The **Making Mission Possible** Series

Making the Hydrogen Economy Possible:

Accelerating Clean Hydrogen in an Electrified Economy

April 2021

Version 1.1

Executive Summary

Energy Transitions Commission

Making the Hydrogen Economy Possible

Accelerating Clean Hydrogen in an Electrified Economy

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

Our Commissioners come from a range of organisations – energy producers, energy-intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is chaired by Lord Adair Turner who works with the ETC team, led by Faustine Delasalle. Our Commissioners are listed on the next page.

Making Clean Electrification Possible: 30 Years to Electrify the Global Economy and Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy were developed by the Commissioners with the support of the ETC Secretariat, provided by SYSTEMIQ. They bring together and build on past ETC publications, developed in close consultation with hundreds of experts from companies, industry initiatives, international organisations, non-governmental organisations and academia.

The reports draw upon analyses carried out by ETC knowledge partners SYSTEMIQ and BloombergNEF, alongside analyses developed by Climate Policy Initiative, Material Economics, McKinsey & Company, Rocky Mountain Institute, The Energy and Resources Institute, and Vivid Economics for and in partnership with the ETC in the past. We also reference analyses from the International Energy Agency and IRENA. We warmly thank our knowledge partners and contributors for their inputs.

This report constitutes a collective view of the Energy Transitions Commission. Members of the ETC endorse the general thrust of the arguments made in this report but should not be taken as agreeing with every finding or recommendation. The institutions with which the Commissioners are affiliated have not been asked to formally endorse the report.

The ETC Commissioners not only agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century, but also share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C, and that many of the key actions to achieve these goals are clear and can be pursued without delay.

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Executive Summary

The Paris climate accord committed the world to limiting global warming to well below 2°C above pre-industrial levels, while striving to limit it to 1.5°C. To meet this commitment, the world must bring CO_2 emissions to net-zero by mid-century, and the Energy Transitions Commission (ETC) has described in a number of reports how this can be done.[1] Clean electrification must be at the heart of the global decarbonisation strategy – electrifying as much as possible while fully decarbonising electricity supply. The ETC's report on massive green electrification, issued in parallel with this report describes how to meet that challenge.[2] But there are some sectors where direct electrification is likely to be impossible or prohibitively expensive, and hydrogen will play a key role in decarbonising these. In steel production, it can replace coking coal as the energy source and reduction agent; in the form of ammonia, it could decarbonise long-distance shipping; and it is likely to play a major role as a storage mechanism within the power sector.

Across these and multiple other sectors, total hydrogen use could grow from today's 115 Mt per annum to around 500 to 800 Mt by mid-century, with hydrogen (and fuels derived from it) by then accounting for about 15-20% of total final energy demand on top of the close to 70% provided by direct electricity use (Exhibit A). In some sectors, its role relative to other decarbonisation options (whether direct electrification, CCS/U, or bioenergy) is inherently difficult to predict and will reflect future technology and cost trends. However, it is almost certain that the total use of hydrogen will and should grow dramatically.

All of this hydrogen must be produced in a zero-carbon fashion via electrolysis using zero-carbon electricity ("green hydrogen") or in a low-carbon fashion using natural gas reforming plus CCS ("blue hydrogen") if deployed in a manner that achieves near-total CO_2 capture and very low methane leakage. Blue hydrogen will often be cost-effective during the early stages of the transition, particularly where existing "grey hydrogen" production can be adapted and retrofitted with CCS. But, in the long-term, green hydrogen will very likely be the cheaper option in most locations, with dramatic cost reductions to below $2/kg possible during the 2020s.

This green hydrogen production will in turn generate a very large electricity demand, increasing total required supply of zero-carbon electricity by as much as 30,000 TWh. This will add to the estimated 90,000 TWh for direct electrification described in the ETC's parallel report Making Clean Electrification Possible. In that report, we explain how such a massive ramp-up in clean power production can be achieved at low cost.[3]

1 This includes (not exhaustive): ETC (2020): *Making Mission Possible: Delivering a Net-Zero Economy*; ETC (2017), *Mission Possible: Reaching net-zero carbon emissions from harder-to-abate sectors*

2 ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*

3 ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*

Strategies for net-zero emissions by 2050 must therefore recognise the major role of clean hydrogen and the implications for clean electricity supply required. They must also ensure a sufficiently rapid take-off during the 2020s to make the transition to 2050 feasible. This requires policy support since hydrogen use in end applications will often impose a 'green cost premium' versus today's high carbon technologies, even if hydrogen production costs fall dramatically. Policy must combine broad instruments such as carbon prices, focused support in specific end use sectors, and the development of geographically focused clusters of clean hydrogen production and use.

This report therefore sets out:

- The role of clean hydrogen in a zero-carbon deeply electrified economy;
- How to drive the transition to large-scale clean hydrogen supply and demand;
- Critical industry and policy actions required in the 2020s.

Final energy mix in a zero-carbon economy: electricity will become the dominant energy vector, complemented by hydrogen and fuels derived from it

Final energy demand
EJ/year

Illustrative scenario

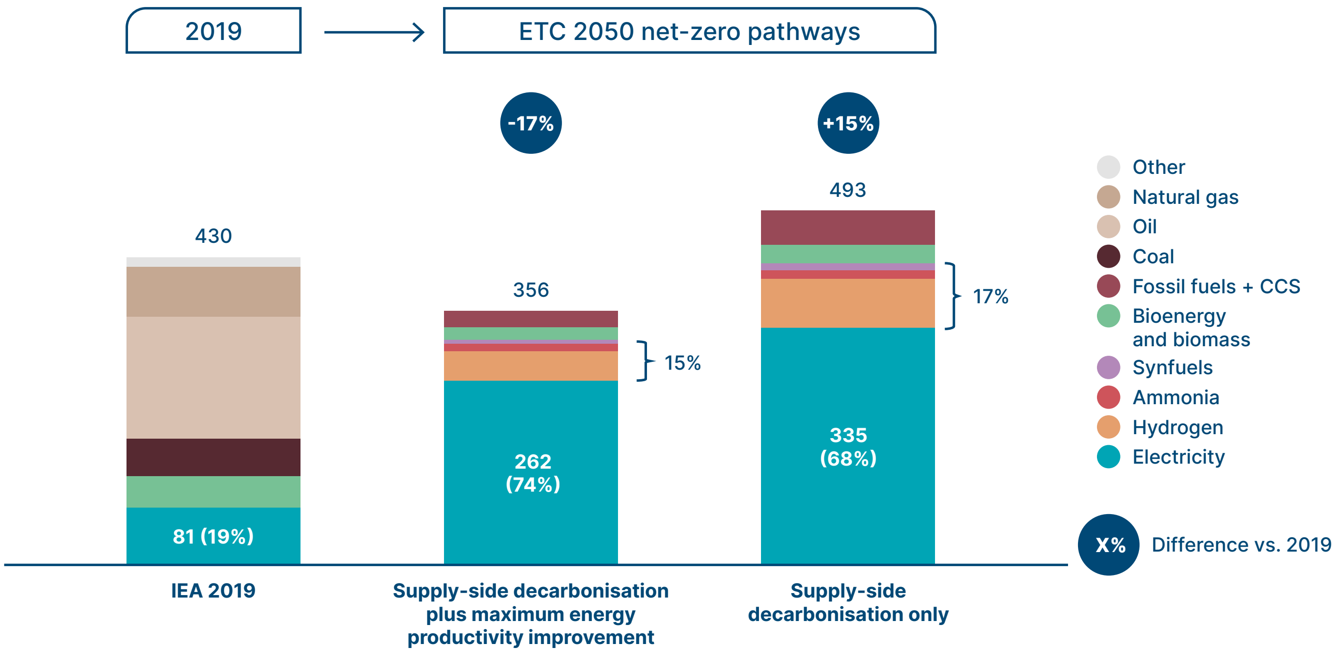


Exhibit A

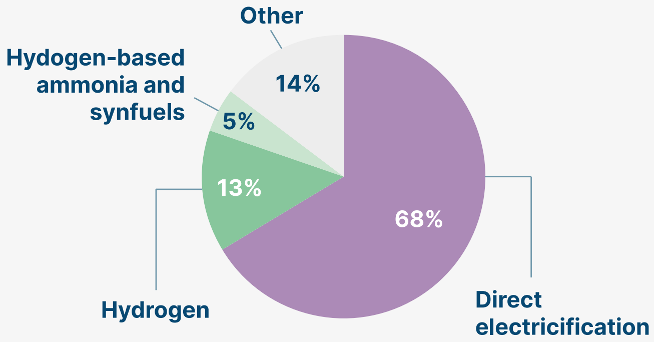
SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *World Energy Outlook*

Energy Transitions Commission

MAKING THE HYDROGEN ECONOMY POSSIBLE

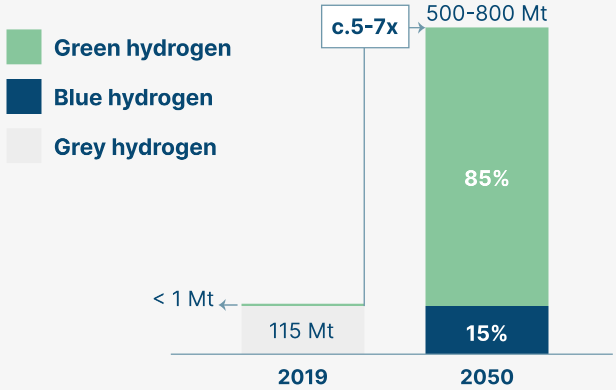
HYDROGEN: THE SECOND DECARBONISATION VECTOR

Final energy demand, ETC 2050 Indicative Scenario



A 5-7 FOLD INCREASE IN HYDROGEN PRODUCTION TOWARDS NET-ZERO

Hydrogen production 2050
Mt Hydrogen / year

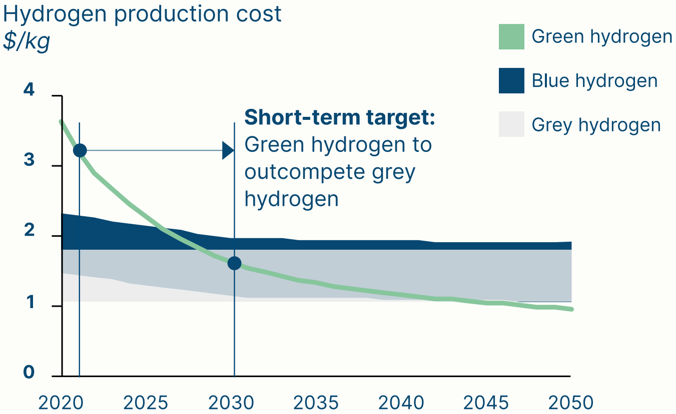


What will it take?

SIMULTANEOUSLY

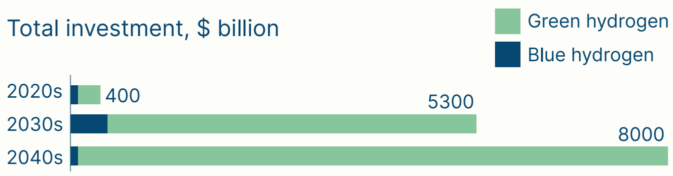
GROW PRODUCTION VOLUMES TO MAKE GREEN HYDROGEN COMPETITIVE

Hydrogen production cost
$/kg



TO UNLOCK LARGE-SCALE INVESTMENT IN HYDROGEN SUPPLY

Total investment, $ billion



RAPIDLY ACCELERATE DEMAND FOR CLEAN HYDROGEN

From grey to clean

Refining / Ammonia / Methanol

Development needed but large long-term need

Steel / Shipping / Aviation / Chemicals / Power

Potential transitional

Co-firing / Blending

Possible future uses if electricity doesn't win

Trucking / Residential heating / High temperature heating

DEVELOP TRANSPORT AND STORAGE INFRASTRUCTURE WHERE NEEDED

Clusters

Early use cases will develop around industrial clusters with shared hydrogen production, distribution and storage infrastructure.

Inter-regional

Limited international trade will be mainly supported by interregional pipelines and sometimes ammonia ships where final use is ammonia.

I. A vision for 2050: Hydrogen's role in a zero-carbon, deeply electrified economy

In 2018, about 115 Mt of hydrogen was used globally, of which 70 Mt was produced via dedicated production predominantly from natural gas (71%) and coal (27%).[4] This production resulted in about 830 Mt of CO_2 emissions, around 2.2% of the global energy-related total.

Over the next 30 years, hydrogen use is set to increase dramatically, and hydrogen production must become zero-carbon, for clean hydrogen to be used as a decarbonisation solution in existing as well as multiple new applications. By 2050, a zero-carbon economy could consume 500 to 800 Mt of zero-carbon hydrogen. New production methods will need to be matched by developments in hydrogen transport and storage, with opportunities to produce hydrogen in low-cost locations and transport it for end use elsewhere.

Technological progress will make it possible to produce this clean hydrogen at much lower cost than today, but its end use application will still, in some cases, impose a "green cost premium". While trivial at the consumer level, it could be significant for intermediate products.

Potential demand growth

The role of hydrogen relative to other decarbonisation options will reflect its inherent chemical characteristics, advantages, and disadvantages.

- **Compared with direct electrification,** using hydrogen is generally less efficient due to energy conversion losses. Therefore, where direct electrification is clearly feasible (e.g. in light duty road transport), hydrogen will be uneconomic. However, the higher energy density per mass of hydrogen and hydrogen-derived fuels (e.g. ammonia or synthetic fuels) relative to batteries, can outweigh this disadvantage in several long-distance transport applications.

- **In electricity system storage**, batteries are more economic for short durations, but hydrogen offers an economic and practical way to store large amounts of energy over the long term (days, months, especially to address seasonal variations).[5]

- Hydrogen can also serve **as a chemical agent or feedstock**, for instance replacing coking coal as the reduction agent in steel production, and as a chemical building block for ammonia and methanol production.[6]

- **Safety and leakage issues** may also carry implications for its relative role. While hydrogen has been used in industry for many years and can be stored at room temperature, it poses significant storage and transport challenges due to its small molecule size and extreme flammability. Ammonia is toxic and requires stringent safety procedures. The costs involved in managing these factors favour direct electrification wherever possible, especially for dispersed uses like transport and building heating.

Likely applications by sector

As a result, the potential uses of hydrogen in a zero-carbon economy can be usefully categorised into four groups (Exhibit B):

- **Existing uses** of hydrogen, where clean hydrogen production should replace "grey" production as rapidly as possible, eliminating the 830 Mt of CO_2 currently being released.[7] Key sectors here are crude oil refining, ammonia and methanol production.

- **Highly likely and large long-term uses,** where hydrogen use will grow slowly as the relevant application technologies develop and capital assets are replaced. These include steel production, long-distance shipping (as ammonia) and perhaps aviation (directly as hydrogen for short distance or as synfuel). In addition, there will very likely be a major use of

4 The 45 Mt difference stems from hydrogen produced as a by-product in a number of industrial processes such as catalytic naphtha reforming, chlor-alkali electrolysis and steam cracking of propane. Source: IEA (2019), *The future of hydrogen*

5 As outlined in the parallel report on power, batteries are well suited to cover intermittencies on shorter timeframes.

6 Plastics are produced from a wide variety of feedstock that could ultimately be produced via methanol.

7 IEA (2019), *The future of hydrogen*

hydrogen for seasonal storage within power systems, with hydrogen produced via electrolysis when there is a surplus of variable renewable supply relative to demand, and converted back to electricity (probably via combustion in gas turbines) when needed to meet demand peaks or compensate for a supply deficit.

- **Potential short-term but transitional opportunities** which may enable partial emissions reductions of existing high-carbon assets that will eventually need to be phased out. These could include co-firing hydrogen with natural gas in power production, or with coal in steel blast furnaces.

- **Possible uses where the relative advantages of hydrogen versus other decarbonisation options are still unclear**. These include:
  - Heavy-duty road transport where it is likely that hydrogen will play a significant role but where the balance between battery electric and hydrogen fuel cell trucks remains unclear due to uncertainty on technology developments,
  - Residential heating where electrification is likely to dominate, but where hydrogen may play a role in certain circumstances,
  - Hydrogen for back-up power generation at specific energy-intensive sites (e.g. data centres) where hydrogen competes with battery storage,
  - Plastics production where the balance between (or combination of) hydrogen-based production routes, bio-feedstock technologies, electrification, CCS and recycling remains uncertain.[8]

Multiple potential uses of hydrogen in a low carbon economy, some of which can provide early 'off-take' for clean hydrogen

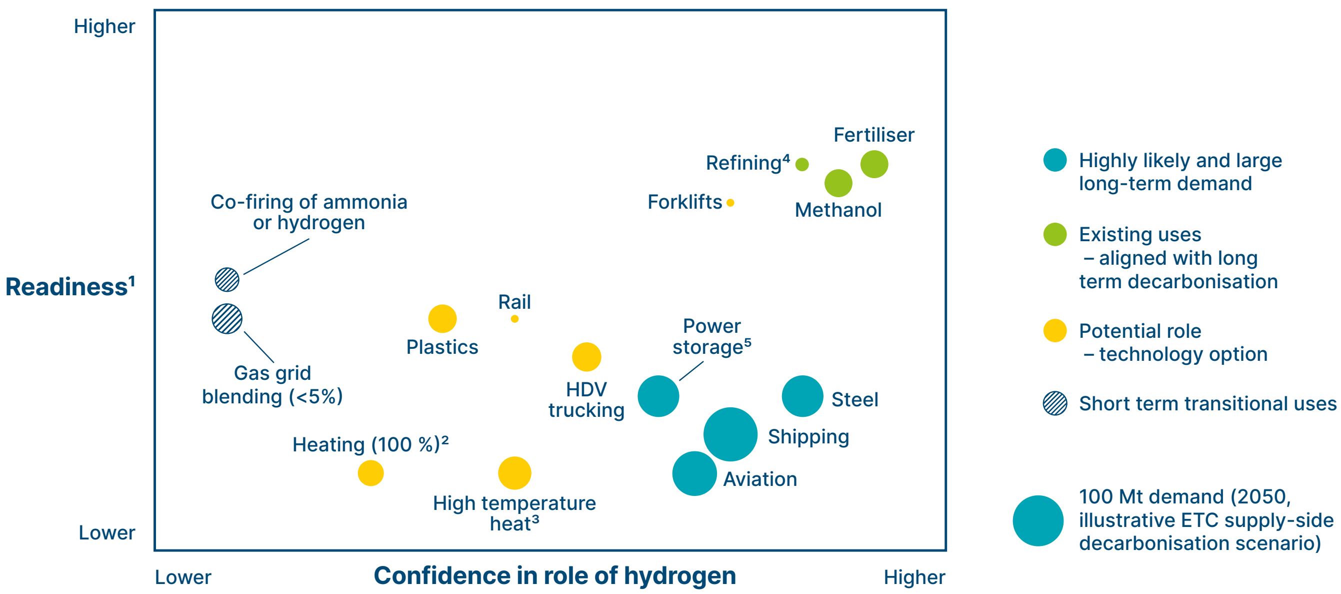


Exhibit B

NOTES: [1] Readiness refers to a combined metric of technical readiness for clean hydrogen use, economic competitiveness and ease of sector to use clean hydrogen. [2] 'Heating (100%)' refers to building heating with hydrogen boilers via hydrogen distribution grid, [3] 'High temperature heat' refers to industrial heat processes above ca. 800°C [4] Current hydrogen use in refining industry is higher due to greater oil consumption. [5] Long-term energy storage for the power system.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)

An illustrative scenario

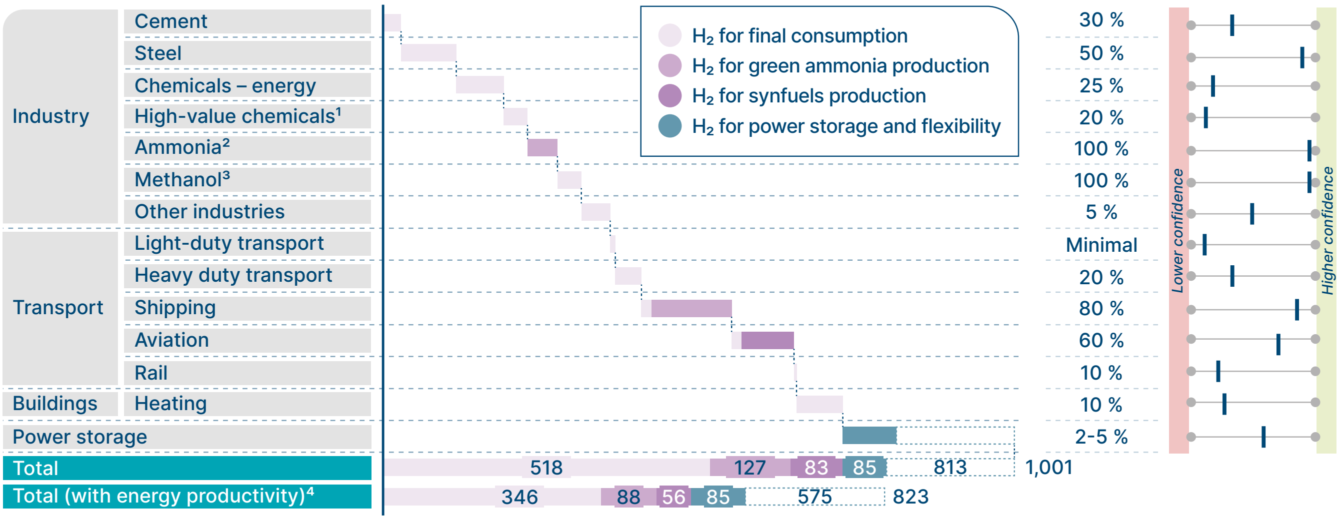
If all potential use cases of hydrogen materialise, total demand could reach as much as 1000 Mt by 2050, but a reasonable estimate of probabilities by sector implies a range of about 500-800 Mt (Exhibit C). This would imply that hydrogen (and its derivatives) could account for about 15% to 20% of total energy demand on top of the roughly 70% to be met by direct electrification. Our estimates suggest the same order of magnitude as recent scenarios produced by the Hydrogen Council and BloombergNEF, but with a different mix of sectoral applications (Exhibit D). Government and national strategies for hydrogen should therefore assume that hydrogen will play a major role in a zero-carbon economy even if the precise balance of decarbonisation technologies by sector is uncertain.

8 ETC (2019), *Mission Possible – Sectoral focus: Plastics*

Exhibit C

Clean hydrogen will play a growing role across the economy as the world transitions towards net-zero

Clean hydrogen demand in a net-zero CO_2 emissions economy (2050, illustrative scenario)
Million tonnes per year, ETC supply-side decarbonization pathway



Level of confidence in role of H_2 in a net-zero CO_2 emissions economy

Lower	Multiple decarbonisation routes available, eventual role of hydrogen likely to vary by region depending on local costs and availabilities
Higher	Hydrogen based routes likely to play a significant decarbonisation role due to, e.g. limits to alternative routes, likely cost evolution, industry actions

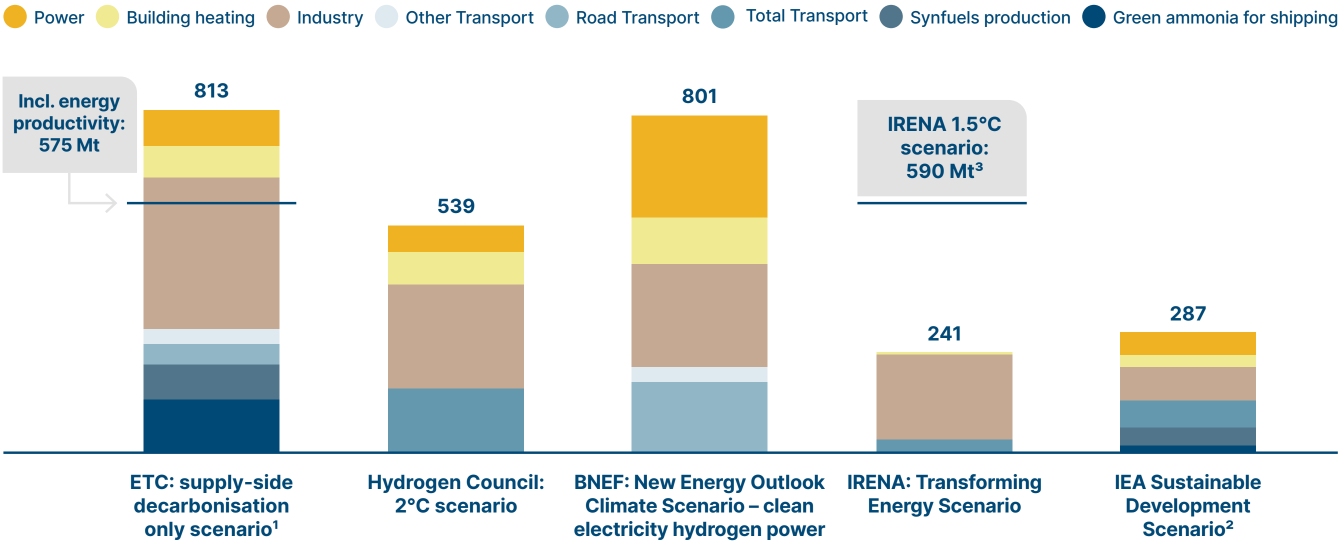
NOTES: [1] High value chemicals predominantly used to produce plastics, which could potentially be produced via Hydrogen and CO_2 in the future (via methanol and MTO process); [2] Around 80% of ammonia (excl. shipping) is used to produce fertilisers; [3] Methanol is used as intermediate in numerous chemical processes, including plastics production. [4] ETC scenario including maximum energy productivity improvements.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)

Exhibit D

Others share this vision for a significantly expanded role of hydrogen, but with different assumptions about sectoral mix

2050 hydrogen demand
Mt hydrogen / year



% of 2050 final energy demand[2]	15-17%	18%	24%	6-7% (13%[3])	6-7% (13%[2])

NOTES: [1] Illustrative scenario considering 2050 final energy demand without application of energy productivity levers which would reduce energy needs in a net-zero scenario,
[2] Hydrogen reaches 13% of final energy demand by 2070 in IEA SDS, with hydrogen volumes of 520 Mt/year,
[3] IRENA 1.5C scenario does not include split in uses, but represents 13% final energy demand.

SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); Hydrogen Council (2017), *Hydrogen scaling up – A sustainable pathway for the global energy transition*; BloombergNEF (2020), *New Energy Outlook*; IRENA (2021), *World Energy Transitions Outlook – 1.5C Pathway*; IRENA (2020), *Global Renewables Outlook*, IEA (2019), *The future of hydrogen*

Falling production costs for green and blue hydrogen: implications for electricity demand

Any hydrogen used in 2050 must be produced in an almost zero-carbon fashion. This can be achieved through either:[9]

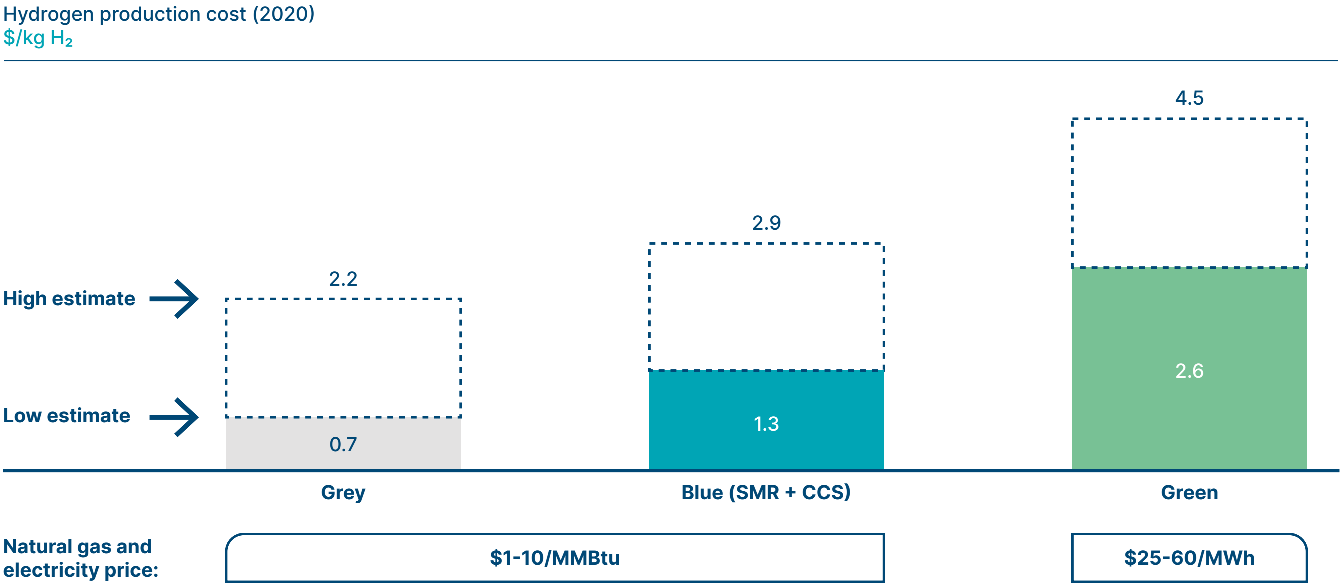
Green hydrogen production via the electrolysis of water, which can deliver completely zero-carbon hydrogen if all of the electricity used comes from zero-carbon sources.

Blue hydrogen production, deriving hydrogen from natural gas, with carbon capture and storage (CCS) applied. This can result in low but not zero-carbon hydrogen, with the size of residual emissions determined by the completeness of the carbon capture process (with at least 90% required) and the scale of methane leaks in natural gas extraction, transport and use (aiming for <0.05%).

Feasible blue hydrogen production costs are currently below those for green hydrogen and the production of grey hydrogen (hydrogen from fossil fuels without CCS) is cheaper still (Exhibit E).

Exhibit E

Today's production prices range based on local costs: clean production routes more expensive with green hydrogen ca. 2-4x more expensive than grey



NOTES: No carbon tax applied. Costs for SMR+CCS (90% capture rate) shown as there are no dedicated ATR (or POX) + CCS facilities for blue hydrogen production today. Green: assumed 50% capacity utilisation factor, $850/kW CAPEX for large scale alkaline electrolyser, energy consumption: 53 kWh/kg. Green hydrogen costs can even be higher for smaller scale applications.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021); BloombergNEF (2020), *Hydrogen Economy Outlook*

Excluding the impact of any carbon tax, the "blue" route will always be more expensive than producing grey hydrogen due to the extra cost of CCS. By contrast, green hydrogen costs depend on two factors – the cost of zero-carbon electricity and the capital cost of electrolysers – both of which are likely to fall rapidly.[10] As a result, green hydrogen costs are likely to fall below blue hydrogen costs in some locations before 2030 and in most by 2050 (Exhibit F). In many locations, the future cost of green hydrogen could be below today's grey hydrogen cost, making the eventual cost of decarbonising hydrogen production very small and potentially even negative.

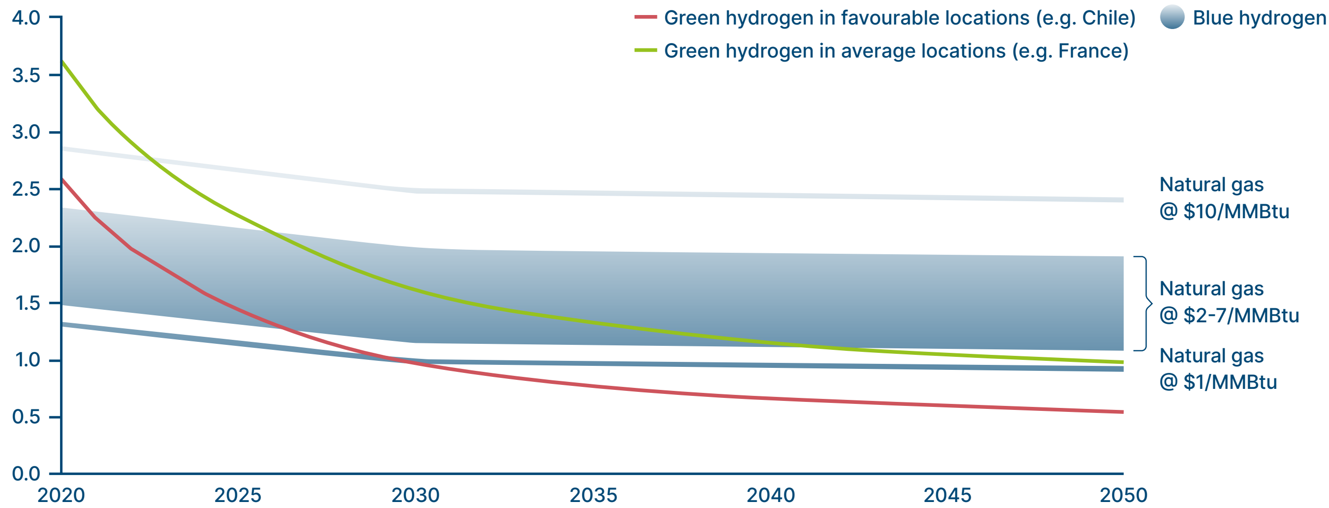
9 Hydrogen can also be produced from coal starting with a gasification process, or via other technologies such as pyrolysis (sometimes labelled "turquoise hydrogen) among others. These are discussed in the full report and appendix.

10 The capacity utilisation factor (i.e.. how many hours the electrolyser is running) at the given cost of electricity and the efficiency are other key factors.

It is therefore likely that the "green" production route will be the major production route in the long term, though with a significant role for "blue" in transition and in specific locations where gas costs are very low. Our base case scenario assumes that by 2050, 85% of the 500-800 Mt of annual production could be produced via the "green" route. This would require about 30,000 TWh of electricity input[11] on top of the 90,000 TWh potentially required for direct electrification.

Green hydrogen from electrolysis likely to become cheapest clean production route in the long term, in favourable locations it could be competitive with blue in the 2020s

Cost of hydrogen production from different production routes (excluding transport & storage costs)
$/kg H_2



NOTES: Blue hydrogen production: i) forecast based on SMR+CCS costs (90% capture rate) in 2020 transitioning to cheaper ATR+CCS technology in the 2020s; Green hydrogen production: i) favorable scenario assumes average LCOE of PV and onshore wind of lowest 33% locations (falling from $22/MWh in 2020 to $10/MWh in 2050) and average scenarios assumes median LCOE from lowest 75% locations (falling from $39/MWh in 2020 to $17/MWh in 2050) from BloombergNEF forecasts, ii) additional 20% (favorable) and 10% (average) LCOE savings included due to directly connecting dedicated renewables to electrolyser, iii) 18 % learning rate for favorable & 13 % for average scenario. Electrolyser capacity utilization factor: 45%. Comparison to BloombergNEF most favorable ($0.55/kg) and average ($0.86/kg) and Hydrogen Council favorable (ca. $0.85/kg) and average (ca. $1.45/kg) in 2050.

SOURCE: BloombergNEF (2021), *Natural gas price database* (online, retrieved 01/2021), BloombergNEF (2020), *2H 2020 LCOE Data Viewer*; BloombergNEF (2021), *1H2021 Hydrogen Levelised Cost Update*; Hydrogen Council (2021), *Hydrogen Insights*

Exhibit F

The green cost premium at intermediate and end consumer level

Producing hydrogen in a zero-carbon fashion will not impose a large cost on the economy in the long run. However, in some applications, using hydrogen will likely impose significant costs compared to the continued use of an unabated fossil fuel based technology, due to the remaining cost differential between hydrogen and fossil fuels (in the absence of a carbon price) and to the capital expenditure triggered by the switch to hydrogen-based technologies.

There will therefore be a "green product premium" when applying hydrogen to achieve decarbonisation. For example, using hydrogen as the reduction agent rather than coking coal may increase steel prices by 40%, and burning ammonia rather than heavy fuel oil in ship engines could mean that ship freight rates increase by 60% or more.

However, except for the case of aviation, the "green consumer premium" (i.e. how much more consumers will need to pay for the products and services they directly purchase) will still be trivial since intermediate products or services typically account for only a very small proportion of total end product cost. For instance, using hydrogen to decarbonise steel will add less than 1% to the cost of a vehicle built with one tonne of steel and using ammonia to decarbonise shipping will add less than 1% to the cost of imported goods (Exhibit G).

In that context, demand for zero-carbon hydrogen will not develop without strong policy support at intermediate product level and pass through of costs to end consumers. In turn, without strong demand growth, potential production cost reductions will not be achieved.

11 Assuming 45 kWh/kg, versus today's typical 50-53 kWh/kg

Use of clean hydrogen would have a significant impact on the price of intermediate products, but a negligible impact on final product prices in most sectors

Exhibit G

Hydrogen technology at $2/kg H_2	Impact on intermediate product 1 US$ / % price increase	Impact on intermediate product 2 US$ / % price increase	Impact on end product US$ / % price increase
Steel	+40% Increase on a ton of steel	n/a	+0.7% increase on retail price of automobile
Shipping	+160% compared to ton of VLSFO	+3% increase per ton of imported soybean	+0.8% increase per litre of dairy milk
	+160% compared to ton of VLSFO	+60% increase in container freight rate	+0.7% increase on retail price of flat screen TV
	+160% compared to ton of VLSFO	+60% increase in container freight rate	+0.4% increase on retail price of pair of shoes
Fertiliser	+45% compared to ton of ammonium nitrate	+3% increase per ton of soybean	+0.8% increase per litre of dairy milk
	+45% compared to ton of ammonium nitrate	+5% increase per ton of wheat	+0.6% increase on price of loaf of bread
	+45% compared to ton of ammonium nitrate	+9% increase per ton of corn	+3.2% Increase in price of pork
Aviation	+130% compared to ton of kerosene	n/a	+18% increase on long-haul flight ticket price

NOTE: Calculated for 2 $/kg delivered hydrogen cost.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)

Transport, storage and international trade

The vast majority of hydrogen used today is captive – i.e., produced on the same site where it is used (e.g., in ammonia production or petroleum refining).[12] Current demand for hydrogen transport and storage is therefore very small. In the future, most use will likely remain captive, but vastly increased demand in a wider range of applications will require extensive systems for transport and storage. In some cases, this might require converting hydrogen into suitable forms for transport. This will add costs in some applications, but may also create opportunities to produce hydrogen in favourable, low-cost locations for use elsewhere.

Technology options and costs

Hydrogen can be transported in different forms: compressed, liquified or as ammonia derived from hydrogen. Lowest cost transportation options will depend on the required volumes and distances involved: trucks are preferred for shorter distances and low capacities, pipelines are least costly for very large volumes, and, for intercontinental transport, ships are most competitive.

Significant storage will be needed to support some large-scale applications, particularly where green hydrogen production relies on variable renewable electricity input. Requirements will be greatest when hydrogen is used to provide seasonal supply balance within the power system. Large-scale geological storage will be needed, given the limited capacity and large costs of compressed hydrogen containers. Salt caverns will offer lowest cost geological storage where salt formations are available, but the total storage requirements are enormous – if 5% of total 2050 annual hydrogen use needed to be stored, that would require about 4,000 typical size salt caverns, compared with only about 100 in use for natural gas today.[13] Rock caverns and depleted oil and gas fields are potential alternatives which could provide more than sufficient storage capacity, but further development is required before these could be used.

12 The percentage of captive production differs by region and end-use sector, with an average of 95% estimated at the global level. Sources: IEA (2019), The Future of Hydrogen. Renewable Energy and Environmental Sustainability (2019), *The hydrogen economy and jobs of the future*.

13 Storage of up to 20% of annual demand may be required in a fully decarbonised economy, meeting both the need to store intermittently produced green hydrogen to stabilise flows of hydrogen for industrial processes and the storage of hydrogen to balance the power system). Source: BloombergNEF (2019), *Hydrogen – the economics of storage*

For distributed applications such as road transport, distribution and storage costs could add circa $1.3/kg to production costs below $2/kg, and are thus key determinants of end use competitiveness relative to direct electrification.

Opportunities for international trade

Green hydrogen production costs depend crucially on the cost of zero-carbon electricity, which differs considerably between locations. Blue hydrogen costs reflect gas prices which also vary greatly. It may therefore be economic to produce green or blue hydrogen in locations with very low input prices and transport it to higher cost ones.

The scale of international trade in hydrogen (or ammonia) will however be limited by three factors:

- The potential for long-distance electricity transmission (via HVDC lines) as an alternative to hydrogen transport via pipeline or ship. For distances above 1000 km, transporting cheap electricity and converting it to hydrogen at destination may often be lower cost than producing hydrogen close to cheap renewable resources and piping it to the end use location.

- The fact that natural gas pipelines will always be lower cost than hydrogen pipelines, making it cheaper to transport natural gas from low-cost areas to blue hydrogen production sites rather than to produce hydrogen close to the gas field and transport it as hydrogen.

- The likelihood that falling renewable electricity cost in all regions will probably reduce the cost differential between regions faster than transport costs decline.

As a result, long-term opportunities for profitable international trade in hydrogen (as against in electricity or gas) may be limited to:

- Situations where cheap high-capacity pipeline transport is economic, typically up to distances of 1000 km, and particularly where existing gas pipelines can be retrofitted to carry hydrogen;

- Transporting ammonia for end use as ammonia (rather than for reconversion to hydrogen at the destination).

- A limited number of countries that may need to import hydrogen due to a lack of local resources (e.g., enough land area for local renewable energy generation).

Moreover, it is likely that the emergence of a hydrogen economy will, over time, lead to changes in the optimal location of hydrogen-intensive industries, such as steel.

II. Driving the transition to large-scale clean hydrogen supply and use

It is clear that hydrogen can and must play a major role in the future zero-carbon economy. The challenge is to ensure that the transition occurs fast enough to first unlock low-cost production and then put the sector on a growth trajectory to meet 2050 objectives. This will require action to reduce green hydrogen production costs in the 2020s, to ensure sufficiently rapid growth of end use applications, and to grow green or blue hydrogen capacity in line with that demand. Clusters of co-located hydrogen production and use are likely to play a key role in early deployment.

National strategies should also plan for:

- The huge growth in zero-carbon electricity supply necessary to deliver green hydrogen on the scale required,[14]
- Future hydrogen transport and storage needs, and possible solutions,
- International standards on safety quality and carbon-intensity.

Reducing green hydrogen production costs

While green hydrogen is not competitive today, if already announced public policies and private investment plans materialise, they would be sufficient to drive strong cost reductions in the 2020s, making it competitive with blue hydrogen in many locations and with grey in some.

The costs of both the key inputs – electrolyser equipment and renewable electricity – are likely to fall rapidly in the 2020s:

- Electrolyser costs have until recently been around $850-1000/kW, and have reflected very small scale production. However, costs in China are already estimated to be a far lower at $300/kW. Western producers are planning greatly increased production, and costs will be driven down by economy of scale and learning curve effects. If appropriate demand side support materialises, it is reasonable to assume that public policies which have already been announced – such as the EU's commitment to have 40 GW of electrolyser capacity in place by 2030 – are sufficient to drive electrolyser prices below $300/kW across the world before 2030 (Exhibit H).[15]

- High electrolyser costs have made high-capacity utilisation essential in order to reduce capital costs per kilogram, but, as CAPEX costs collapse, high utilisation will no longer be crucial. This makes it possible to use low-cost renewable electricity, whether from dedicated renewable capacity or using grid electricity at low-cost times of day. Together with continuing reductions in solar and wind generation costs, this indicates that dramatic falls in electricity input costs are likely.

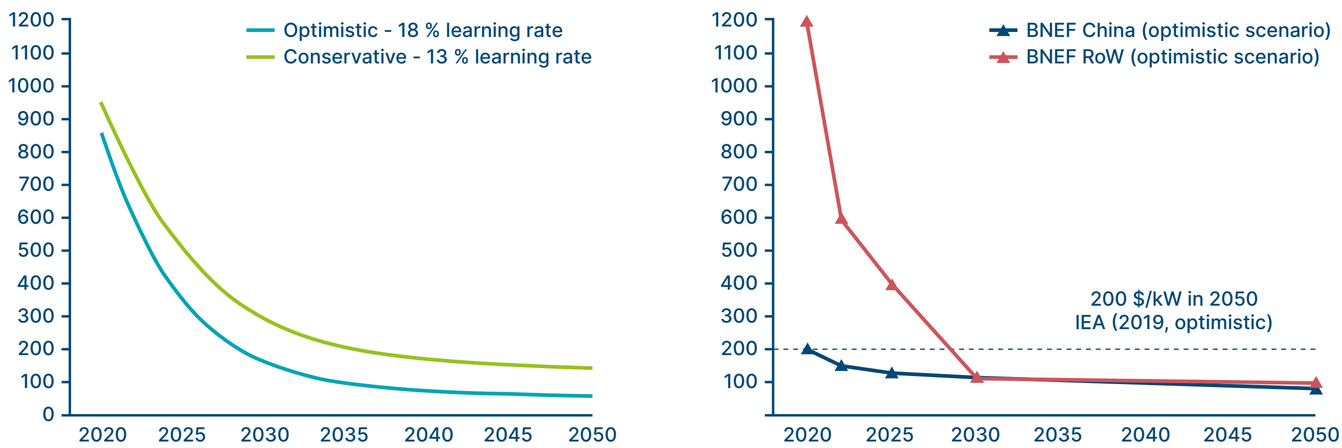
The cost of green hydrogen production is therefore likely to fall below $2/kg and in some locations below $1.5/kg during the 2020s. Several private investment projects are already targeting production at those costs.

14 Critical actions to scale zero-carbon power systems are described in the ETC power report. Source: ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*

15 Policy support mechanisms will be required, including critically policies to overcome the use-case cost-premium, see page 18.

Green hydrogen production costs are expected to fall driven by both falling cost of electrolysers and continued declines in renewable electricity prices

Fully installed system capex forecast of large alkaline electrolysis projects
US$/kW

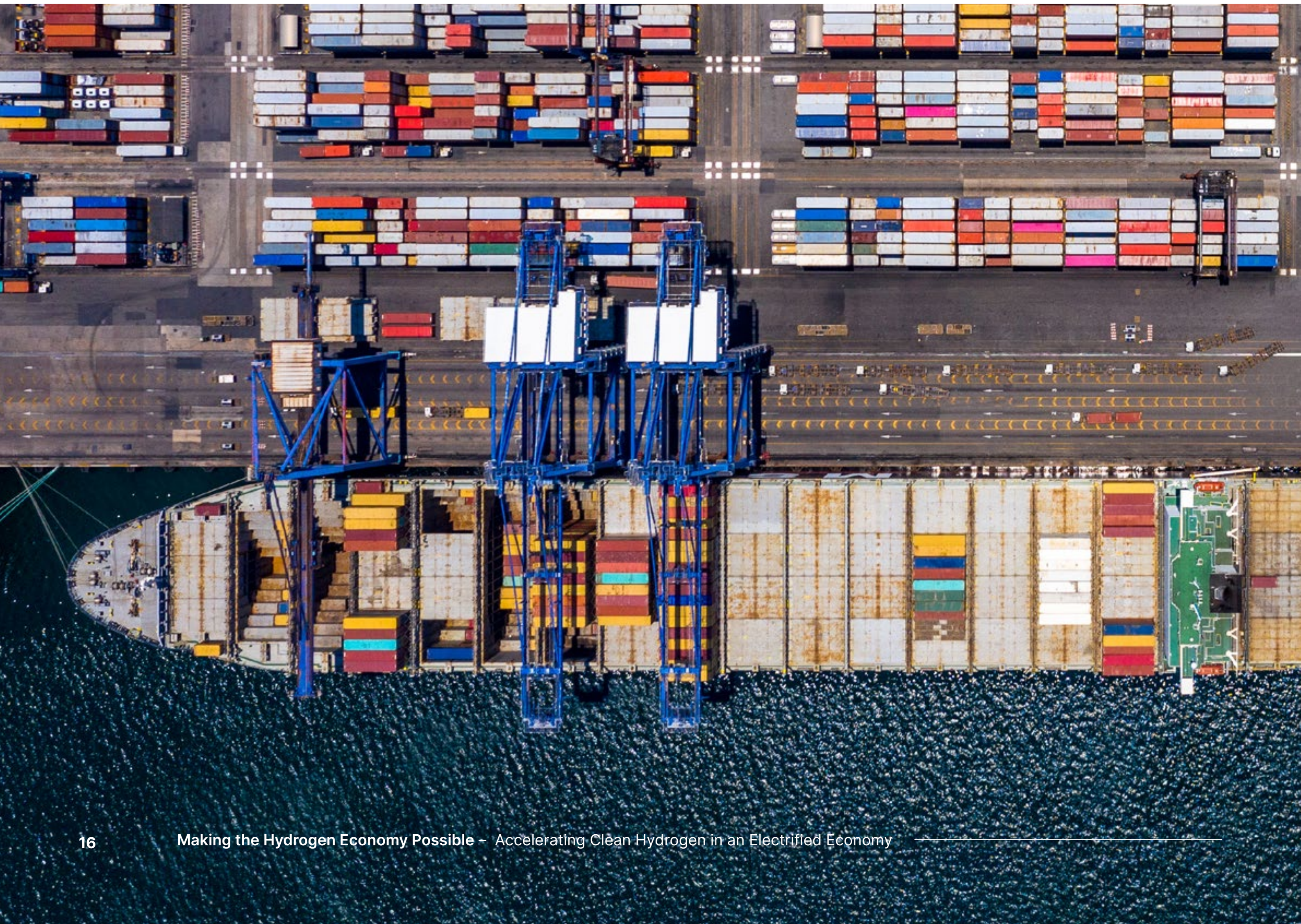


Electrolyser capacity (GW)	15	225	1300	3300	5500	7800

NOTES: CAPEX figures include full installation costs for a large scale (>20 MW) alkaline electrolyser including stack, balance of plant (power electronics for voltage transformation, hydrogen purification and compression), construction and mobilisation and soft costs (project design, management, overhead, contingency and owners cost). There are significant differences in electrolyser CAPEX forecasts likely related to differences in definitions of what is included/excluded in quoted figures and differences in system size (costs decline significantly with order and module size). Hydrogen Council suggests electrolyser CAPEX could drop to about $200-250/kW (IRENA: $360/kW in Transforming Energy Scenario) by 2030 at the system-level but do not include installation and assembly, building, indirect cost.

SOURCES: BloombergNEF (2019), *Hydrogen – Economics of production from renewables*; BloombergNEF (2021), *1H2021 Hydrogen Market Outlook*; Hydrogen Council (2021), *Hydrogen Insights;* IRENA (2020), *Green hydrogen cost reduction*; Expert interviews.

Exhibit H



Accelerating demand growth

By the late 2020s, clean hydrogen is likely to be cost-competitive with grey hydrogen in some locations. However, end-use applications of hydrogen, and thus total demand, may not grow fast enough in the 2020s to allow a credible path to the 500-800 Mt that would likely be required in a zero-carbon economy by mid-century. Public policy should therefore support faster demand growth in the 2020s than is required simply to secure a decline in the cost of green hydrogen. Key priorities are to:

- Drive rapid decarbonisation of all existing hydrogen production (in particular in oil refining and ammonia production);
- Accelerate rapid technology development and sufficient early adoption of hydrogen in other key sectors with lower technology-readiness but large potential demand, like steel production and ammonia in shipping, to make rapid take-off in the 2030s feasible.

The appropriate specific sectoral focus should reflect national circumstances, making it difficult to predict how the global balance of hydrogen demands will evolve. A broad indication of possible sequencing is shown in Exhibit I.

Potential sequencing of demand sector "take off" over next 3 decades

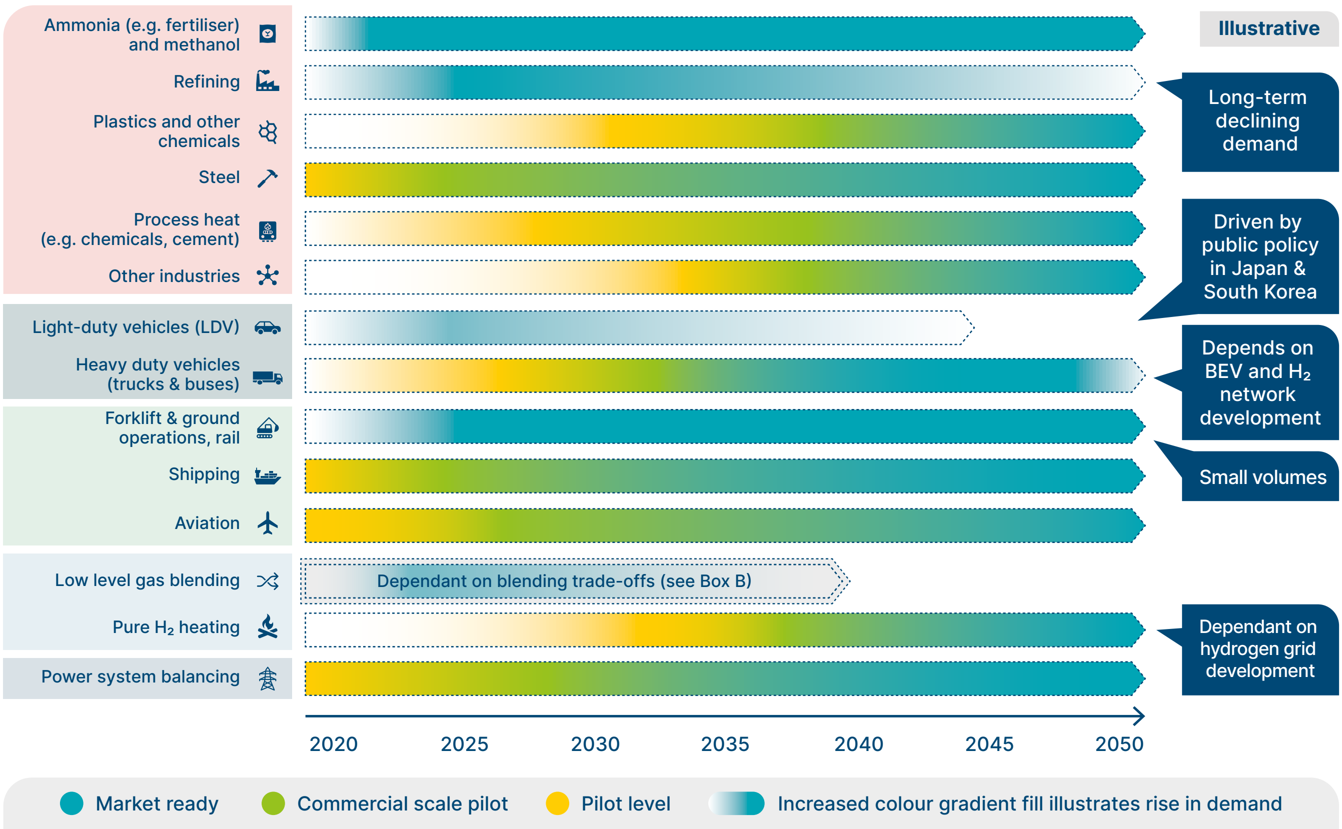


Exhibit I

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)

Enabling rapid capacity growth

Strategies for the development of the hydrogen economy should also anticipate the scale of investment ramp-up required and identify and remove any barriers.

- For **green hydrogen,** natural resources are clearly sufficient to support massive growth, with no long-term constraints on the supply of key minerals for electrolysers (in particular nickel), nor of water. But it is important to anticipate the timing of mineral demand growth which will be driven both by hydrogen developments and by direct electrification. Plans for power system developments must also anticipate the very large electricity demand for green hydrogen production.[16]

16 ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*

- **Blue hydrogen** development could be slowed due to long project lead times, difficulty to develop shared pipeline networks and public resistance to CCS. This could limit the speed with which existing grey hydrogen production is decarbonised. Clear national strategies for the appropriate development of blue hydrogen are therefore required even if electrolysis will become the major production route in the long term.

The actual balance between green and blue hydrogen will reflect future trends in technology and cost, varying in line with specific national and regional circumstances. Nevertheless, it is useful to consider scenarios which illustrate broad orders of magnitude and likely limits (Exhibit J).

- In all scenarios blue hydrogen is likely to play a major role in the 2020s, in particular through the conversion of grey hydrogen facilities to blue hydrogen. However, build-up of new blue hydrogen facilities will likely slow in the 2030s as green hydrogen becomes the lower-cost option in most locations.

- In the long run, a reasonable base case could see blue hydrogen accounting for 15% of total production and green for 85%. It is important to note, however, that this would still bring blue production to the same scale as today's total hydrogen use.

Exhibit K shows a combined picture of how demand by sector and sources of supply could evolve over the next 30 years.

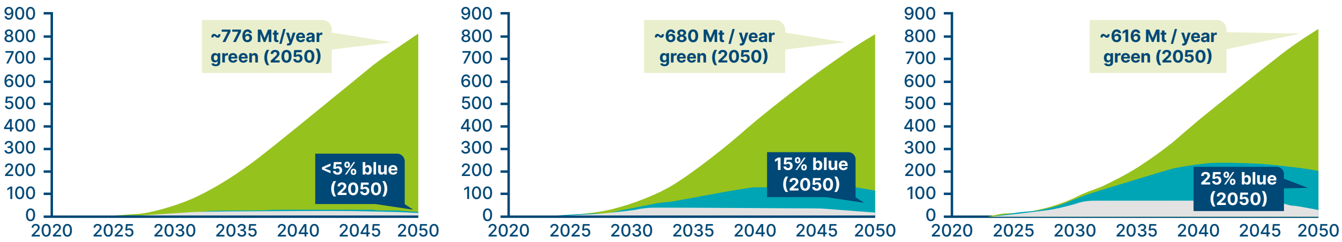
Rapid ramp up of blue production in the 2020s would see blue taking a greater share of supply in next decade, and green ramping up faster in the 2030s to compensate

Illustrative scenarios

Scenario 1: Limited role for blue	Scenario 2: Medium role for blue	Scenario 3: Higher role for blue

Clean hydrogen production (green and blue)
Mt hydrogen/year

Green hydrogen · Greenfield blue hydrogen · Retrofit grey hydrogen



Build rate assumption underpinning illustrative scenarios

Retrofit of existing production facilities:

Scenario 1	Scenario 2	Scenario 3
ca. 40% gas plants by 2030	**ca. 70% gas plants by 2030**	**ca. 80% coal and gas plants by 2030**

New clean hydrogen production facilities:

Scenario 1	Scenario 2	Scenario 3
• ca. 20 plants[1] constructed 2028-2038 • Max addition of plants per year: 4 in 2037, equivalent to ca. 8 GW electrolysis	• ca. 250 plants[2] constructed 2028-2038 • Max addition of plants per year: 40 in 2036, equivalent to ca. 110 GW electrolysis	• ca. 475 plants3 constructed 2028-2038 • Max addition of plants per year: ca. 60 in 2036, equivalent to ca. 210 GW electrolysis or ca. 25% of today's dedicated grey hydrogen production

Clean hydrogen production in the 2020s (green and blue)
Mt hydrogen/year

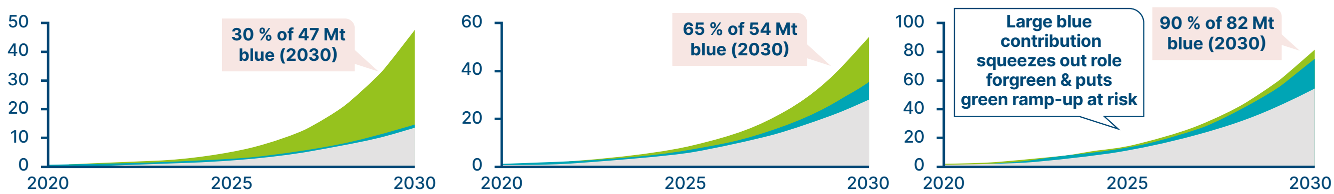


Exhibit J

NOTES: Details on the models methodology describing these scenarios can be found in the Annex. Historical build rates for green and blue projects were based on public databases. Size of plant: 1) 500 2) 700, 3) 800 tons of hydrogen/day

SOURCES: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *Hydrogen Projects Database; IEA (2020), World large-scale CCUS facilities operating and in development, 2010-2020*

In a mass-electrification scenario, what could the scale up of the hydrogen economy look like?

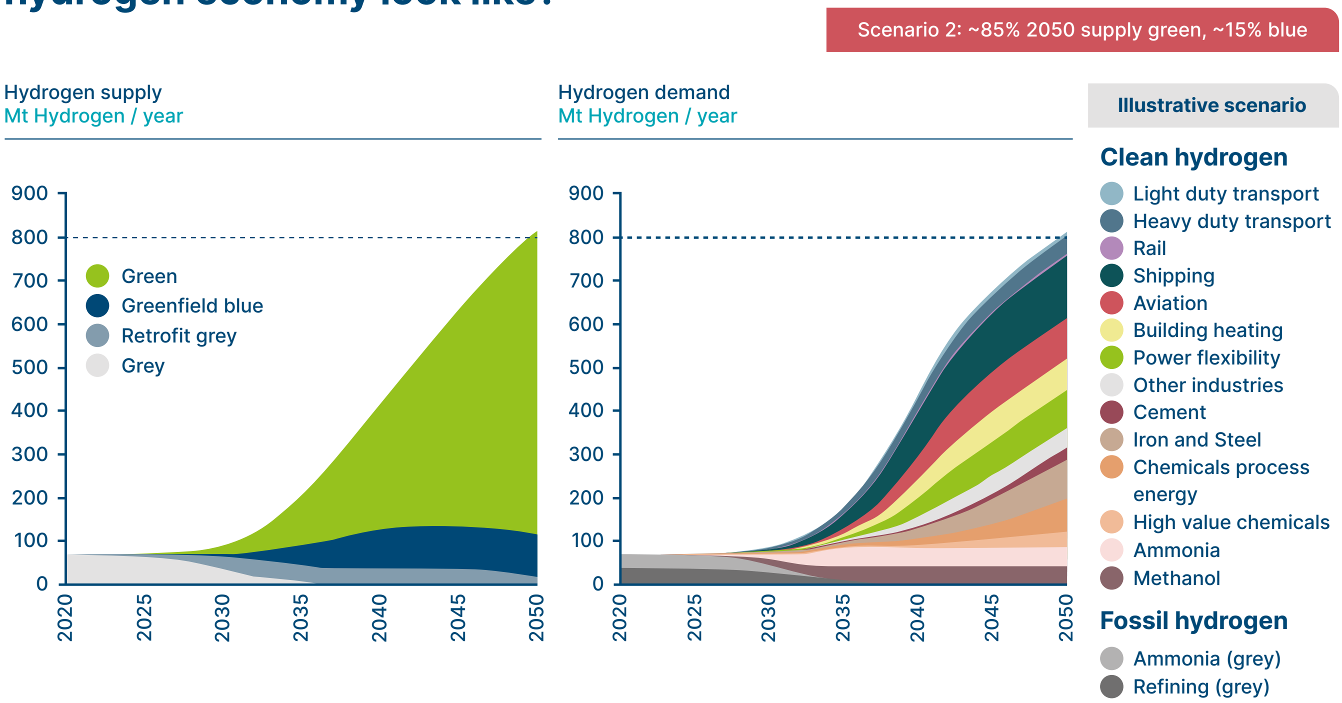


Exhibit K

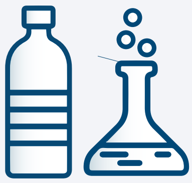
SOURCE: SYSTEMIQ analysis for Energy Transitions Commission (2021)

Developing hydrogen clusters and identifying future transport needs

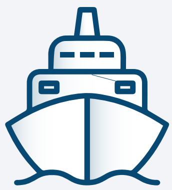
Strategies to simultaneously develop low-cost hydrogen production and demand growth will often be most effective if initially focused on "hydrogen clusters" in which hydrogen production, storage, transport and end use can develop concurrently. Such a focus can:

- Provide hydrogen producers with greater certainty on local hydrogen demand and de-risk their business case by diversifying off-takers;
- Support the simultaneous development of several different end use applications, rapidly achieving economies of scale in local hydrogen production;
- Accelerate the development of new uses for hydrogen at the same time as decarbonising existing grey hydrogen production;
- Minimise the initial need for investments in large-scale long-distance pipeline – with shorter-distance transport infrastructure costs shared between several potential users;
- Promote early development of storage infrastructure, with costs shared between different users;
- Focus policy support on developments that benefit several companies and sectors.

Details of potential cluster developments will depend on specific geographies and initial starting points, but 4 variants may be important:

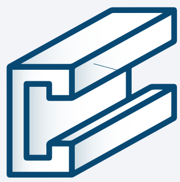


Existing **refining, petrochemical and fertiliser clusters**, where production should be decarbonised and new industrial applications could be added;



Ports, which need to support future shipping decarbonisation, are also nodes for long-distance trucking or rail connection, and are often located close to heavy industry sites;

Non-coastal transport and logistics nodes, where demand from aviation, road transport and warehousing could develop;



Steel plants, which are large enough in themselves to be the anchor for cluster development.

Exhibit L shows an initial analysis of potential cluster developments in India.

Development of clusters will often require coordination between multiple industrial companies involved in both hydrogen production and end use, supported by governments at local and national level. Key public policy levers could include planning and permitting processes which support rapid development, actions to reduce the cost of grid connections, targeted support for technology development (for instance in relation to new storage systems), and investment support for hydrogen production, shared infrastructure and use case equipment.

The focus on cluster developments will reduce the initial need for major investments in hydrogen transport, but more extensive hydrogen networks may be required over time, to support both a wider range of applications, and the use of dispersed renewable electricity resources. National strategies for hydrogen should therefore also identify potential long-term transport needs, including the potential role for long-distance international links.

Spatial analysis in India identified 46 favourable clean hydrogen industrial cluster locations

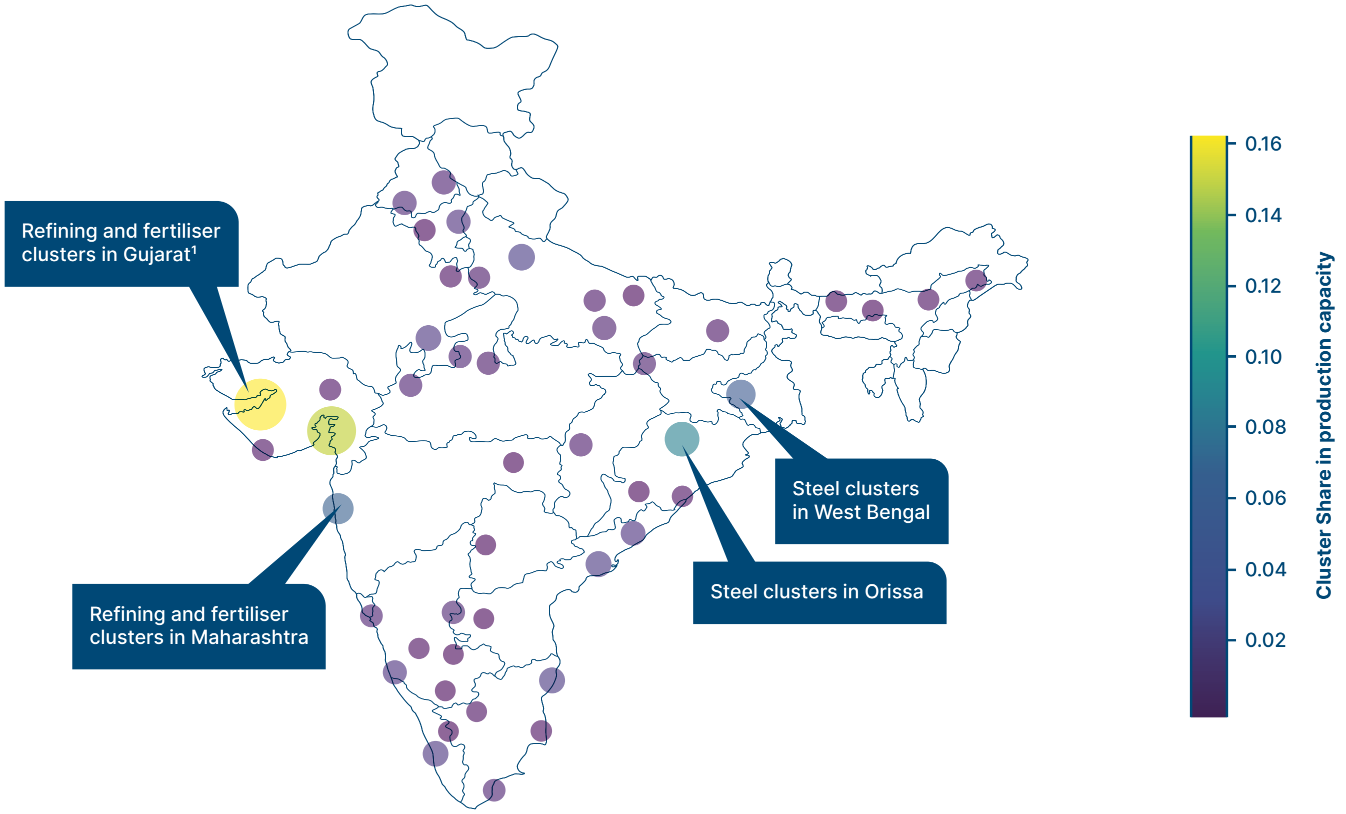


Exhibit L

NOTES: [1] There is also a significant chlor-alkali industry in Gujarat which may offer by-product clean hydrogen for these clusters.

SOURCE: TERI/ETC India analysis published in TERI (2020), *The Potential Role of Hydrogen in India*

Safety, quality and low-carbon standards

Hydrogen's major role within a zero-carbon global economy could be facilitated by international rules and standards on safety and purity. Clear standards for greenhouse gas emissions measurements are also essential.

- **Safety**: International standards could facilitate the growth of global trade and enforce limits on hydrogen leakage. Local standards and certification will be required if hydrogen is used in smaller-scale residential and transport applications.
- **Quality**: Hydrogen purity standards are needed to facilitate market development and international trade. This should include assessment of residual impurities as the purity requirements differ between applications.
- **Clean hydrogen standards**: It is vital to develop standards to define how low-carbon different sources of hydrogen are and drive both green and blue production as close to zero emissions as possible. This should include carbon standards for products derived from hydrogen (e.g. ammonia and synfuels). Certification schemes must incorporate full lifecycle emissions, including, in the case of blue hydrogen, residual CO_2 emissions not captured by CCS and methane leakage occurring before and during production. If methane leakage were 1.5% (the estimated global average today[17]), producing the 120 Mt of blue hydrogen indicated in the base case on Exhibit K would result in ca. 0.5 Gt of CO_2 equivalent emissions per year.

17 IEA (2020), *Methane Tracker*

Total investment needs – dominated by power sector growth

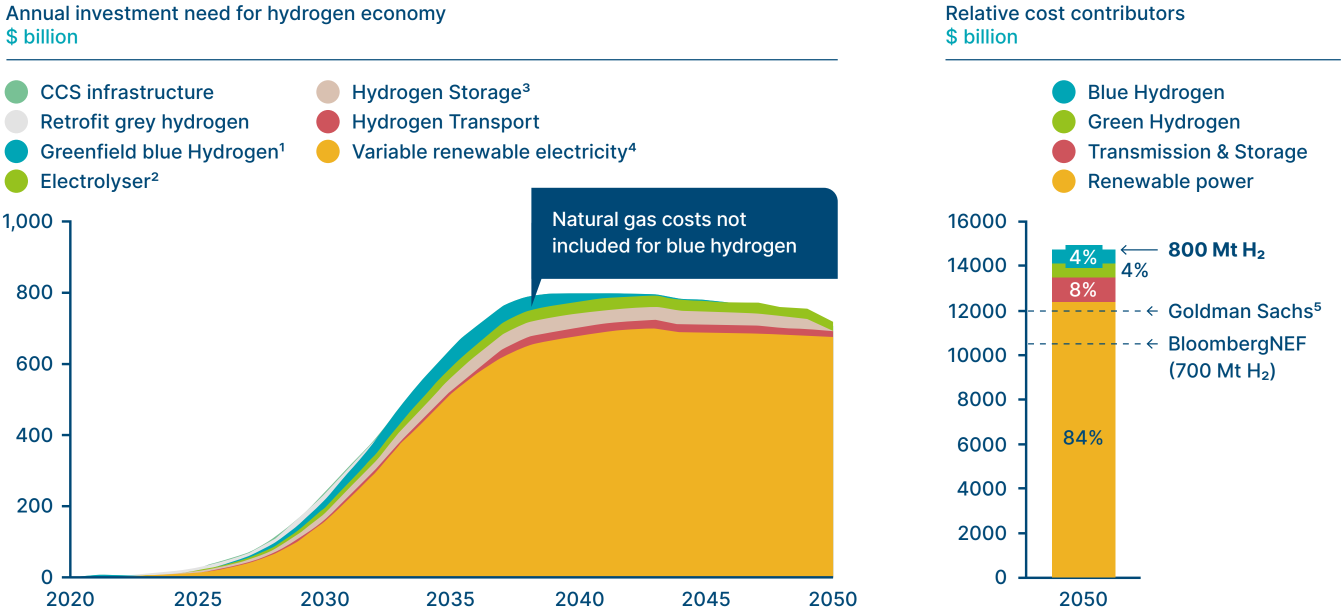
Building a hydrogen economy that accounts for 15-20% total final energy demand, with hydrogen use increasing by 5-7 times relative to today's 115 Mt,[18] will require very large investments. However, the largest investments are not in the hydrogen production and use systems themselves, but in the electricity system required to support the massive increase in green hydrogen production (Exhibit M).

In total, investments could amount to almost $15 trillion between now and 2050 – peaking in the late 2030s at around $800 billion per annum.[19]

- Of this, about $12.5 trillion (85%) relates to the required increase in electricity generation[20], with only 15% (peaking at almost $150 billion per annum in the late 2030s) relating to investment in electrolysers, blue hydrogen production facilities or transport and storage infrastructure.
- These large power system investments to support green hydrogen production would be additional to investments required for massive direct electrification (from around 25,000 TWh to around 90,000 TWh) described in our parallel power report.[21]
- Additional investments will be required in hydrogen-using sectors, but these will primarily replace existing investment in current carbon-based energy.[22]

Clear long-term strategies for massively expanded clean electricity supply are therefore vital to achieve a zero-carbon economy where direct electricity and and hydrogen along with its derived fuels will together account account for over 85% of all final energy use.

Cumulative investment needs amount to ~$15 trillion until 2050 for supply ramp-up with peak at $800 billion per year, dominated by renewable electricity production (~85%)



NOTES: The investment is assumed to take place in the year the plant is going in operation. Used middle ramp-up scenario with 85 % green and 15 % blue hydrogen.
[1] Blue hydrogen cost: $ 0.1 billion/TWh.
[2] Learning rate model for electrolyser CAPEX assuming 18% learning rate, 200 MW cumulative installed capacity (2020), $1200/kW CAPEX (2020). Average utilisation factor: 50%.
[3] Assume 20% of global hydrogen demand needs to be stored.
[4] Assumed capacity split (in terms of GWh produced) of 33 % PV, 53 % onshore wind, 13 % offshore wind. Used BloombergNEF cost predictions for variable renewable energy production (median cost of lowest 1/3 globally in terms of cost) with global average fleet load factors.
[5] Hydrogen demand volume in 2050 unknown.

SOURCE: Goldman Sachs (2020), *Green Hydrogen - The next transformational driver of the Utilities industry*; BloombergNEF (2020), *Hydrogen Economy Outlook*. Element Energy (2019), *Hydrogen production with CCS and bioenergy*

Exhibit M

18 IEA (2019), *The future of hydrogen*
19 The average investment need over 30 years is ca. $500 billion per year which is on the same order of magnitude as upstream oil and gas spending during the last 10 years ($400-600 billion per year). Source: IEA (2020), *World Energy Investment 2020*.
20 In some instances, additional transmission infrastructure may also be required, e.g. in the case of dedicated renewable power from offshore wind.
21 ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*
22 Although the pace of capital expenditure might be accelerated compared to a business-as-usual scenario as decarbonisation efforts drive faster asset turnover.

III. Critical policy and industry actions in the 2020s

In some sectors of the economy, accelerated decarbonisation can be driven via the use of a few, well-understood and powerful policy levers:

- In the power sector, a dramatic decline in the cost of renewables was achieved because policy levers which provided price certainty and initial subsidy, created powerful economy of scale and learning curve effects.[23]

- Similarly, in the light-duty road transport sector, initial government support for battery R&D, together with subsidies for initial EV purchases, have driven a dramatic fall in battery costs and improvements in performance. Declared dates beyond which no new ICE vehicles can be sold are now reinforcing this.

Specific features of the hydrogen value chain mean that the policy levers required are inevitably more varied and need to be focused on specific sectors, regions or technologies.

- While many applications of direct electrification – including road transport – do not impose a "green cost premium" (indeed in many cases they deliver a cost advantage), many hydrogen applications will entail additional costs. Public policy interventions are therefore needed to enable hydrogen to compete with fossil fuel alternatives in some end-use applications.

- While in many countries, electricity is already universally available over existing T&D networks, some hydrogen applications will depend on the development of new hydrogen transport infrastructure.

- The green versus blue choice introduces an additional complexity for public policy, which must address potential scale-up bottlenecks for both routes.

- Early and cost-effective development may best occur within clusters which support the simultaneous and self-reinforcing development of hydrogen production and end use.

A feasible pathway to a mid-century net-zero economy requires a significantly accelerated ramp-up of clean hydrogen supply and use by 2030. Progress must occur along two critical dimensions:

- The production of clean hydrogen should reach 50 Mt by 2030, unlocking average clean hydrogen production costs of below $2/kg in all regions and putting capacity scale-up on a trajectory to reach 2050 targets.

- The majority (60%+) of the corresponding demand should stem from decarbonisation of existing hydrogen uses, combined with early scale-up of key new uses of hydrogen in mobility (i.e. for shipping, long-distance trucking, aviation) and industry (e.g., steel).

23 Our Making Clean Electrification Possible report describes the mix of policies required to maintain rapid progress in the power sector. Source: ETC (2021), *Making Clean Electrification Possible: 30 years to electrify the global economy*

As a result, public and private action to drive hydrogen application must combine broad policy levers with focused interventions, which sometimes require coordination between multiple actors. Key priorities should include:

1. **Carbon pricing**, which should ideally be part of the policy mix in all countries, providing broad incentives for decarbonisation of hydrogen supply and of potential use cases, and creating a level-playing field for clean hydrogen technologies (and other decarbonisation options) versus fossil fuel technologies.

2. **Sector specific policies to support demand growth and compensate the "green premium"** in particular applications, via a combination of:

    - Mandates and regulations requiring a percentage use of low-carbon energy (e.g., fuel mandates in shipping or aviation) and lifecycle emissions standards on product categories using key energy-intensive materials (e.g., on automotive, which can indirectly drive demand for low-carbon steel, aluminium and plastics);
    - Voluntary private-sector commitments to purchase low-carbon services and products (e.g., commitment from logistics firms to shift to low-carbon trucking, shipping and aviation) to reduce their Scope 3 emissions and create a basis for a marketable green offer;
    - Green public procurement policies (e.g., to require "green steel" in publicly-funded construction);
    - Financial incentives for hydrogen uptake, through mechanisms like contracts for difference to bridge the "green premium" of low-carbon products.

3. **Targets for the development of large-scale electrolysis manufacturing** and installation and public investment support for the first large-scale electrolysis manufacturing and installation projects.

4. **Public support and collaborative private-sector action to bring to market key technologies and capabilities** across production (e.g., electrolysers with faster ramping), transportation and storage (e.g., new forms of bulk hydrogen storage such as rock caverns), and use (e.g., hydrogen-based direct reduction of iron).

5. **The development of clean hydrogen industrial clusters**, through coordinate private-sector action, supported by national and local government. This includes for example public investment support for hydrogen production, shared hydrogen and/or CCS infrastructure, and end-uses equipment and assets.

6. **International rules and standards** on safety, purity and clean hydrogen certification.

Energy Transitions Commission

ACCELERATING CLEAN HYDROGEN IN THE 2020S

2030 TARGETS:

SUPPLY

50 Mt — Clean hydrogen production

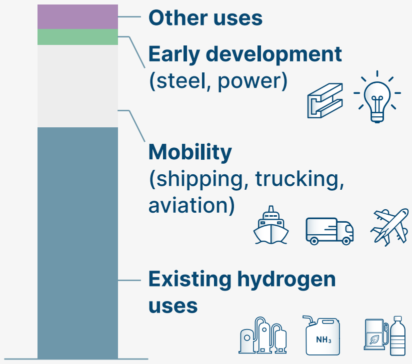
<$2/kg — Average clean hydrogen production cost

DEMAND

> 60% — Clean hydrogen demand from existing hydrogen use

> 30% — From new mobility and industry use-cases

HYDROGEN USE



TOP 5 ACTIONS ACROSS VALUE CHAIN

SUPPLY

1. Direct investment support and access to low-cost capital for clean hydrogen industrial clusters
2. Access to lower power prices through corporate purchase agreements, grid-tariff waivers and power market design
3. Ban new greenfield unabated grey hydrogen plants
4. Streamline permitting process for VRE generation and CCS for clean hydrogen production

TRANSPORT AND STORAGE

1. Adapt and expand existing regulatory & safety frameworks for hydrogen and ammonia
2. Geological siting of potential hydrogen storage locations (e.g. salt caverns)
3. National infrastructure planning to design (inter-) national hydrogen networks where required
4. Government support (e.g. blended finance) for storage & transmission network build out

DEMAND

1. Carbon taxes of $100/ton by 2030 with further increase until mid-century
2. Sector specific policies & actions to create early demand (e.g. mandates, public procurement, voluntary green market)
3. Sector specific financial support mechanisms for investments and to overcome the cost premium (e.g. contracts for difference)
4. Establish clean hydrogen & product certification scheme

INNOVATION

5. (Supply) Electrolyser technology improvements (e.g.faster ramping for alkaline and less scarse catalysts for PEM)

5. (Transport and storage) Development of rock caverns and depleted gas fields for large scale hydrogen storage

5. (Demand) Improve technological readiness of hydrogen use in heavy industry and liquid transport fuels (ammonia, synfuels)

Glossary

Abatement cost: The cost of reducing CO_2 emissions, usually expressed in US$ per tonne of CO_2.

Aggregators: New market players that can bundle the energy consumption or generation of several consumer-level electricity market actors (i.e. Distributed Energy Resources) to engage as a single entity – a virtual power plant (VPP) – and sell this flexibility (i.e. 'avoided' electricity consumption through temporary reduction in electricity consumption when there is high demand for electricity) or electricity (e.g. from behind-the-meter storage or distributed generation) in power or ancillary service markets.

Autothermal Reforming (ATR): A catalytic process in which natural gas reacts with oxygen to produce hydrogen and CO_2.

BECCS: A technology that combines bioenergy with carbon capture and storage to produce energy and net negative greenhouse gas emissions, i.e., removal of carbon dioxide from the atmosphere.

Behind-the-meter: A generation or storage system (e.g., rooftop solar PV, home batteries) which produces power on site at a commercial, residential, or industrial site, behind the utility meter.

BEV: Battery-electric vehicle.

Biomass or bio-feedstock: Organic matter, i.e. biological material, available on a renewable basis. Includes feedstock derived from animals or plants, such as wood and agricultural crops, organic waste from municipal and industrial sources, or algae.

Bioenergy: Renewable energy derived from biological sources, in the form of solid biomass, biogas or biofuels.

Capital expenditure (CAPEX): Monetary investments into physical assets (e.g., equipment, plants).

Carbon capture and storage or use (CCS/U): We use the term "carbon capture" to refer to the process of capturing CO_2 on the back of energy and industrial processes. Unless specified otherwise, we do not include direct air capture (DAC) when using this term. The term "carbon capture and storage" refers to the combination of carbon capture with underground carbon storage; while "carbon capture and use" refers to the use of carbon in carbon-based products in which CO_2 is sequestered over the long term (e.g., in concrete, aggregates, carbon fibre). Carbon-based products that only delay emissions in the short term (e.g., synfuels) are excluded when using this terminology.

Carbon emissions / CO_2 emissions: We use these terms interchangeably to describe anthropogenic emissions of carbon dioxide in the atmosphere.

Carbon offsets: Reductions in emissions of carbon dioxide (CO_2) or greenhouse gases made by a company, sector or economy to compensate for emissions made elsewhere in the economy.

Carbon price: A government-imposed pricing mechanism, the two main types being either a tax on products and services based on their carbon intensity, or a quota system setting a cap on permissible emissions in the country or region and allowing companies to trade the right to emit carbon (i.e. as allowances). This should be distinguished from some companies' use of what are sometimes called "internal" or "shadow" carbon prices, which are not prices or levies, but individual project screening values.

Circular economy models: Economic models that ensure the recirculation of resources and materials in the economy, by recycling a larger share of materials, reducing waste in production, light-weighting products and structures, extending the lifetimes of products, and deploying new business models based around sharing of cars, buildings, and more.

Combined cycle gas turbine (CCGT): An assembly of heat engines that work in tandem from the same source of heat to convert it into mechanical energy driving electric generators. Newer CCGT models can be compatible with a retrofitting process to enable the plant to switch from burning methane to burning hydrogen for power generation.

Contract for difference (CfD): A contract between a buyer and seller that stipulates that the buyer must pay the seller the difference between the current value of an asset (spot price) and a pre-determined fixed contract value (strike price). Where public actors act as the buyer this model can be used to cover the cost premium faced by green commodity producers deploying low-carbon technologies that are higher cost than traditional fossil technology. For example, CfDs have been used in the offshore wind industry where generators are reimbursed the difference between the fluctuating wholesale electricity prices and a fixed strike price, typically determined via a public auction. Under a 'two-way' CfD design, where the spot price rises above the strike price the winning bidder must pay back the differential.

Distributed Energy Resource (DER): Small and medium-sized power resources connected to the distribution network, including storage, distributed generation, demand response, EVs and their charging equipment.

Distribution System Operator (DSO): Emerging system operator capability to manage and optimise the transport of electrical power through the fixed infrastructure of a local distribution network. This includes procuring flexibility services from network users, managing local generation and network congestion, and managing flows of energy from and to the wider electricity grid, coordinating with the Transmission System Operator (TSO).

Decarbonisation solutions: We use the term "decarbonisation solutions" to describe technologies or business models that reduce anthropogenic carbon emissions by unit of product or service delivered though energy productivity improvement, fuel/feedstock switch, process change or carbon capture. This does not necessarily entail a complete elimination of CO_2 use, since (i) fossil fuels might still be used combined with CCS/U, (ii) the use of biomass or synthetic fuels can result in the release of CO_2, which would have been previously sequestered from the atmosphere though biomass growth or direct air capture, and (iii) CO_2 might still be embedded in the materials (eg, in plastics).

Direct air capture (DAC): The extraction of carbon dioxide from atmospheric air.

Direct reduced iron (DRI): Iron (so called "sponge iron") produced from iron ore utilising either natural gas or hydrogen. This DRI is then converted to steel in a second step called electric arc furnace (EAF). The DRI-EAF is an alternative primary steel production process enabling decarbonisation of the traditional coke-fired blast furnace/basic oxygen furnace (BF-BOF).

Electrolysis: A technique that uses electric current to drive an otherwise non-spontaneous chemical reaction. One form of electrolysis is the process that decomposes water into hydrogen and oxygen, taking place in an electrolyser and producing "green hydrogen". It can be zero-carbon if the electricity used is zero-carbon.

Embedded carbon emissions: Lifecycle carbon emissions from a product, including carbon emissions from the materials input production and manufacturing process.

Emissions from the energy and industrial system: All emissions arising either from the use of energy or from chemical reactions in industrial processes across the energy, industry, transport and buildings sectors. It excludes emissions from the agriculture sector and from land use changes.

Emissions from land use: All emissions arising from land use change, in particular deforestation, and from the management of forest, cropland and grazing land. The global land use system is currently emitting CO_2 as well as other greenhouse gases, but may in the future absorb more CO_2 than it emits.

Energy productivity: Energy use per unit of GDP.

Final energy consumption: All energy supplied to the final consumer for all energy uses.

Fuel cell electric vehicle (FCEV): Electric vehicle using a fuel cell generating electricity to power the motor, generally using oxygen from the air and compressed hydrogen.

Greenhouse gases (GHGs): Gases that trap heat in the atmosphere. Global GHG emission contributions by gas – CO_2 (76%), methane (16%), nitrous oxide (6%) and fluorinated gases (2%).

Heavy Goods Vehicles (HGV) or Heavy Duty Vehicle (HDV): Both terms are used interchangeably and refer to trucks ranging from 3.5 tonnes to over 50 tonnes.

High Voltage Direct Current (HVDC) transmission: A power transmission technology utilising direct current for the bulk transmission of electrical power. It is particularly useful for high capacities and longer distances due to minimal energy transmission losses compared to classical AC technology.

Hydrocarbons: An organic chemical compound composed exclusively of hydrogen and carbon atoms. Hydrocarbons are naturally occurring compounds and form the basis of crude oil, natural gas, coal and other important energy sources.

Internal combustion engine (ICE): A traditional engine, powered by gasoline, diesel, biofuels or natural gas. It is also possible to burn ammonia or hydrogen in an ICE.

Learning rate: The learning rate describes the cost decline for one unit (e.g., electrolyser) for each doubling of the total cumulative number of previously produced units.

Levelised cost of electricity (LCOE): A measure of the average net present cost of electricity generation for a generating plant over its lifetime. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of an electricity-generating plant divided by a discounted sum of the actual energy amounts delivered.

Liquified Natural Gas (LNG): LNG is the clear and non-toxic liquid state of natural gas at temperatures below -162ºC. It enables the transport and storage of natural gas without pressurisation, especially over longer distances via ships.

Natural carbon sinks: Natural reservoirs storing more CO_2 than they emit. Forests, plants, soils and oceans are natural carbon sinks.

Nature-based solutions: Actions to protect, sustainably manage and restore natural or modified ecosystems which constitute natural carbon sinks, while simultaneously providing human, societal and biodiversity benefits.

Near-total-variable-renewable power system: We use this term to refer to a power system where 85-90% of power supply is provided by variable renewable energies (solar and wind), while 10-15% is provided by dispatchable/peaking capacity, which can be hydro, biomass plants or fossil fuels plants (combined with carbon capture to reach a zero-carbon power system).

Net-zero-carbon-emissions / Net-zero-carbon / Net-zero: We use these terms interchangeably to describe the situation in which the energy and industrial system as a whole or a specific economic sector releases no CO_2 emissions – either because it doesn't produce any or because it captures the CO_2 it produces to use or store. In this situation, the use of offsets from other sectors ("real net-zero") should be extremely limited and used only to compensate for residual emissions from imperfect levels of carbon capture, unavoidable end-of-life emissions, or remaining emissions from the agriculture sector.

Operating Expenditures (OPEX): Expenses incurred through normal business operations to ensure the day-to-day functioning of a business (e.g., labour costs, administrative expenses, utilities).

Partial Oxidation (POX): A non-catalytic chemical process to convert hydrocarbon residues or natural gas with oxygen to hydrogen and carbon dioxide.

Power Purchase Agreement (PPA): A PPA describes the contractual obligations between an electricity generator and buyer. Typically, these contracts are used to guarantee long-term offtake security for the supplier prior to the construction of a new generation asset.

Proton Exchange or Polymer Electrolyte Membrane (PEM) electrolyser: A specific water electrolysis technology which operates under acidic conditions using a polymer to separate the electrodes.

Primary energy consumption: Crude energy directly used at the source or supplied to users without transformation – that is, energy that has not been subjected to a conversion or transformation process.

Steam methane reforming (SMR): A process in which methane from natural gas is heated and reacts with steam to produce hydrogen.

SMR/ATR/POX with carbon capture and storage (SMR/ATR/POX + CCS): Hydrogen production from SMR/ATR/POX, where the carbon emitted from the combustion of natural gas is captured to be stored.

Sustainable biomass / bio-feedstock / bioenergy: In this report, the term 'sustainable biomass' is used to describe biomass that is produced without triggering any destructive land use change (in particular deforestation), is grown and harvested in a way that is mindful of ecological considerations (such as biodiversity and soil health), and has a lifecycle carbon footprint at least 50% lower than the fossil fuels alternative (considering the opportunity cost of the land, as well as the timing of carbon sequestration and carbon release specific to each form of bio-feedstock and use).

Synfuels: Hydrocarbon liquid fuels produced from hydrogen, carbon dioxide and electricity. They can be zero-carbon if the electricity input is zero-carbon and the CO_2 is from direct air capture. Also known as "synthetic fuels", "power-to-fuels" or "electro-fuels".

Technology Readiness Level (TRL): Describes the level of matureness a certain technology has reached from initial idea to large-scale, stable commercial operation. The IEA reference scale is used.

Transmission System Operator: Existing system operator capability responsible for managing flow of electricity through the electricity transmission system, ensuring its stable and secure operation and matching demand and supply in time and space.

Virtual Power Plants (VPP): Aggregation of many disperse Distributed Energy Resources (DERs) with the aim of enabling DERs to provide services to the grid. VPP operators aggregate DERs to behave similar to a conventional power plant, with features such as minimum / maximum capacity, ramp-up, ramp-down, etc. and to participate in markets to sell electricity or ancillary services.

Zero-carbon energy sources: Term used to refer to renewables (including solar, wind, hydro, geothermal energy), sustainable biomass, nuclear and fossil fuels if and when their use can be decarbonised through carbon capture.

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