Climate Compatible Growth

GREEN HYDROGEN FOR DEVELOPMENT

AN ALTERNATIVE TO NATURAL GAS

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LIST OF ABBREVIATIONS

BNEF	Bloomberg New Energy Finance
CAGR	Compound annual growth rate
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
FCDO	Foreign, Commonwealth and Development Office
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWP	Global warming potentials
HFO	Heavy Fuel Oil
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCA	Life cycle assessment
LMIC	Low- and Middle-Income Country
LPG	Liquefied petroleum gas
MGO	Marine Gas Oil
PV	Photovoltaic
SMR	Steam methane reforming
VLSFO	Very Low Sulphur Fuel Oil

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EXECUTIVE SUMMARY

It is well accepted that hydrogen and its carriers, such as ammonia and methanol, will play a part in our future global energy system. Despite significant uncertainty in future hydrogen demand, one thing is clear: the use of hydrogen is set to increase.

A move to green hydrogen would reduce dependance on natural gas not only because it would remove the need for natural gas in grey hydrogen production, but also because it can offer a climate compatible alternative to fossil fuels in some use-cases.

In this report, we find that this could be anywhere between two- and eleven-fold relative to present day consumption [1–4]. Currently, almost all hydrogen is produced using fossil fuels, predominantly gas (e.g., grey hydrogen). Even blue hydrogen – which captures the CO_2 released during grey hydrogen production using carbon capture and storage (CCS) technology – cannot be considered net-zero due to inefficiencies in the CCS process and fugitive emissions during oil and gas extraction. In addition to reducing greenhouse gas (GHG) emissions, moving away from dependence on gas imports may be a popular political decision, considering the devastating war in Ukraine and rising, volatile gas prices. Therefore, there is an urgent need to change production of grey hydrogen to its green alternative. Green hydrogen offers a net-zero pathway to hydrogen. In this report we explore the techno-economic and geographic opportunities of green hydrogen from renewable electricity in the context of Low- and Middle- Income Countries (LMICs) and point to key research gaps.

To do this, we have reviewed current literature on: the opportunity for moving from grey to green (and blue) hydrogen production; the cost of production and potential to reduce cost in elements of green hydrogen (electricity, electrolysers) and reduce water-related constraints; relevant use-cases for green hydrogen, considering the costs of current alternatives; and geographical variations in supply and demand of green hydrogen. From this, the report answers a number of key questions as follows:

How does green hydrogen production compare to that of blue hydrogen?

As mentioned above, blue hydrogen cannot be considered net-zero. In addition, the cost of production is highly dependant on the cost of natural gas and the uncertainty around CCS deployment. Despite this, the major perceived challenge of green hydrogen is cost. In this report we show that according to Bloomberg New Energy Finance, in 2019, the price range of green hydrogen already overlapped with that of blue, although on average it was twice as expensive [5]. The cost of green hydrogen is forecast to fall in the future and expected to be consistently cost-competitive with blue hydrogen by 2030 and cheaper by 2050 [5]. Therefore, choosing blue over green hydrogen, based only on current costs, would be unwise for the long-term.

How will green hydrogen likely be used?

Green hydrogen (and its derivatives such as green ammonia, green methanol, and synthetic hydrocarbon fuels such as kerosene) can help eliminate GHG emissions in challenging sectors like fertilizer, steel, chemicals, long-haul transport, shipping, and aviation. Additional benefits of green hydrogen also include the potential for electricity system flexibility and storage, matching an increasingly renewable electricity supply to demand, which supports the further deployment of variable renewable energy. This could contribute to energy security and provide other socio-economic benefits such as economic growth and job creation. Fertilizer production, long-term energy storage, shipping, high-temperature industrial heat, and steel manufacture are highlighted in this report as sectors where green hydrogen is likely to play a significant role in decarbonization.

How can green hydrogen be cost-competitive with current day alternatives?

Although green hydrogen will soon be cost-competitive with blue hydrogen, this is not necessarily sufficient to encourage its use. The use of hydrogen in providing a service (for instance, shipping) must be cost-competitive with the input currently in use (in this instance, bunker fuel). Analysis in Section 4.2 has shown that, although green hydrogen or ammonia may be able to compete with the status quo by 2030 in use-cases such as fertilizer and shipping; for other use-cases the cost of this green alternative will need to be lower still. This is where carbon taxation comes in. If a carbon tax of 100 US$/t[1] were applied to emissions, green hydrogen would compete with fossil-fuels for the five deep-dive use-cases assessed in this report (fertilizer, long-term energy storage, shipping, high-temperature heat, and steel production – including reduction of the iron ore). This is a vital point when considering hydrogen with respect to development, as carbon prices are not uniform globally. In regions where carbon taxation exists, demand for green hydrogen is likely to accelerate faster as it reaches cost parity sooner.

Where geographically will green hydrogen be low-cost to produce?

Green hydrogen production requires plentiful renewable electricity and water. As such, geographical considerations are vital. As the cost of green hydrogen is largely dependent on the cost of renewable electricity, and the majority of the world's renewable resources (solar and wind) are in the Global South, there is great potential for cost-competitive green hydrogen production across many Low- and Middle-Income Countries [6]. However,

[1] *This is equivalent to 25¢ on a litre of petrol under current petrol prices (April 2022).*

it is these countries that also experience constraints on water resources. In such countries, two options can be explored for sourcing water without exacerbating water stress: seawater desalination and wastewater recovery. Both these options come at an additional, but manageable, cost.

In which regions will green hydrogen demand be greatest?

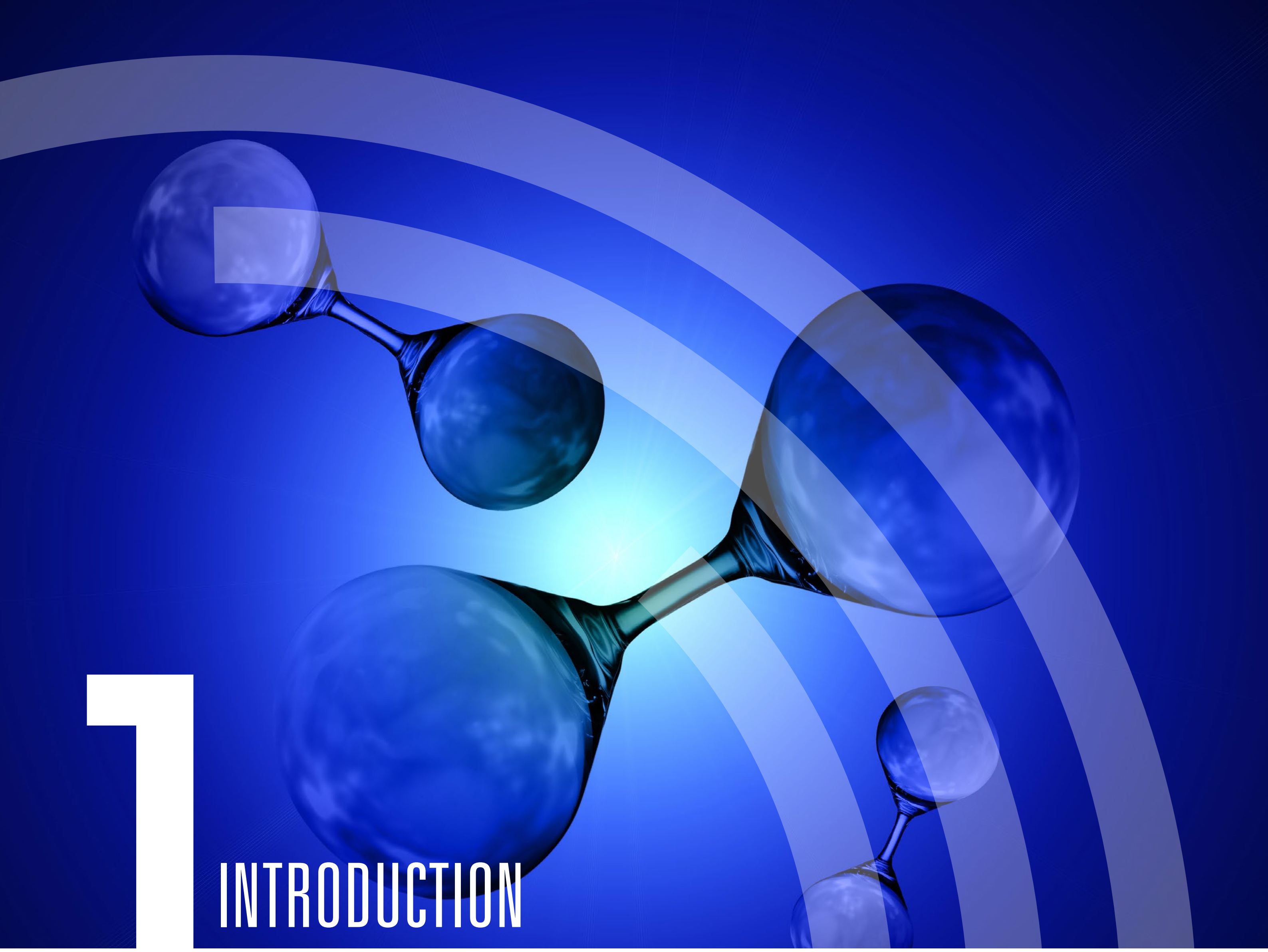
Demand for hydrogen will likely be significant in different regions depending on the use-case, but generally it will be needed in highly industrialized regions and those where the demand for long-term energy storage will be greatest in a net-zero world. These are regions such as the USA, Europe, China, South Korea, Australia, and Japan. Hydrogen demand is likely to be accelerated in countries where a carbon taxation is assisting green hydrogen in becoming economically viable for replacing fossil-based alternatives.

What are the trade implications?

Although nations within these regions may produce their own hydrogen to some degree, this demand does not always overlap with the cheapest supply; therefore, the international trade of green hydrogen (or ammonia) is inevitable. Trade partnerships are already forming between certain Global North and Global South countries such as Germany with Namibia and Chile, Japan with Brunei and Australia, and the Netherlands with Morocco [4]. Green hydrogen that is produced in agriculturally dependant economies could also be used in domestic markets to meet growing population demands for food and facilitate economic development.

What knowledge gaps need filling?

Knowledge gaps need to be filled to support the realization of a future green hydrogen economy. This report highlights that there is a need to understand (i) in which use-cases green hydrogen could gain market share; (ii) potential advancements in electrolysers to reduce the cost, extend the lifetime, and improve the efficiency, which in turn will reduce the electricity demand and cost of green hydrogen; (iii) where green hydrogen production may be constrained by freshwater resource and the cost, scale up, and waste disposal solutions of using sea or wastewater; (iv) which hydrogen carriers for long-term energy storage and distribution are most suitable and the mechanisms to overcome safety concerns; and (v) how the geography of green hydrogen production and demand may transform international trade, including the balance between domestic use and international export for producing regions.



1 INTRODUCTION

Globally, as we transition to net-zero, it is believed that hydrogen will play a key role in society. However, it is unclear what shape the net-zero transition will take, and the extent to which this will depend on hydrogen. To understand this, several important questions must be considered, including:

- How will hydrogen likely be used?
- How does green hydrogen production compare to that of blue hydrogen (cost and emissions)?
- How can green hydrogen be cost-competitive with current day alternatives?
- Where geographically will green hydrogen be low-cost to produce?
- In which regions will green hydrogen demand be greatest?
- What are the trade implications?

By reviewing the current literature, this report investigates each of these questions, highlighting uncertainty and knowledge gaps. Before doing so, a brief summary of current hydrogen demand scenarios is given next.

Demand scenarios

Interest in hydrogen has been gathering momentum, with investment expected to amount to US$500 billion by 2030 [7]. Just as with solar PV installation for energy, planned hydrogen projects appear to be significantly outstripping forecasts [7]. At present, hydrogen production is around 120 million tonnes (Mt) per annum (pa) and is predominantly used in industry for oil refining and ammonia production. Combined, these uses account for almost two-thirds of demand [1]. At present, it is not commonly used directly for energy generation.

In a net-zero scenario, we will not only need to replace the production pathway for hydrogen (e.g., grey hydrogen) with clean alternatives (e.g., green hydrogen) but also to understand future applications of hydrogen. The potential roles for hydrogen are broad and varied; they include, for instance, a clean pathway for steel manufacturing or an alternative net-zero fuel for heavy goods road transport or shipping. It may be used to produce greener fertilizers or support the power sector by acting as energy storage.

With many applications, and a range of potential policy scenarios, it is no wonder that the predicted future role of hydrogen is often varied. **Figure 1** gives a summary of forecasts by the International Renewable Energy Agency (IRENA), Bloomberg New Energy Finance (BNEF), the International Energy Agency (IEA), and the Hydrogen Council. These scenarios are further discussed next.

IRENA [1] forecast a modest demand for hydrogen by 2050 under their 'Transforming Energy Scenario', of 240 Mt pa. This is only double the present-day hydrogen production. In contrast, BNEF [2] offers one of the most ambitious forecasts. In their 'Green Energy Scenario', hydrogen demand rises to 1,320 Mt pa. This is eleven times greater than the production today. Under this scenario, hydrogen accounts for 22% (23,900 TWh

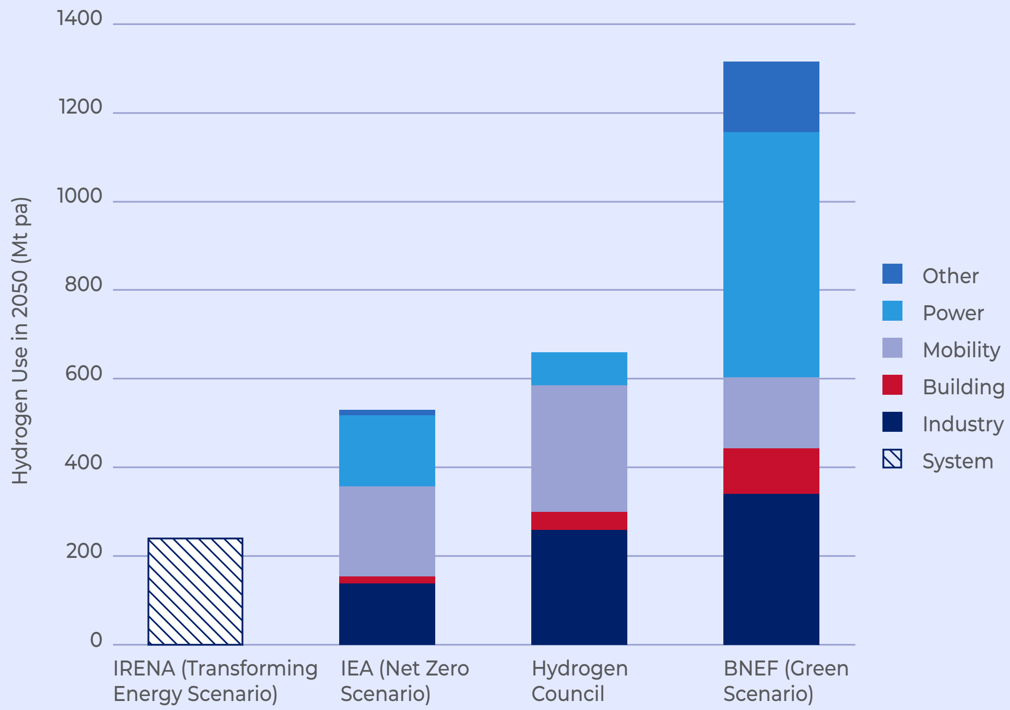


Figure 1
Forecasts of hydrogen demand in 2050
Data from references [1]–[4]

pa) of final energy consumption by 2050, compared to 0.002% today. This is a remarkable increase in the use of hydrogen as an energy vector. It is asssumed that hydrogen will be used for power, high-temperature heat in industry, aviation, shipping, road and rail transport, and in boilers for space and water heating.

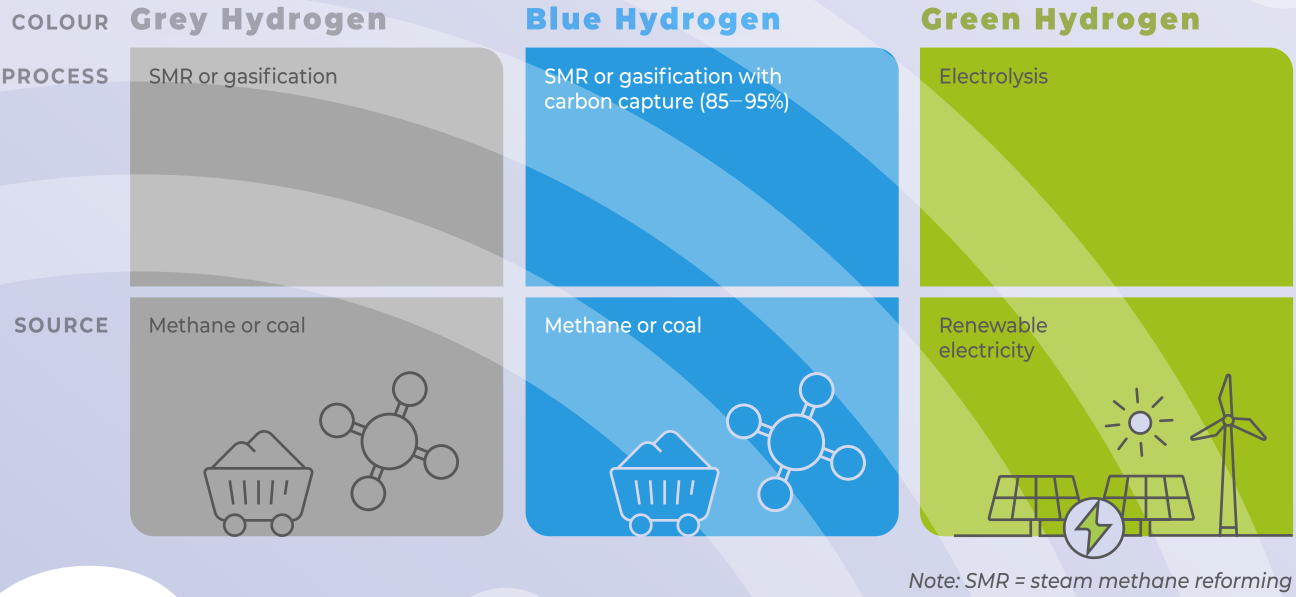
However, hydrogen could play a much wider role outside of the energy sector and could be used more commonly for fertilizer production (which currently requires 33 Mt pa [3]) or as a reducing agent in the steel industry (which is forecast to require 35 Mt by 2050 [4]), as is the case in the scenario by the Hydrogen Council [4]. Their scenario includes the use of hydrogen for fertilizer and steel production among other use-cases of mobility (including maritime and aviation), chemical feedstock (where fertilizer is included), power, industrial high-temperature heat, and space and water heating. Nevertheless, this forecast is half that of BNEF at 660 Mt pa by 2050. The main reason for such a difference is the inconsistency of the use of hydrogen for power in the analyses. BNEF forecasts a 553 Mt pa demand, 8.5 times greater than the demand forecast by the Hydrogen Council of 65 Mt pa.

The IEA [3] projects that by 2050 hydrogen demand will reach 530 Mt pa across uses of chemical feedstock (including fertilizer), reduction in iron and steel processing, some transport demand, space and water heating in buildings, power, and high-temperature heat in industry. Again, the discrepancy between this and the forecast of BNEF is in part due to a significantly lower estimated demand for hydrogen in the power sector of around 80 Mt pa. It appears that under this scenario BNEF has assumed hydrogen will conquer significant market share in many energy-related applications compared to other potential “green” alternatives.

Despite the range in forecast demand for hydrogen in the power sector, one thing is clear: the use of hydrogen is set to increase.

It should be noted that not all of this demand will be directly met by hydrogen (H_2), many of these use-cases will be undertaken by a hydrogen carrier, such as ammonia (NH_3) or methanol (CH_3OH). These require further chemical processing which comes with an additional ‘energy cost’ that can be offset by favourable properties such as ease of storage and transportation. The promise of the different hydrogen carriers will be discussed in more detail throughout the report and in particular in Sections 3.3 and 4.

Despite the range in forecast demand for hydrogen in the power sector, one thing is clear: the use of hydrogen is set to increase. In this section we have shown that this increase may be anywhere between two- and eleven-fold relative to present day production. Next, hydrogen production pathways are reviewed for their compatibility with net-zero (Section 2); the cost of production is considered (Section 3); and acknowledging the uncertainty in future demand outlined above, the likely uses-case of hydrogen are outlined (Section 4). Additionally, the geography of hydrogen production and demand is discussed (Section 5). All of this helps to identify knowledge gaps (Section 6).



2 HYDROGEN PRODUCTION

It is clear that hydrogen will play an important role in the future, but questions remain over how it will be produced. Although much of this will depend on cost, which is discussed in Section 3, the emissions from production are also a vital consideration in moving towards a net-zero energy transition.

2.1. THE HYDROGEN RAINBOW

Hydrogen is a colourless gas; however, because hydrogen can be produced by multiple processes and energy sources, a colour code nomenclature is becoming commonly used to differentiate between them. Although nowadays it is possible to find in the literature a rainbow of hydrogen colours, the most common are grey, blue, and green[2]. Their processes and sources are shown in **Figure 2** and are discussed below.

Grey hydrogen

Grey hydrogen is produced from fossil fuels by a hydrocarbon reformation technique involving steam and/or oxygen. Steam methane reforming (SMR) is the most common and is currently responsible for approximately three-quarters of all hydrogen production globally, due to the relatively low capital cost and the easy control of the chemical reaction [9,10]. Currently, 99% of hydrogen is produced

Figure 2
Selected colours of hydrogen.
Reproduced with permission from reference [8]

[2] The use of colours to define the level of carbon intensity, however, should be done carefully, especially since these colour-codes rely only on the production route, and there may be cases that do not fully fall under only one colour. To measure the impact of a certain route of hydrogen production a life cycle assessment (LCA) also needs to be considered.

using fossil fuels (90% grey and 10% blue) [3]. However, the use of grey hydrogen results in the release of a large amount of greenhouse gas emissions (153 g CO_2eq/MJ) [10]. This makes grey hydrogen unsuitable for a net-zero emissions economy.

Blue hydrogen

One option, namely blue hydrogen, is to capture the CO_2 released during grey hydrogen production and sequester it via carbon capture and storage (CCS) technology. However, there are huge uncertainties around the viability of this technology at scale. This avoids the direct CO_2 emissions from the process being released into the atmosphere; however, the method of extracting natural gas for hydrogen production also produces emissions (often referred to as fugitive emissions). Thus, the greenhouse gas emissions from blue hydrogen generation, although they are reduced compared to grey hydrogen, cannot be eliminated, as discussed further in Section 2.2. Moreover, the blue hydrogen production also incurs additional costs for CO_2 transport and storage and requires monitoring of the stored CO_2 [11,12]. CCS infrastructure may increase the total cost and decrease the efficiency of an SMR process by 5–14% [13].

Green hydrogen

Green hydrogen is the hydrogen produced from a 100% renewable source. For example, water can be converted into hydrogen and oxygen using an electrolyser and renewable electricity, a process known as water electrolysis[3]. Water electrolysis is a well proven process and can convert electricity to hydrogen at an efficiency of 60–80%. This green hydrogen production produces net-zero hydrogen, without requiring CCS, consistent with net-zero [12]. It must also be noted that a transition to green hydrogen will drastically increase demand for electricity. The International Energy Agency estimated that if all current dedicated hydrogen production were produced through water electrolysis, the demand for renewable electricity would be 3,600 TWh, which means more than the annual electricity generation of the European Union [3,8]. This is before increased demand for hydrogen is considered, which, as shown in the Introduction, could be up to eleven-fold by 2050. Although green hydrogen production via electrolysis was used at scale in the 1930s [14], green hydrogen represents only 1% of global hydrogen production today [3].

2.2. HYDROGEN EMISSIONS

To achieve a transition to net-zero, we must transition away from grey hydrogen. Often, the generation cost appears to be the main barrier to a decision to use green hydrogen but, to align with the Paris Agreement, production without emissions is vitally important[4] [10].

Blue hydrogen emissions occur at two stages: (a) direct emissions from SMR, and (b) fugitive emissions associated with oil

[3] There are other routes to produce green hydrogen, including biomass gasification and biomass pyrolysis, supercritical water gasification of biomass, thermochemical water splitting, and photocatalysis. But most of these processes are still in the Research & Development stage and present low conversion efficiencies. Thermochemical pyrolysis and gasification are economically feasible methods with great potential for large-scale applications in the near future. Biological methods are also a promising pathway but need further research to increase their productivity [11,19,105].

[4] When we discuss emissions in this section, we do not consider non-production embedded emissions, such as those from the production of solar panels.

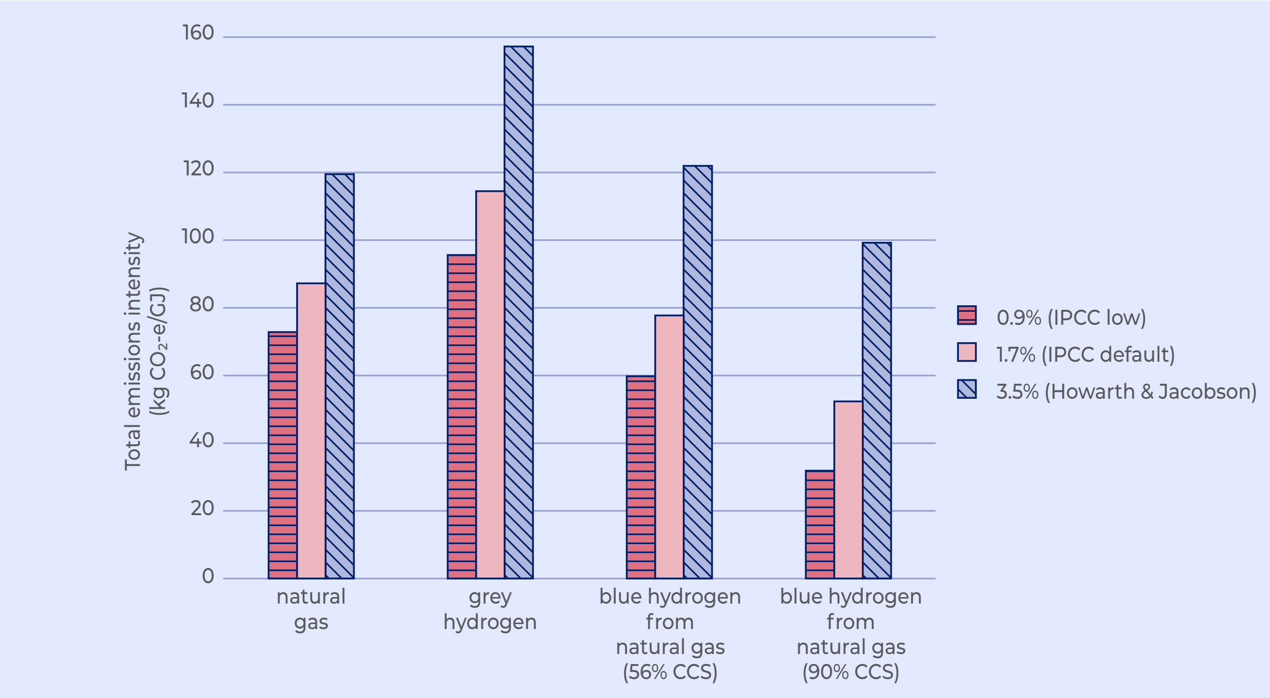


Figure 3 Total emissions intensities (including fugitive, process, and direct emissions) for natural gas compared to hydrogen produced from natural gas (grey and blue). Calculated for different methane leakage rates and using 20-year global warming potentials (GWP) for methane. *Data from Longden et al. 2022 [17].*

and gas extraction. Although the majority of (a) direct emissions, 70–90% [15,16], can be captured and stored through CCS, 10–30% of the CO_2 emissions escape into the atmosphere. To achieve net-zero, these emissions would require direct air capture of CO_2, which is an expensive technique [17,18]. Fugitive emissions (b) usually result from the methane released during fossil-fuel extraction; these cannot be completely avoided. This is especially detrimental as methane is a powerful greenhouse gas (GHG), responsible for approximately 25% of the net global warming in the last decades [9,10,13,19]. In addition, it is unlikely to be viable to capture methane from the air through direct air capture in the manner which can be adopted for CO_2 [20].

Figure 3 presents the total emission intensities for natural gas and hydrogen produced from natural gas (grey and blue) in 2022 [17][5]. Emissions from blue hydrogen could be substantial even if 90% of the direct CO_2 emissions are captured. And, when assuming a high fugitive rate of methane emission (3.5%) and 90% CCS, the blue hydrogen emissions (99 kg CO_2eq/GJ) are only 17% less than burning natural gas directly with no CCS (119 kg CO_2eq/GJ). Furthermore, with these assumptions, the greenhouse gas emissions of blue hydrogen are slightly greater than burning natural gas, if only 56% of CCS were applied. It is noteworthy that fugitive emission rates of over 3% have been observed in USA gas fields [17]. These analyses demonstrate that even with the process of carbon capture, hydrogen from fossil fuels will always have significant emission intensities. This means that, although blue hydrogen could slightly reduce greenhouse gas emissions, it is not compatible with achieving the net-zero objective.

In this section we have shown that blue and grey hydrogen have high emissions associated with them, and therefore producing green hydrogen through electrolysis driven by renewable energy is the only viable option compatible with net-zero [21].

[5] The values were calculated for different fugitive emission rates (IPCC: 0.9 and 1.7%; and Howarth: 3.5%) and a 20-year global warming potential (GWP) of 86 for methane. Please note that there is much debate surrounding the most appropriate GWP value to use when calculating CO_2eq values. Using a 20-year timeframe instead of a 100-year timeframe emphasizes the importance of methane as a GHG. This is deemed appropriate in this instance where urgent action is needed by 2050 to avoid detrimental temperature rises [9].

3 THE COST OF HYDROGEN

Emissions alone are not the only criteria when considering production of hydrogen and technology adoption. Cost is a vital criterion[6].

3.1. BLUE AND GREEN HYDROGEN COST

Green hydrogen produced using electricity from a typical variable renewable energy is currently 2–3 times more expensive than grey hydrogen [8], but already the price range of green hydrogen overlaps with that of blue hydrogen, although it can be twice as expensive [5]. Furthermore, an IRENA [12] report shows that up to 85% of green hydrogen production costs can be reduced in the long-term by combining low-cost renewable electricity, low electrolyser capital costs, and a high number of operating hours, making green hydrogen cost-competitive with fossil-based hydrogen. Another point that should also influence the relative cost of green hydrogen in the future – as compared to fossil-fuel alternatives – is policy action, including regulatory frameworks and financing mechanisms, such as incentives, carbon pricing, and green bonds.

As grey hydrogen is far from net-zero compatible, the comparison here is between blue and green. For blue hydrogen, the price is in the range of 1.4–3.4 US$/kg, depending on the source [5]. Green hydrogen is slightly costlier in most places, at a range of 2.5–4.5 US$/kg [5]. As a benchmark, grey hydrogen from natural gas costs between 0.5–1.7 US$/kg [3].

[6] It should be noted that this paper was written during the 2022 Russian invasion of Ukraine. This has had and will continue to have significant impacts on gas prices around the world. Though the specific effects on gas prices are beyond the scope of this paper, we recommend that further work be undertaken on researching what the mid- to long-term effects of the conflict will be on the relative prices of gas and thus on the cost of blue and grey hydrogen.

For both grey and blue hydrogen, the price is largely dependent on the natural-gas price. Over the past years, the price of natural gas has been rising; compounded by the recent war in Ukraine, gas prices in Europe and the UK has reached a record levels [22]. Blue hydrogen costs are also affected by the cost of implementing and operating the CCS facilities, which remain uncertain; and increasing focus on CCS is risky, as it is currently not viable at scale. Furthermore, since CCS cannot remove all emissions from the process, direct air capture or a carbon price should be factored into the cost of blue hydrogen.

Without incorporating the recent uncertainty surrounding gas prices, **Figure 4** presents an estimation of future cost trends for green and blue hydrogen, based on estimations from BNEF data [5].

In this section we have shown that the cost of producing green hydrogen is forecast to fall in the future and that it will likely be consistently cost-competitive with blue hydrogen by 2030 and cheaper than blue hydrogen by 2050. Therefore, choosing blue over green hydrogen based only on current costs would be unwise for the long term. In the section that follows, we further discuss the cost structure of green hydrogen to identify factors and intervention points which could accelerate cost reduction and reduce constraints on its production.

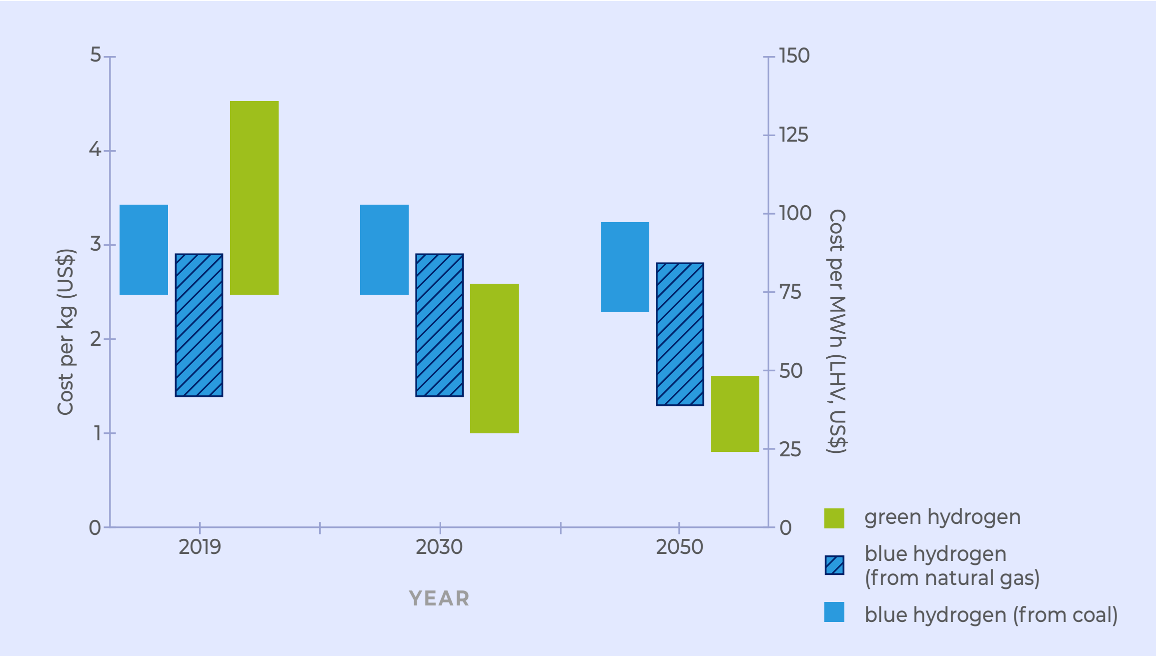


Figure 4. Estimation of future hydrogen costs for different pathways. Note: renewable hydrogen costs based on large projects with optimistic projections for capital expenditure. Natural gas prices range from US$1.1–10.3/MMBtu, coal from US$30–116/t. *Adaption of BNEF data, 2020 [5].*

3.2. THE COST STRUCTURE OF GREEN HYDROGEN

Several technical and economic factors are responsible for determining how much it costs to produce green hydrogen from water electrolysis, but the most pertinent are electricity costs and the capital cost of electrolysers [23]. The largest cost component is that of the renewable electricity needed to power the electrolyser unit. Currently, this represents around 30–60% of the cost of green hydrogen production [21,24,25]. The second greatest cost is that of the electrolysers, which currently comprises 33–45% of the cost. Other cost components such as water, labour, land make up the remainder of the overall cost. As water is a necessity for green hydrogen production it will be discussed in the sections below along with the cost of electricity and electrolysers.

Cost of electricity

Green hydrogen production does not require constant power, making it compatible with renewable energy as it can utilize renewable energy generation when available. For green hydrogen to reach price parity with blue hydrogen (current pricing), it is thought that the price of renewable energy needs to be around 20 US$/MWh, if all other prices were to remain the same [24]. This is quite possible, following the 80% and 40% cost reductions in solar and wind over the last decade, respectively [8]. The average cost of energy for solar PV installations was 57 US$/MWh in 2020. The cost is projected to reach between 20–80 US$/MWh by 2030 and 14–50 US$/MWh by 2050. For wind, the equivalent numbers are an average of 39 US$/MWh (2020), decreasing to 30–50 US$/MWh (2030) and 20–30 US$/MWh. This shows that the threshold value of 20 US$/MWh needed to make renewable energy cost competitive is possible. For comparison, the range price of fossil fuels in 2020 is 55–148 US$/MWh [26–28].

To ensure that green hydrogen supply cost is as low as possible, however, a holistic approach needs to be applied to system design and operations. The variability of energy supply (i.e., constant consumption of grid electricity, or direct feed from variable solar or wind farms) and the hydrogen demand need to be optimized to minimize the costs [12]. Running the electrolysis during a period of oversupply from variable renewables has low costs, but often the number of hours during which this surplus occurs is low. For the hydrogen production cost to be lowered, electrolysers should have a higher utilization rate, which is not compatible with low availability of otherwise curtailed electricity. A balance needs to be struck between buying electricity at times of low prices and increasing the utilization of electrolysers [29]. Consequently, it is also necessary to reduce the cost of electrolysers and improve their efficiency so that less electricity is required. This is discussed in the next section.

Cost of electrolysers

Electrolyser[7] costs are often given as cost per unit of power needed for electrolysis (US$/kW). To lower the cost of hydrogen by modifying the electrolyser one can (a) decrease the cost of the electrolysers, for example by reducing use of rare and expensive materials, (b) increase the efficiency, so that the demand for electricity is reduced, and (c) improve lifetime and durability of the electrolyser, so that the cost per unit of hydrogen is reduced. Since 2010, electrolyser costs have fallen 40% due to technological progress (to a range of 500—1000 US$/kW) and there is potential for further reducing the costs in the coming years [12,24].

[7] There are four types of water electrolyser that are used to create green hydrogen: alkaline, polymer electrolyte (PEM), anion exchange membrane (AEM), and solid oxide cells (SOEC). Alkaline is the most developed and commercialized process (61% of installed capacity in 2020), with PEM being the next most mature technology with growing commercialization (31%) [3]. AEM and SOEC are still in the pilot/development stage and are not expected to be commercialized before the mid-2020s [8,12]. Each one of these technologies has its own advantages and challenges in terms of performance, durability, and maturity; and as incentives, competition, and innovation continue, one may become a front-runner. Therefore, this assessment of electrolyser cost is technology agnostic.

A final consideration is that increasing the plant size reduces the electrolyser balance of system costs per unit of hydrogen. For example, a 1 MW alkaline electrolyser capacity could cost 1,060 US$/kW compared to a cost of 450 US$/kW for 100 MW capacity, half the relative price [12]. However, as the capacity is greater, the investment will be significantly more, and financing challenges may need to be considered.

To demonstrate the forecast reduction in cost, learning curve forecasts for electrolyser scale-ups range from 9% to 21%, with an average estimation of 18%, 15%, and 12% by IRENA, IEA, and the Hydrogen Council, respectively. It is possible to misestimate learning rates. With solar PV [30], learning rates were underestimated, and if the same were to be the case for electrolysers, actual cost decline could happen faster, accelerating the competitiveness of green hydrogen.

Through cost reduction and efficiency improvements, the electrolysers could achieve cost reductions of about 40% for a 100 GW global installed capacity (likely by 2030) or a 55% cost reduction for a 270 GW global installed capacity. This could bring green hydrogen costs below the 2 US$/kg mark [8]—a crucial milestone for cost competitiveness. In the long term, where 1,700 GW of electrolysis is deployed by 2050, the cost reduction could be over 80% [12].

The potential for electrolyser cost reduction depends on the combination of manufacturing scale, learning rate, technological improvements, and increased module size [31]. And for that, innovation is crucial. Governments can drive further innovation in electrolysers by supporting ongoing research and development, facilitating investments, establishing regulations, and designing markets that support investments in innovation and help scale up the production.

Research and development is necessary to reduce costs and improve efficiencies of electrolysers

In summary, there is uncertainty surrounding which electrolyser technologies will dominate and what prices will be achieved. Research and development is necessary to reduce costs, extend lifetimes, and improve efficiencies of electrolysers, which could have a significant impact on green hydrogen reaching cost competitiveness in the near future.

Cost of water

In addition to energy and electrolysers, producing green hydrogen requires water. The water consumption rate for electrolysis is 9 kgH_2O/kgH_2 [16][8]. If the entire 2050 hydrogen demand were satisfied with green hydrogen, the water consumption would be about 21 billion m^3. To put this into context of other sectors, agriculture consumes 1,080 billion m^3 of water, and the fossil-fuel energy production and power generation industry consumes 31 billion m^3 of water [32].

[8] This is less than blue hydrogen demands, which are between 13–18 kgH_2O/kgH_2 [3]

99% of the planet's water is seawater, which can be purified through a desalination process, such as reverse osmosis, before being used in the electrolysis process.

As climate change continues to put strains on freshwater sources (25% of the world's population do not have access to freshwater [16]), there are two main viable options for sourcing water without putting additional strain on current freshwater resources: seawater desalination or wastewater recovery. Irrespective of the source, the input water to an electrolyser stack must first be cleaned and deionized [16].

99% of the planet's water is seawater, which can be purified through a desalination process, such as reverse osmosis, before being used in the electrolysis process. While the purity level required varies depending on the technology, desalination by reverse osmosis would require less than 0.2% of the minimum energy needed for the electrolysis process. This would add an energy cost of 0.53—1.50 US$/m³ of clean water produced, an addition of no more than 0.01 US$/kg to the cost of hydrogen production [32]. In addition to desalination, it is also necessary to deionize the water to avoid impurities that could have an impact on the lifetime of the electrolyser. The cost of this process depends on the purity level required, but still has a low impact on the overall cost of green hydrogen production [12]. The brine effluents produced by desalination plants, however, are salt-rich and may contain dangerous pre-treatment chemicals, organics, and heavy metals. Their disposal can affect the local marine environment. To reduce this, before the brine is discharged back into the ocean it may be diluted with seawater, oxygenated with green oxygen, and "mined" to recover minerals [16]. The brine treatment, to reduce its environmental impact, will increase the cost of the water by another 0.6—2.4 US$/m³ [33]. Desalination of seawater for industry but not for locals in regions where access to clean water is challenging may raise equity questions; thus, upscaling of desalination plants to provide for local communities may be considered. This could offer benefit to the surrounding community. Direct use of seawater currently leads to corrosive damage and to the production of chlorine, but scientists are already researching new ways to make it easier and feasible to use seawater directly in electrolysis in the future [34–36].

Another option is to use wastewater (urban and industrial) as a source of water for green hydrogen. This can be purified and deionized as described above. More recently, scientists have been investigating the possibility of new technologies using wastewater that will simultaneously produce green hydrogen and clean the water at the same time [37]. However, although the idea sounds promising, it has not yet been developed on an industrial scale and presents low rates of hydrogen. With incentives and proper investments, this type of

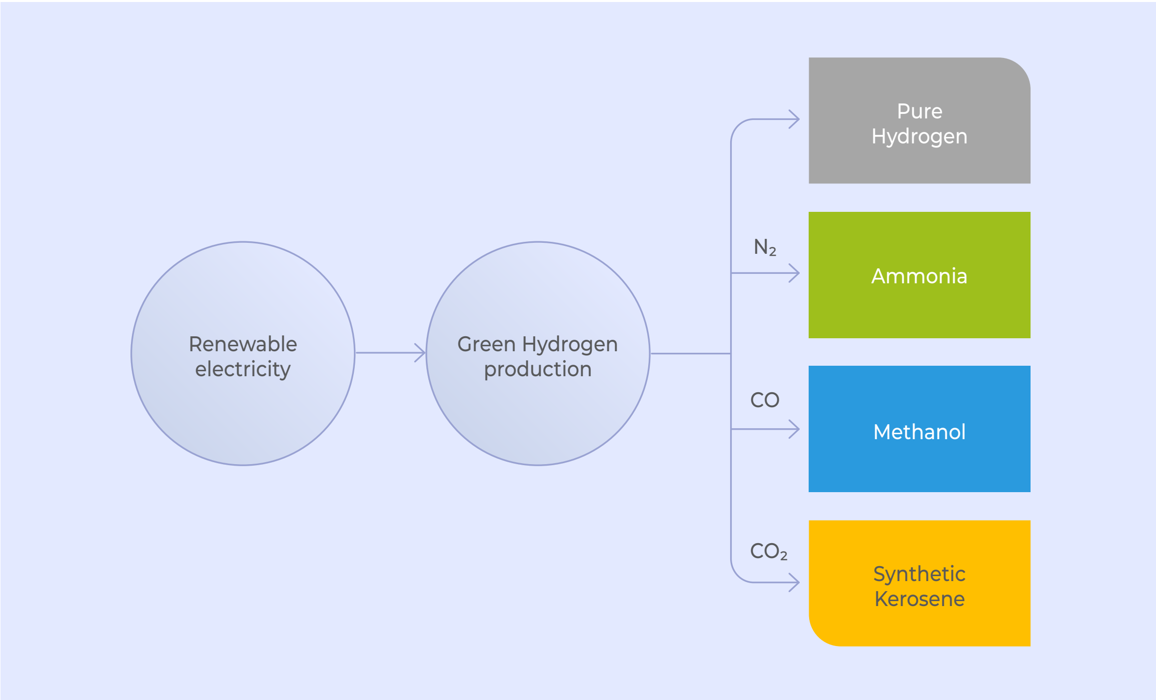


Figure 5 The various hydrogen carriers. *Data from references [1,3,38]*

technology has the potential to create a circular economy and help society to achieve long-term sustainable goals.

3.3. COST OF OTHER HYDROGEN CARRIERS

When discussing the use of green hydrogen, it is usually considered in its pure or "bare" form. But it can also be utilized via hydrogen-based derivatives such as ammonia, methanol, and, to a minor extent, synthetic kerosene (shown in **Figure 5**).

These uses can increase the future demand for hydrogen, assisting with economies of scale and learning rates, which will decrease costs in the green hydrogen value chain [8]. Ammonia and methanol produced from green hydrogen are also known as green ammonia and green methanol, respectively.

Ammonia and methanol production currently accounts for most of the industrial use of hydrogen, with a demand of 46 Mt, nearly 40% of the total 120 Mt produced in 2020 [3]. At present, green ammonia costs 400–2000 US$/t [23], but is projected to reduce to 400–850 US$/t in 2025–2030, with a further decrease to 275–450 US$/t in 2040–2050 [39]. This is two or three times more expensive than the current price of grey ammonia (200–450 US$/t [39]). In contrast, green methanol (640–1750 US$/t) is currently six to seven times more expensive than grey methanol (100–250 US$/t) [40]. This additional cost is because green methanol also requires CO_2 for the reaction. With an increase in the demand in the short to medium term and a decrease in green hydrogen prices, by 2030, the prices of green methanol are expected to fall to 240–580 US$/t if the cost of CO_2 feedstocks are 100 US$/t [40].

Currently, around 185 Mt of ammonia are produced annually [41] with about 80% being used as a fertilizer and the remainder for various industrial applications [42]. With rising efforts to decarbonize across economic sectors the use of ammonia as an energy carrier and chemical feedstock is becoming increasingly important. In addition to its traditional uses, ammonia holds great potential for long-term energy storage and shipping, as outlined in a Royal Society report of 2020 [43]. The IEA forecasts that the additional demand from the power sector and shipping would call for ammonia production of over 550 Mt pa by 2050 [41].

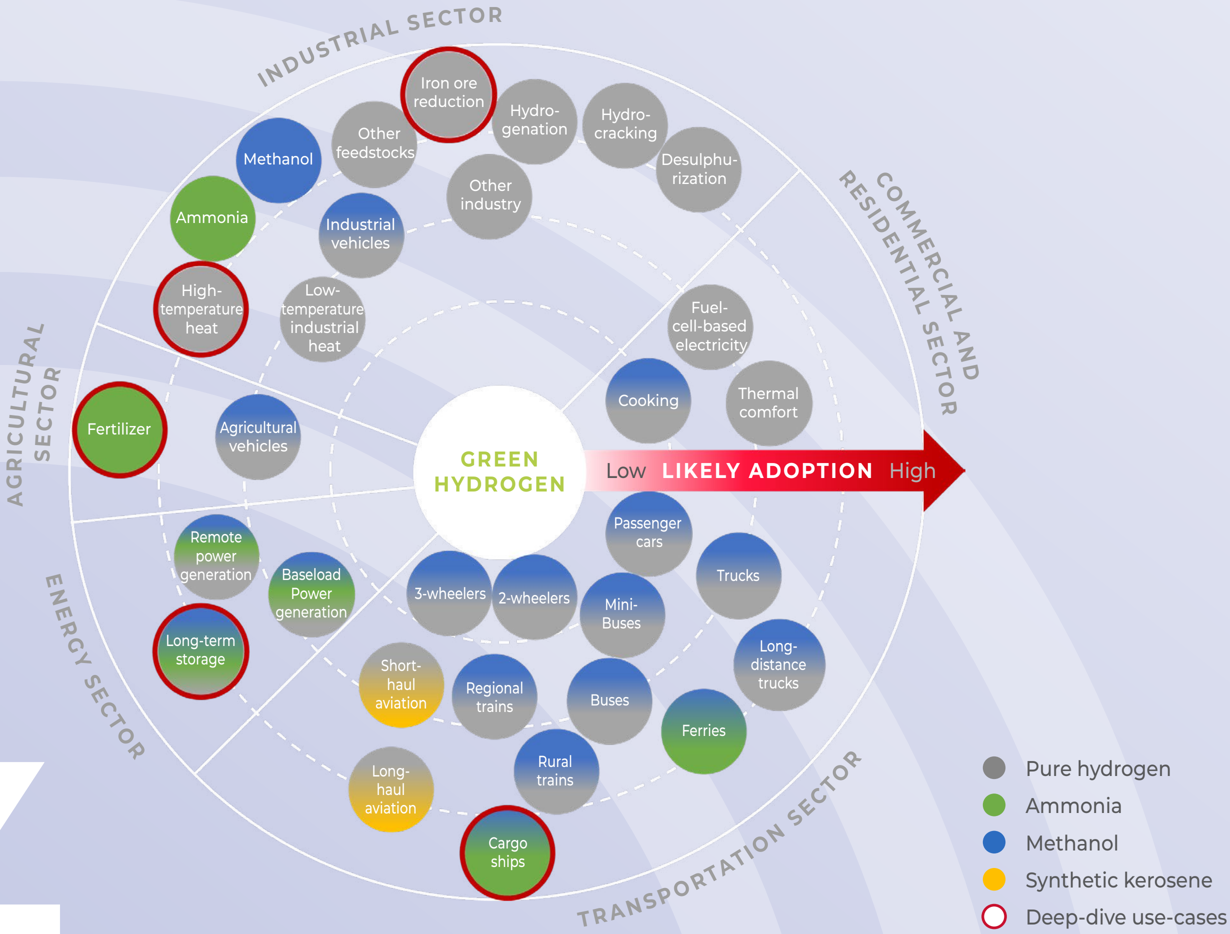
Green ammonia and methanol could play a key role in decarbonizing important sectors of the economy

The second hydrogen derivative is renewable methanol. It is currently used in the chemical industry with an annual demand of approximately 100 Mt [1]. However, in a net-zero world, it may play a role in the transportation sector, with demand potentially increasing 5-fold by 2050, reaching 500 Mt pa, according to IRENA's Transforming Energy Scenario [40].

Synthetic kerosene (or synthetic paraffinic kerosene) is a synthetic fuel produced from green hydrogen and a sustainable carbon source especially designed to replace fossil jet fuels or biofuels. In contrast to electric propulsion with batteries or fuel cells, synthetic fuels have a significantly higher energy density and do not require expensive technological changes. Unlike biofuels they do not face the challenges of land use for feedstock growth and competition with food crops. The main disadvantage of synthetic kerosene is the current price which is nearly 12 times higher than that of fossil-based jet fuels [1].

Green ammonia and methanol could play a key role in decarbonizing important sectors of the economy, but this will only be an option with the decrease of green hydrogen prices and increase of incentives.

In summary, the price of green hydrogen and therefore its derivatives is highly dependent on the price of electricity. However, the price of renewable electricity is expected to continue to fall. Further research is needed surrounding electrolysers to reduce use of rare materials, improve efficiency (to reduce electricity consumption), and increase lifetime. Water may need to be sourced from seawater and wastewater—these solutions and their co-benefits require more research, and are especially relevant to water-stressed regions.



4 FACILITATING USE OF GREEN HYDROGEN

Figure 6 The potential hydrogen use-cases and hydrogen's likely adoption for each

The potential use-cases for hydrogen are many and varied. In this section, the likely adoption of hydrogen (or its derivatives) is considered across different use-cases, and for several specific use-cases the cost of green hydrogen is compared to that of the traditional input.

4.1. HYDROGEN USE-CASES

In the transition to a zero-carbon future, green hydrogen and its renewable derivatives are likely to play a significant role across various economic sectors and use-cases. However, it is still unclear for which applications hydrogen (or its carriers) will prevail. This will of course depend on technical viability of other solutions and (if competition exists) the cost of this competition. Certain use-cases where hydrogen will likely be used are already emerging [44].

Figure 6 depicts the various use-cases of hydrogen by five sectors: agricultural, commercial and residential, power, industrial, and transportation. Definitions of the use-cases and examples are available in the Appendices. From reviewing the literature, the figure also indicates the likelihood of hydrogen (or a hydrogen carrier) being adopted to meet this need, taking into consideration the alternatives that could enable the varying use cases. These use cases must be considered within the wider system. The importance of green hydrogen will increase in the future, and in some cases will need to be deployed to those use cases that have no current alternative option for achieving net zero. The colours indicate which form of hydrogen is likely to be used.

Some important highlights from each sector are outlined below.

Agricultural sector

The agricultural sector has only two potential applications for green hydrogen identified so far. In a low-carbon future, agricultural vehicles may be equipped with fuel-cells or powered by methanol. But the competition with conventional fuels or battery driven vehicles is still strong. In contrast, the use of green hydrogen in fertilizers is extremely promising not to say unavoidable when a zero-carbon future is pursued [45].

Nitrogen-based ammonia fertilizers already account for half of global fertilizer use, reaching a demand of 152 Mt in 2020 [42]. This demand has not reached saturation, as it will increase with population growth and economic development. For example, in 2017 the average use of fertilizer per hectare of cropland in Africa was estimated to be around 15 kg while at the same time in Europe and South-East Asia the application of nitrogen fertilizer was around four times greater (52 kg and 61 kg per hectare of cropland respectively) [42,46,47]. If sustainable fertilizer were to become more affordable, it is inevitable that demand would increase.

Research into the potential geographical growth in demand for fertilizer if prices were to fall would be valuable in assessing the future market size. This will be impacted by food systems more generally and should be considered in the context of a potential shift to alternative proteins.

Commercial and residential sector

Recently, several projects across various countries have been launched to blend hydrogen into the natural gas network for use in boilers and cooking appliances. According to the UK's Energy Networks Association, the country will be able to blend up to 20% into the national gas grid by 2023. Safety concerns and the need for infrastructure upgrades surround the integration of higher concentrations of hydrogen into the gas network. Existing boilers and gas pipelines would need to be retrofitted, which can only be justified by a switch to 100% hydrogen [23,48,49].

Because of the need to overcome safety challenges, a switch to pure hydrogen may require changes to be made by the government and regulatory bodies

Because of the need to overcome safety challenges, a switch to pure hydrogen may require changes to be made by the government and regulatory bodies [49]. Furthermore, hydrogen boilers are low efficiency compared to heat pumps and face competition as a residential heat supply [50,51].

In China methanol is already replacing kerosene and LPG in various cook stoves ranging from small household applications to industrial kitchens [52]. For Low- and Middle-Income countries

(LMICs), there is the possibility of using hydrogen as a replacement for traditional cooking fuels [52–54].

However, again, there are safety concerns and mechanisms to overcome these require more investigation.

It remains unclear how safety concerns would be overcome should governments deploy hydrogen for domestic use (e.g., cooking), or whether other technologies will outcompete. Until strategies to ensure safety in different environments have been well researched and trialled, it will be challenging to conduct demand and economic assessments of these use-cases or to make informed political decisions.

Power sector

Hydrogen or ammonia may be used for power generation or energy storage. Green hydrogen has potential as a long-term energy store, and it is one of the few viable solutions for such storage [31,55]. The storage of hydrogen is cheaper at scale and can be done in salt caverns and other suitable underground stores, providing a renewable energy 'lung' for the entire energy system [15]. When the stored hydrogen is needed it can be used in combined cycle gas turbines (CCGTs) or fuel cells. To date, hydrogen-powered turbines are still being researched, but strong efforts are being made to drive them purely on hydrogen [56]. Fuel cells are especially interesting for remote and back-up power generation due to their scalability and expected decline in capital costs. The main drawback of all the aforementioned power-to-gas-to-power routes is the poor round-trip efficiency of around 45% [23,31,48]. The distribution of hydrogen can pose difficulties in handling due to its low volumetric density. To overcome this, it can either be compressed or liquefied. Both are capital and energy intensive [57]. The third option is to process hydrogen into ammonia [58,59]. The energy requirements for each of these transformations are shown in the Appendices.

Green hydrogen has potential as a long-term energy store, and it is one of the few viable solutions for such storage

There is debate regarding whether ammonia or hydrogen is the most appropriate medium for hydrogen storage [59], and more research is needed. A summary of the energy consumption for transition into various mediums can be found in the Appendices.

Transportation sector

While annual sales for battery electric vehicles are increasing rapidly, hydrogen powered fuel-cell electric vehicles have not yet made a breakthrough. This is despite the fact that the market potential for urban vehicles is large and anticipated to grow by over 600 million vehicles over the next 10 years due to increasing mobility in LMICs [23]. Currently hydrogen-powered vehicles are significantly more expensive than battery electric vehicles and offer comparatively low round-trip efficiencies. This includes not just passenger cars but all light-duty vehicles, like 2-and-3 wheelers, minibuses, and urban trains, where direct electrification has substantial advantages.

In contrast, when it comes to long-distance transport in remote regions and areas with less infrastructure in place, fuel-cell powered vehicles offer various advantages. They have higher power capabilities and are less dependent on battery capacities or electricity access [23,44,50,60]. Ballard and Siemens are working to replace regional and commuter diesel-powered trains with hydrogen fuel-cell trains which can achieve similar distances and refuelling times [61].

The global maritime sector is currently almost entirely reliant on fuel oils such as Very Low Sulphur Fuel Oil (VLSFO), Marine Gas Oil (MGO), and Heavy Fuel Oil (HFO), accounting for 5% of global oil demand and 2.5% of global energy-related CO_2 emissions [48]. Efforts are being intensified to investigate various alternative fuel technologies since batteries and hydrogen-powered fuel cells are unlikely to be suitable [62]. Green ammonia offers a promising low-carbon alternative. Additionally, because it is already traded globally, infrastructure for distribution is already in place [23,62,63]. The Global Maritime Forum [64] considers ammonia to be the primary decarbonization fuel for achieving the International Maritime Organization's target of reducing shipping emissions to 50% by 2050 [65]. However, as ship's engines can last 30 years, this transition needs to begin soon. By 2030, 6% of all ocean-going vessels are expected to run on clean hydrogen-based fuel [4].

This year, Airbus has publicly announced their intention to pursue hydrogen as an aviation fuel, and start-ups are appearing in this space

Like the maritime sector, the aviation sector is also characterized by a steadily growing fuel demand and significant CO_2 emissions. A large part of those emissions is caused by long-haul flights, over 1,500 km, which makes them especially challenging for decarbonization pathways. This is in contrast to short-haul flights where electric propulsion offers certain advantages in terms of lower maintenance requirements. Potential solutions are either biofuels derived from biomass or hydrogen derived synthetic e-fuels (i.e., synthetic kerosene). As both technologies are in their early stages, production is limited and costs are still high. This year, Airbus has publicly announced their intention to pursue hydrogen as an aviation fuel [66], and start-ups are appearing in this space [67,68].

Uncertainty surrounds whether hydrogen will be suitable to meet the needs of long-haul aviation. The lower energy density of hydrogen poses a particular challenge. Further research into overcoming this is necessary.

Industrial sector

Hydrogen is already used in several industrial processes and chemicals [44]. It is the main feedstock in methanol and ammonia production as well as for other chemicals, serving as a base chemical to manufacture several daily life products [40].

Hydrogen is also a manufacturing agent for several industrial processes. One of the largest applications is the desulphurization and hydrocracking in oil refining which accounted for around 40 Mt H_2 demand in 2020 [48]. This, of course, is not net-zero compatible, and the demand is forecast to decline to zero by 2050 [51].

Hydrogen may also be used in fuel-cell powered industrial vehicles, including mining trucks, excavators, and forklifts [69].

One often discussed use-case of hydrogen within the industrial sector is industrial heat provision. It can be divided into low-to-medium temperature heat up to 400°C or high-temperature heat, which often exceeds 1,000°C. At present, these heating needs are often met by burning fossil fuels such as coal or gas; however, hydrogen offers a suitable clean alternative to provide heat and is especially vital in meeting high-temperature needs in a climate compatible fashion [31,70].

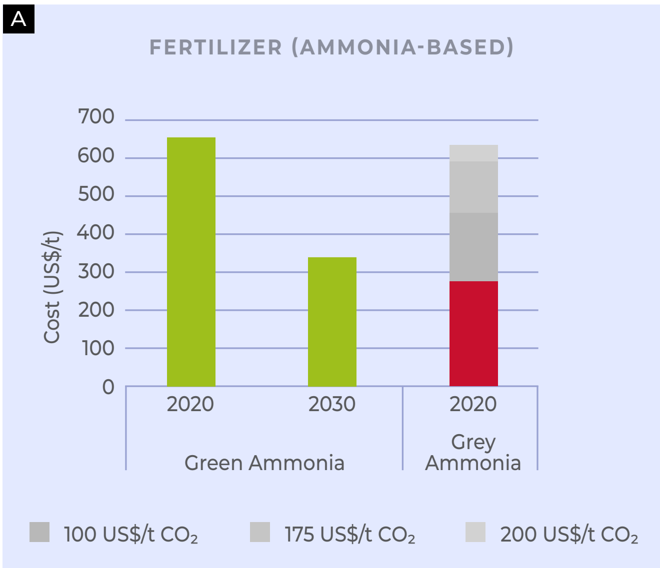
Another promising application of green hydrogen is the reduction of iron ore in steel production. The demand for steel in 2016 was 1,600 Mt with around 400 Mt being recycled steel [71]. While it is expected that by 2050 around half of the total demand of produced steel will be scrap steel, demand will still climb up to 2,800 Mt [71]. The Swedish joint venture "HYBRIT" is currently developing an emission free production route in which hydrogen gas is used as the main reductant. In the described process, hydrogen reacts with iron oxides to form water instead of carbon dioxide. While the process is still in its development phase, the joint venture aims to begin demonstrations by 2025 [71,72].

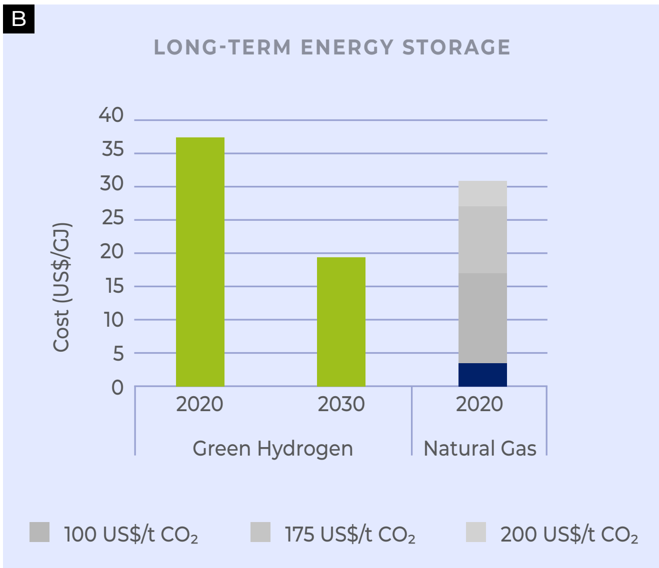
In addition to the previously mentioned use-cases, green hydrogen is also seen in various other industrial niche applications, for example use as a manufacturing agent for semiconductors or glass, the cooling of industrial generators, or in hydrogenation processes of fats [73,74].

For many of these applications, especially those where hydrogen is used in manufacturing an internationally traded good with tight margins, the uncertainties surround the economics of using hydrogen instead of current inputs. The next section provides an overview of cost-comparisons for five deep-dive use-cases, but more detailed research and analyses are needed into each specific use-case, considering cost as well as regional carbon prices, emission targets, and policies.

4.2. COST COMPARISON OF USE-CASES: TRADITIONAL VS GREEN HYDROGEN

Having considered different hydrogen use-cases within five sectors, five distinct use-cases are selected for further consideration – fertilizer, long-term energy storage, shipping, high-temperature heat, and steel production – where the cost of hydrogen is compared to the cost of the conventional input. Although hydrogen is likely to play a major role in these use-cases due to its suitability and net-zero credentials, it will need to outperform its fossil competitors on price. This is especially challenging due to the well-established production and supply





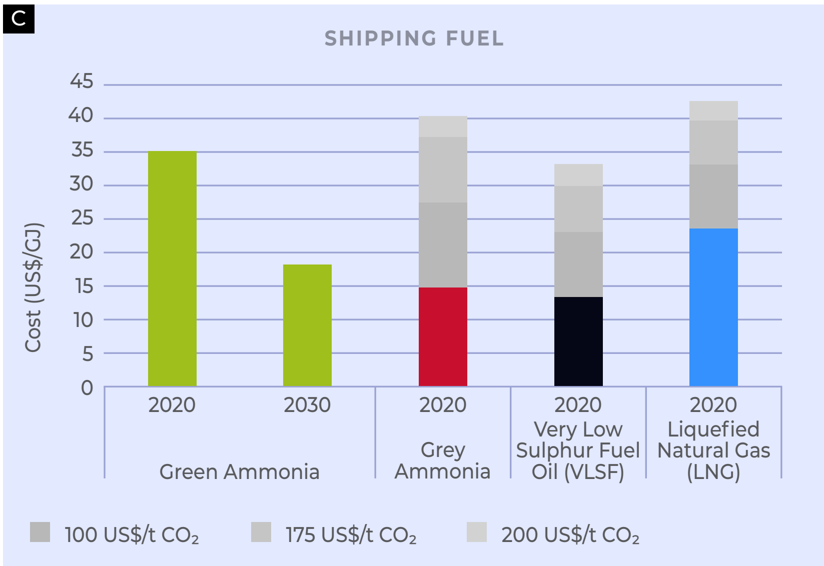
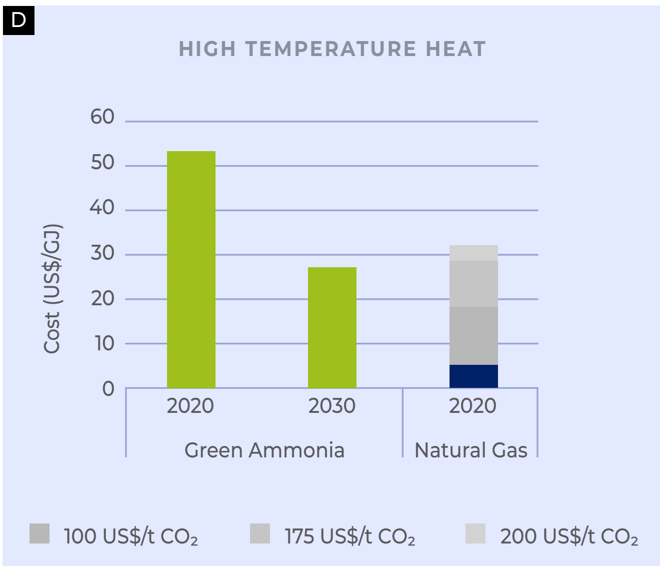
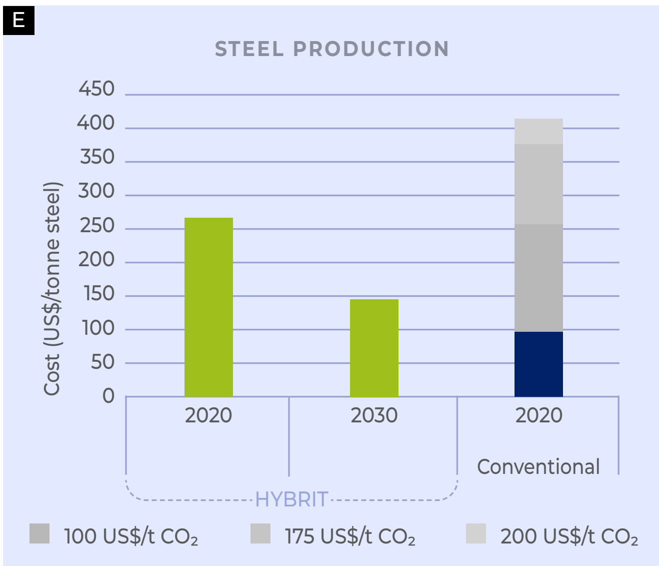


Figure 7 Cost comparison between conventional fossil-based inputs and green hydrogen or ammonia at different cost points for a) fertilizer, b) long-term energy storage, c) shipping fuel, d) high-temperature heat, e) steel production. *Details of assumptions and inputs in the Appendices.*





chains of coal, oil, and gas. The following cost analyses between hydrogen or its derivatives for our selected use-cases and the most established competitor are conducted on an economic level (shown in **Figure 7**), based on simple assumptions of present and future fuel prices[8]. While there may be geographic variations in green hydrogen prices (discussed in Section 5), the average prices for green hydrogen in each use-case are used. As the current cost of the fossil fuels does not include the externalities from GHG emissions (i.e., the costs associated with the damage that greenhouse gases cause), in this assessment we consider three levels of carbon price: 100 US$/t CO_2, 175 US$/t CO_2, and 200 US$/t CO_2. Carbon prices are already applied in 45 countries, across different sectors, and have increased from covering 5% of emissions in 2010 to 22% in 2021 [75]. Some economies, such as Sweden, Lichtenstein, and Switzerland already utilize carbon prices over 100 US$/t CO_2 [75]. The carbon prices used in this analysis were selected to reflect future carbon prices and to demonstrate the prices necessary to incentivize a shift away from the status quo towards green hydrogen or ammonia.

From Figure 7 it is evident that, to date, green hydrogen is not (in general) economically competitive with its fossil alternative in any of the five selected use-cases. Current commercial electricity prices of 50 US$/MWh result in a green hydrogen cost of 4.5 US$/kg [76] and green ammonia cost of 650 US$/t [39], which are too high to be financially competitive (at least in the absence of a carbon price on emissions).

From Figure 7 (a) and (c) it is evident that by 2030 green ammonia for fertilizers and shipping fuel will likely be near cost parity with grey ammonia. Other green hydrogen use-cases will struggle to compete at the 2030 price level. However, a carbon tax of 100 US$/t would mean that for all the use-cases, by 2030, green hydrogen or ammonia would be roughly cost competitive or, in most cases, favourable. If a carbon tax of 175 US$/t were implemented, price parity would be achieved even earlier. In order for this to be effective and for countries not to be disadvantaged by domestic carbon taxes and remain competitive on the global market, there is a need for a border carbon tax.

Carbon pricing would transform the economics of green hydrogen and ammonia use by encouraging a switch to these clean fuels. In doing so the progress to lower cost production would be accelerated, thus beginning a positive cycle. Countries with an appropriate carbon price will be the first to adopt green hydrogen, which could strongly influence geographical demand.

Carbon prices are already applied in 45 countries, across different sectors

Mapping regional plans to increase carbon prices (across sectors relevant to hydrogen demand) would facilitate analysis of the rate of hydrogen demand in different regions, and assist with understanding a suitable scale-up rate for production as well as identifying the form of hydrogen required (i.e. hydrogen, ammonia, methanol).

5 GEOGRAPHICAL OVERVIEW

Due to the economic dependence of green hydrogen on the price of renewable energy, production will be more favourable in certain regions compared to others.

Conversely, applications and demand will vary in different economies and regions. This section will look at the possible geospatial supply and demand of hydrogen carriers for three use-cases – ammonia for fertilizer production, long-term energy storage, and shipping – as the demand for all three is non-uniform globally.

5.1. VARIED GLOBAL SUPPLY

As mentioned in Section 3, a significant share of the green hydrogen production costs can be linked back to the electricity generation costs. Countries with low-cost renewable energy potential could therefore become supply hubs and export hydrogen to other regions. This is already happening with countries such as Morocco being identified as promising suppliers of green hydrogen for Europe [77].

Solar photovoltaics (PV) and onshore wind power, along with hydropower, are the cheapest renewable energy sources. They are also relatively quick and capital-efficient to set up [26]. Green hydrogen generation projects will therefore most likely be powered by wind or solar power. The highest PV potential is around the equatorial climate belt, at high altitudes, and in other sun-intensive regions, such as Australia and Africa [78]. Areas located close to the coast and the North and South Pole as well as

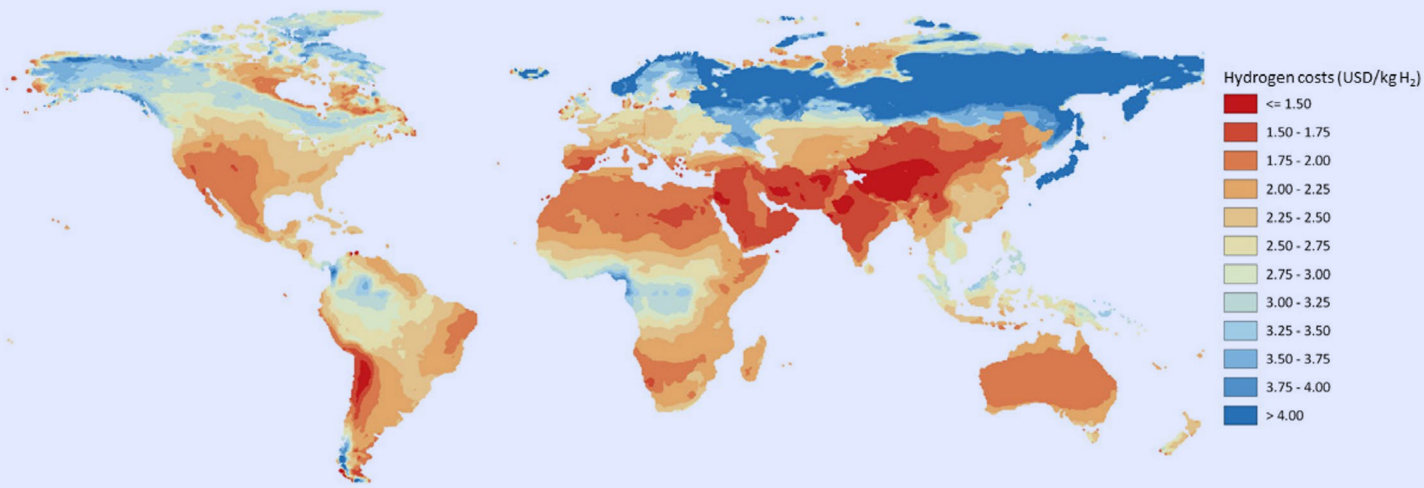


Figure 8 Forecast green hydrogen production costs from solar and onshore wind in 2030. Red indicates lower cost of green hydrogen and blue higher cost. *From reference [48]*

desert regions show the greatest wind energy potential [79]. In fact, Africa holds 45% of the world's renewable energy potential [80]. The mid-term (2030) green hydrogen production costs through the utilization of wind and solar energy are shown in **Figure 8**.

Figure 8 highlights the dramatic difference in price of green hydrogen expected across different regions of the world. Africa, the Middle East, Australia, South-East Asia, and the southern regions of South America are able to produce green hydrogen at the lowest cost and are thus likely to become major producers of the cheapest green hydrogen [48]. Green hydrogen is already competitive today in specific regions with favourable conditions for low-cost renewable energy. For example, in Patagonia, wind energy could achieve a capacity factor of almost 50% with an electricity cost of 25–30 US$/MWh, which means a green hydrogen production cost of around 2.5 US$/kg [12].

However, production is not technically limited to these regions. For example, in Norway, which has comparatively low potential for cheap green hydrogen production (Figure 8), Yara and Linde Engineering have announced a 24 MW green hydrogen plant to supply green ammonia for fertilizer [81]. This means that green hydrogen production need not suffer the same fate as gas production, where supply is geographically limited and there are a few powerful suppliers meeting global demand and offers prospects of re-shaping geopolitics of energy trade in the future. Instead, green hydrogen could be produced locally in any region where there is renewable energy potential, and the economics of production are the only factor. Thus, it may be financially advantageous to produce hydrogen in regions where renewable electricity is cheap.

Access to water (fresh, sea, or waste) will need to be considered in planning hydrogen production. As discussed in Section 3.2, the cost of desalinating and purifying seawater should not be prohibitive; therefore access constraints will be the greatest concern, for example access to seawater in the case of land-locked countries. A water strategy will need to be developed in each instance. Further research into water sources (such as sea and waste) are needed to develop such strategies.

While many countries in the Global North – such as the UK, Germany, Norway, and the Netherlands – have produced hydrogen strategies for the future (see Appendices for detailed table), several countries in the Global South have also been implementing projects and strategies. An overview of some selected ongoing operations can be drawn from **Table 1** [82], which demonstrates that production is already evolving in low-cost renewable geographies.

5.2. REGIONAL DEMAND

In general, it can be expected that hydrogen demand will build upon the current economic sectors of a region. For example, areas which depend on agriculture will require hydrogen for ammonia and thus fertilizer production; countries in need of long-term energy storage to achieve net-zero (due to their geographical location and risk of windless winter weeks) will require hydrogen carriers; and shipping routes will need to be served by low-carbon hydrogen-based fuels. The geographical variation of these three use-cases is considered.

Ammonia for fertilizer production

Today, 80% of the 180 million tonnes of ammonia produced per annum is used for fertilizers [7]. By transitioning from conventional to green ammonia, it would be possible to save 1.8 tonnes of CO_2 per tonnes of ammonia. Considering the fertilizer industry alone, this would offer a saving of almost 260 million tonnes of CO_2 per annum [41].

As population growth continues and more stress is placed on harvests through the effects of climate change, a rise in demand for fertilizer is likely. The map in **Figure 9** shows the dependence of GDP on agriculture for different regions, as well as those regions' share of global agriculture by value.

From Figure 9, it is evident that the world's biggest share of agriculture by value is found in North America, Europe, Central Asia, and the East Asia and Pacific Region.

Table 1 Selected ongoing hydrogen projects in Global South Countries

NATION	STATE OF PROJECT	PROJECT
Egypt	Realized	Installation of > 100 MW Electrolysis
Zimbabwe	Realized	Installation of > 100 MW Electrolysis
Mauritius	Project outline	Development of 16 GW electrolysis with 45 GW renewable energy
Namibia	Project outline	Development of 3 GW electrolysis with 5 GW renewable energy
Chile	Project outline	Aims to be among top H_2 exporters by 2040 (Target: 5 GW of electrolysis by 2025, 25 GW by 2030)
Morocco	Project outline	H_2 a key growth sector: By 2030 4 TWh for local market and 10 TWh for export market
South Africa	Project outline	10 GW of electrolysis deployed by 2030 and 15 GW by 2040

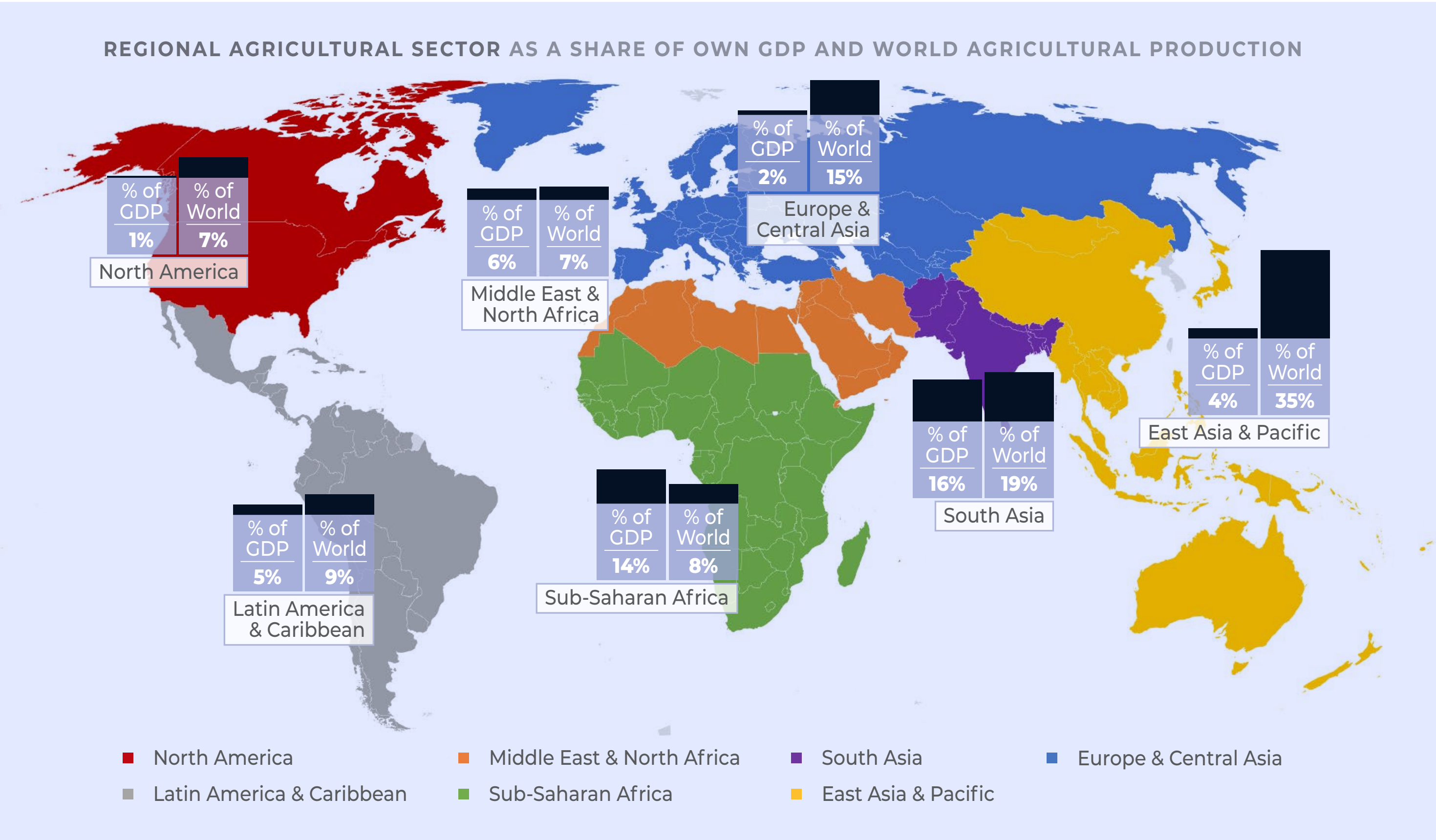


Figure 9: Regional agricultural sector importance, *using data from World Bank [83]*

Therefore, in the near term, the absolute highest demand for ammonia in terms of fertilizer production will likely be in those regions. However, economic dependence on agriculture is significant in the Middle East, North Africa, Sub-Saharan Africa, and South Asia, where agriculture accounts for 6–16% of GDP, as shown in **Figure 9**. In these areas the relative importance of green hydrogen-based fertilizers will therefore be much higher and will likely grow in the future. These are also the regions where population growth is expected to accelerate most significantly in the coming decades [84], driving a domestic demand for fertilizer.

Generally, the whole fertilizer market will grow in the coming years. The fastest increase in the five upcoming years is expected in the Asia-Pacific region with a compound annual growth rate (CAGR) of ~6.9 % followed by Africa with a CAGR of ~5.1 %, which indicates that, especially in LMICs, a significant rise will be seen [85].

Hydrogen for fertilizer production will likely be one of the domestic uses of hydrogen produced in LMICs. If there is a significant price differential between the export market price for green hydrogen and the domestic market price, this may result in domestic needs being neglected in favour of higher export prices. Research into the forecast international market price for hydrogen will assist in understanding the likely dynamics of domestic versus export markets for LMICs. Analysis of the potential economic and social impact of retaining hydrogen for domestic use in fertilizer may be valuable for governments to understand the true value of green hydrogen.

Long-term energy storage

Long-term energy stores are currently mostly prominent in countries located in the Global North, which have big industries that are reliant on stable and secure energy supply. Large capacities can be found in North America, Europe, Japan, South Korea, India, Chile, and Japan. However, in a net-zero future, demand for long-term energy storage will expand to meet the needs of extreme weather events such as windless winter weeks and, in some instances, variation in seasonal demand. According to the Long Duration Energy Storage Council and McKinsey, the global energy capacity for long-term energy storage is forecast to be between 80–135 TWh in 2040 [86]. Depending on the cost development of other storage technologies, hydrogen will meet 23–47 % of this demand (i.e., 18.4–63 TWh) [86]. This demand varies by region globally depending on weather events, country policies, and energy demand profiles. The likely demand for long-term energy storage in certain regions by 2040 is shown in **Figure 10**.

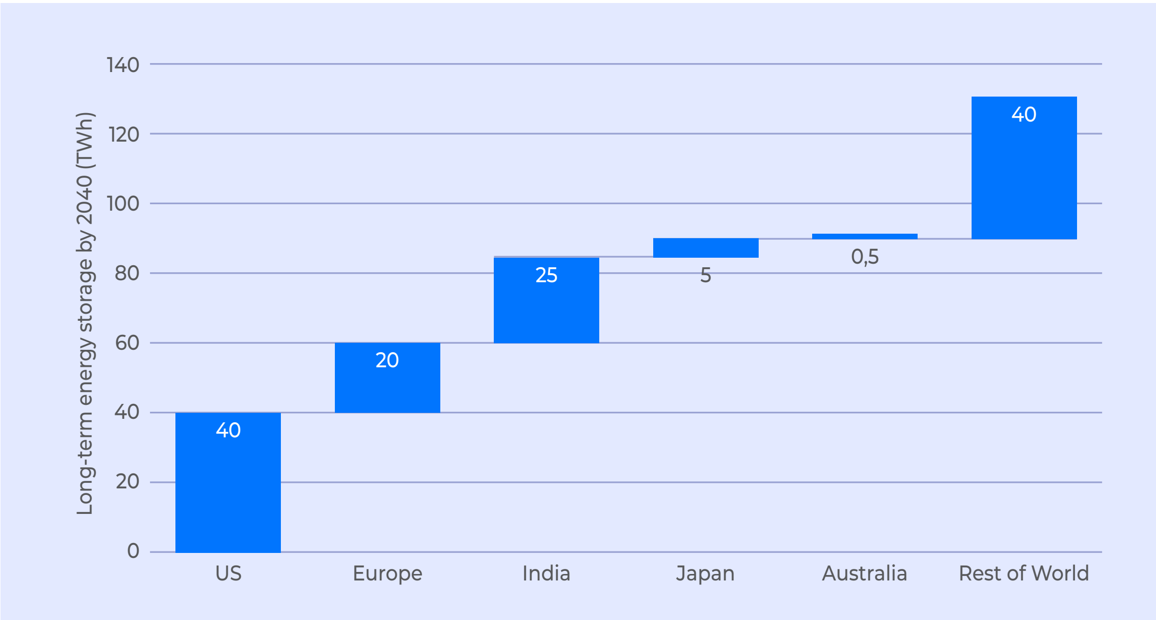


Figure 10 Forecast long-term energy storage requirements in different world regions by 2040. *Data from reference [86]*

Figure 10 shows that the demand for long-term energy storage varies drastically by region. The fact that the USA, Europe, and India together require nearly twice as much storage as the rest of the world combined, demonstrates this large discrepancy.

There is limited information available on the requirements for long-term energy storage globally, and this results in geographical demand uncertainties for this use-case. Certainly, many High-Income Countries will require significant long-term storage in the form of green hydrogen or ammonia, but further research is required to quantify how much long-term energy storage will be needed, how much the country is likely to produce in-house, and how much it will hope to import. The Royal Society is due to publish such a report on large-scale energy storage in the UK later this year.

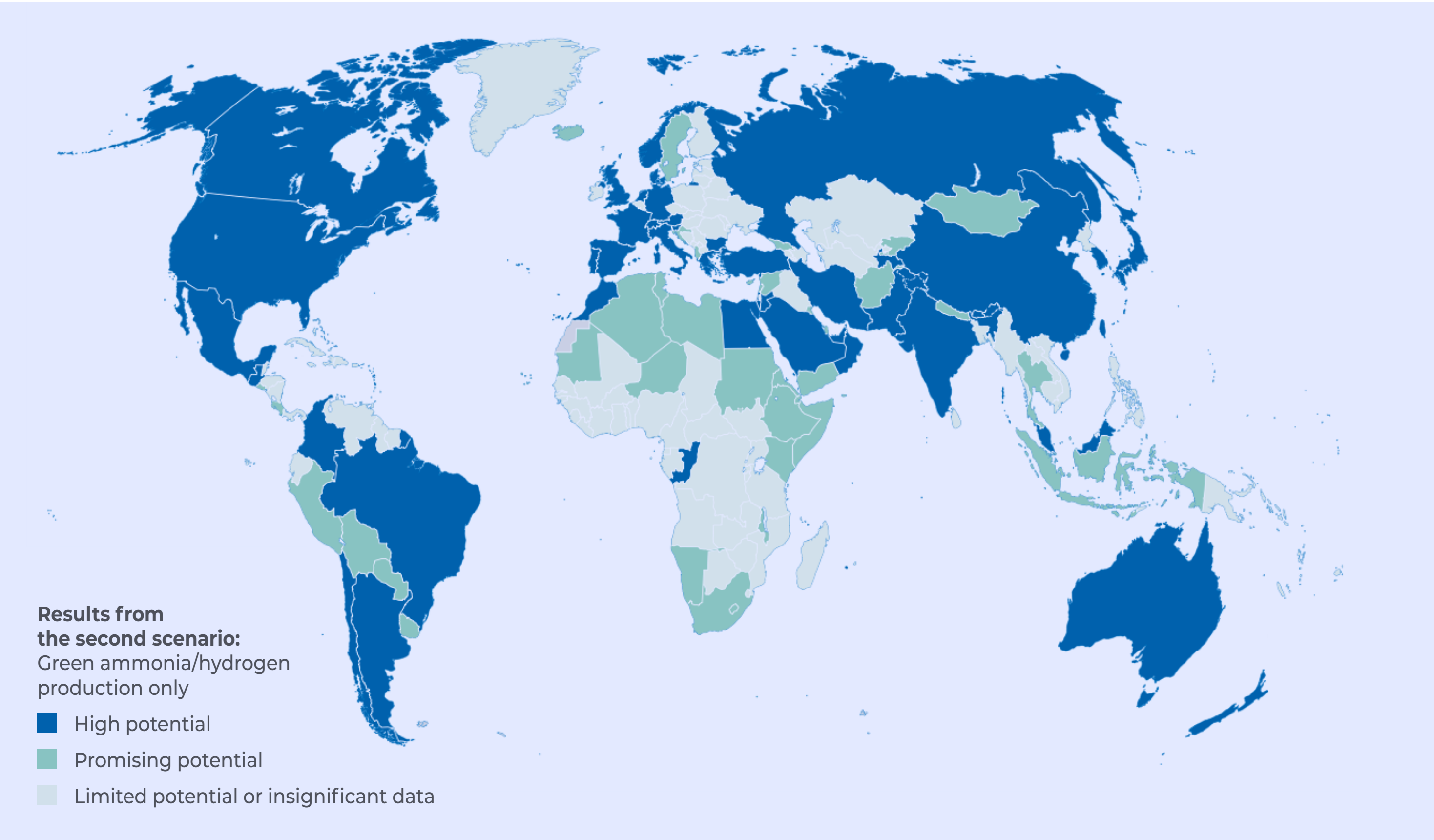


Figure 11 Potential for countries to produce green ammonia for shipping. *From reference [87].*

Ammonia for shipping

The demand for ammonia to fuel container ships will predictably follow the set routes of the global maritime trade market and can therefore be mapped towards the most important harbours around the world. In a recent report, the World Bank designed a metric to evaluate the potential of countries to become producers of zero-carbon bunker fuel [87]. The results of their analysis for green ammonia and hydrogen production are shown in **Figure 11**.

The results shown in this map are heavily influenced by the proximity to shipping activitiy: in other words, fuel demand.

Another solution for supporting a transition to cheap green ammonia fuel for shipping includes wind-powered ammonia plants at sea [88]. This facilitates the use of surplus wind energy and prevents the need to transport the ammonia or for the ship to dock at port to refuel. But the feasibility of this is not well understood.

5.3. IMPLICATIONS FOR TRADE

Given the geographical mismatch between cheap hydrogen supply and expected demand, hydrogen trade and investment flows will contribute to new bilateral trade agreements [82]. Several trade partnerships have already been established connecting demand centres with areas of low-cost hydrogen production. These existing and planned trade routes are shown in **Figure 12**. Note that these trade relationships are related to hydrogen in general, not only green hydrogen.

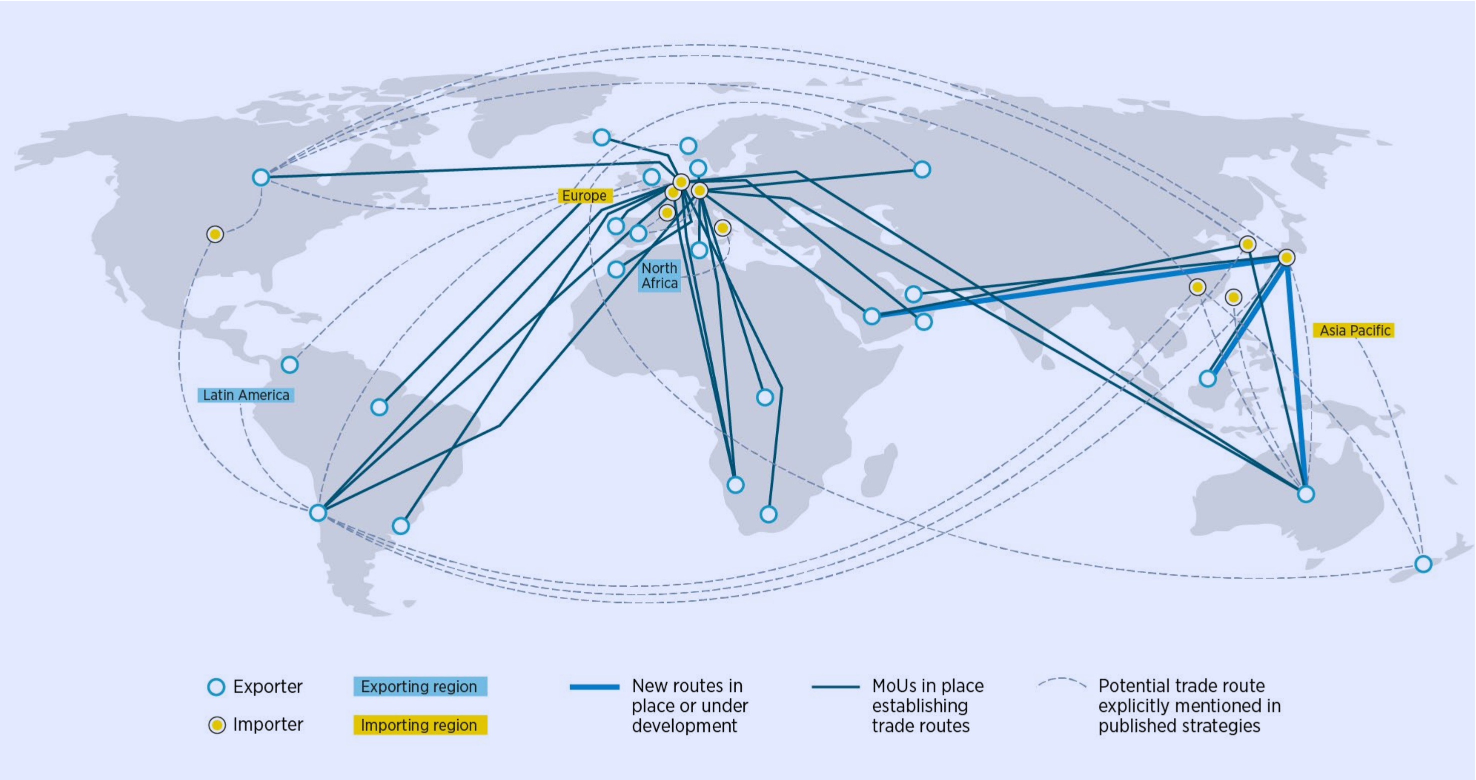
The trade partnerships shown in **Figure 12** include those of Germany with Namibia and Chile, Japan with Brunei and Australia, and the Netherlands and Morocco [82]. There is uncertainty surrounding the evolving trade agreements and what this might mean for international trade.

Although certain regions will offer export, that does not preclude them from also meeting domestic demand. For example, LMICs that are highly dependent on agriculture or industrial processes may wish to meet their local demand as well as exporting. As green hydrogen for fertilizer production is one of the use-cases where green hydrogen will meet price parity with fossil alternatives (even without a carbon tax), it is possible that green hydrogen produced in LMICs will be used domestically to produce green ammonia for fertilizer. The share of domestic versus export use will likely come down to whether there is a higher price to be had for the export market than for domestic resale and distribution constraints, as discussed in Section 5.1.

Distribution of green hydrogen and ammonia is one of the key knowledge gaps. There is uncertainty around which medium hydrogen is best (and safest) stored and transported in and, thus, the distribution infrastructure necessary to transport it. Until this is clarified, it may hinder investment in large-scale distribution infrastructure.

Historically, many countries around the globe have been dependant on oil and gas imports. However, the ongoing war

Figure 12: Hydrogen trade routes, plans, and agreements *[82]*



in Ukraine puts these strategies in a new light [89]. For example, the UK prime minister has announced an energy independence strategy [90]. European countries are trying to break away from the dependency on Russian natural gas and the EU has been expanding import capacity for gas since 2019 [91]. However, the challenge is identifying alternative supply options in a globally traded commodity. The USA has agreed to increase supply, but this will be more expensive than the price of importing gas from Russia [92]. All of this has resulted in the current price hikes of oil and gas [93].

We currently have no viable means of removing methane (a potent greenhouse gas) from our atmosphere.

The long-term impact on the price of natural gas is uncertain. Modelling of the cost of blue hydrogen under different natural gas price scenarios would be useful further research in understanding the potential impact on the cost competitiveness of green hydrogen with blue.

6 CONCLUSIONS AND KNOWLEDGE GAPS

This report has addressed how hydrogen will be produced in line with a net-zero future; what this will cost; how hydrogen will likely be used; how green hydrogen can be cost-competitive with current day alternatives; where hydrogen will be produced and demanded; the trade implications emerging; and highlighted knowledge gaps.

The following conclusions can be made along with the identification of several key areas for future research.

It is impossible for blue hydrogen to be net-zero, due to inefficiency of carbon capture and storage (CCS) technologies and upstream fugitive emissions of methane. We currently have no viable means of removing methane (a potent greenhouse gas) from our atmosphere. Therefore, the current cost comparisons are incomplete as they do not include the negative externalities due to emissions from blue hydrogen and do not take account of the current high gas price. Despite this, the cost range for green hydrogen already overlaps with that of blue hydrogen, and it is expected to be cost competitive by 2030.

Understanding the life cycle benefits of green hydrogen compared to blue hydrogen (including externalities) is an area that warrants further investigation to support policy decisions.

The cost of electricity has the greatest impact on the cost of green hydrogen, accounting for 30–60% of the cost. Cost reductions for renewable energy are forecast to continue, which in turn leads to projects of rapidly decreasing costs for green hydrogen, with a learning rate of 18%. In addition, the cost of electrolysers is still significant (33–45%). Although reducing the cost of the electrolyser is important, improving the efficiency of the electrolyser is also vital as it reduces the demand for electricity, thereby reducing the overall spend on electricity.

Understanding the impact of electrolyser efficiency increase on the overall cost can help clarify the need for technology advancements. Further investigation surrounding the use of sea and wastewater is necessary to alleviate water-related constraints, along with research into how to handle water purification waste.

Green hydrogen is expected to play a significant role for use-cases such as fertilizer production, long-term energy storage, shipping, high-temperature industrial heat, and industrial processes (e.g., reduction of steel). For LMICs specifically the dominant use cases are likely to be agriculture, transport (cargo), and industry, but this will be highly context specific to the country.

- **FERTILIZER PRODUCTION** makes up a third of hydrogen demand today. This demand is set to grow, especially if prices fall, with this additional demand focused in LMICs. Hence it is vital that this sector transitions to green hydrogen to reduce emissions.

- **LONG-TERM ENERGY STORAGE** is a challenge faced by many countries in the Global North, which have significant seasonal variation in solar and wind resource and suffer from windless winter weeks. Chemical energy carriers have widely been accepted as a necessity for long-term energy storage.

- **SHIPPING** is a clear use-case for ammonia. The maritime industry needs to transition in the near term to meet long-term targets due to the lifetime of the engines.

- **HIGH-TEMPERATURE INDUSTRIAL HEAT** currently uses natural gas, and there are very few suitable and efficient alternatives, except hydrogen.

- **INDUSTRIAL PROCESSES** such as steel manufacturing require a reducing agent; currently charcoal in the form of coke is utilized, which releases CO_2 during the chemical reaction. Green hydrogen offers a clean alternative with only water as a by-product.

Solutions to overcome safety concern of distribution of hydrogen and ammonia need to be researched to inform decision making

The export market for green hydrogen could transform the dynamics of international trade. Geographically, hydrogen will be produced where electricity is cheap and water supply is readily available (fresh, sea, or waste). The demand for hydrogen use in the fertilizer and power sector will vary globally, resulting in both domestic and export markets for hydrogen. Domestic markets for green hydrogen could improve security of supply, although it will be more expensive to produce in some regions.

Understanding which use-cases may demand green hydrogen, to what extent, and the geographical variation of this will impact decision making and investment into green hydrogen production and distribution. The balance between domestic use and export, in line with renewable energy potential, by country or region warrants further investigation, including evaluation of possible economic benefits through domestic utilisation.

In summary, uncertainty and knowledge gaps remain.

1. In which use-cases will green hydrogen gain significant market share?
2. How efficient can electrolysers be and what impact will this have on electricity demand and cost?
3. What are the costs, scale-up requirements, and waste disposal solutions of using sea or wastewater? This is especially relevant in Low- and Middle-Income Countries where fresh-water can be scarce.
4. What is the most suitable hydrogen carrier for long-term energy storage and distribution (i.e., hydrogen or ammonia) considering the need to overcome safety concerns?
5. And finally, what will be the future distribution channels, both domestically in developing countries and internationally following trade partnerships.

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APPENDICES

HYDROGEN STRATEGY USE-CASES IN CERTAIN COUNTRIES

For a net-zero future, hydrogen consumption will increase by up to 11-fold by 2050, as outlined in the Introduction. It is expected that hydrogen will be used globally and in a wide variety of applications. This transition will likely be led by countries that can afford the initial investment. So far 16 governments have adopted hydrogen strategies [3]. Most of these 16 governments belong to high-income countries which can therefore finance a national technology push on their own and thus also directly influence the intended areas of application of hydrogen technology. The announced use sectors are illustrated in Table A-1 with data from the IEA [3].

While all 16 governments seem to put high hopes on hydrogen demand in the transport sector, the other demand cases vary to some extent.

HYDROGEN OR AMMONIA FOR LONG-TERM ENERGY STORAGE

As ammonia is already a global commodity, the distribution system, handling process, and legal frameworks are already in place and well developed. At ambient temperature, ammonia can be stored as a liquid (boiling point at 33 °C vs. -253 °C for hydrogen), which decreases

Table A-1 Announced use-cases of hydrogen in the published hydrogen strategies of various countries

GOVERNMENT	ANNOUNCED USE-CASES
Australia	Buildings, Electricity, Export, Industry, Shipping, & Transport
Canada	Buildings, Electricity, Export, Industry, Mining, Refining, Shipping, & Transport
Chile	Buildings, Export, chem. Industry, Mining, Refining, & Transport
Czech Republic	Chem. Industry, & Transport
European Union	Industry, Refining, & Transport
France	Industry, Refining, & Transport
Germany	Aviation, Electricity, Industry, Refining, Shipping, & Transport
Hungary	Electricity, Refining, & Transport
Japan	Buildings, Electricity, Industry, Refining, Shipping, & Transport
South Korea	Buildings, Electricity, & Transport
Netherlands	Aviation, Buildings, Electricity, Industry, Refining, Shipping, & Transport
Norway	Industry, Shipping, & Transport
Portugal	Electricity, Industry, & Transport
Russia	Electricity, Industry, Refining, & Export
Spain	Aviation, Electricity, Industry, Refining, Shipping, & Transport
United Kingdom	Aviation, Buildings, Electricity, Industry, Refining, Shipping, & Transport

the storage costs. Moreover, ammonia is less flammable, and its intense smell provides early warnings if leakage occurs. Lastly, a litre of ammonia carries a greater mass of hydrogen (~105 g/l) than a litre of liquid hydrogen (~71 g/l) [57].

Nevertheless, there are also downsides to ammonia. Firstly, it is extremely toxic. A small amount of ammonia can be extremely hazardous to its environment and the prevention of leakage is therefore important.

Secondly, processing hydrogen to ammonia requires two further steps: air separation to gain the nitrogen, followed by a process to combine nitrogen and hydrogen to ammonia. This necessity brings along further capital and energy costs that must be considered. Lastly, even though there is a wide range of use-cases in which ammonia is used directly, it can be necessary to convert it back into pure hydrogen. This process is called 'cracking' and again comes with economic and energy costs that should not be neglected [57,93].

DEFINITIONS OF USE-CASES

Use-case	Explanation	Example
Fertilizer	Feedstock for ammonia-based fertilizer	UREA, Ammonium nitrate
Agricultural vehicles	Fuel for transportation and processing vehicle in agriculture	Tractors, harvesters
Metro and regional trains	Fuel for transportation vehicle for small to medium distances in populated areas	
Rural trains	Fuel for transportation vehicle for long distances with little infrastructure in place	
Trucks	Fuel for transportation vehicle for medium to long distances	
Passenger cars	Fuel for passenger transportation vehicle	Compact urban car, vans, taxis
2-wheelers	Fuel for two-wheeled transportation vehicle	Scooters, motorbikes
3-wheelers	Fuel for motorcycle-based three-wheeled vehicle	Rickshaws

Use-case	Explanation	Example
Buses	Fuel for large-sized passenger vehicle	Short-distance (single-deck, double-decker, articulated), Long distance (coaches)
Mini-buses	Fuel for medium-sized passenger vehicle	SUVs, buses for small-size urban transportation
Cargo ships	Fuel for transportation vehicle for goods for medium to long distances	Container ships
Ferries	Fuel for transportation vehicle for passengers over small to long distances	Regional ferries, Cruise ships
Short-haul aviation	Fuel for transportation vehicles for passengers or goods for short distances	Helicopter, commuter, regional and short-range aircrafts
Long-haul aviation	Fuel for transportation vehicle for passengers or goods for medium to long distances	Medium-range and long-range (large and cargo aircraft)
Storage	Chemical as a way of energy storage	Long-term energy storage, back-up generator, energy imports
Baseload power generation	Fuel for power generation for power system balancing, islands grids	Fuel cells, hydrogen turbines, ammonia and methanol combustion
Ammonia	Feedstock for ammonia-based chemicals	Nitric acid for ammonium nitrate as an explosive for mining, quarrying, and tunnelling; UREA for manufacture of durable resins; chemical reduction agent for NO_x; intermediate for certain plastics, rubber, fibres
Methanol	Feedstock for methanol-based chemicals	Formaldehyde, Methanol-to-Olefines (MTO)
Other chemical feedstocks	Feedstock for other chemicals	Alcohols, amines, hydrogen peroxide
Desulphurization	Chemical for removing sulphur from oil and gas products	Oil refining
Hydrocracking	Chemical for upgrading heavy oils into lighter, higher-value products	Oil refining
Process heating	Fuel for low-to-medium and high-temperature industrial heat	Melting, sintering, drying materials and heating large furnaces (Cement, Glass, Aluminium)

Hydrogenation	Chemical for preservation and purification	Vegetable oils
Iron ore reduction	Reduction of iron ore to sponge iron	Steelmaking
Other industry	Manufacturing agent	Electronics industry for semiconductors, Generator cooling
Industrial vehicles	Fuel for transportation and processing vehicle in industrial applications	Mining vehicles, forklifts, cranes, excavators
Cooling-based services	Electricity for cooling	Refrigeration units in trucks
Cooking	Fuel for cooking	Cook stoves, gas stoves
Thermal comfort	Fuel for residential and commercial heating	Gas grid blending, hydrogen boilers
Fuel-cell-based electricity	Fuel for power generation	Remote and household generators

INPUTS AND ASSUMPTIONS FOR COST MODELLING

Prices	Year	Value	Reference
Electricity [$/MWh]	2020	50	[23]
	2030	20	
Green hydrogen [$/kg]	2020	4.5	[23]
	2030	2.3	[97]
Green ammonia [$/t]	2020	650	[98]
	2030	340	[97]

Green ammonia [$/t]	2020	650	[98]
	2030	340	[97]
Natural gas [$/MMBTU]		4	[99]
Grey ammonia price [$/t]		275	[98]
Crude oil [$/barrel]		39	[100]
VLSFO [$/t]		544	[101]
LNG [$/MMBTU]		25	[102]
Coal for coke producers [$/t]		127	[103]
Emissions	**Year**	**Value**	**Reference**
Natural gas [g CO_2/kWh]		488	[104]
Grey ammonia [kg CO_2/t]		2400	[23]
VLSFO [kg CO_2/GJ]		99	[105]
LNG [kg CO_2/GJ]		94	[105]
Traditional steel manufacture [kg CO_2/t steel]		1600	[71]
Additional information	**Year**	**Value**	**Reference**
Energy intensity shipping [MJ/t-km]	2020	0.09	[106]

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"The views expressed in this material do not necessarily reflect the UK government's official policies."

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