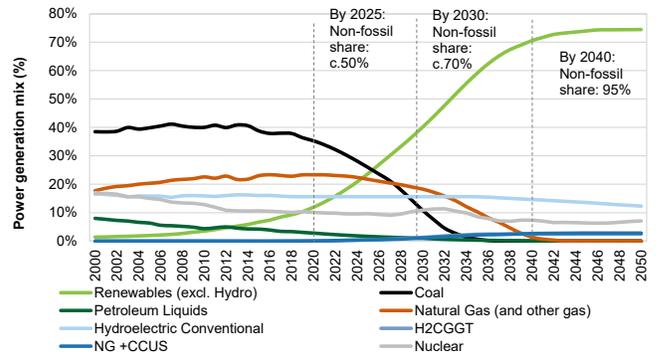
Source: BP Statistical Review, Goldman Sachs Global Investment Research

We identify four key roles of clean hydrogen in the power generation industry that are likely to lead to its use as a key pillar of this sector's de-carbonization:

(a) Ammonia co-firing in existing coal power plants: Hydrogen can act as a direct de-carbonization fuel using co-firing of clean ammonia in existing coal power generation plants, therefore reducing the carbon intensity of the conventional coal power generation plants. Blending rates of around 20% could be achievable with only minor adjustments and plant modifications. This is especially important for the near term for countries largely still relying on coal for their power generation and those that currently have a very young coal plant fleet, which is the case for China and India. Without co-firing of ammonia or carbon capture technologies, the implied required retirement of these assets for a global net zero scenario could result in a major stranded assets issue, with young coal power plants often in need of retirement two decades before their average useful life (shown in Exhibit 169). The key constraint to ammonia co-firing remains the lack of economic competitiveness, as shown in Exhibit 170, in the absence of carbon pricing. We estimate that for ammonia co-firing to be at cost parity with a conventional coal power plant in Asia, an ammonia price of US$300/tn NH3 and a carbon price close to US$100/tnCO2 would be required.

Exhibit 169: Coal power plant retirements will need to take place by 2035 in the 1.5° scenario, 20 years before the end of their useful life...
Coal-fired power plants net retirements (GW)
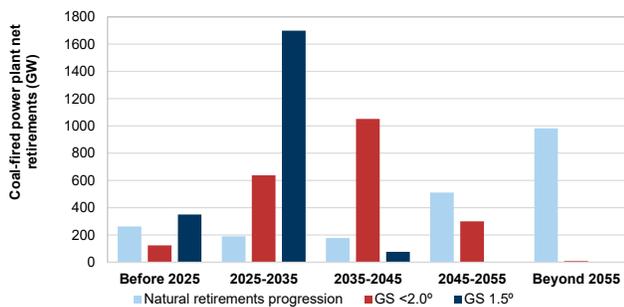
Source: Goldman Sachs Global Investment Research

Exhibit 170: ..making CCUS and ammonia co-firing important to avoid stranded assets, albeit economic competitiveness in the absence of a carbon price is very hard to achieve at current costs
LCOE for coal power generation vs carbon intensity
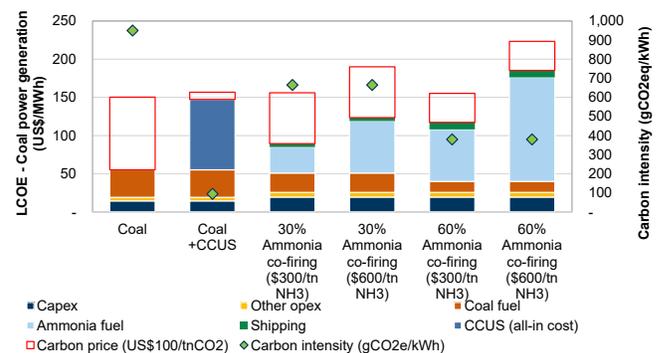
Source: Goldman Sachs Global Investment Research

(b) Flexible power generation: Hydrogen-fired gas turbines and combined-cycle gas turbines could be used as a source of flexibility in electricity systems with increasing shares of variable renewable energy (VRE) aiding the intermittency problem. Fuel cells can also be used with electrical efficiencies typically exceeding 50%-60% (similar to those of turbines) and the stationary fuel cells market has been steadily growing over the past decade. However, fuel cells typically have shorter technical lifetimes than gas turbines and smaller power output making them more suited to distributed power. In the power sector, the timing of variable electricity supply and demand is not well matched requiring additional operational flexibility. Various options exist to resolve this intermittency issue, such as grid infrastructure upgrades or technologies for short- or longer-term balancing of supply and demand (dynamic power networks), flexible back-up generation, demand-side management, or energy storage technologies.

Exhibit 171: Both carbon capture and hydrogen turbines and fuel cells can be used for load balancing, with hydrogen turbines and fuel cells typically requiring a hydrogen cost below $2/kgH2 (cost parity with grey) to be competitive

Levelized cost of electricity - LCOE (US$/MWh)
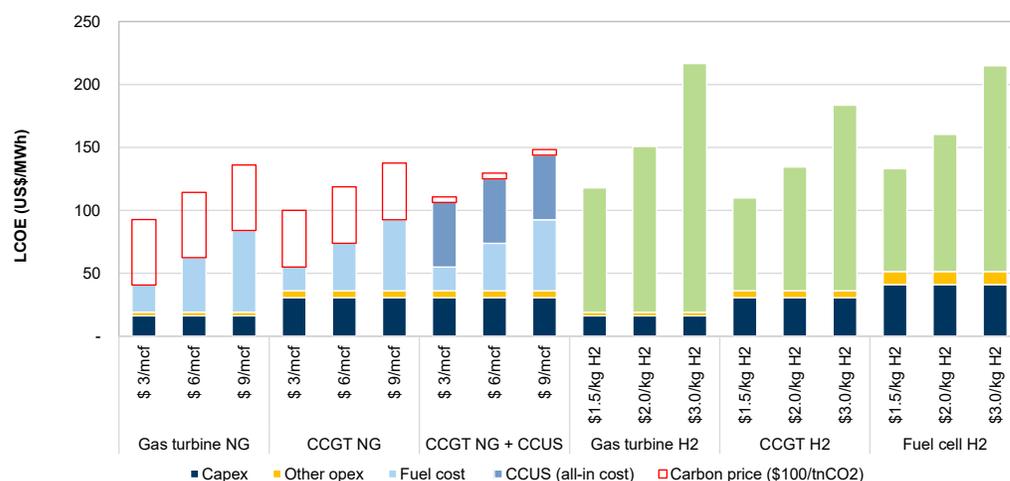
Source: Company data, Goldman Sachs Global Investment Research

(c) Buffer, back-up and off-grid power supply: Hydrogen has valuable attributes that could make it a key solution for power generation system back-up as electrolysis can convert excess electricity into hydrogen during times of oversupply. The produced hydrogen can then be used to provide back-up power during power deficits or can be used in other sectors such as transport, industry or residential. Hydrogen offers a centralized or decentralized source of primary or back-up power. Power from hydrogen has a relatively quick response time making it useful to dealing with sudden drops in renewable energy supply. In addition, electrolyzers may provide ancillary services to the grid, such as frequency regulation. Fuel cells therefore in combination with storage are considered a cost-effective de-carbonization alternative to diesel generation (currently often deployed for back-up power).

(d) Long-term, large-scale seasonal energy storage: In the form of gaseous hydrogen or ammonia, methanol, LOHC, and synthetic fuels, hydrogen could also become a solution for long-term energy storage required to balance seasonal variation of power generation demand, particularly important as the share of electricity through heat pumps for residential heating becomes a more prominent feature and rises in share in total power generation demand. Hydrogen represents the optimal overall solution for long-term, carbon-free seasonal storage, in our view. While batteries, super-capacitors, and compressed air can also support balancing, they lack either the power capacity or the storage timespan needed to address seasonal imbalances, as outlined by the Hydrogen Council and shown in Exhibit 172. While pumped hydro offers an alternative to hydrogen for large-scale, long-term energy storage and therefore has been to date the preferred power storage solution, accounting for more than 95% of global power storage, its remaining untapped potential is subject to local geographic conditions. The key disadvantage of hydrogen-based storage options remains its low round-trip efficiency with the process of electrolysis and then conversion of hydrogen back to

electricity consuming c.60% of the total energy, as opposed to batteries where only 10%-15% of the energy is lost.

Exhibit 172: Hydrogen could be the optimal solution for large-scale, long duration energy storage, particularly for discharge durations beyond 50 hours
Capacity vs discharge duration for energy storage
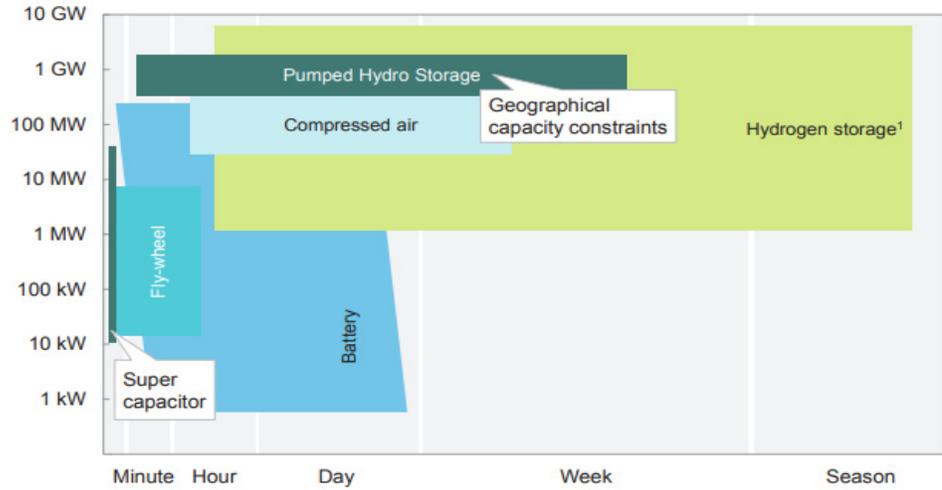
Source: Hydrogen Council

Exhibit 173: We believe long-term seasonal energy storage is the sweetspot for hydrogen, while utility scale batteries may be more suited for intra-day storage given their higher efficiency
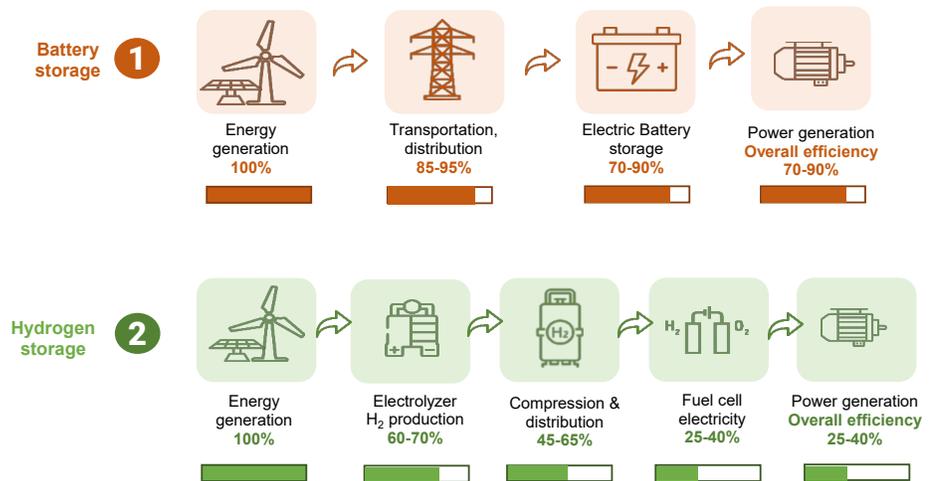
Source: Company data, Goldman Sachs Global Investment Research.

Carbon sequestration: Carbon capture the key missing piece to the carbon neutrality puzzle

Carbon sequestration

We envisage two complementary paths to enable the world to reach net zero emissions: conservation and sequestration. The former refers to all technologies enabling the reduction of gross greenhouse gases emitted and the latter refers to natural sinks and carbon capture, usage and storage technologies (CCUS) that reduce net emissions by subtracting carbon from the atmosphere. The need for technological breakthroughs to unlock the potential abatement of the **emissions that cannot at present be abated** through existing conservation technologies **makes the role of sequestration a critical piece of the puzzle in solving the climate change challenge and leading the world to net zero carbon** emissions at the lowest possible cost. Carbon sequestration efforts are critical for a global carbon neutrality path, as they can (a) unlock emissions abatement across the hardest-to-abate sectors, where technological net zero alternatives have not yet been developed or remain highly inefficient and expensive, with heavy, highly energy-intense industrial processes being a prominent example, (b) avoid the early retirement of young plant fleets and assets therefore aiding the debate around stranded assets in the age of de-carbonization, and (c) reduce the total load of greenhouse gases in the atmosphere to the required carbon budget therefore correcting for any overshoot, with direct air carbon capture the key technology to abate already emitted and accumulated emissions directly from the atmosphere.

Carbon sequestration efforts can be broadly classified into three main categories: **(1) Natural sinks**, encompassing natural carbon reservoirs that can remove carbon dioxide. Efforts include reforestation, afforestation and agro-forestry practices. **(2) Carbon capture, utilization and storage technologies (CCUS)** covering the whole spectrum of carbon capture technologies applicable to the concentrated CO_2 stream coming out of industrial plants, carbon utilization and storage. **(3) Direct air carbon capture and storage (DACCS)**, the pilot carbon capture technology that could recoup CO_2 from the air, unlocking almost infinite de-carbonization potential, irrespective of the CO_2 source. In this section of the report, **we primarily focus on the technological aspect of sequestration that encompasses carbon capture technologies (CCUS and DACCS).**

Carbon Capture: Regaining momentum after a 'lost decade'

CCUS technologies can be an effective route to global de-carbonization for some of the 'harder-to-abate' emission sources: they can be used to significantly reduce emissions from coal and gas power generation, as well as across industrial processes with emissions characterized as 'harder to abate' such as iron & steel, cement and chemicals. CCUS can also facilitate the production of clean alternative fuels such as blue hydrogen, as mentioned in the previous section, as well as advanced biofuels (BECCS).

CCUS encompasses a range of technologies and processes that are designed to capture the majority of CO_2 emissions from large industrial point sources and subsequently provide long-term storage solutions or utilization. **We have incorporated carbon capture technologies in our GS global net zero models** and **under all three, carbon capture grows to be a major industry.** In our GS 1.5° path for carbon neutrality by 2050, **CCUS contributes across sectors an annual CO2 abatement of c.7.2 GtCO2 by 2050**, as shown in Exhibit 174 below. The single largest contributor to the CCUS abatement is industry, with sectors such as cement, steel, non-ferrous metals, fugitive and waste emissions all in need of carbon sequestration technologies in the absence of technological breakthroughs. This is followed by the CCUS retrofits required for the production of clean hydrogen from industrial hydrogen plants (blue hydrogen). Finally, CCUS can be retrofitted to the newest gas and coal power plants in power generation, as well as contribute to the full abatement of emissions through the use of biofuels (we assume the use of advanced biofuels in our analysis, yet we appreciate the potential availability constraint of waste and other advanced biofuels' sources and as such we further incorporate some CCUS to complement the use of bioenergy). DACCS, the potentially infinitely scalable de-carbonization technology, complements process-specific CCUS and contributes to c.1 GtCO1 annual abatement by 2050.

Exhibit 174: Our GS 1.5 path highlights the importance of CCUS, with the annual CCUS abatement reaching c.7.2 GtCO2 by 2050 with industrial sources the key contributor
Global CO2 emissions captured by source in our GS GL0S (MtCO2)
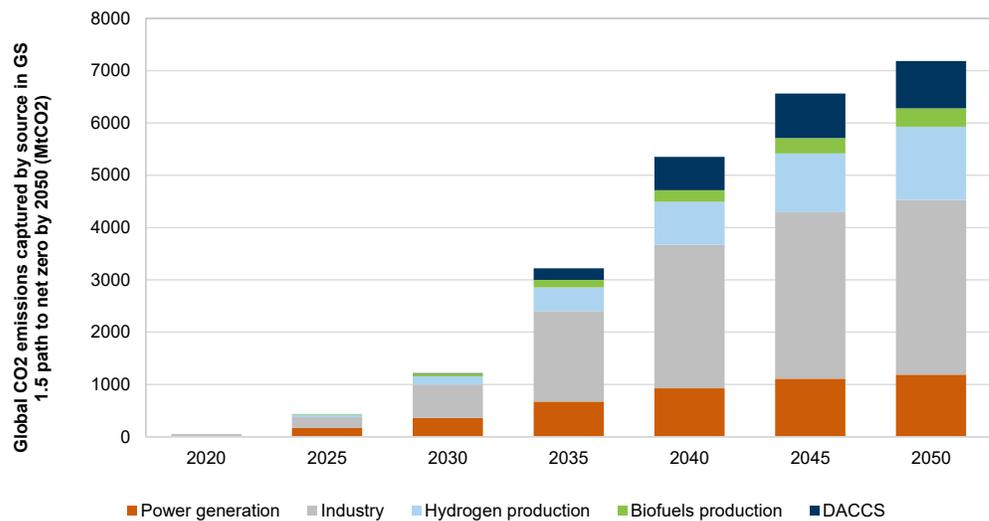
Source: Goldman Sachs Global Investment Research

Despite their critical role to any aspirational path aiming to reach net zero by 2050, carbon capture technologies have been to date largely under-invested. We nonetheless believe in the return of interest in the technology following a lost decade with more projects under development. Currently, we identify more than 25 commercial scale CCS facilities operating globally (mostly in the US, Canada, UK and Norway), with a total capacity around 37 Mtpa, with another 4 projects under construction bringing the total capture capacity to c.40 Mtpa. **2021 marks another year of a strong increase in the total potential CCS capacity from projects currently in the pipeline,** as shown in Exhibit 175, **with the total potential carbon capture capacity of these projects summing up to c.149 MtCO2 pa, four times the current operating capacity** implying the potential quadrupling of this industry by the end of this decade. Notably, we see a large portion of the current CCS projects pipeline focusing on new processes' capture such as power generation, industrial processes including chemicals, cement, oil refining and hydrogen production as opposed to the traditional natural gas processing industrial separation. Overall, **we identify three key transformational drivers that are likely to continue to support the renewed momentum for CCUS:**

(1) Any aspiring net zero plans make carbon sequestration a necessity and not an option: A growing appreciation that carbon capture is a necessary pillar to achieving national and global goals for carbon neutrality and net zero.

(2) The investment proposition has started to improve on the back of renewed policy support momentum: We see a rising momentum of policy support for carbon capture projects with the US (expansion of the 45Q tax credit), Canada and Europe (government support for clusters development and EUR 10 bn European Innovation Fund) leading on that front.

(3) The rise of the clean hydrogen economy, with CCS providing a platform for 'blue' hydrogen: Growing interest in producing low-carbon hydrogen has resulted in >15 large-scale CCS facilities to capture CO2 from hydrogen-related processes and another 30 smaller projects under way.

Exhibit 175: The pipeline of large-scale CCS facilities is regaining momentum after a 'lost decade'...
Annual CO2 capture & storage capacity from large-scale CCS facilities
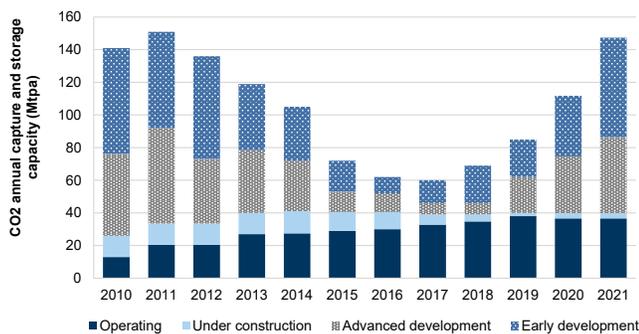
Source: Global CCS Institute Status Report 2021

Exhibit 176: ...as more projects in the development stage start to focus on industries with lower CO2 stream concentrations (industrial processes such as cement, chemicals, oil refining, hydrogen production & power generation)
Large-scale CCS projects by status and industry of capture (Mtpa, 2021)
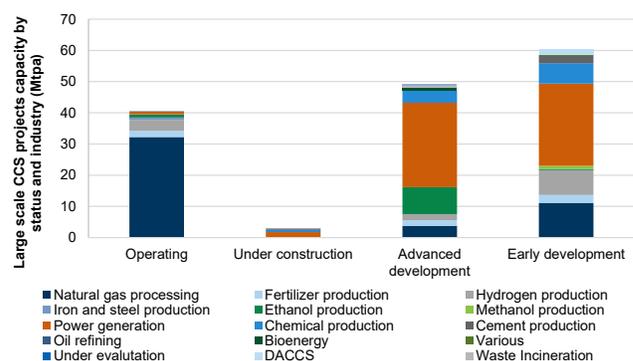
Source: Global CCS Institute, Goldman Sachs Global Investment Research

Exhibit 177: Summary of global large-scale CCS projects including operating, under construction and under early development projects
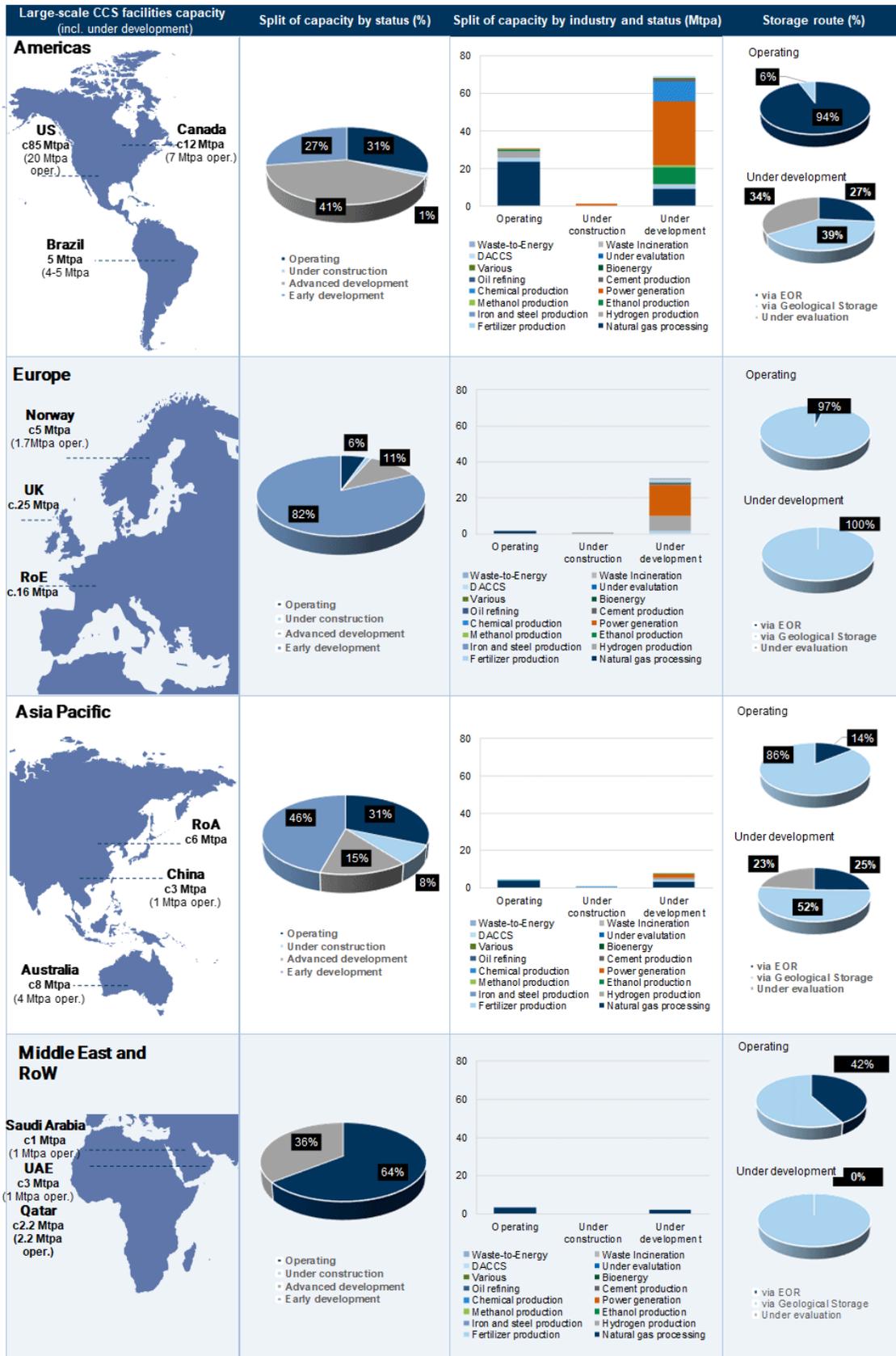
Source: Global CCS Institute CO2RE, Data compiled by Goldman Sachs Global Investment Research

Historical under-investment in CCUS has held back large-scale adoption and economies of scale. However, the tide may be turning, with several projects moving forward

Cost remains the primary barrier to the deployment of CCS technologies. The incremental costs of capture and the development of transport and storage infrastructure are not sufficiently offset by government and market incentives, albeit efforts have intensified in regions such as Norway (where carbon prices are at the higher end of the global carbon price spectrum) and the US (with the introduction of the 45Q scheme). The cost of individual CCS projects can vary substantially depending on the source of the carbon dioxide to be captured, the distance to the storage site and the characteristics of the storage site, although the cost of capture is typically the largest driver of the total expense and it shows an inverse relation to the concentration of CO_2 in the stream of capture.

Although carbon sequestration has seen a revival in recent years, it **has not yet reached large-scale adoption and economies of scale that traditionally lead to a breakthrough in cost competitiveness**, especially when compared with other CO_2-reducing technologies such as renewables. Despite the key role of sequestration in any scenario of net carbon neutrality, investments in CCS plants over the past decade have been <1% of the investments in renewable power. Although we are seeing a clear pick-up in CCS pilot plants after a 'lost decade', we do not yet know where costs could settle if CCS attracted similar economies of scale as solar and wind. The vast majority of the cost of carbon capture and storage comes from the process of sequestration and is inversely related to the CO_2 concentration in the air stream from which CO_2 is sequestered. The cost curve of CCS therefore follows the availability of CO_2 streams from industrial processes and reaches its highest cost with direct air carbon capture and storage (DACCS), where economics are highly uncertain, with most estimates at US$40-400/ton and only small pilot plants currently active. The importance of DACCS lies in its potential to be almost infinitely scalable and standardized, therefore setting the price of carbon in a net zero emission scenario.

Exhibit 178: Solar PV cost per unit of electricity has fallen 80%+ over the last decade as cumulative solar capacity has increased exponentially...
Solar PV capex (US$/kW) vs. global cumulative solar PV capacity (GW)
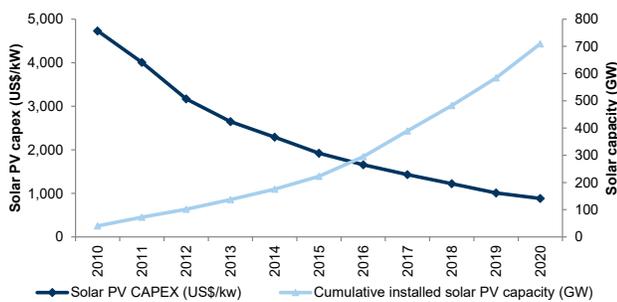
Source: Company data, Goldman Sachs Global Investment Research

Exhibit 179: ...while the languishing investment in CCS sequestration technologies has possibly prevented a similar cost improvement
Annual investment in solar PV (LHS) and large-scale CCS (RHS)
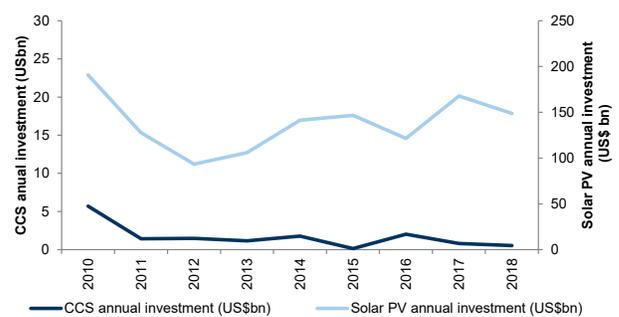
Source: Company data, IEA, IRENA, Goldman Sachs Global Investment Research

A glimpse into the current carbon capture technologies

One of the key parameters for CO_2 capture technologies is the ability to increase the concentration of CO_2 in the resulting stream and provide a sufficiently high pressure to be transported to the storage site. Depending on the plant and process application, there are four technical pathways to capture CO_2:

- **Post-combustion:** These systems operate through separating CO_2 from the flue gases (post combustion gases) produced by the combustion of the primary fuel in air. They typically involve the use of liquid solvent to chemical bind to CO_2 present in the flue gas stream. This technological approach has been demonstrated in the majority of operating power generation plants adopting CCS, including modern pulverized coal (PC), natural gas combined cycle (NGCC) and cement.

- **Pre-combustion:** These systems process the primary fuel with steam and air (or oxygen) in a reactor producing a mixture of mainly CO and H_2 ('syngas'). The resulting CO can be used to produce further hydrogen in a second reactor involving steam ('shift reactor'). The final mixture of hydrogen and CO_2 is then separated into a CO_2 gas stream and a stream of hydrogen. This process route involves more robust and costly initial conversion steps than post-combustion systems, yet the high concentration of CO_2 produced by the final shift reactor and the high pressures are often beneficial. Pre-combustion has also been demonstrated in plants, such as integrated gasification combined cycle (IGCC).

- **Oxyfuel combustion:** These systems rely on oxygen instead of air for combustion of the primary fuel resulting in a stream primarily composed of water vapour and CO_2. The resulting stream has a high CO_2 concentration making the process the most successful in achieving a concentrated CO_2 stream, yet further treatment of the flue gas may be needed to remove air pollutants and non-condensed gases. Oxyfuel combustion could potentially be used for industrial plants such as cement, yet remains in earlier stages of development.

- **Industrial separation:** This approach involves the lowest-cost technology and is applicable in industrial plants where a highly concentrated CO_2 stream is generated as part of the existing plant separation process (intrinsic process). This is typically the case for natural gas processing and ammonia plants where the majority of operating large-scale CCS plants have been involved to date.

Exhibit 180: There exist different CO2 capture processes for use in power generation and industrial plants CCS
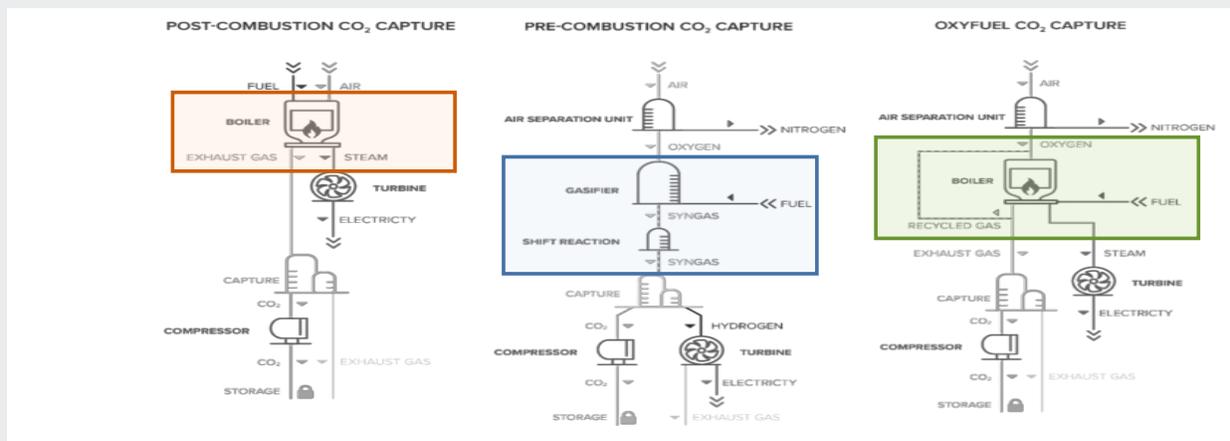
Source: Provided by Global CCS Institute, IPCC, Goldman Sachs Global Investment Research

The cost of capture is highly process-specific whilst the cost of transport and storage shows a wide regional variability

CCUS encompasses a range of technologies and processes that are designed to capture the majority of CO_2 emissions from large industrial point sources and then to provide long-term storage solution or utilization. The CCUS chain constitutes processes that can be broadly categorized into three major parts: (1) **the separation and capture** of CO_2 from gaseous emissions; (2) the subsequent **transport** of this captured CO_2, typically through pipelines, to suitable geological formations; and (3) the **storage** of the CO_2, primarily in deep geological formations such as former oil and gas fields, saline formations or depleting oil fields or the **utilization** of captured CO_2 for alternative uses and applications (for instance, we have examined its potential for use to produce synthetic-hydrogen based fuels in the previous section).

The cost of CCS can therefore be broken down into three key components: (a) the cost of capture from the industrial point source, (b) the cost of transport, either through onshore or offshore pipelines or via shipping, and (c) the cost of storage. The cost of capturing CO2 is the key contributor to the total cost and can vary significantly between different processes, mainly according to the concentration of CO2 in the gas stream from which it is being captured, the plant's energy and steam supply, and integration with the original facility. For some processes, such as ethanol production or natural gas processing or after oxy-fuel combustion in applications such as power generation, CO2 can be already highly concentrated leading to costs below US$50/tnCO2 (such as in natural gas processing, ethanol, ammonia). For more diluted CO2 streams, including the flue gas from power plants (where the CO2 concentration is typically below 20%) or a blast furnace in a steel plant (20-30%), the cost of CO2 capture is much higher.

Exhibit 181: The levelized cost of carbon capture depends on the concentration of CO2 in the capture stream. Lower concentration typically requires more energy and cost in capturing.
Levelized cost of CO2 capture by industry
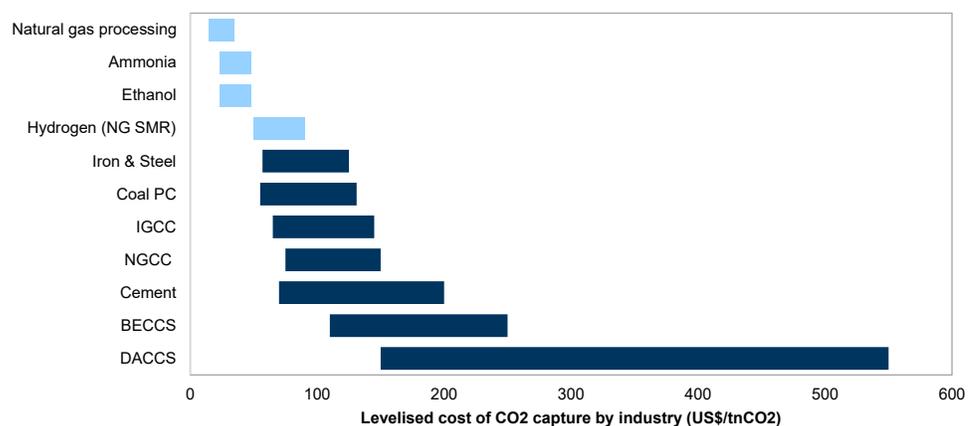

Source: Company data, Global CCS Institute, Goldman Sachs Global Investment Research

Post the capture of the CO2, compression and transport are the two steps that typically follow. The availability of CO2 transport infrastructure is therefore an essential determinant for the deployment of CCUS. The currently large-scale available technologies for the transport of CO2 include pipelines (both onshore and offshore) and shipping. Transport via pipelines is the option that has currently been developed at large, commercial scale, whilst CO2 shipping is still at early stages of development yet could utilise the technological knowledge of shipping of liquefied petroleum gas (LPG) and liquefied natural gas (LNG). There already exists an extensive pipeline network for CO2 transportation in the United States, currently used for enhanced oil recovery (EOR) in onshore depleted shale oil and gas fields, whilst the launch of the Alberta Carbon Truck Line (ACTL) opens up further the possibility for the formation of an integrated CO2 pipeline transport system. Trucks and rail could also be used for shorter distances yet tend to be more economically unattractive options.

For shorter distances, pipelines appear to be the most economically attractive option, yet this is very much dependent on the region and the infrastructure constraints. While the properties of CO2 lead to different design specifications compared with natural gas, CO2 transport by pipeline bears many similarities to high-pressure transport of natural gas. Repurposing existing natural gas or oil pipelines, where feasible, would normally be much cheaper than building a new line. Shipping CO2 by sea may be viable for regional CCUS clusters. In some instances, shipping can compete with pipelines on cost, especially for long-distance transport, which might be needed for countries with limited domestic storage resources. The share of capital in total costs is higher for pipelines than for ships, so shipping can be the cheapest option for long-distance transport of small volumes of CO2.

Exhibit 182: Pipeline transport appears to be the most economically attractive option for large CO2 transport capacity...
Transport cost of CO2 (US$/tnCO2)
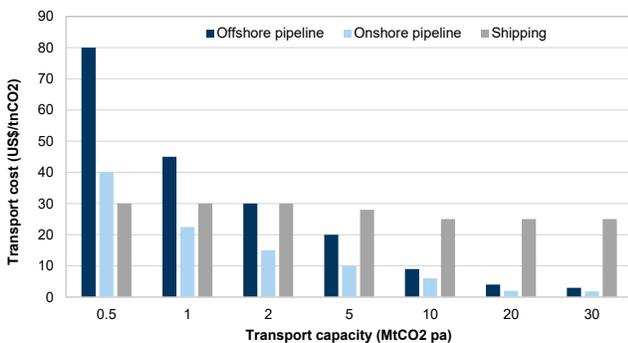
Exhibit 183: ..and for smaller distances, as shipping becomes more economically attractive for distances >1000km
Transport cost of CO2 (US$/tnCO2)

Source: Company data, IPCC, Goldman Sachs Global Investment Research
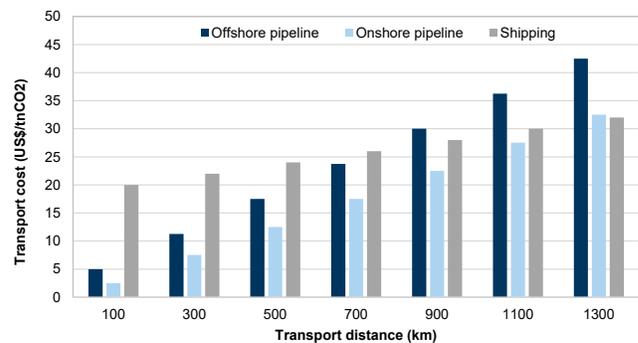
Source: Company data, IPCC, Goldman Sachs Global Investment Research

Finally, the CO2 will either be utilized (we discuss the potential of CO2 utilisation in the section that follows) or permanently stored. Storing CO2 involves the injection of captured CO2 into a deep underground geological reservoir of porous rock overlaid by an impermeable layer of rocks, whose purpose is to seal the reservoir and prevent the upward migration of CO2. There are several types of reservoir suitable for CO2 storage, with deep saline formations and depleted oil and gas reservoirs having the largest

capacity. The availability of storage is the key determinant factor influencing the associated storage cost and this varies considerably across regions globally, with North America, Russia and Australia appearing to hold the largest capacities. Data by the Global CCS Institute suggests that there is sufficient storage potential for what is required to be aligned with the most ambitious climate scenarios.

Exhibit 184: Based our GS 1.5 path to net zero by 2050, c.100 GtCO2 will be captured in total by 2050 (cumulative) across sectors...
Cumulative CO2 abated through CCUS (MtCO2)
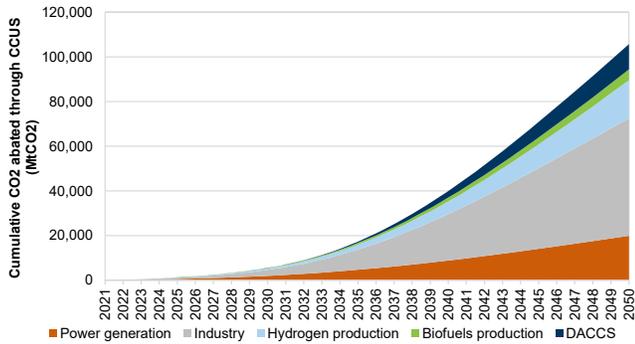
Exhibit 185: ...with the global CO2 storage resource potential in major oil & gas fields alone more than sufficient to compensate for this, according to the Global CCS Institute
CO2 storage resource in majors' oil & gas fields (MtCO2)

Source: Goldman Sachs Global Investment Research
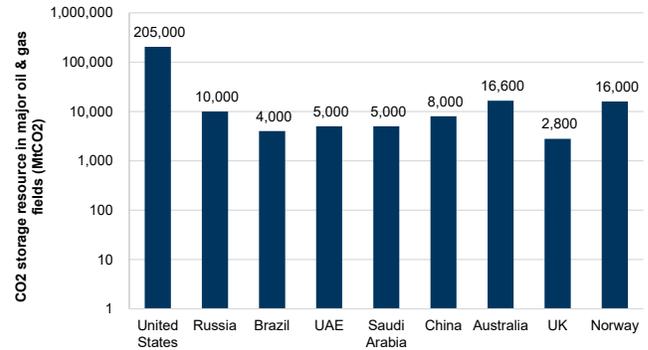
Captured CO_2 Utilization: A potentially valuable commodity in search of new markets

Globally, >200 Mtpa of CO_2 is used every year, with the majority of demand coming from the fertilizer industry, the oil & gas industry for enhanced oil recovery (EOR), and food & beverages. The rising focus on CO_2 emissions reduction and carbon capture technologies has sparked further interest in CO_2 utilization across a number of applications, involving both direct use (CO_2 not chemically altered) and CO_2 transformation or conversion. CO_2 has, as a molecule, some attractive qualities for utilization purposes, including its stability, very low energy content and reactivity. The most notable examples of those include the use of captured CO_2 with hydrogen to produce synthetic fuels and chemicals, the production of building materials such as concrete (replacing water during concrete production, known as CO_2 curing, as well as a feedstock to produce aggregates during the grinding phase) and crop yield boosting for biological processes. CO_2 utilization can form an important complement to carbon capture technologies, provided the final product or service that consumed the CO_2 has a lower life-cycle emission intensity when compared with the product/process it displaces. For CO_2 utilization to act as an efficient pathway for emissions reduction, there are therefore a few key parameters that need to be assessed, including: the source of CO_2, the energy intensity and the source used in the process (net zero energy is vital in most cases where electricity and heat requirements are large) and the carbon's retention time in the product (can vary from one year for synthetic fuels to hundreds of years in building materials).

Exhibit 186: There exists a very wide range of potential uses and applications for captured CO2 globally, involving both direct use and conversion
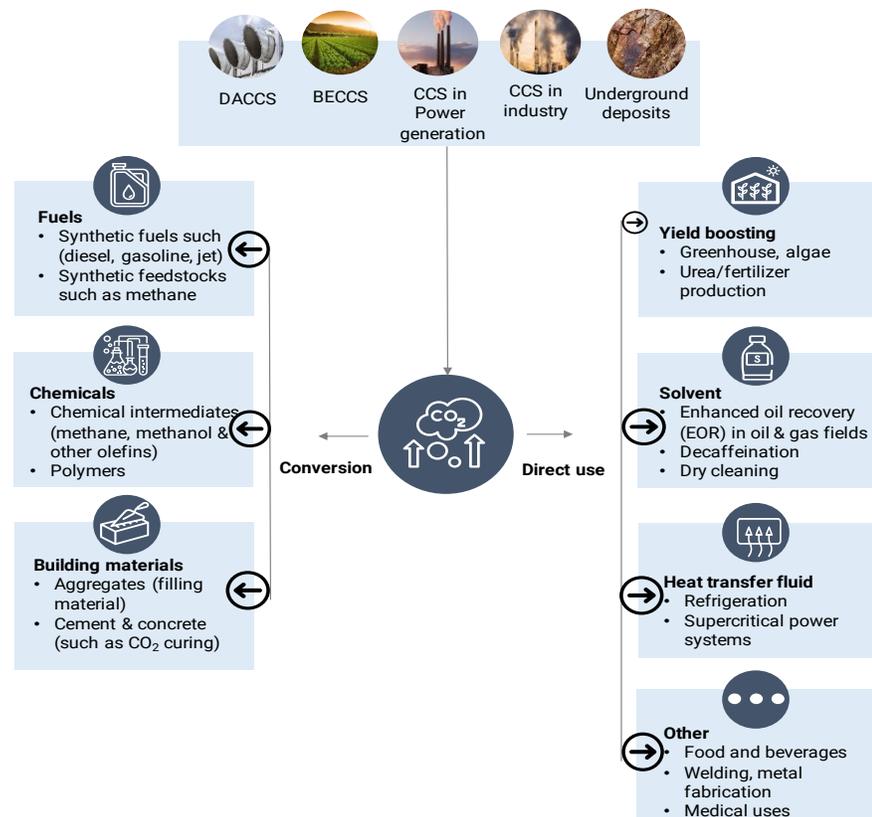
Source: IEA, Goldman Sachs Global Investment Research

The most scalable technology: Direct Air Carbon Capture and Storage (DACCS)

Direct air capture (DAC) is a different form of sequestration, as it does not apply to a specific process (like traditional CCUS), but takes CO_2 from the air in any location and scale. Nascent DAC technologies are capable of **achieving physical and/or chemical separation and concentration of CO_2 from atmospheric air**, unlike CCS, which captures carbon emitted from 'point source' industrial processing streams (flue gas). Carbon captured through DAC can then be repurposed for other uses, for example to make carbon-neutral hydrocarbon fuels. It is early days for DACCS, however, as the technology is still being developed and existing implementation projects are small-scale and very high cost. Nonetheless, we identify this technology as a potential wild card in the challenge of climate change as **it could in theory unlock almost infinitely scalable de-carbonization potential**. A summary of the most prominent DACCS designs to date and the associated details is described in the summary box that follows.

Exhibit 187: DACCS: A roadmap of challenges with yet unique opportunities ahead

Direct Air Carbon Capture (DACCS)		
Strengths	**Challenges**	**Opportunities**
1) Very large cumulative potential in relation to other carbon removal pathways that could be infinitely scalable	**1)** New concept in need of further technological innovation required to bring energy requirements and costs down to a level that is commercially competitive.	**1)** Primary energy consumption in DACCS is attributed to the heat required for sorbent/solvent regeneration. Identifying sorbents that optimize the binding to CO2 such that it is strong enough to enable efficient capture but weak enough to reduce heat requirement during regeneration is key.
2) DACCS can be sited in a very wide range of locations including areas near high energy sources and geological storage potential since there is no need to be close to sources of emissions	**2)** The very small concentration of CO2 in air (c0.04%) compared to industrial streams makes the economics of the capture process unattractive and calls for further innovation.	**2)** Reaction kinetics are important as they impact the rate at which CO2 can be removed from air. If the rate is low a much larger area for air-sorbent/solvent material contact will be required which translates into a large air contactor area and thus higher capital costs. Optimization of air contactor design through geomtery and pumping strategy is another key technological aspect.
3) There are limited land and water requirements for DAC relative to other pathways such as natural sinks or BECCS.	**3)** Given the high energy intensity of carbon capture technologies, there is an evident need for zero carbon electricity for the most efficient, from a climate change standpoint, operation.	**3)** CO2 offtake, transport and utilization is a key component for an efficient system operation. Finding new opportunities for CO2 utilization is therefore vital. Examples include synthetic fuels and petrochemicals.
4) Technological advantages over conventional CCS include the absence of high levels of contaminants present in plants' flue gas streams, and no need for a design targeting the complete CO2 capture with a single stream pass which is usually the case for CCS applied to industrial flue gas streams.		

Source: ICEF Roadmap, Goldman Sachs Global Investment Research

Related Research

Carbonomics: 10 key themes from the Carbonomics conference & link to replays
17 Nov 2021
We hosted our second Carbonomics conference last November. Speakers including the co-hosts of COP26 (UK Prime Minister Johnson and Minister Cingolani from Italy) and 40 CEOs of leading corporates discussed profitable investments to de-carbonise power, mobility, buildings, agriculture and industry in an interactive day of virtual fireside chats.
Visit the conference page for replays >

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Carbonomics: Five themes of progress for COP26
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COP26, held in the UK in late 2021, presented a historic opportunity to accelerate the de-carbonization pledges laid out by COP21 (the Paris Agreement) in 2015. In this report we analyze five key themes of de-carbonization we believe can drive progress: 1) Carbon pricing; 2) Consumer choice; 3) Capital markets pressure; 4) Net Zero; and 5) Technological innovation.

Carbonomics: Introducing the GS net zero carbon models and sector frameworks
23 Jun 2021
We present our modeling of the paths to net zero carbon, with two global models of de-carbonization by sector and technology, leveraging our Carbonomics cost curve. We present a scenario consistent with the Paris Agreement's goal to keep global warming well below 2°C (GS <2.0°), and a more aspirational path, aiming for global net zero by 2050, consistent with limiting global warming to 1.5°C (GS 1.5°).
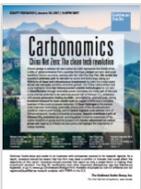
Carbonomics: China Net Zero: The clean tech revolution
20 Jan 2021
China's pledge to achieve net zero carbon by 2060 represents two-thirds of the c.48% of global emissions from countries that have pledged net zero, and could transform China's economy, starting with the 14th Five-Year Plan. We model the country's potential path to net zero by sector and technology, laying out US$16 tn of clean tech infrastructure investments by 2060 that could create 40 mn net new jobs and drive economic growth.

Carbonomics: Innovation, Deflation and Affordable De-carbonization
13 Oct 2020
Net zero is becoming more affordable as technological and financial innovation, supported by policy, are flattening the de-carbonization cost curve. The result: a broader connected ecosystem for de-carbonization that includes renewables, clean hydrogen (both blue and green), batteries and carbon capture. We update our 2019 Carbonomics cost curve to reflect innovation across c.100 different technologies to de-carbonize power, mobility, buildings, agriculture and industry.

Carbonomics: The Rise of Clean Hydrogen
8 Jul 2020
Clean hydrogen is gaining strong political and business momentum, emerging as a major component in governments' net zero plans such as the European Green Deal. This is why we believe that the hydrogen value chain deserves serious focus after three false starts in the past 50 years. In this report we analyze the clean hydrogen company ecosystem, the cost competitiveness of green and blue hydrogen in key applications and its key role in Carbonomics: the green engine of economic recovery.

Explore our dedicated Carbonomics page »

Appendix: National hydrogen strategies and roadmaps overview

Exhibit 214: Summary of key hydrogen targets across hydrogen strategies

Region/country	Hydrogen Strategy	Quantitative deployment targets	Production routes covered
Asia & Asia-Pacific			
Japan	Strategic Roadmap for Hydrogen and Fuel Cells (2019) Green Growth Strategy (2020, 2021)	Supply: 420 kt H2 by 2030 Demand: 3 Mt H2 pa by 2030, 20 Mt H2 by 2050 *Transport:* 200,000 FCEVs (2025) 800,000 FCEVs (2030) 1,200 FC buses (2030) 10,000 FC forklifts (2030) 320 HRSs (2025) 900 HRSs (2030) 3 Mt NH3 pa demand	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Korea	Hydrogen Economy Roadmap (2019)	Demand: 470 kt H2 (2022), 1.94 Mt H2 pa (2030), 5.26 Mt H2 pa (2040) 8 GW FC stationary (2040) 50 MW, 2.1 GW FC micro-generation (2022, 2040) 1.5 GW, 15 GW FC for power gen (2022, 2040) *Transport:* 1,200 HRSs (2040), 310 HRSs (2022) 2.9 million FC cars domestic, 3.3 million FC cars exported (2040), 100,000 units by 2025, 81,000 units by 2022 80,000 FC taxis (2040) 40,000 FC buses (2040) 30,000 FC trucks (2040)	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS) By-product
Australia	National Hydrogen Strategy (2019)	New Sotuh Wales aims for 700 MW electrolysis capacity by 2030 *Transport:* 10,000 FC vehicles, 100 HRSs	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
India	National Hydrogen Mission (2021)	The NHM, according to a draft paper prepared by the Ministry of New and Renewable Energy (MNRE), has identified pilot projects, infrastructure and supply chain, research and development, regulations and public outreach as broad activities for investment with a proposed financial outlay of Rs 800 crores for the next three years.	N/A
MENA (Middle East & North Africa)			
Oman	Oman Hydrogen Strategy (2021-22)	1GW by 2025 10GW by 2030 30GW by 2040 *Capacity targets for green energy production	Green hydrogen (electrolysis)
Morocco	Green Hyrogen Roadmap (2021)	Scenarios based on capacity required to meet H2 demand: Base case (GW): 2.8 in 2030, 13.9 in 2040, 31.4 in 2050 Optimistic (GW): 5.2 in 2030, 23 in 2040, 52.8 in 2050	Green hydrogen (electrolysis)
Europe			
European Union	EU Hydrogen Strategy (2020)	6 GW by 2024 (up to 1 Mt green H2) 40 GW by 2030 (up to 10 Mt green H2)	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS) transitional role
France	Hydrogen Deployment Plan (2018) National Strategy for Decarbonised Hydrogen Development (2020)	10% clean hydrogen by 2023 and 20-40% by 2030 6.5 GW by 2030 *Transport:* 100 HRSs by 2023 400-1,000 HRSs by 2028 5,000 FCEVs by 2023 20,000-50,000 FCEVs by 2028 200 FC heavy vehicles by 2023 800-2,000 FC heavy vehicles by 2028	Green hydrogen (electrolysis)

Source: Various sources; data compiled by Goldman Sachs Global Investment Research

Netherlands	National Climate Agreement (2019) Government Strategy on Hydrogen (2020)	500 MW by 2025, 3-4 GW by 2030 *Transport:* 50 HRSs by 2025 15,000 FCEVs by 2025 3,000 heavy duty trucks by 2025 300,000 FCEVs by 2030	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Spain	National Hydrogen Roadmap (2020)	4 GW by 2030 (25% consumption of industrial hydrogen to be green by 2030), 300-600 MW by 2024 *Transport:* 5,000-7,500 FC vehicles by 2030 150-200 FC buses by 2030 100-150 HRSs by 2030	Green hydrogen (electrolysis)
Portugal	National Hydrogen Strategy (2020)	1.5-2.5 GW by 2030 5 GW by 2050 50-100 HRSs 10-15% injection in gas networks 1-5% consumption of road transport 3-5% consumption of shipping 2-5% consumption in industry 1.5%-2% consumption in final energy	Green hydrogen (electrolysis)
Germany	National Hydrogen Strategy (2020)	5 GW by 2030 (14 TWh) Another 5 GW to be added by 2035-40 *Transport:* 400 HRSs by 2025	Green hydrogen (electrolysis)
Czech Republic	Hydrogen Strategy (2021)	97 kt H2 pa by 2030 consumption of low carbon hydrogen 2035 - 273 kt H2/yr, 2040- 857 kt H2/yr, 2045 - 1241 kt H2/yr, 2050 - 1728 kt H2/yr *Transport:* 900 FC buses by 2030 45,000 FC cars by 2030 4,000 FC trucks by 2030	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Hungary	National Hydrogen Strategy (2021)	36 kt H2 pa (low carbon) by 2030 of which 16 kt H2 pa green 240 MW electrolysis *Transport:* 4,800 FCEVs by 2030 20 HRSs by 2030 10 kt H2 pa carbon free Min 2% pa blending in gas system 60 MW cut-off capacity	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Italy	National Hydrogen Strategy Preliminary Guidelines (2021)	5 GW by 2030 2% hydrogen penetration in final energy demand by 2030 and 20% by 2050	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
United Kingdom	UK Hydrogen Strategy (2021)	5 GW low carbon production by 2030, 1GW by 2025	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Poland	Polish Hydrogen Strategy (2021)	2 GW by 2030 Transport: 100-250 FC buses by 2025 2,000 FC buses by 2030 32 HRSs	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)

Source: Various sources; data compiled by Goldman Sachs Global Investment Research

Norway	**Government Hydrogen Strategy** (2020) **Hydrogen Roadmap** (2021)	na	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Russia	**National Hydrogen Roadmap** (2020)	Export targets of 0.2 Mt by 2024, 2 Mt by 2030	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
	Federal Hydrogen Vision and Strategy (2021)	Capacity of 150 MW by 2026 Belgium demand to reach 125-175 TWh/yr by 2050 for both hydrogen and its derivatives Import renewable molecules of 3 to 6 TWh by 2030, 100 to 165 TWh by 2050 from other countries	Renewable hydrogen (green hydrogen) Low-carbon hydrogen (fossil fuel with CCUS)
Sweden	**Hydrogen Strategy Proposal** (2021)	Electrolyser capacities: 5GW by 2030 15GW by 2045 These capacities could supply the potential demand of 22-42TWh by 2030, increasing to 44-84TWh by 2045.	Green hydrogen (electrolysis)
Americas			
Canada	**Hydrogen Strategy for Canada** (2020)	4 Mt H2 pa production by 2030 6.2% of total final energy consumption 20 Mt H2 pa production by 2050 30% of total final energy consumption	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS) By-product Biomass
Chile	**National Green Hydrogen Strategy** (2020)	5 GW electrolysis capacity operating and under development by 2025 25 GW in projects with committed funding by 2030	Green hydrogen (electrolysis)
Colombia	**Colombia Hydrogen Roadmap** (2021)	1-3 GW installed capacity by 2030 (green) 50 kt H2 blue Demand: 1.5-1.8 Mt H2 by 2050, 120 kt H2 by 2030 Transport: 1,500-2,000 LD FCEVs 1,000-1,500 HD FCEVs 50-100 HRSs 40% low carbon H2 in total industry H2 consumption	Green hydrogen (electrolysis) Blue hydrogen (fossil fuel with CCUS)
Paraguay	**Towards the Green Hydrogen Roadmap in Paraguay** (2021)	Paper states it will be necessary to install 600MW capacity or 90ktH2/y by 2030 to meet government fossil fuel reduction target of 20% by 2030.	Green hydrogen (electrolysis)
Uruguay	**National Green Hydrogen Strategy** (2021)	ST: H2U pilot scheme 1.5-5 MW MT: Pilots for other energy uses (ammonia, methanol, marine fuel). More than 10 MW LT: Exportation. More than 150 MW Long term strategy to be detailed beginning of 2022	Green hydrogen (electrolysis)

Source: Various sources; data compiled by Goldman Sachs Global Investment Research

Disclosure Appendix

Reg AC

We, Zoe Clarke, Michele Della Vigna, CFA and Georgina Fraser, Ph.D., hereby certify that all of the views expressed in this report accurately reflect our personal views about the subject company or companies and its or their securities. We also certify that no part of our compensation was, is or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

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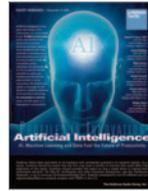# MINDCRAFT: OUR THEMATIC DEEP DIVES

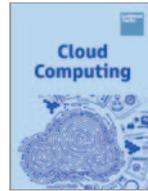The Great Reset

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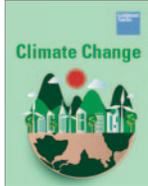
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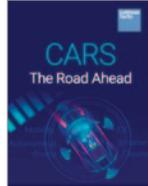
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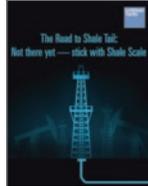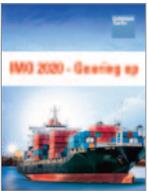
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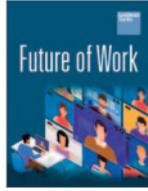
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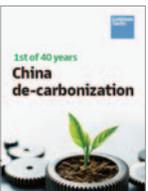
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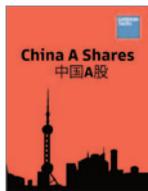Womenomics

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