

EMERGING HYDROGEN ENERGY TECHNOLOGY AND GLOBAL MOMENTUM

Dan Millison and Kee-Yung Nam

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Emerging Hydrogen Energy Technology and Global Momentum

Dan Millison and Kee-Yung Nam

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ABBREVIATIONS

ADB	–	Asian Development Bank
CHP	–	combined heat and power
CO ₂	–	carbon dioxide
CUF	–	capacity utilization factor
DMC	–	developing member country
EU	–	European Union
GHG	–	greenhouse gas
IEA	–	International Energy Agency
ISA	–	International Society of Automation
LNG	–	liquefied natural gas
LOHC	–	liquid organic hydrogen carrier
OTEC	–	ocean thermal energy conversion
PEM	–	proton exchange membrane
PRC	–	People's Republic of China
SMR	–	steam-methane reforming
US	–	United States

WEIGHTS AND MEASURES

Btu	–	British thermal unit
kg	–	kilogram
km	–	kilometer
MW	–	megawatt
MWh	–	megawatt-hour
tCO ₂ e	–	tons of carbon dioxide equivalent
TWh	–	terawatt-hour

ABSTRACT

This paper provides an overview of the emerging hydrogen economy with attention to the merit order for hydrogen applications and prospective investments, which might be supported by the Asian Development Bank (ADB). This paper is not a guidance document nor is it a design handbook. Rather, it provides basic information on global context, technologies, costs, and prospective developments in ADB's developing member countries. This paper aims to help decision-makers navigate the green hydrogen value chain and understand what is required for successful implementation and reap the potential rewards in the energy transition.

Today, most hydrogen is produced from natural gas with emissions of about 9 tons of carbon dioxide (CO₂) per ton of hydrogen. In 2021, greenhouse gas (GHG) emissions from hydrogen were estimated at around 900 million tons of CO₂ per year, about 1.8% of GHG emissions.

Green hydrogen is a scalable and flexible energy carrier produced by converting renewable electricity (electrons) to split water into hydrogen (protons) and oxygen, which can be stored indefinitely or converted into other molecules. The oxygen by-product can be sold into existing markets depending on local demand. Hydrogen-derived chemicals (molecules) can be transported in bulk as is the case for crude oil, natural gas, refined petroleum products, and other chemicals. Like fossil fuels—which are formed by a combination of solar, biomass, geothermal energy, and geologic time—hydrogen is an energy carrier. Specifically, solar-to-hydrogen mimics the natural processes that create fossil fuels, and potential uses of green hydrogen mimic the existing global hydrocarbons business. The scalability of intermittent solar and wind resources is limited by the ability to time-shift renewable energy output to match demand, and hydrogen appears to be a scalable solution for both time-shifting and location-shifting of renewable energy.

One kilogram of hydrogen has the energy equivalent of 1 gallon (3.94 liters) of gasoline. The cost-effectiveness of green hydrogen production depends on electricity input costs, electrolyzer costs, and electrolyzer load factors. Green hydrogen production may be commercially viable today at \$4/kg; although \$2/kg is typically referenced as a price benchmark, \$4/kg is at par with gasoline prices in many countries. The use of intermittent versus “baseload” renewable energy does not dictate the commercial viability of green hydrogen production. A key rate-limiting factor for scaling up green hydrogen production is the availability of critical metals, specifically iridium and platinum for use in electrolyzers.

From a policy perspective, green hydrogen is energy-intensive and is not the solution to all. Green hydrogen development must be considered in the broader context of renewable energy development and the need for accelerating the global energy transition. Green hydrogen is a “power-to-X” business proposition based on selling molecules rather than selling electrons via power purchase agreements. Today, there is no global hydrogen market analogous to global crude oil and other hydrocarbons. Therefore, the viability of green hydrogen production depends primarily on electrolyzer costs, local energy costs, specific end-use applications, and willingness of hydrogen buyers to commit to long-term offtake agreements (like traditional liquefied natural gas export projects). Hydrogen supply chain development is expected to continue globally, and as global electrolyzer manufacturing capacity increases a virtuous cycle of development may emerge.

I. BACKGROUND AND CONTEXT

Green hydrogen is produced by electrolysis, a process that splits water into hydrogen and oxygen that is powered by renewable energy or by reforming biogas.¹ The technical logic for green hydrogen is straightforward: hydrogen production from fossil fuels is emissions-intensive and subject to volatility of fossil fuel prices, while green hydrogen production is energy-intensive² but creates cost certainty. The merit order for green hydrogen deployment begins with replacement of established fossil hydrogen production and use, followed by displacement of fossil fuels in heavy, hard-to-decarbonize industries. Production of renewable fuels from hydrogen for transport applications and production of hydrogen for long-term bulk storage appear less attractive compared to electrified transport and evolving energy storage technologies. Until there is a global hydrogen supply chain resembling that for crude oil and refined petroleum products, green hydrogen development will be location-specific, with decisions made on a “targets of opportunity” basis.

For the foreseeable future, the uptake of green hydrogen investment is expected to increase dramatically in Asia and the Pacific region in both developed and emerging economies. Green hydrogen hubs are growing in Australia, the European Union, and the Middle East. The pace and scale of the investment remains to be seen in developing countries due to up-front = capital costs, limited renewable energy development, and lack of supporting policies and technical expertise in both public and private energy companies to establish a financially viable green hydrogen supply chain. Additional challenges are high initial costs of production, storage and transportation constraints, commercial viability, and limited market with large-scale purchase agreements yet to be seen.

Green hydrogen will be part of the energy mix if the Asian Development Bank (ADB) developing member countries (DMCs) are to reach their climate goals and transition to a net-zero economy. The International Energy Agency (IEA) estimates that about 34 million tons per year of green hydrogen will be needed by 2030 to meet Paris commitments, and about 100 million tons per year will be needed by 2050 to meet net-zero targets (IEA 2022). Multiple gigawatt-scale investments will be needed across the green hydrogen supply chain for renewable energy, electrolyzer systems, hydrogen storage, and retrofitting ports and pipelines. According to the IEA net-zero scenario, global annual investments in low-emissions hydrogen stand at about \$500 million, but would need to increase at least tenfold by 2030. ADB has supported multiple assessments in DMCs via technical assistance, but minimal investment operations have been made as of June 2023.

Overall, ADB DMCs that seek to explore green hydrogen will need support in developing policies, enhancing knowledge and technical expertise, and developing pilot projects across the hydrogen supply chain and covering all related infrastructure from production to transmission and distribution to demand-use. Furthermore, both private and state-owned oil and gas companies (e.g., Pertamina in Indonesia, Sinopec in the People’s Republic of China [PRC], and Adani and Reliance in India) and heavy industries are developing their own decarbonization plans and are actively assessing potential investments and developing large-scale hydrogen projects.

Hydrogen is rapidly evolving globally, and it is impossible to cover everything in a single document. Therefore, this paper provides an overview of the emerging hydrogen economy with attention to the

¹ Reforming of biogas is technologically the same as hydrogen production from natural gas. A third production pathway is thermal decomposition of water into hydrogen and oxygen, which requires temperature of at least 1,800°C.

² Electrolysis of water to produce hydrogen and oxygen requires about 50 megawatt-hours (MWh) per ton of hydrogen produced, with 8 tons of oxygen by-product.

merit order for hydrogen applications and prospective investments in DMCs that might be supported by ADB.

This paper is not a guidance document nor is it a design handbook. Rather, it provides key information on technologies, costs, and prospective developments that might be supported by ADB in the foreseeable future. This paper aims to help decision-makers navigate the green hydrogen value chain and understand what is required for successful implementation and reap the potential rewards in the energy transition.

II. THE GREEN HYDROGEN VALUE CHAIN

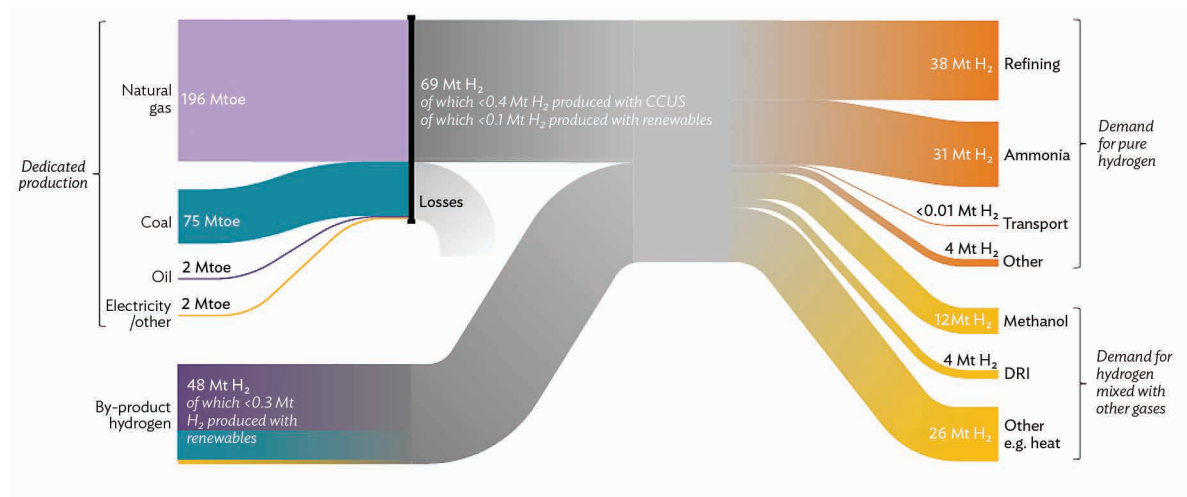
Hydrogen is used primarily as an intermediate product in petroleum refining and chemical manufacturing such as in the production of fertilizers (e.g., ammonia). For purposes of discussion in this paper, hydrogen is commonly classified as follows (this classification is simplified and not comprehensive):

- (i) **Green hydrogen** (or “renewable hydrogen”) is produced by electrolysis of water with renewable electricity, at a cost range of about \$2.7–\$5.9/kilogram (kg). No greenhouse gases (GHGs) are emitted during the electrolysis process. Green hydrogen can also be produced by reforming biogas, which may have some fugitive methane emissions. Oxygen is a by-product of the electrolysis process, with 8 kg of oxygen for each kg of hydrogen. Green hydrogen production was demonstrated at megawatt scale at a hydropower plant in Norway in 1929.³
- (ii) **Gray hydrogen** is produced from natural gas, a fossil fuel, by steam-methane reforming (SMR) at a cost around \$1.62/kg, depending on the price of gas and carbon emissions. This production process results in emissions of about 9.3 kg carbon dioxide (CO₂) per kg of hydrogen.
- (iii) **Blue hydrogen** uses the same production processes as gray hydrogen, but the CO₂ is captured and stored permanently. Its production costs around \$2.16/kg, making it more expensive than gray hydrogen but cheaper than green hydrogen. Where CO₂ storage capacity is available, existing hydrogen production facilities could be converted to blue hydrogen, thus reducing investment costs.

In 2021, global hydrogen production was about 94 million tons recovering to above pre-coronavirus disease (COVID-19) pandemic levels (91 million tons in 2019), which contains energy equal to about 2.5% of global final energy consumption. Most of the increase came from traditional uses in refining and industry, though demand for new applications grew to about 40,000 tons (up 60% from 2020, albeit from a low base) (IEA 2022). More than 75% of the global hydrogen market is produced from natural gas (gray hydrogen), which consumes 6% of global natural gas production; GHG emissions are estimated at around 900 million tons of CO₂ per year, about 1.8% of global GHG emissions in 2021.⁴ Just under one-fourth (23%) of the global hydrogen market is produced from coal (“brown” hydrogen) consuming about 2% of the global coal supply. The remaining share of global hydrogen comes from oil and electricity (Figure 1). Green hydrogen currently accounts for only about 0.1% of overall hydrogen production (World Economic Forum 2023).

³ LinkedIn. Terje Hauan’s Post.

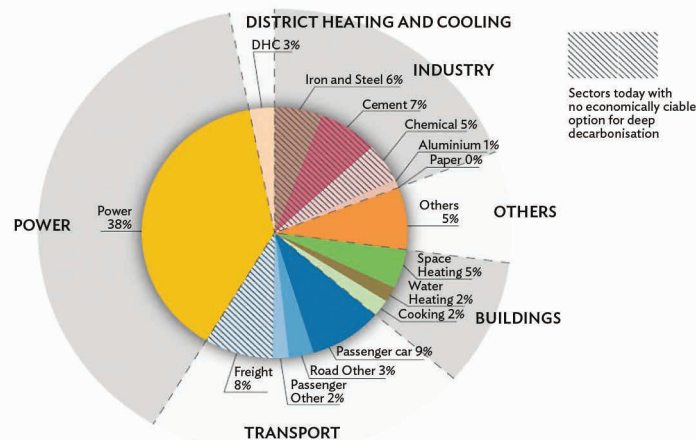
⁴ Global GHG emissions were above 54 billion tons of carbon dioxide equivalent (tCO₂e) in 2021: Our World in Data. Total greenhouse gas emissions (accessed August 2023).

Figure 1: Hydrogen Value Chain

DRI – direct reduced iron production, H₂ – hydrogen, Mt – million tons, Mtoe – million tons of oil equivalent.

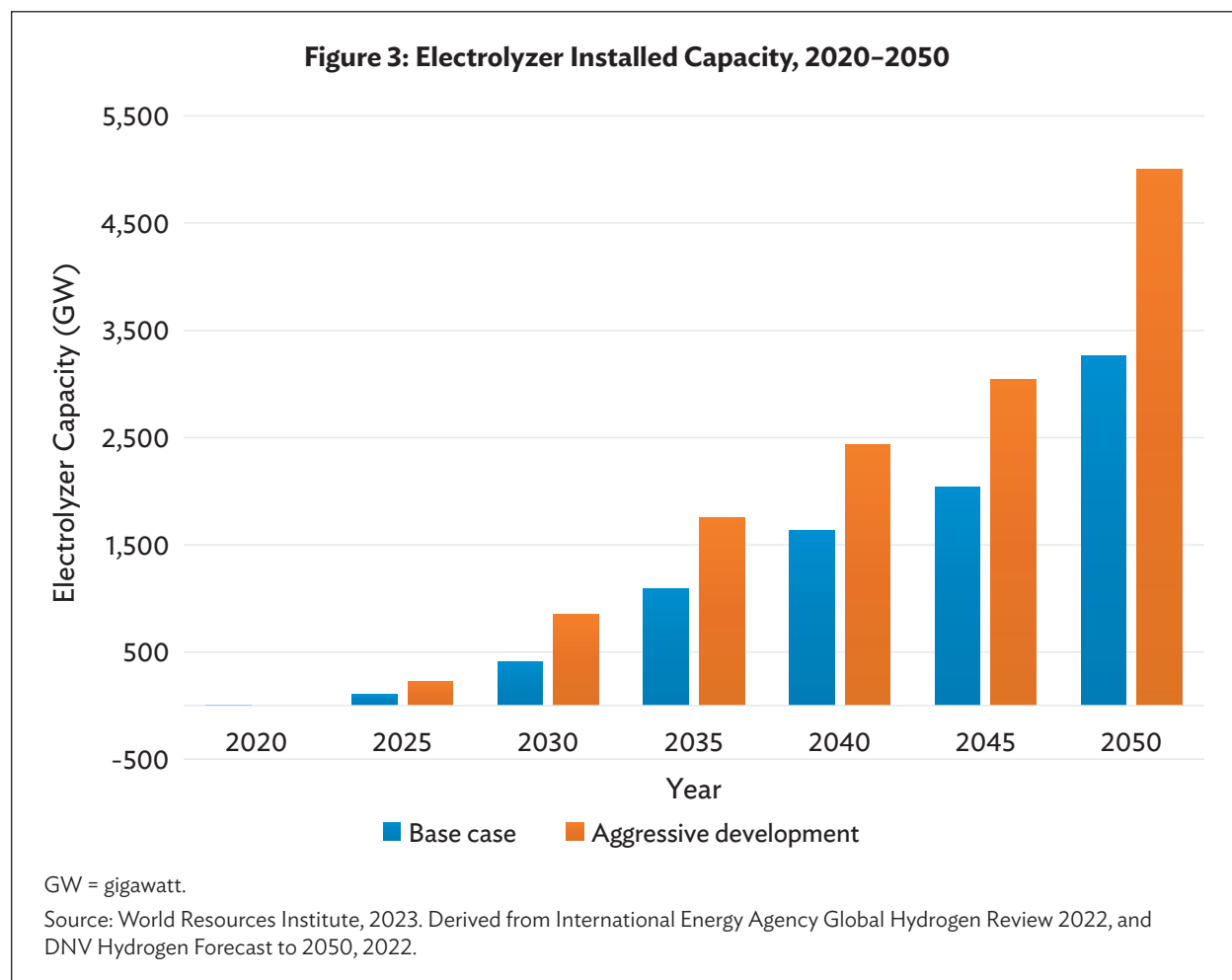
Source: International Energy Agency, 2019.

Green hydrogen will be an essential part of the energy mix if ADB DMCs are to reach their climate goals and transition to a net-zero economy. Figure 2 illustrates global CO₂ emissions by sector, with electric power generation accounting for 38% of emissions with other sectors accounting for 62% (International Renewable Energy Agency 2018). Freight transport, along with iron and steel, cement, chemical, and aluminum production, account for 27% of emissions: addressing these hard-to-decarbonize sectors is required to reach the 1.5 target of the Paris climate accords (IPCC 2018, UNEP 2019).

Figure 2: Global Carbon Dioxide Emissions by Energy Sector

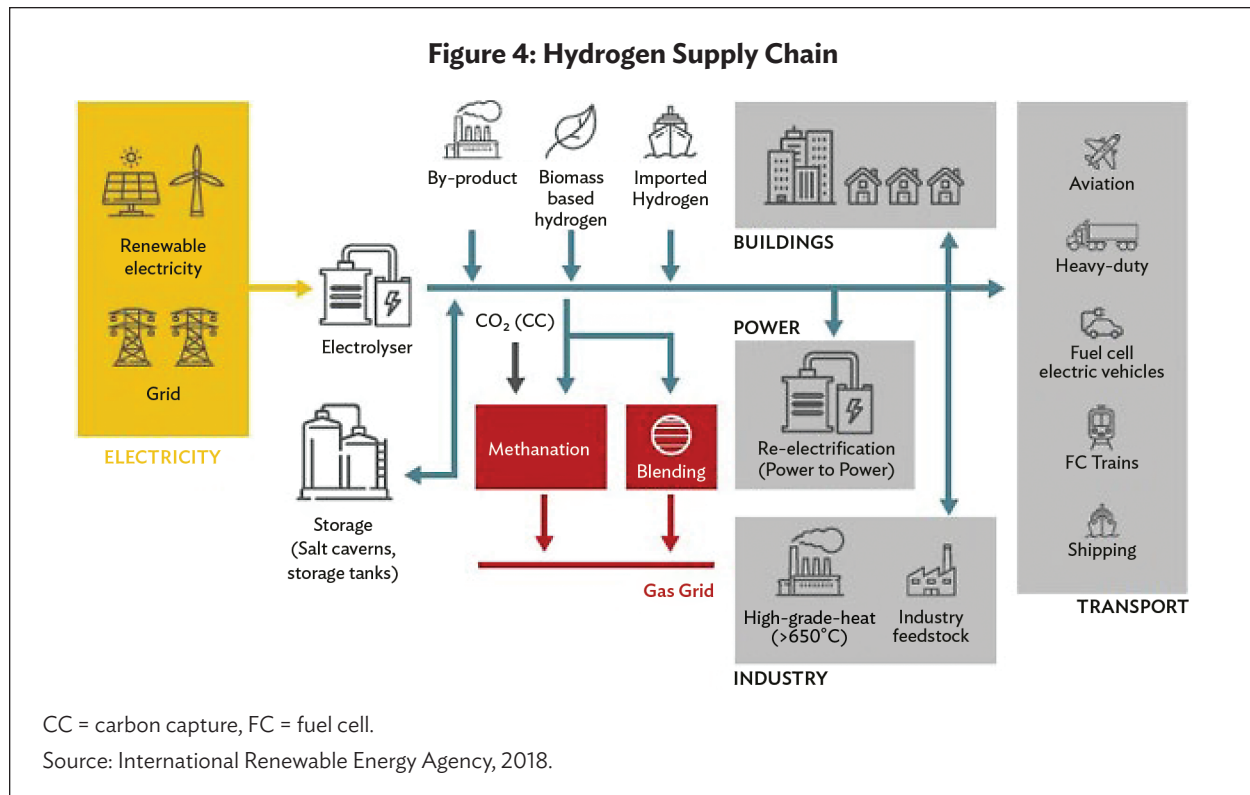
Source: International Renewable Energy Agency, 2018.

Although green hydrogen currently makes up a very small share of the hydrogen market (less than 1%), the amount of electrolyzer capacity for green hydrogen production has significantly increased in recent years (Figure 3). The cost-competitiveness of green hydrogen production will improve as electrolyzer efficiency increases and electrolyzer costs decline.



As shown in Figure 4 the hydrogen supply chains include:

- (i) Access to raw materials for production (feedstock, electricity, etc.).
- (ii) Production technologies: steam-methane reforming (SMR, electrolyzers, etc.).
- (iii) Storage: Hydrogen can be stored physically as either a gas or a liquid. Storage of hydrogen as a gas typically requires high-pressure tanks (350–700 bar [5,000–10,000 pounds per square inch (psi)] tank pressure) (US Department of Energy 2019). Transport and distribution: pipelines, tube trailer, tankers, etc.
- (iv) End-use applications: transport, stationary consumption.
- (v) Support services, which are usually not recognized as part of the hydrogen supply chain but are critical to the operation of hydrogen projects (e.g., health, safety, and environment; quality assurance, training, etc.).



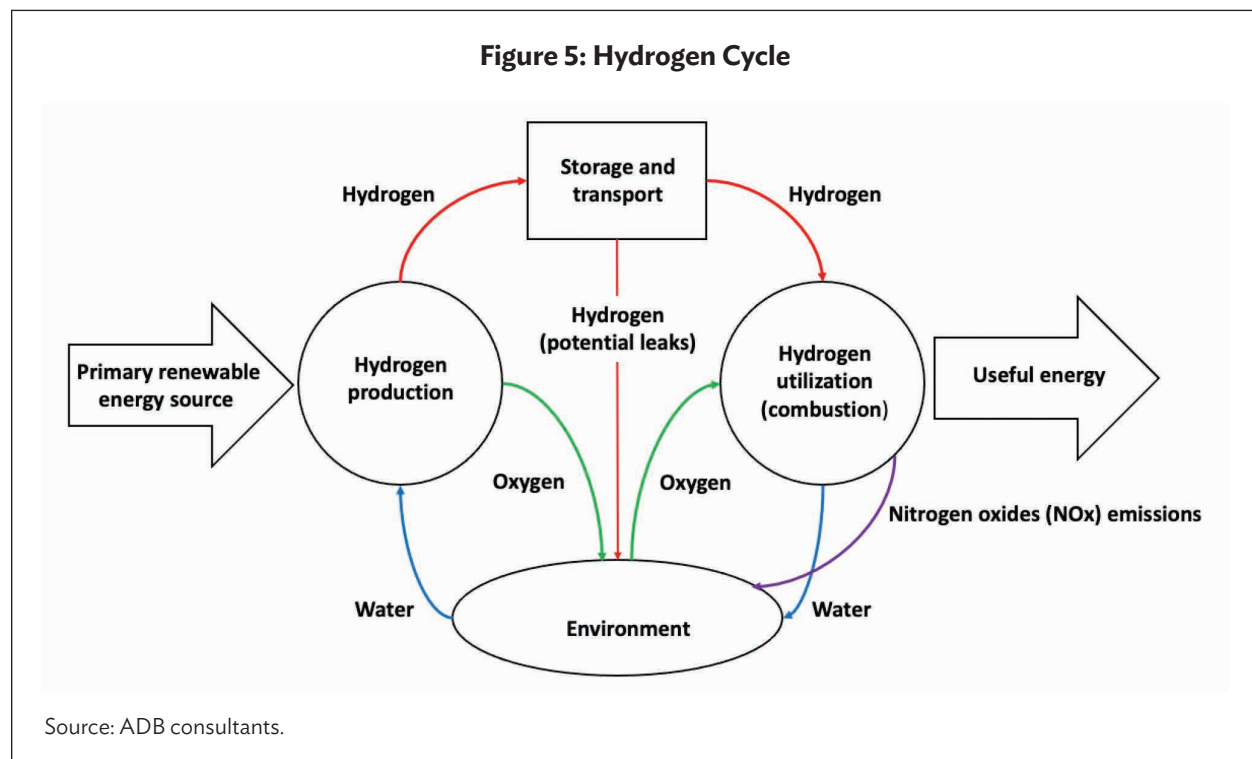
A. Advantages of Green Hydrogen

Green hydrogen appears to be a multipurpose and adaptable approach to reduce CO₂ emissions at scale but faces technical, safety, financial, and economic challenges. Green hydrogen solutions, when developed and deployed widely, can provide numerous benefits as follows:

- (i) Accelerating the integration and penetration of clean energy solutions, including solar, wind, mini and large hydro, marine energy, etc.
- (ii) Improving the techno-commercial viability of demand-side management with better, more resilient, reliable, and versatile energy storage.
- (iii) Delivering a better operation and management solution to peak loads and reduce grid instability and congestion.
- (iv) Increasing the number of end user applications in different sectors (transport, heat, etc.).
- (v) Expanding new variable intermittent renewable generation with green hydrogen for electrical grid network balancing and long-term bulk storage.
- (vi) Providing a decentralized solution and reducing risks associated with electricity infrastructure leading to bulk curtailment of renewable energy generation.
- (vii) Creating new employment in green hydrogen, automotive, fuel cell, safety, and other businesses.
- (viii) Increasing energy security, reducing dependence on fossil fuels, and providing optimum use of national resources.
- (ix) Forming new regional markets selling and buying green hydrogen energy.

A key advantage of hydrogen is that its production and utilization can be ultra-low emissions, with only water as a by-product that meets drinking water quality standards (Abad and Dodds 2020). If hydrogen is combusted with air, nitrogen oxides are formed, similar to nitrogen oxide emissions from natural gas combustion. Hydrogen production from renewable energy by electrolyzing water into hydrogen and oxygen is essentially emissions-free (except for the life-cycle emissions embedded in the production hardware). The GHG intensity of hydrogen can be documented through certificates of origin and the Green Hydrogen Organization's green hydrogen standard (which also includes accounting for stress on water resources).⁵

The complete cycle from production to use of green hydrogen is a green “circular” energy solution, which has embedded emissions in the hardware production cycles, as is the case for other energy production life cycles. Figure 5 illustrates the renewable hydrogen cycle.



The other potential advantages of hydrogen are adaptability, reliability, scalability, and sustainability with many different end-use applications.

Adaptability. Hydrogen can be used instantly or stored for short term (minutes, hours, and days), medium term (weeks), and long term (seasonal and annual storage—months to years). It can be transported in pipelines and trucks and transformed into other chemicals, such as ammonia, methanol, etc. Of prime importance, hydrogen can be produced and used with no associated sulfur oxide, particulates, and other forms of hazardous emissions; the use of green hydrogen instead of fossil fuels directly reduces these air pollutants and GHG emissions with associated public health and ecosystem benefits. Hydrogen is a potential substitute for natural gas as an alternative feedstock for chemical manufacturing, e.g., production of ammonia. Some observers predict that the global hydrogen market will exceed the global liquefied natural gas (LNG) market by 2030 (Matalucci 2023.).

⁵ Green Hydrogen Standard.

Reliability. Hydrogen production, storage, and use has proven reliability. When stored, it does not incur any inherent degradation, as some battery technologies do, (Sasaki et al. 2013, Wenz 2009) and this stability means it is more reliable than other options for critical applications (Ainscough et al. 2011, Hendricks et al. 2015).

Scalability and sustainability. Hydrogen energy storage can be integrated in parallel to rapid deployment of renewable energy and is well suited to coupling with intermittent renewable energy output from hydropower, solar, and wind. Hydrogen is one of the only scalable solutions for hard-to-decarbonize applications such as iron and steel production and heavy transport (Gazey et al. 2020). Production of hydrogen from water is infinitely scalable relative to energy demand.⁶ Production of hydrogen from electrolysis has manufacturing economies of scale, as electrolyzers are being mass-produced in factories similar to wind, solar, and some battery systems. Electrolyzers are inherently modular and are both upward and downward scalable.⁷

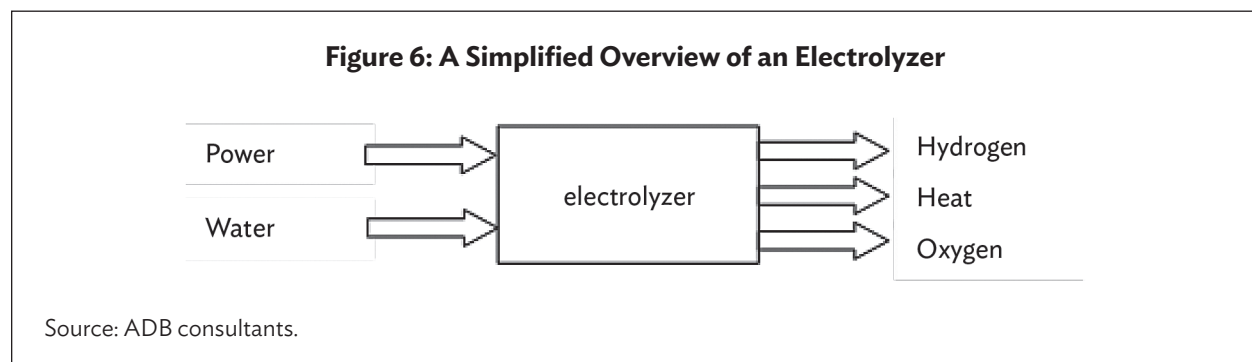
Versatility. Hydrogen can be produced from fossil fuels, as well as biomass, plastic, and wastes. End-use applications include (i) emissions reductions in refineries, chemical industries, steel industries, etc.; (ii) grid balancing due to high penetration of intermittent renewable energy; (iii) fuel for electricity generation, on-grid and off-grid, and for combined cooling, heating, and power solutions; (iv) transport fuel; and (v) blending with natural gas for use in existing pipeline systems, natural-gas-fueled power plants, and other natural gas applications with minimal modifications (a “drop-in” solution).

B. Production

1. Electrolyzer

Today, electrolysis of water is considered by many experts to be a pivotal technology for the large-scale storage of renewable energy in the context of the energy transition. Electrolyzers are a well-established technology dating back to the 19th century when it was proven that passing direct current through water caused it to separate into hydrogen and oxygen atoms (footnote 3).

An electrolyzer is a device that uses electricity and water as inputs, and produces hydrogen, oxygen, and heat as outputs (Figure 6). Hydrogen is stored for later use, while oxygen is, in most cases, released into the atmosphere. A typical electrolyzer consists of an anode and a cathode, both separated by an electrolyte.



⁶ Production of hydrogen directly from seawater is not yet commercially viable; desalination adds a modest cost to the overall cost of production, estimated to be about \$0.10 per kg of hydrogen.

⁷ In the foreseeable future, the cost of electrolyzers may be low enough that they become used for household energy storage similar to residential energy storage products such as the Tesla Powerwall and other off-the-shelf products.

The three most common commercially available types of electrolyzers are alkaline, proton exchange membrane (PEM), and solid oxide. Alkaline and solid oxide electrolyzers operate more effectively with baseload forms of power that have less variations in power generation such as biomass, geothermal, and hydropower inputs. PEMs can respond to rapid changes in load and exhibit good turndown capability and are therefore well suited for coupling with intermittent solar and wind generation. Anion exchange membrane technology has evolved beyond the laboratory and is now at demonstration project stage. Alkaline and PEM systems have reached technology readiness level 9, while solid oxide systems are still at technology readiness level 5–6. PEMs require platinum and iridium metals, of which 71% and 92%, respectively, are produced in the Republic of South Africa. Based on current global platinum and iridium production, PEM production is limited to 7.5 GW per year.⁸ Table 1 summarizes the key characteristics of electrolyzer technologies.

Table 1: Characteristics of Existing Electrolyzer Technologies

Electrolyzer Type	Electrolyte	Efficiency η (LHV)	Technology Maturity	Main Advantages	Challenges
Proton exchange membrane	Solid polymer membrane (Nafion)	65%–82%	Demonstration project and early market	(i) Solid electrolyte reduces corrosion and electrolyte management problems (ii) Low temperature (iii) Quick start-up and load following	(i) Availability of platinum and iridium catalysts are rate-limiting factor in manufacturing capacity (ii) Sensitive to fuel impurities
Solid oxide	Solid ceramic membrane	81%–86% up to 100% with heat recovery	Laboratory scale and demonstration project	(i) Enhanced kinetics, thermodynamics: (ii) Lower energy demand (iii) Low capital cost	(i) Mechanical unstable electrodes (cracking effect) (ii) Safety issue: improper sealing (iii) Long start-up time (iv) Limited number of shutdowns
Alkaline	Liquid electrolyte with alkaline solution (NaOH or KOH)	59%–70%	State of art and mature commercial	(i) Low capital cost (ii) Relatively stable (iii) Mature technology	(i) Corrosive electrolyte has impact on reliability/durability (ii) Gas permeation (iii) Slow dynamics (iv) Electrolyte management (aqueous)
Anion exchange membrane	Solid polymer-based anion exchange membrane in KOH or K_2CO_3 solution	62%	Laboratory scale and small demonstration project	(i) Non-noble metal catalyst (ii) Noncorrosive electrolyte (iii) Compact cell design (iv) Low cost (v) Absence of leaking (vi) High operating pressure	(i) Low current densities (ii) Durability (iii) Membrane degradation

K_2CO_3 = potassium carbonate, KOH = potassium hydroxide, LHV = lower heating value, NaOH = sodium hydroxide.
Source: ADB consultants.

⁸ Alternatives to platinum and iridium, such as iron-based materials, would create a path to faster ramp-up of PEM production. E.g., see: Hydrogen Central. 2023. Developing Technologies to Reduce The Cost of Green Hydrogen Production. 6 June.

2. Hydrogen Supply Chains and Costs of Production

Hydrogen is not an energy source, but is an energy carrier (like coal, oil, and natural gas, which carry solar, biomass, and geothermal energy derived from biological and geological processing). Feedstocks are needed to produce hydrogen, and the conversion step involves costs and technical challenges.

Currently, more than 90% of global hydrogen is produced from natural gas via SMR technology, which is installed at or adjacent to industrial sites where hydrogen is needed, with minimal transport costs. Displacing and replacing existing global hydrogen production will require obtaining large volumes of readily available renewable electricity (and/or biomass), integrating electrolyzer technologies with renewable energy assets, and addressing the cost of green hydrogen production versus local prices of natural gas and/or coal. According to the IEA, the price of green hydrogen ranges between \$3.83/kg and \$5.47/kg, which is expensive compared to hydrogen from fossil fuels (depending on local fossil fuel prices and ignoring externalities). A target price below \$2/kg will enable green hydrogen to compete with fossil fuel derived hydrogen (SGK PLANET 2021).

Green hydrogen has inherent benefits in utilizing surplus electricity, air quality improvement, energy storage, and CO₂ reduction. These benefits should be quantified to the extent possible and incorporated into project design to enhance financial viability, especially in new markets. For example, incorporating a cost of carbon of \$50 per ton of carbon dioxide equivalent (tCO₂e) adds about \$500 per ton to the cost of gray hydrogen and offsets the cost of green hydrogen by the same amount, i.e., there is a built-in economic cost difference of about \$1,000 per ton (\$1/kg) in favor of green hydrogen.

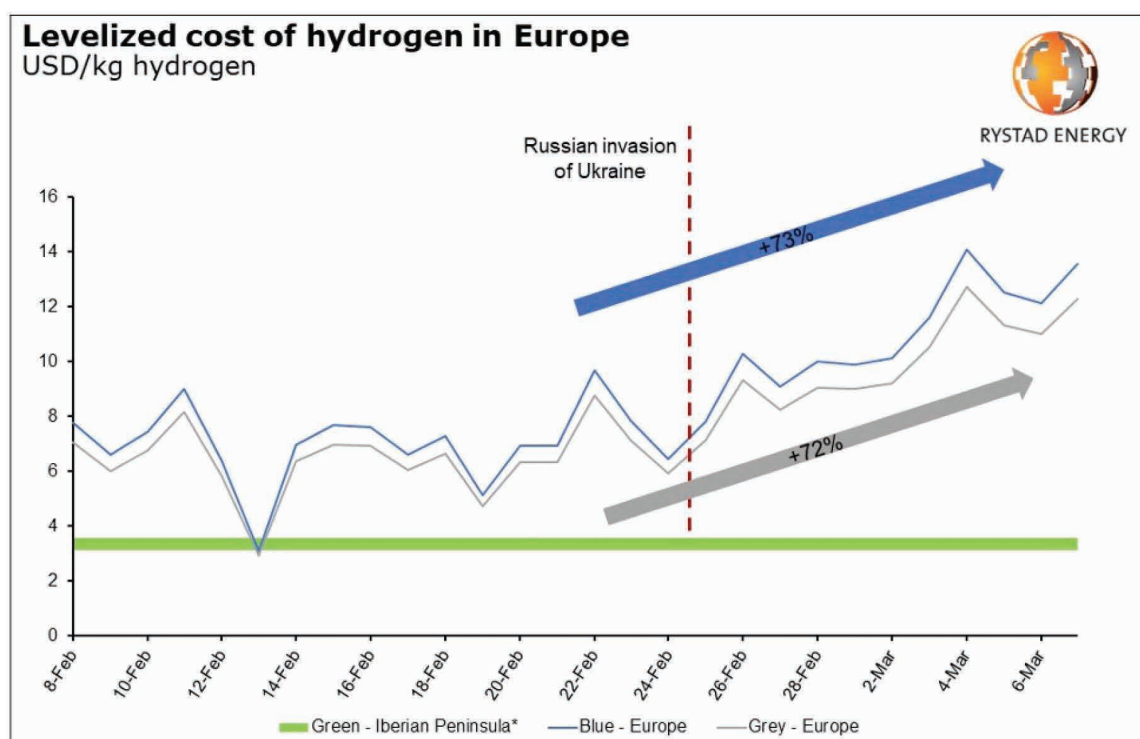
The levelized production cost of green versus gray and brown hydrogen varies with input prices of electricity, electrolyzer costs, and electrolyzer load factor for green hydrogen versus local prices of coal and natural gas for black and gray hydrogen. The levelized cost of hydrogen ranges from \$0.5 to \$1.7 per kg with the lower end in countries with natural gas prices below \$0.28 per kg (\$6 per million British thermal units [Btu]),⁹ while green hydrogen costs can range from \$3 to \$8 per kg. There are three main types of electrolyzer systems in the market today, which are still expensive due to limited manufacturing capacity. Electrolyzer systems can account for 45%–75% of hydrogen production costs depending on the load factor and capacity. In the PRC, brown hydrogen production cost is around \$1/kg of hydrogen due to low domestic coal prices. It is expected that green hydrogen will become cost competitive with gray and brown hydrogen before 2030 if renewable energy and electrolyzer system costs continue to decrease, assuming that natural gas and coal prices remain stable or increase. A carbon tax, or other robust carbon pricing policy, can facilitate the competitiveness of green hydrogen.

The costs of blue and gray hydrogen in Europe were around \$8/kg to \$14/kg in early 2022. Decreases in fossil fuel prices will directly reduce costs for blue and gray hydrogen, but price volatility should be expected in the near term. The levelized cost of hydrogen increased due to elevated natural gas prices after the Russian invasion of Ukraine (as shown in Figure 7). Figure 7 illustrates the location-specific nature of gray and blue hydrogen costs, which are directly proportional to natural gas prices; in early 2022, natural gas prices in the United States (US) were relatively stable at around \$5–\$6 per million Btu versus European spot prices of more than \$20 per million Btu. Figure 7 also highlights the value of cost certainty associated with green hydrogen production versus the price volatility of fossil fuels. In other words, we cannot predict the future but we are constantly building it.

⁹ While crude oil prices are set in global markets, natural gas prices are set at trading hubs or in national and local markets. There is no global pricing market for natural gas. Therefore, gray hydrogen costs of production are location-specific and subject to price volatility. International coal trade is based on prices set at international trading hubs, but many countries administer coal prices and may set local prices below international benchmarks.

Electrolyzers are inherently modular like solar, wind, and battery storage, and increased manufacturing capacity and deployment are expected to drive down green hydrogen production costs. Costs as low as \$2/kg are conceivable today, in regions with excellent renewable energy resources and surplus renewable electricity. Reducing the cost of production to \$1.5/kg would require further improvements in electrolyzer efficiency as well as continued declines in cost of electrolyzer production.¹⁰

Figure 7: Levelized Cost of Hydrogen in Europe Before and After the Russian Invasion of Ukraine



USD/kg = United States dollar per kilogram.

* Price based on 2020/21 renewable auctions in Spain and Portugal.

Source: Rystad Energy HydrogenCube.

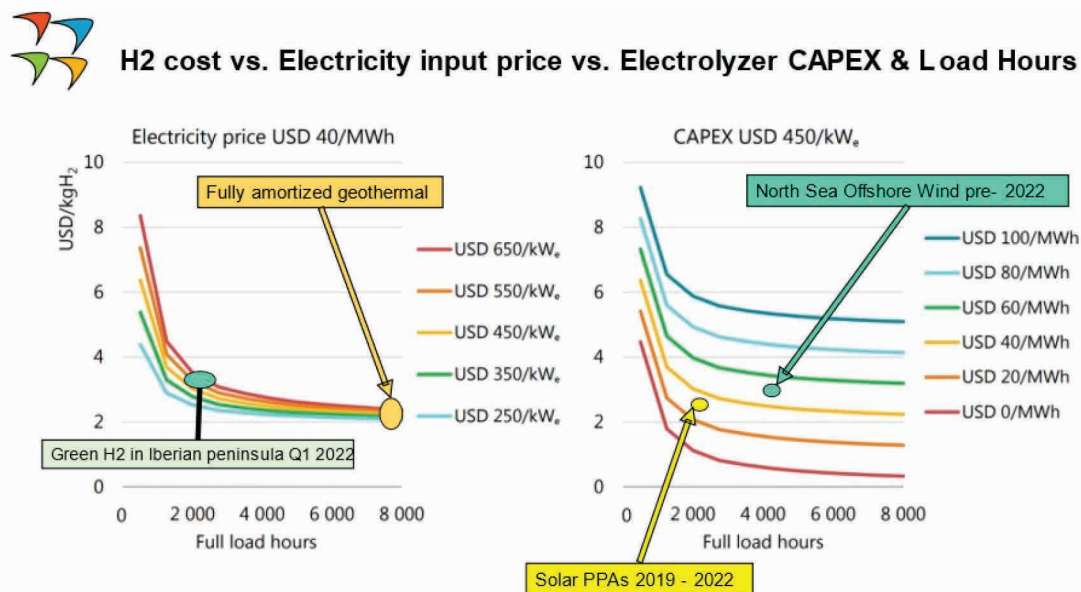
Figure 8 shows the relationship between electricity input price, cost of electrolyzers, and electrolyzer capacity utilization factor, and illustrates the indicative levelized cost of hydrogen for different renewable energy configurations in different geographic areas. The current gigawatt-scale projects in the North Sea and Western Europe are projecting levelized cost of hydrogen below \$4/kg, using offshore wind, onshore solar, and combinations of solar and wind. Prospective projects based on large-scale solar photovoltaic are expected to achieve less than \$3/kg cost of production depending on electrolyzer costs. For older geothermal plants that are fully amortized and depreciated, the levelized cost of hydrogen is expected to be close to \$2/kg.¹¹ Note that these costs do not include cost of GHG emissions and other environmental and social externalities.

¹⁰ For additional details on cost components and cost reductions, see, for example, Gurunath, S. Developing Low Carbon Hydrogen Economy. LinkedIn.

¹¹ The Indonesian national oil company, Pertamina, is assessing the feasibility of green hydrogen production from older geothermal power plants. In Nepal, ADB has supported a preliminary assessment of using surplus hydropower for green hydrogen production, where similar cost of production may be possible.

A kilogram of hydrogen has energy equivalent of 1 gallon (3.94 liters) of gasoline. Although \$2/kg is typically referenced as a price benchmark, \$4/kg is at par with gasoline prices in many countries. Figure 8 also indicates that using intermittent versus “baseload” renewable energy does not dictate cost-effectiveness of green hydrogen production, which is consistent with a recent research paper on this topic (Jacobson et al. 2023). At these prices, a possible application today is to use hydrogen to time-shift intermittent solar and wind output to replace diesel-fired electricity generation in remote mini-grid locations.

Figure 8: Cost Factors and Levelized Costs of Production



CAPEX = capital expenditure, H₂ = hydrogen, kW = kilowatt, MWh = megawatt-hour, PPA = power purchase agreement, USD = United States dollar.

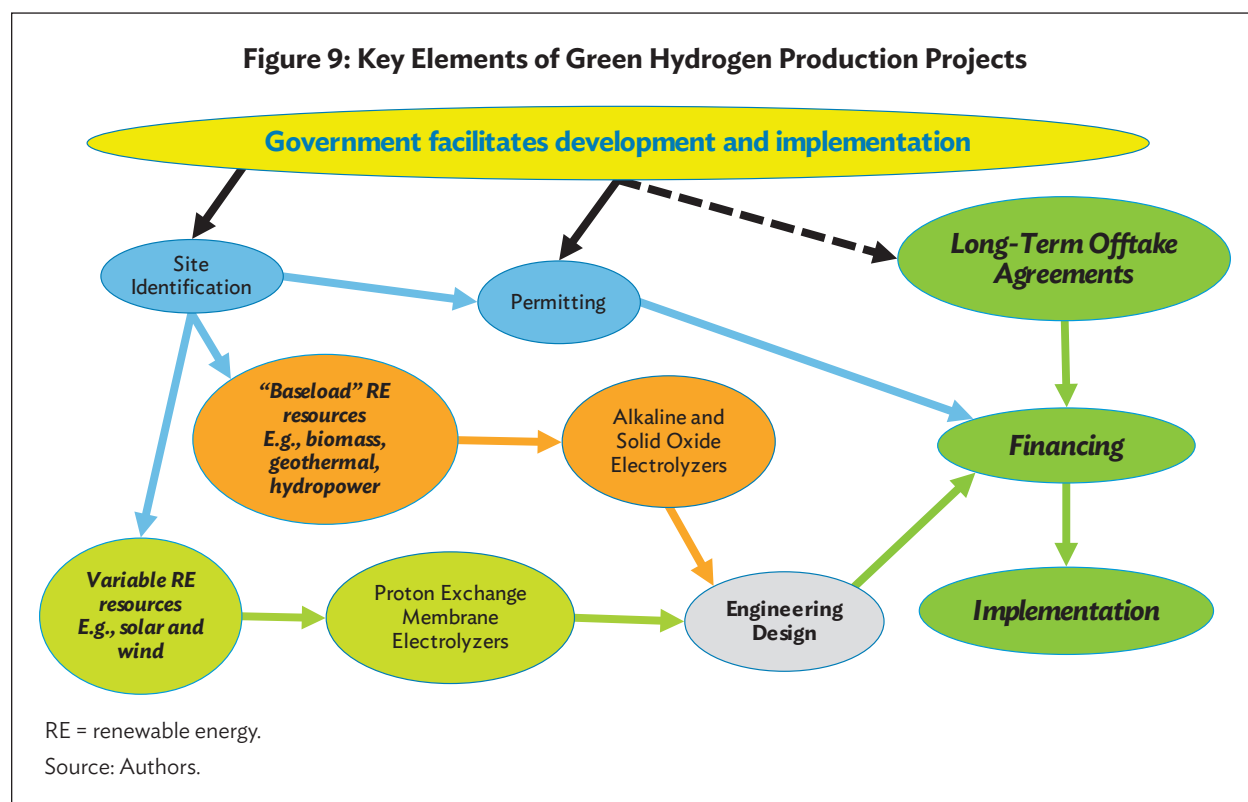
Source: International Energy Agency, 2019d.

The ability to time-shift and location-shift renewable energy makes green hydrogen analogous to crude oil, petroleum products, and natural gas including LNG, hence there is significant interest in green hydrogen on the part of traditional oil and gas companies. The abundance of renewable resources in DMCs points to green hydrogen as an energy democratization vector coincident with sustainable economic growth and decarbonization.

3. Green Hydrogen Production

Approximately 9 tons (9,000 liters) of water are needed to produce 1 ton of hydrogen with 8 tons of oxygen by-product. The efficiency of electrolyzer systems ranges from 60% to 80% depending on the technology type and load factor. Figure 9 illustrates the key elements for hydrogen production projects, including government intervention in the project development cycle and electrolyzer choices matched to renewable energy resources. Existing renewable energy plants can be retrofit with electrolyzers for hydrogen production, which may be an attractive option for renewable energy plants, which are fully amortized and depreciated in areas with ample surplus electricity (see further discussion in section F End Uses – The Merit Order on p. 20).

The theoretical energy required for electrolysis is about 36–38 megawatt-hours (MWh) of electricity per ton of hydrogen. Commercially available electrolyzers today require about 50–60 MWh/ton of hydrogen. Producing hydrogen from electricity results in high energy losses, which vary depending on the efficiencies at each conversion step as well as during storage and transport. The production of green hydrogen via electrolysis results in about 32% losses.¹² Additional losses are expected if the hydrogen is stored (e.g., 5% losses if compressed and 30% losses through liquefaction). If the green hydrogen is converted back to electricity through a combined cycle gas turbine, then there will be an additional 50%–60% loss. The round-trip efficiency of electricity–hydrogen–electricity is about 35%, similar to the thermodynamic efficiency of coal-fired power plants and open-cycle gas turbine plants.



C. Transmission and Distribution

Hydrogen can be produced and used at the point of production or transported as a gas by pipelines or in liquid form by ships or trucks (e.g., liquefied hydrogen or liquid organic hydrogen carriers). Hydrogen can be transported via existing natural gas pipelines at 5%–10% by volume without any modification to the pipeline system. Higher blends of hydrogen with natural gas can be transported in polyethylene pipelines. Hydrogen can also be converted into other chemicals such as ammonia and methanol which can be transported longer distances, or for sale into existing markets. According to the IEA, for large volumes and distances below 1,500 kilometers (km), transporting hydrogen as a gas by pipeline is likely to be the cheapest option, and for above 1,500 km, shipping hydrogen in the form of ammonia is likely to be more cost-effective when factoring in the conversion and reconversion from hydrogen to ammonia and then to hydrogen again. For small volumes, transport via trucks using compressed hydrogen is the most cost competitive.

¹² This is excluding the losses from the conversion of wind/solar to electricity in the first stage.

Hydrogen has high gravimetric energy density: 1 ton of hydrogen contains 2.6 times the energy of 1 ton of natural gas. Hydrogen has low volumetric energy density; at standard temperature and pressure, 1 ton of hydrogen occupies about 11 cubic meters versus 3.3 cubic meters for an energy equivalent amount of natural gas. Compressing or liquefying hydrogen or converting it to ammonia reduces the volume but does not change the mass. For example, it would take about 2.5 ships with liquefied hydrogen or 1.9 ships with green ammonia to move the same amount of energy as one ship with the same volume of LNG. Furthermore, liquefied hydrogen requires a lower temperature than LNG, which imposes additional energy costs for liquefaction.

1. Pipeline Systems

Hydrogen can be transported in pipelines, analogous to natural gas pipelines, but tailored to the chemical and material properties of hydrogen (Figure 10). There are many pure hydrogen pipelines around the world, with about 2,600 km of hydrogen pipelines operating in the US alone. These exist where large quantities of hydrogen are used in chemical industries and refineries. Essentially all these dedicated hydrogen pipelines operate in captive mode, moving hydrogen relatively short distances from the point of production to the point of use in petroleum refining and chemical manufacturing plants. Hydrogen can be transported in existing natural gas pipelines, but hydrogen concentration by volume is limited to about 10% without modification of the pipeline system. Analogous to blending of biodiesel and bioethanol, blending green hydrogen with natural gas in existing pipelines is a straightforward path to commercial operations. Transporting hydrogen via pipeline can be a cost-effective solution when compared to transporting electricity. For instance, the transport of hydrogen is about 10–20 times cheaper than transporting electricity via a subsea cable.

Figure 10: Polyethylene Pipelines Used to Distribute Natural Gas



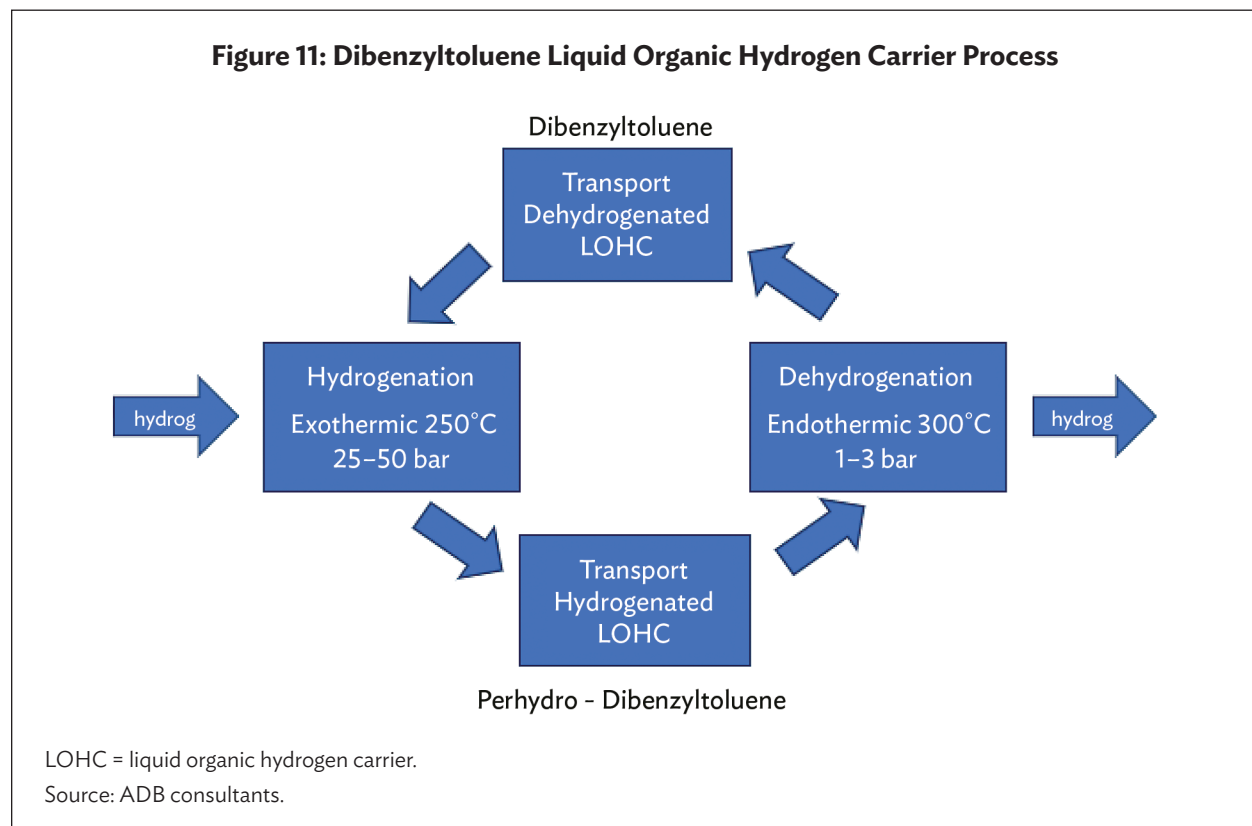
Source: E. Avrigean and L. F. Hunyadi. 2014. *Comparative Study on the Temperatures of Welding the Polyethylene Fittings – Sockets – High Density Polyethylene Pipe*. ResearchGate.

2. Liquid Organic Hydrogen Carriers

Liquid organic hydrogen carriers (LOHCs) are chemical energy storage solutions that use reversible hydrogenation. Hydrogen is fed to a reactor, where it is hydrogenated with a carrier. The LOHC can then be transported to another site, where it can be dissociated from the carrier through a process called dehydrogenation (i.e., hydrogen is separated from the carrier). As soon as the hydrogen is separated, it is ready for use or storage. Logistically, LOHC technology is appealing for transport via truck, rail, ships, and potentially in pipelines.

During the separation process, the carrier is captured for reuse. The carrier is taken back to the site where hydrogen is being produced for another cycle hydrogenation, shipment, and dehydrogenation process. There are many different carriers that can be used as a bonding chemical. These include N-ethyl carbazole, toluene, and dibenzyltoluene, with many others being at near commercialization stage. What differentiate carriers from one another is the quantity of hydrogen they can bond (i.e., absorb) and at what pressure and temperature the bonding occurs. The viability of large-scale LOHC operations has yet to be commercially demonstrated, and in practice, conversion of green hydrogen to ammonia or methanol for sale into existing markets is a more straightforward path to commerciality.

For liquid organic storage, hydrogen is bonded to another chemical, i.e., a carrier, as illustrated in Figure 11. As discussed earlier, LOHC operations have not been commercialized yet and are inherently complicated due to the additional hydrogenation and dehydrogenation steps.



3. Hydrogen Absorbing and Desorbing Metal

Metal hydride storage uses a metal alloy to absorb and desorb hydrogen. A hydride is a mixture of hydrogen and one or more other elements such as a metal alloy (Figure 12). The amount of hydrogen a hydride compound can absorb varies depending on the specific complex chemical composition. Metal hydride cylinders have a limited lifetime before they become contaminated with impurities. The hydride becomes filled with impurities during hydrogen charging (absorption) and discharging (desorption) cycles.

Figure 12: Hydrogen Metal Hydride Cylinders



MH = metal hydride.

Source: G. Friedlmeier et al. 1995. Cyclic Stability of Various Application-Relevant Metal Hydrides. *Journal of Alloys and Compounds*. 231 (1-2): pp. 880-7.

D. Hydrogen Storage

Long-term bulk energy storage requires a stable storage medium, which can be readily scaled up and which is not subject to restrictions on its location. A storage system should not have a high rate of self-discharge or degradation in performance through time. Chemical storage in the form of hydrogen (either as gas or liquid) has the potential to meet all these requirements.

Several forms of hydrogen storage systems are available, each of them having specific advantages and disadvantages. Currently, apart from cost, the main deciding factor in the selection of a storage mechanism is safety. This is followed by “ease of use” of the storage system within a given environment and location. Different types of hydrogen storage mechanisms are mentioned in the following paragraphs. The financial and economic viability of hydrogen storage will depend on local energy pricing and availability of other long-term bulk storage options such as pumped hydropower storage, e.g., hydrogen may be the best option for small island grids switching from diesel generation to renewable electricity.

Compressed hydrogen gas. Hydrogen can be compressed for long-term seasonal and short-term stationary or mobile storage applications. The process of storing hydrogen requires energy (usually electrical or heat) to compress hydrogen to pressures high enough to facilitate a significant storage volume.

Liquefied hydrogen storage. Liquefied hydrogen has been used within the space industry for many decades. Hydrogen becomes a liquid at minus 253°C. Storing hydrogen in a liquefied form requires heavily insulated Dewar tanks to keep the change in temperature between the inside and outside of the cylinder as low as possible (Figure 13). Transporting liquid hydrogen is being piloted on a commercial scale with purpose-built tankers carrying liquid hydrogen from Australia to Japan. The commercial viability of such cryogenic hydrogen transport remains to be proven.

Figure 13: Liquefied Hydrogen Tank



Source: A. Swanger. 2022. World's Largest Liquid Hydrogen Tank Nearing Completion. 11 March.

Storage in salt caverns. Salt caverns and depleted oil and gas fields or aquifers have been used for underground natural gas storage and have the potential to be used for storing large-scale industrial quantities of hydrogen. Globally, operational experience of hydrogen storage caverns exists in a few locations predominantly in Europe and North America. Figure 14 shows a typical underground salt cavern.

Several types of caverns can be used to store gases and hydrogen. They differentiate from one another based on the geological properties. Some of the most common underground caverns are salt caverns. Natural caves are also known as empty cavities, aquifer structures, and mined caverns. Where geography and geology allow, salt caverns have very good containment properties and are almost impermeable to air and water. A storage reservoir is made in the salt by dissolving it using water. Cement is sometimes applied on top of the salt. The gas is then injected and stored for future use, analogous to long-standing practice for underground natural gas storage.

Figure 14: An Example of Salt Cavern

Source: edie. Investigation Begins for Pioneering Salt Cavern Hydrogen Storage Projects.

Ammonia as fuel. Ammonia has been demonstrated as a zero-carbon fuel for trucks, cars, tractors, buses, boats, electricity generation, and any other type of applications where an internal combustion engine is available. Ammonia can also be used in fuel cells and turbines. As such, it has a wide range of potential uses in the stationary and mobile applications, with notable interest in marine transport (Thomson 2023). Figure 15 shows a heavy-duty tractor fueled by ammonia. Only hydrogen and nitrogen molecules are needed to produce ammonia. Ammonia can be produced from different feedstocks, including biomass, electrolysis of water, coal gasification, natural gas through SMR technology, etc.

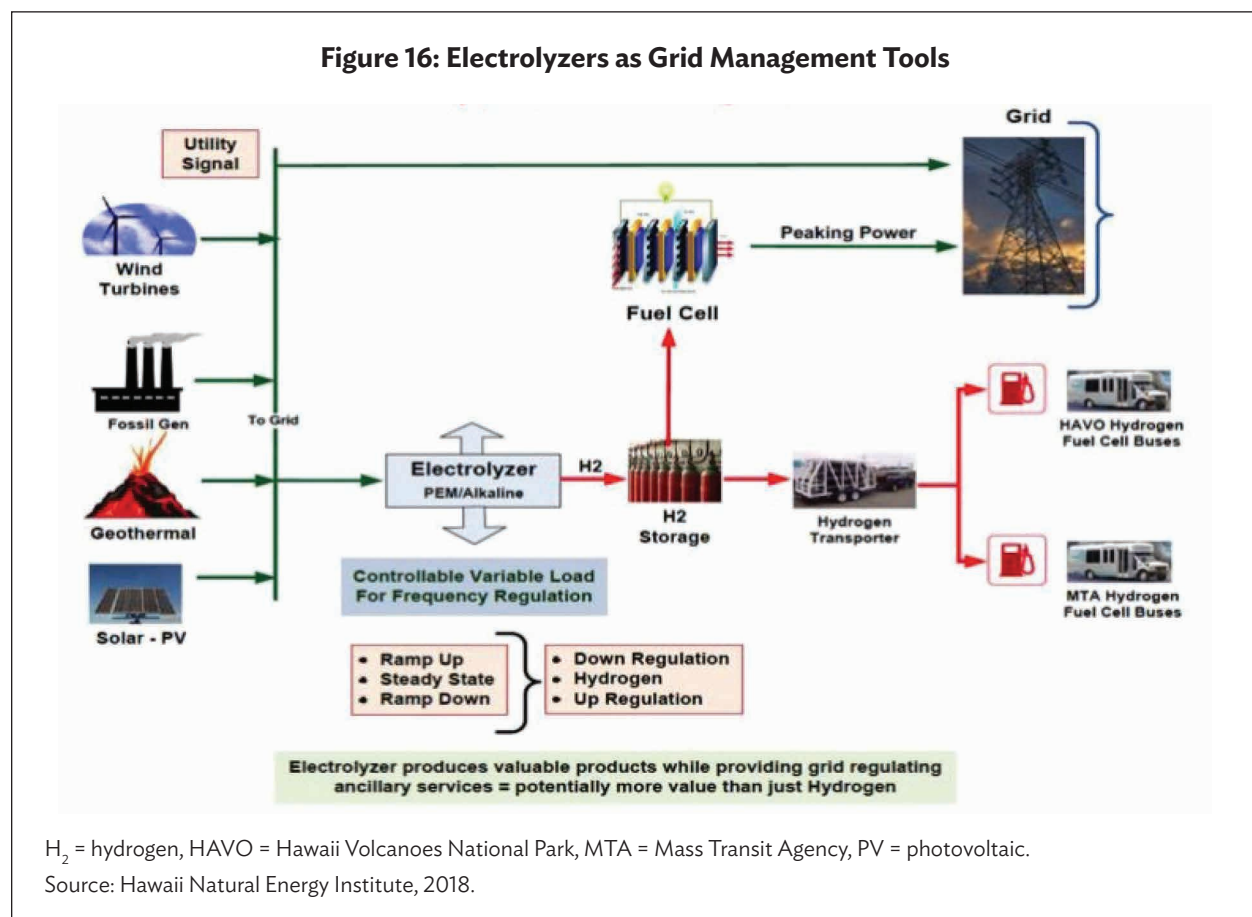
Figure 15: Ammonia-Fueled Tractor

Source: D. Gunderson. 2019. Can Fertilizer Fuel Greener Tractors? *MPR News*. 19 June.

1. Ancillary Services: The Use of Electrolyzers

Electrolyzers can be used for ancillary services to maintain electrical grid balance (generation matches demand in equilibrium), to ensure that the flow of power and its direction is appropriate, and to help the system to recover after a fault or other transient event has occurred on the electrical grid. Electrolyzers can manage demand of electrical energy for hydrogen production via power-to-gas conversion. Hydrogen can be stored for long periods of time, which is advantageous over battery storage. Furthermore, hydrogen can be used by fuel cells to provide electrical power back to the power grid when it is needed. These services are illustrated in Figure 16.

Before the relatively recent appearance of renewable sources of power, ancillary services were provided by large energy generation plants, pumped storage hydropower, and large industrial loads. The rationale behind this is that the electrical system was a one-way system starting with bulk generation, transmission, distribution, and finally consumption. The ancillary services were, conventionally, covered by bilateral agreements and sometimes via auctions.



Large-scale ancillary services are also required for highly specific needs. For instance, the services needed to provide capacity to absorb energy or generate power, the right speed of ramping the generation and then decreasing it, the appropriate dumping load made available at the time needed, the duration that the service is required during the day (milliseconds, minutes, hours); the location (close to where there is a need for such service); and some auxiliary units for measurement, communication, control, the management system, etc. All these made it difficult for the electrical grid operator to involve small-potential ancillary service providers.

Grid networks have changed dramatically and continue to evolve, with many small-, medium-, and large- scale intermittent renewable energy and distributed generation. As such, demand for ancillary services is increasing, with smaller and varied solutions required to manage the intermittency, power variability, and uncertainty of renewable energy generation at the different voltage levels (transmission, distribution). The aim is to provide an electrical network that can cope with all the new events created by introduction of renewable energy. Electrolyzers are now seen as a viable option for providing high-quality ancillary services such as stabilizing the frequency in a power system.

In addition, the oxygen produced by an electrolyzer can be turned into a high-value asset for use in industrial and medical applications. At present, oxygen produced from electrolyzers is considered of low-value potential and is not utilized (and completely ignored in much of the recent literature on green hydrogen). In remote locations, oxygen is an expensive commodity, and producing it locally could turn it into a highly valuable economic asset, as observed during the COVID-19 pandemic in 2020. Figure 17 illustrates a green oxygen system used to store oxygen produced by an electrolyzer supplied with renewable electricity. The oxygen is then transported to a fish hatchery.

Figure 17: Green Oxygen Stored and Used, Increasing Hydrogen Project Value



Source: Pure Energy Center.

2. Potential Leakage of Hydrogen

Given the small molecule size, high diffusivity, and low viscosity of hydrogen, leakage is possible along the entire value chain. The lack of information about hydrogen leakage rates makes it difficult to assess the potential impacts and risks. Today, empirical measurements for on-site production and use of hydrogen in industrial applications are mainly for the safety of stationary operations. Detectors for hydrogen leaks do not operate below the threshold for hydrogen gas flammability. In addition, there is very limited information about how much hydrogen can leak in pipes and compressors. Research is needed to assess how leakage levels might change with repurposed natural gas infrastructure. Moreover, the extension of hydrogen to new uses will result in new value chains that will require the development of international trade and hydrogen infrastructure. Some of these operations, e.g., loading and unloading pressurized or liquefied hydrogen in trucks, ships or storage tanks, present significant risks for leakage (IEA 2022).

Although hydrogen is not included as a GHG in the United Nations Framework Convention on Climate Change, the 100-year global warming potential is estimated at 11.6, almost 12 times higher than the global warming potential of CO₂ (Sand et al. 2023). Therefore, controlling leakage (fugitive emissions)

is critical to ensure that green hydrogen can actually be a climate mitigation solution, i.e., that “the cure is not worse than the disease.” This global warming potential should be considered along with the fact that hydrogen is lighter than air and floats up into and above the atmosphere (as is the case with helium).

E. Environmental Considerations

1. Resource Stress and Emissions

The production of green hydrogen requires fresh water, which may increase stress on surface and groundwater resources in many DMCs and extreme droughts in the future will exacerbate competition for water for different uses. Water treatment is expected to be an integral component of green hydrogen production. Desalination will be required for green hydrogen produced from offshore renewable energy and may be required in many areas where surface and groundwater are not readily available in the needed quantities (e.g., the Middle East). As noted earlier, desalination is expected to increase the cost of green hydrogen production by \$0.01–\$0.02/kg. It should be possible to structure projects with surplus desalination capacity to augment local water supplies.

There are concerns about the impacts of hydrogen leakage and the global warming potential of hydrogen (although hydrogen is lighter than air, like helium, and like helium, hydrogen readily floats into and above the upper atmosphere [see footnote 18]). Further studies are needed to understand the potential impacts and procedures need to be put in place to minimize hydrogen leakages.

2. Air Quality Improvement

Air quality is a major issue in Asia and hydrogen can play a role in improving air quality by reducing transport sector emissions. For example, the European Union (EU) Clean Hydrogen in European Cities project aims to deploy zero-emission hydrogen fuel cell buses and filling stations in cities across Europe. Emissions from a standard 12-meter diesel bus of about 0.45 grams nitrogen oxides/km, 6 milligrams of particulate matter/km, and 2.67 kg CO₂ per liter of diesel fuel, can be eliminated by switching to hydrogen fuel cell buses.

As hydrogen pipelines and the hydrogen supply chains are made ready, pure hydrogen will be used and higher air quality improvement achieved as combined heat and power (CHP) systems can reduce carbon emissions. CHP is an efficient conversion device of one form of energy into two, as it takes waste heat and converts it to usable heat. By generating both heat and power at the same time, CHP can reduce carbon emissions compared to a combination of conventional power generation and a stand-alone heat supply. If hydrogen boilers and cookers are used in cities, only water vapor is emitted, reducing pollution, and improving air quality. Overall, hydrogen technologies could dramatically reduce emissions and improve air quality.

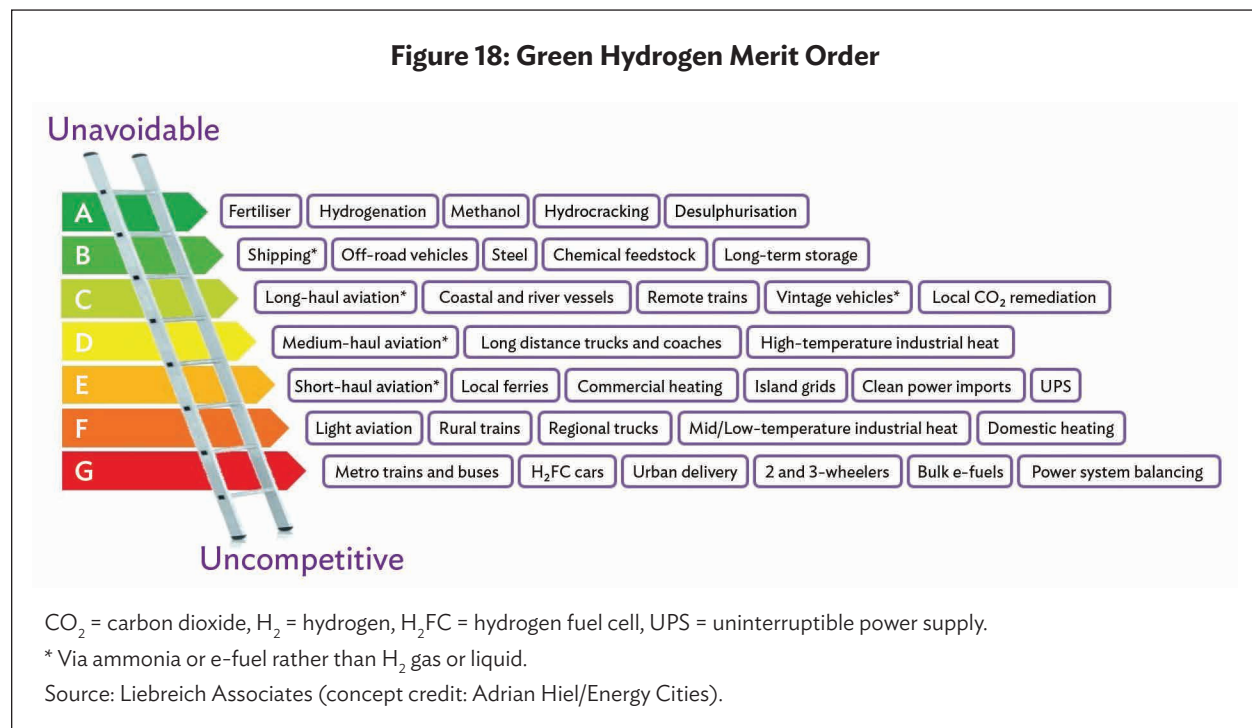
F. End Uses—The Merit Order

Green hydrogen is of interest for clean energy transition because (i) it can enable long-term time-shifting and location-shifting of renewable energy, and (ii) it can be used in hard-to-decarbonize applications such as heavy industry and shipping. Hydrogen can be stored indefinitely and is one of the few prospective options for gigawatt-scale energy storage together with pumped hydropower storage. Hydrogen can be used in industrial processes requiring high temperatures, e.g., cement and steel

production, displacing coal, coke, and natural gas. Hydrogen in the form of e-fuels is also of interest for heavy transport, specifically for ships (Thomson 2023, Dixon 2023).¹³

Green hydrogen production is still in its infancy and in the near term its use should be prioritized toward hard-to-decarbonize applications. For example, steelmaking can be decarbonized with green hydrogen, but increasing steel recycling using renewably-powered electric arc furnaces should be prioritized over green hydrogen for virgin steel production. For passenger cars and other light-duty vehicles, electrification is a cheaper and a more energy-efficient alternative than using hydrogen and fuel cell technology (Collins 2023).

Figure 18 illustrates the hydrogen merit order (also referred to as Liebreich's Ladder) indicating which sectors should be prioritized, with A being the highest priority and G the lowest priority. Broadly, there are three use cases: (i) replacement of hydrogen produced from fossil fuels, (ii) fuel switching, and (iii) new uses. At the top of Liebreich's Ladder is the decarbonization of the existing global hydrogen supply chain (which presumably will decarbonize itself as fossil fuel production and use are displaced by renewable energy in general). This merit order is based on macroeconomic considerations and does not anticipate every possible project concept or investment opportunity in local development contexts.



It is important to understand the massive scale required to decarbonize **only the existing global hydrogen production system**. Producing 100 million tons/year of green hydrogen from renewable electricity at 50 MWh/ton hydrogen requires 5,000 terawatt-hours/year (TWh/y) of electricity, which is about 22% of current total global electricity production and close to 100% of current total global renewable electricity production. The renewable electricity generation capacity required to produce 5,000 TWh/y, if powered by only one renewable resource, is as follows:

¹³ International Maritime Organization regulations driving interest in e-fuels are also sparking interest in reinvention of sailing ships augmented with other renewable energy propulsion. Norwegian Coastal Express. Sea Zero.

(i)	Biomass power at 60% capacity utilization factor (CUF ¹⁴):	951,294 MW
(ii)	Geothermal at 80% CUF:	713,470 MW
(iii)	Solar at 16% CUF:	3,567,352 MW
(iv)	Hydropower at 60% CUF:	951,294 MW
(v)	Ocean thermal energy conversion at 80% CUF:	713,470 MW
(vi)	Offshore wind at 50% CUF:	1,141,553 MW

The scale of investment in the renewable energy inputs alone would be about \$2 trillion, not including electrolyzer costs.¹⁵ Mobilizing this amount of investment is conceivable. According to IEA, global clean energy investments have exceeded \$1 trillion per year since 2015 and are projected to be over \$1.7 trillion in 2023 (IEA 2023). The bigger issues, especially for DMCs, revolve around (i) the potential opportunity costs of pursuing green hydrogen in favor of investments in renewable energy to “electrify everything,” and (ii) direct uses of renewable energy for heating and cooling applications and other value-added economic activities. Stress on local water resources is also expected to be an issue in many locations.

The scale of investment to decarbonize existing global hydrogen production highlights the need to prioritize investment in nature-based solutions, which protect, rehabilitate, and create new ecosystem services that remove CO₂ from the atmosphere and oceans. The scale of investment also invites questions about renewable resource availability, accessibility, scalability, and proximity to existing hydrogen production and use facilities. Terrestrial biomass cultivation is inherently limited due to land availability, even if biomass power is integrated with agricultural production (“agrivoltaics”). Marine biomass could be cultivated at much larger scale in exclusive economic zones, but commercial viability for marine biomass to hydrogen has not yet been demonstrated.

Global installed geothermal capacity is less than 15,000 MW today (Richter 2023). Expanding that by a factor of 60 requires fundamental advances in drilling technology that are energy-intensive and not yet proven (Blain 2022). Ocean thermal energy conversion (OTEC) potential is estimated at 30 terawatts (Xiao and Gulfam 2023), which could be rapidly exploited if a standardized OTEC unit were available to retrofit on existing ships or standardized purpose-built vessels. Current OTEC development is focused on commercializing 1.5–10 MW units, which means more than 70,000 floating OTEC units would be required for 100 million tons per year of green hydrogen.

IEA estimates the technical potential of offshore wind at 420,000 TWh/year, 1.2% of which would be sufficient to decarbonize current hydrogen production. This would require more than 9,400 of the newly available 15 MW offshore wind machines. Global hydropower output is about 4,000 TWh/year,¹⁶ which could produce 80 million tons of green hydrogen per year, if other renewables could replace the hydroelectricity. Solar photovoltaic systems are inherently modular and scalable. Using 10% of the surface area of existing purpose-built reservoirs would support electricity output of 5,600 TWh/year (World Bank Group, ESMAP, and SERIS 2019), but this would require three orders of magnitude increase in global floating solar capacity. Floating wind to hydrogen is being developed offshore France (using a repurposed wave energy test platform), which is a prototype for a 1 GW project offshore Scotland (Fairley 2023). Direct electrolysis of seawater is being tested offshore the PRC (Tianwen 2023).

Of the various renewable resources, offshore wind and floating solar in existing hydropower reservoirs appear to be relatively more attractive in terms of resource availability, accessibility, and scalability. However, developing these resources requires proactive government policy- and decision-making, i.e., governments need to facilitate project development as illustrated in Figure 9.

¹⁴ CUF is the number of hours of electricity output at nameplate capacity divided by 8,760 hours in a year.

¹⁵ Assuming a 20-year lifetime of production systems, the undiscounted cost of eliminating 900 million tCO₂e per year is \$111 per tCO₂e.

¹⁶ International Hydropower Association. Hydropower’s carbon footprint.

Figure 19 illustrates the GHG intensities of various production pathways for steelmaking, which shows that green hydrogen can reduce emissions by more than 95% if hydrogen is produced from 100% renewable electricity. Decarbonizing steel production also requires decarbonizing iron ore production, as well as the transport systems to move iron ore to steel mills (Clifford 2023). Global steel production reached 1.878 billion tons in 2022, of which more than half is produced in the PRC (Conte 2023). Decarbonizing the global steel industry would require 113 million to 169 million tons per year of green hydrogen, which is well above today's global production of 94 million tons hydrogen per year. Assuming 50 MWh/ton of hydrogen, this would require electricity input of 5,650–8,450 TWh/year versus current global electricity production of about 23,000 TWh/year.

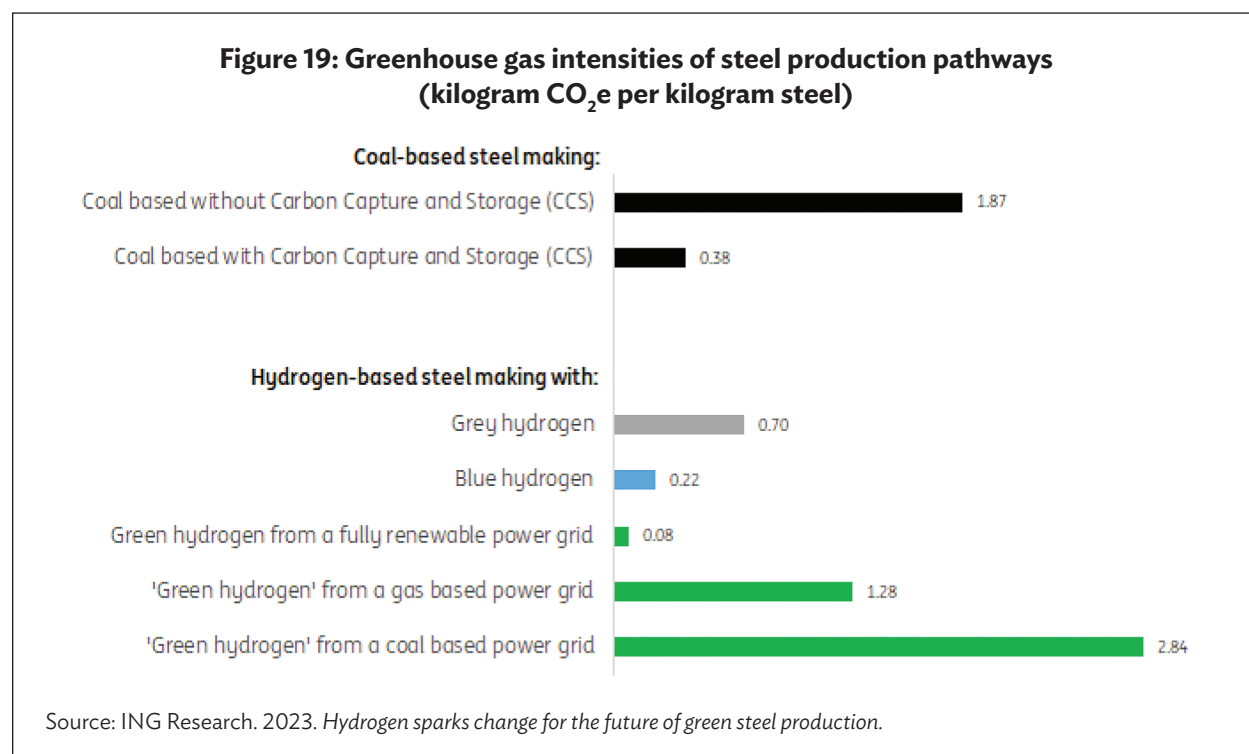


Table 2 summarizes applications that are consistent with the ADB Energy Policy 2021 and ADB Strategy 2030, which might be supported by ADB investment operations. The merit order shown in Figure 18 is based on economic and thermodynamic considerations and should not be taken as an absolute law of nature (in the vernacular of the clean energy cognoscenti, the merit order shown above is Leibrich's Ladder and not one of Newton's laws). ADB support for green hydrogen investments must meet ADB policy requirements, be consistent with Strategy 2030, meet environmental and social safeguards requirements, and should present some value addition for ADB intervention (e.g., first-mover risk cannot be readily mitigated with commercial financing). ADB can utilize existing financing modalities and instruments, mobilizing concessional funds as necessary depending on specific project needs, applying the principle of minimum concessionality (also known as "precision-guided subsidies") to cover financial viability gaps.

Existing financing facilities such as the Association of Southeast Asian Nations (ASEAN) Catalytic Green Financing facility¹⁷ and the recently announced Innovative Finance Facility for Climate in Asia and the Pacific (IF-CAP)¹⁸ may be possible sources of funding for specific projects. Depending on specifics of individual investment operations, ADB funding may qualify as “green” or “blue” finance. ADB has been actively providing blended finance for clean energy and climate change investments for more than 20 years, and based on this experience, it is safe to say that financing can be mobilized if there is a viable investment which warrants ADB support.

Table 2: Merit Order and Potential ADB Support

Merit Order	Application	Potential ADB Assistance	Financing Modality and Instruments
A	Replace fossil H ₂ in petroleum refining and chemical manufacturing	Retrofit of existing facilities via state-owned enterprises or nonsovereign corporate sponsor. Projects must be consistent with host country. Paris commitments, national development plans, and have quantifiable greenhouse gas reductions [ADB Energy Policy 2021 on petroleum sector].	Project loans Nonsovereign equity investment
B – 1	Shipping / e-fuels, e.g., NH ₃ , methanol, other	Green H ₂ production and conversion to NH ₃ , methanol, etc., for sale into existing global markets Green H ₂ production and conversion to e-fuel specifically for regional and domestic shipping routes The rationale is analogous to support for LNG export projects.	Project loans Nonsovereign equity investment Commercial terms if price-taking buyers commit to long-term offtake agreements If no price takers, then blended finance, viability gap financing, contract for difference, etc.
B – 2	Steel	Retrofit of existing industrial plants	Similar to A
B – 3	Long-term energy storage	H ₂ storage only if economically more attractive than other options, e.g., pumped hydropower sites are not available and no other viable options for long-term bulk storage.	Similar to A and B – 1
C – 1	Long-haul aviation	Possible for e-fuels production if sustainable aviation fuel specifications can be met.	Similar to A and B – 1
C – 2	Coastal and river vessels	Public transport operations – ferry services Fishing vessels E-fuel production and bunkering at ports	Project loans and grants (depending on country borrowing capacity) Sovereign loans to state-owned enterprises Nonsovereign loans to private or other commercial enterprises
D	High-temperature industrial heat	Retrofit of existing facilities	Project loans Blended finance

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¹⁷ ADB. ASEAN Catalytic Green Finance Facility (ACGF).

¹⁸ ADB. IF-CAP: Innovative Finance Facility for Climate in Asia and the Pacific.

Table 2 continued

Merit Order	Application	Potential ADB Assistance	Financing Modality and Instruments
E – 1	Public ferry services	Retrofit of existing ferries	Similar to C – 2
		Procurement of new ferries,	Reference case is PSOD/PSIF2 nonsovereign e-ferries investment in Thailand
		Procurement of service contracts for ferry operations	
E – 2	Island grids	Elimination of diesel consumption for 24-7 renewable electricity	Similar to C – 2
			Sovereign for remote islands supported by government policy. Financial intermediation operation can support multiple small projects across a large number of islands.
			Nonsovereign for tourism operations
E – 3	Uninterruptible power supplies	Replacement of diesel backup generators at critical facilities, e.g., hospitals, schools, emergency shelters	Similar to C – 2
F	Light aviation	Health-care services, e.g., delivery of medical equipment, vaccines, and other critical supplies	Project loans
			Blended finance
G – 1	Bulk e-fuels	Green H ₂ production and conversion to e-fuel for regional and domestic shipping routes (rationale is analogous to support for LNG export projects)	Project loans
			Blended finance
G – 2	Power system balancing	Long-term bulk storage where pumped hydropower sites are not available and no other storage options are viable at scale	Project loans
			Blended finance

ADB = Asian Development Bank, H₂ = hydrogen, LNG = liquefied natural gas, NH₃ = ammonia.

Source: D. Millison.

Green hydrogen projects will be location-specific and the rationale for ADB support will vary from country to country and site to site. Alternatively stated, the merit order should be respected but there may be targets of opportunity, i.e., compelling projects for “learning by doing,” which can be implemented in parallel with road mapping, policy development, etc. Electricity and water supplies will have a key bearing on financial viability. For example, green hydrogen production at existing renewable energy plants which are fully amortized and depreciated, with daily surplus output, may be financially competitive because the effective electricity input cost (not the price) is close to zero. The financial viability will be a function of the renewable energy and electrolyzer capacity utilization factors. Electrofuels production from a greenfield renewable energy plant would likely be viable only if there are buyers who commit to long-term offtake contracts, similar to the business model for LNG export projects wherein offtake commitments “anchor” project financing.

The logical top priority for green hydrogen is to replace emissions-intensive fossil hydrogen produced on-site at existing petroleum refineries, fertilizer plants, etc. If these Merit Order A projects can be financed by the existing users and/or owners with commercial financing, there is no justification for multilateral bank support.¹⁹ Alternatively, integration of green hydrogen with intermittent renewable energy into

¹⁹ For example, multiple projects have been announced in India under the government’s national hydrogen program, with minimal support from multilateral development banks and other development partners.

island grids to eliminate diesel generation may have first-mover risk which could justify ADB support. The replicability of Merit Order E-2 projects would further justify ADB intervention, e.g., with a financial intermediation investment operation to support multiple islands. Opportunities for ADB DMCs are discussed further in section V.

Looking ahead, if electrolyzer costs drop as global manufacturing capacity increases (as has been observed for solar, wind, and battery technologies) the viability envelope for green hydrogen will increase accordingly. The merit order presented in Figure 18 will not go away, but the attractiveness of green hydrogen for hard-to-abate sectors will improve as electrolyzer efficiency increases and electrolyzer costs decline.²⁰

III. OVERVIEW OF DEVELOPMENTS IN GREEN HYDROGEN

A. Business and Commercial Operations

Commercial green hydrogen operations are still rare, but multiple gigawatt-scale projects have been announced (Table 3). Most of these are in three geographic hubs: Western Europe and the North Sea, the Middle East, and Australia. Most of the projects in the Europe and/or North Sea hubs are intended to displace existing gray hydrogen and help decarbonize heavy industries with some developments at the Middle East and Australia hubs intended for export. Some notable projects that have been recently announced are as follows:

- (i) A project at Duqm in Oman will be built in stages with ultimate capacity of 25 GW of solar and wind; an initial contract \$6.7 billion contract was announced in June 2023 (*Oil and Gas* 2023, IEA 2023).
- (ii) One of the largest green hydrogen projects conceived is led by the NEOM Green Hydrogen Company in Saudi Arabia, which will produce up to 210,000 tons of hydrogen per year from up to 4 GW of solar and wind capacity. The total investment of \$8.4 billion is being anchored by \$6.1 billion in nonrecourse financing which reached closure in May 2023 (Segal 2023).
- (iii) In May 2023, a groundbreaking event was held for the FlagshipONE e-methanol production facility with 50,000 tons per year capacity, the largest e-fuel plant in Europe (Reve 2023). The e-methanol is targeted for sale into the maritime shipping sector, where development of cleaner fuels and propulsion systems are being driven by International Maritime Organization regulations for sulfur emissions control and 50% GHG reductions by 2030.
- (iv) Also in May 2023, the South Corridor Trans-Mediterranean pipeline was announced, which is intended to connect Germany via Italy with Algeria, Tunisia, and Egypt. The green hydrogen will be produced from solar and wind farms, which are yet to be constructed (Dokso 2023). A more ambitious pipeline from the Persian Gulf to Europe has been deemed feasible according to a recent study (Kilgore 2023).

²⁰ It is important to remember that mobile telephones were extraordinarily expensive and unaffordable a few decades ago, but today more than 5 billion people have mobile phones. If electrolyzer costs decline exponentially, in 5–10 years the business cases for green hydrogen will be much more compelling.

- (v) ACWA Power has announced a green hydrogen and green ammonia project in Uzbekistan with initial capacity of 3,000 tons hydrogen per year (ACWA Power 2023).
- (vi) In June 2023, Inter-American Development Bank approved a \$400-million loan for green hydrogen industry development in Chile (Inter-American Development Bank 2023).
- (vii) US-based start-up Equatic is commercializing a process which removes CO₂ from seawater while simultaneously producing carbon-negative hydrogen. The company recently signed a pre-purchase agreement with Boeing for the hydrogen offtake (Green Car Congress 2023).
- (viii) One of the largest projects to be commissioned is in the PRC, where the green hydrogen will replace gray hydrogen in an existing petroleum refining and chemical manufacturing complex (Collins and Yihe 2023).

Table 3 lists several gigawatt-scale projects which have been announced, with completion expected by 2030. All these developments will utilize solar, wind, or a combination of solar and wind energy.

Table 3: Notable Green Hydrogen Development

Project	Location	Renewable Energy and Electrolyzer Capacity	Hydrogen Yield (Million tons/year)	Completion Date
HyDeal Ambition	Multiple sites in Spain, France, and Germany	95 GW solar power 67 GW electrolyzer	3.6	2030
Reckaz	Western and central Kazakhstan	45 GW solar and wind 30 GW electrolyzer	3	2028
Western Green Energy Hub	Southeast and western Australia	50 GW solar and wind 28 GW electrolyzer	3.6	2028
Aman	Mauritania	30 GW solar and wind 16 – 20 GW electrolyzer	1.7	Not available
Green Energy Oman	Oman	25 GW solar and wind 14 GW electrolyzer	1.8	2038
Asian Renewable Energy Hub	Pilbara, Western Australia	26 GW solar and wind 14 GW electrolyzer	1.6	2027–2028
NorthH2 (4 GW)	Northern Netherlands	10 GW offshore wind 4 GW electrolyzer	1	2030

GW = gigawatt.

Source: FuelCellsWorks. 2022. Nine of the Largest Green Hydrogen Projects 2022. 12 May.

B. Standards and Regulations Barriers

Current regulations were not developed with a focus on green hydrogen. Regulators and legislators need to address the barriers and obstructions faced by the hydrogen community. Internationally, there is a need for globally harmonized codes and standards that focus on electricity and heat generation, and transport market segments. New legislation may be needed to support the overall supply chain infrastructure. Table 4 and Table 5 are snapshots of the barriers to the industry (see further discussion in Section IV). Specific hydrogen training is a barrier that is very relevant to developing nations in Asia and the Pacific due to the lack of available technical capacity in this technology. Although the other barriers listed apply to the global industry, they are relevant to countries in the Asia and Pacific region as well. A recent report sponsored by the Government of New Zealand is a useful reference for existing standards (Standards New Zealand 2023).

Table 4: Regulatory and Standards Barriers

Barriers	Description	Stakeholders
Certification	Certification schemes that provide Guarantee of Origin are lacking or not yet widely accepted. Such a vacuum requires an urgent attention from legislators and regulators to allow national, regional, and international trading of renewable hydrogen.	Public authorities and private sector manufacturers
Lack of legislation for green hydrogen	There is currently no regulation emphasizing that green hydrogen must be used within the industrial sectors. The industrial sector is the highest user of hydrogen and legislating that a percentage of hydrogen use must be green will provide a clear message to the user. Such legislation should also provide incentives to the sector to ease the transition.	Legislators, policymakers, government leaders
Lack of regulation framework for installing large-scale hydrogen systems	Though many countries have produced pathways and road maps, these countries have not provided regulatory framework to support the transition to hydrogen. For instance, Europe envisages gigawatts of electrolyzer installations by 2024 and 2030, but there is no framework (financial, legislative, etc.) tailored to support such a deployment. This is also true for Australia and other countries that are leading the development of green hydrogen among other hydrogen pathways.	Legislator, regulator, governments, politicians, and industry
Lack of gas blending regulation / legislation	It is important to set up legally binding regulation that clearly set hydrogen blending quantities and limits in natural gas grids for countries. Such legislation is to provide a clear framework for investors into carbon capture and storage or green hydrogen injection into natural gas and set the financial structure ensuring medium- to long-term financial viability. Country-specific study would be required to blend hydrogen into existing gas infrastructure, because material and condition would be different among countries.	Legislator and gas operators
Lack of harmonized standards for filling stations	Hydrogen filling stations still lack comprehensive sets of harmonized standards. This is also true for the permitting processes, which can take many months and at times could take over a year to obtain. The difficult permitting process dramatically increases project development cycles, escalating financial and technical risks, thus reducing the deployment of stations.	Planners, developers, local and national authorities, hydrogen gas companies, hydrogen vehicle manufacturers, and manufacturer of filling stations

Source: Compiled by authors.

Table 5: Technical and Training Barriers

Barriers	Description	Stakeholders
Lack of development of heating systems	Currently, the heating and electrical sector is responsible for about 30% of the world's greenhouse gas emissions (Ge and Friedrich 2020). However, very little has been done to target this market. As there is currently no legislation, regulations and/or standards or even a clear pathway/road map in support for hydrogen heaters or cookers, investments in research and development as well as projects are low. However, this sector is vital, employing thousands around Asia and the world, and has a very strong prospect for manufacture. Legislating that a percentage of heating systems must use hydrogen ready equipment within public buildings will send a clear message to the industry that new products must be developed. It will also support infrastructure development focus on cooking and heating.	Heating manufacturers, legislator, regulator, and research centers

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Table 5 continued

Barriers	Description	Stakeholders
Safety	To date, there is still high apprehension about hydrogen fuel due to the Hindenburg incident of 1937. Lack of commonly accessible knowledge about hydrogen fuel leads to members of the public and some decision-makers formulating reservation, distrust, and hesitation in starting up a project or purchasing a hydrogen system such as a car or other. There is an urgent need to develop highly visible hydrogen safety demonstration case studies for the different hydrogen applications (in all sectors). Special attention should be given to the domestic sector as well as the industrial one. The highest visibility and transparency is to be given to ensure wider acceptance.	Politicians, media, educational institutions, training organizations, hydrogen safety research institutions, private sector
Additional research and development costs	Original equipment manufacturers are still hesitating to invest in developing hydrogen products. This is true for the heating, cooking, etc. household appliances. Original equipment manufacturers concerns are that substantial additional costs will be incurred in the research and development phase with new designs, requirements for new certification (currently there is a lack of certifications for hydrogen appliances and lack of testing facilities to obtain such certification), and the need to launch new manufacturing lines with no guarantee that there is a demand. Original equipment manufacturers will not engage in developing new products unless there is a strong demand and as such, they are calling for incentives and support both at a regulatory and political level, with a clear framework that they can work with.	Heating developers, research institutions, manufacturers, government funding organizations
Distribution channels	As hydrogen technologies are near the commercialization stage, there is still no standard distribution channels. Without clarity on who takes the risks for financing distribution of hydrogen goods (as currently hydrogen goods are featured as highly complex and limited to the few), original equipment manufacturers will not support the investment in the technology.	Government, original equipment manufacturers, distribution channel specialists
Specific hydrogen training	Installers require a framework to be trained and receive a qualification certificate so that they can install hydrogen systems. Such framework should be similar to electrician or gas engineers, but solely focused on hydrogen installations. This is a barrier that needs a rapid attention by the authorities to develop the with the right training and program in addition to the right facilities for such training.	Training centers and colleges

Source: Compiled by authors.

C. Incentives for Incubating Industry Growth

Green hydrogen today is an expensive proposition compared to hydrogen produced from fossil fuels, as has been the case with renewable energy development. In general, incentives are needed to support hydrogen as an integral part of the transition to a zero-emission economy due to the scale of investment envisioned. As discussed in other sections of this paper, green hydrogen has inherent manufacturing economies of scale due to the modular nature of renewable energy and electrolyzer technologies. Based on experience in solar and wind development, a time-bound commitment to scale is critical for increasing global production capacity which will drive down the cost of hydrogen production. Alternatively stated, a combination of precision-guided subsidies and brute force investment is needed to create manufacturing economies of scale and create a virtuous development cycle.

Table 6 and Table 7 present recent announcements providing clear indication that green hydrogen is gaining global momentum. These are just a few sources of local, national, and regional funding, but are already totaling well over \$30 billion for hydrogen and associated technologies.

Table 6: Hydrogen Incentives in Europe and North America

Country/Region	Date	Program Announcement
European Union	September 2022	The European Commission approved €5.2 billion in public funding for hydrogen projects that could unlock an additional €7 billion from the private sector (European Commission 2022).
Germany	November 2022	The Government of Germany set up two new funds worth a total of €550 million to support development of the global hydrogen economy through cooperation, especially with emerging and developing countries. €250 million is allocated to the PtX Development fund to promote hydrogen development in other countries. The economy ministry of Germany also set up the PtX Growth fund with €300 million to support companies in Germany with the aim of accelerating the global market ramp-up and infrastructure for green hydrogen overall. The funds to promote these projects are being administered by Germany's development bank KfW (Clean Energy Wire 2022).
Portugal	January 2023	The Government of Portugal plans to award 10-year contracts to developers for 3,000 tons of green hydrogen. In 2021, the Government of Portugal launched a call for hydrogen projects worth €16 billion (Sanchez Molina 2023).
United States	September 2022	The United States Department of Energy opened applications for a \$7-billion program to create regional clean hydrogen hubs across the country. The Department of Energy aimed to have 6–10 hubs (United States Department of Energy 2022). Tax credits up to \$3/kilogram (kg) for hydrogen production from renewable energy sources or nuclear power are included in the Inflation Reduction Act 2022 (Hanafusa 2022).
Canada	March 2023	(i) The federal government of Canada announced a refundable Clean Hydrogen Investment Tax Credit. The tax credit will range from 15%–40% based on the life-cycle carbon intensity of the hydrogen (Government of Canada 2023). Under the program, the maximum tax credits are as follows: (a) 40% credit when life-cycle greenhouse gas (GHG) emissions from production of clean hydrogen are less than 0.75 kg of carbon dioxide equivalent per kg hydrogen produced (b) 25% tax credit when GHG emissions are between 0.75–2 kg of carbon dioxide equivalent per kg of hydrogen produced (c) 15% tax credit when GHG emissions are between 2–4 kg carbon dioxide equivalent per kg hydrogen produced (ii) Greater tax credits are available for better working conditions.

Source: Compiled by authors.

Table 7: Hydrogen Incentives in Asia and Australia

Country	Date	Program Announcement
Australia	2023	The Government of Australia invested \$1.34 billion in a new Hydrogen Headstart program. The program will provide revenue support for large-scale renewable hydrogen projects through competitive hydrogen production contracts (Department of Climate Change, Energy 2023).
India	April 2023	India approved a \$2.1-billion incentive plan to promote green hydrogen. The government will give incentives worth at least \$0.36 per kg of green hydrogen. The government will award about \$1.58 billion for producing green hydrogen and the rest of the budget will be used for manufacturing electrolyzers (Singh 2023).
Japan	2021	Japan allocated \$3.4 billion from a green fund to accelerate research and development in hydrogen over the next 10 years. One specific project was allocated \$500 million to develop a large-scale hydrogen system by water electrolysis using electricity from renewable energy (Reuters 2021).

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Table 7 continued

Country	Date	Program Announcement
People's Republic of China	2022	The Government of the People's Republic of China laid out a Hydrogen Industry Development Plan (2021–2035). The plan targets green hydrogen production to reach 100,000–200,000 tons per year by 2023. The plan envisions the use of green hydrogen in other sectors, which include energy storage, electricity generation, and industry. Information about investment budget has not been disclosed (IEA 2023).
Republic of Korea	2022	The Republic of Korea hydrogen council launched a \$382-million fund with 70% of the capital allocated to infrastructure and the remaining 30% allocated to technology for the next 10 years. The fund aims to construct a value chain that includes production, distribution, and consumption of hydrogen, and to promote commercialization of environment-friendly hydrogen technology (Nam 2022).

Source: Compiled by authors.

The information in Table 7 indicates that different countries have different incentive and funding strategies. Overall, two main types of incentives are available for hydrogen technologies: (i) long term (or medium term) and (ii) one-off grant funding. Most of the hydrogen grants available around the world are based on the one-off grant model. Very few countries have developed long-term financial mechanisms for green hydrogen. Some countries such as the US and Canada are using tax credits as an incentive. The EU strategy on hydrogen for a climate-neutral Europe (COM/2020/301) was adopted in 2020 and suggested policy action points in five areas: investment support, support production and demand, creating a hydrogen market and infrastructure, research and cooperation, and international cooperation. By the first quarter 2022, all the EU's 20 action points were implemented and delivered (European Commission 2022).

IV. CHALLENGES OF TRANSITIONING TO GREEN HYDROGEN

Key challenges in transitioning to green hydrogen are discussed in the following sections.

A. Cost of Production and Financial Viability

The cost of production of green hydrogen today is generally higher than the cost of production of hydrogen from natural gas and coal, with some exceptions depending on local natural gas prices. Furthermore, substantial investments would be needed to produce green hydrogen in the same volume as fossil-based hydrogen. The production of green hydrogen also competes with the use of renewable electricity, particularly in many DMCs that do not yet have sufficient renewable energy capacity to allow for excess production to be stored and in sufficient constant volumes to enable a financial business model. However, as natural gas and coal prices increase and costs of renewable energy and electrolyzer systems decrease, green hydrogen is likely to become an increasingly competitive option in the next 5–10 years. Table 8 provides information about the key technical factors that affect financial viability of a hydrogen project and Table 9 provides information about policy and other factors that affect financial viability.

Table 8: Key Technical Factors Affecting Financial Viability of a Hydrogen Project and Recommended Actions

Factor	Impacts and Actions
Load factor of electrolyzer	A higher load factor leads to a higher return: a load factor of 40% or higher can be financially viable if electricity input price is \$40/megawatt-hour or lower. Lower electrolyzer load factor may be viable with lower electricity prices, which may occur periodically when there is surplus grid power available. Capital expenditure (CAPEX) on electrolyzers is expected to decline as global manufacturing capacity increases. Electrolyzer load factors correspond closely to capacity utilization factors of renewable energy power plants,^a which are typically as follows: Geothermal 70%–80% Biomass power 60%–70% Hydropower 50%–60% Wind 30%–45% Solar photovoltaic 15%–25% Existing renewable energy plants with high load factors should be the most attractive, if green hydrogen production does not “crowd out” electricity supplies and services.
Electricity price	Lower electricity prices lead to lower cost of hydrogen production. Hydrogen development will be more favorable in countries with low renewable energy electricity prices. As technology CAPEX declines and electrolyzer efficiencies improve, countries with higher renewable energy prices can be targeted. Hydrogen project feasibility will depend on country-specific market factors, specifically availability of surplus electricity; fixed or flexible electricity pricing (i.e., fixed offtake prices under power purchase agreements or spot market pricing); need for long-term bulk energy storage, policy for value-added end use of electricity; and marginal cost of electricity production. E.g., for renewable energy power plants that are fully amortized and depreciated, the cost of electricity production is effectively zero, and these power plants are logically the best candidates for green hydrogen production. Regulations should encourage use of surplus grid electricity and use of existing low-cost renewable energy plants for hydrogen production.
CAPEX and efficiency of electrolyzer	Both CAPEX and operating expenditure costs are dropping rapidly, but still high when compared to incumbent technologies. Currently, hydrogen produced from renewable energy is still more expensive per kilogram than hydrogen produced from fossil fuels. Three points must be monitored for better hydrogen price per kg: the cost of electricity (must be low), the CAPEX of electrolyzers (will drop further in the future with scaling-up), and the efficiency of electrolyzers (must be higher) to produce more hydrogen per kilowatt-hour of electricity. Removal of import taxes for electrolyzers and other equipment sourced from international markets is advisable for first-mover projects.

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Table 8 *continued*

Factor	Impacts and Actions
Water supply for electrolysis	Hydrogen production from water by electrolysis requires 9 liters of deionized water to produce 1 kilogram (kg) of hydrogen. Desalination of seawater or other non-potable water may be advisable to reduce stress on freshwater resources. Desalination is expected to increase the cost of hydrogen production by about \$0.01–\$0.02 per kg hydrogen^b (IEA 2019).
Transportation and storage infrastructure	Cost of hydrogen transportation and storage will affect project viability. Availability of existing gas infrastructure and geological underground storage (for large-scale storage) should be studied to improve project viability. For maritime transport of hydrogen, several technologies are available including compressed or liquefied hydrogen, conversion to ammonia, and liquid organic hydrogen carriers. The most suitable method should be applied considering the entire supply chain, along with relevant energy loss through conversion and storage, hydrogen purity requirements at point of utilization, safety design, etc.
On-grid or off-grid	Proton exchange membrane electrolyzers are suitable for both on-grid and off-grid applications. The alkaline electrolyzers are less amenable to rapid variation in power (e.g., from wind generation) and are best suited for on-grid installations (novel materials are being developed to provide off-grid capabilities). Off-grid systems are much more expensive than on-grid, and as such it is preferable to install electrolyzers on-grid with a renewable energy management system for the electrolyzer to absorb excess energy.
Compressor operating expenditure	Compressors are high-capital expense components, but compressor operating expenditures may have greater impact on project viability, as most of the installed system failures are related to compressors. Project design should incorporate an appropriate maintenance program (European Commission 2020).
Fuel cell lifetime	Lifetime of fuel cells and associated guarantees are still not in line with incumbent technology. Project planning should include specifications for fuel cell lifetime to be consistent with the project life cycle.

^a Typical capacity utilization factors for power plants in the United States (US) can be found here: US Energy Information Administration. Electric Power Monthly.

^b Using reverse osmosis for desalination requires 3–4 kilowatt-hours per cubic meter of water and costs around \$0.7–\$2.5 per cubic meter of water. The desalination process requires less than 0.1% of the energy consumed in electrolyzer operation.

Source: Compiled by authors.

Table 9: Key Policy and Other Factors Affecting Financial Viability and Recommended Actions

Factor	Impacts and Actions
Policy development	Barriers to hydrogen deployment should be removed via supportive policy framework with incentives to facilitate private investment (e.g., waiver of taxes on imported equipment). Regulations should encourage use of surplus grid electricity and use of existing low-cost renewable energy plants for hydrogen production. Public purchasing should be utilized where possible to create “market pull” to accelerate deployment speed, decrease costs, and enhance the understanding of a project life cycle at all levels. Viability gap financing could help reduce investment risk and promote private sector investment, especially for “first-mover” projects.
Scale of supply and demand defined by country road maps with clear targets	Green hydrogen presents a classic “chicken-and-egg” situation where lack of demand inhibits development at scale, and vice versa. Electrolyzer and fuel cell technologies are inherently modular and exhibit manufacturing economies of scale; cost declines are associated with increasing scale of deployment as has been observed for solar photovoltaic, wind, and battery storage. First-mover projects will have higher costs, but the longer-term “portfolio” costs should decline as more projects are completed and the market matures. Lessons learned from national renewable energy programs should be incorporated into hydrogen road maps. In hydrogen exporting, a significant analogy can be made with liquefied natural gas (LNG) industry, where LNG export projects have threshold scales for financial viability, and project financing is anchored by longtime offtake agreements from credit-worthy purchasers. LNG exports have traditionally been developed with price formulas linked to crude oil market prices rather than fixed price per unit of energy (as is common with renewable electricity development). Road maps should be clear in translating policy objectives in terms of scale, public sector funding support, timelines, creation and expansion of distribution value chains, and competitive trading among multiple market players (see Section 3.1 for details). Government policy and road maps should identify priority market segments and end users, specifically hard-to-decarbonize heavy industries, as well as deployment pathways of least resistance (such as blending of hydrogen in existing gas pipeline systems). Road maps should incorporate Nationally Determined Contributions under the Paris climate accord as appropriate.
Standardization	National standards and codes for permitting including safety will reduce the design and installation cycle of a hydrogen project. Standards, codes, and best practices for existing “brown” and “black” hydrogen should be modified as necessary to enable green and blue hydrogen projects. Harmonization across national jurisdictions should be a high priority. Lessons learned from the LNG industry should be incorporated into standards and regulations.
Carbon price impact	Lack of a carbon price and associated framework can reduce the potential for green hydrogen to become viable. Developing a market for guaranteed origins for green hydrogen will support the financial viability and accelerate the deployment of the technology. Negative and positive lessons from under the Kyoto Clean Development Mechanism must be used to ensure any new Guarantee of Origin is effective. However, if there are buyers who will take the current prices on green hydrogen, then there is no cost barrier and no need for support from a price on carbon emissions.
Ancillary service	Electrolyzers and fuel cells can be used to resolve many grid issues, analogous to existing on-grid storage using pumped hydropower, batteries, and other emerging storage technologies. Grid stability (frequency and voltage control) and load balancing (time-shifting) are obvious applications where relatively smaller projects may be able to provide high-value services to grid operations. Policies and regulations should be formulated accordingly to enable such ancillary services in electricity markets.

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Table 9 continued

Factor	Impacts and Actions
Oxygen	Each unit of green hydrogen from electrolysis is accompanied by eight units of oxygen by-product. Currently, oxygen producing incumbent technologies are associated with carbon dioxide (CO₂) emissions. Developing a framework for green oxygen from electrolysis with certificate of origin will increase the value proposition for the hydrogen community, and putting a tax on CO₂ for oxygen production will reduce green oxygen waste. Policies and regulations should be properly formulated to enable expansion of green oxygen utilization.
Land acquisition	Land acquisition is often a major project risk which can delay project execution and drive up development costs. Government can facilitate project development and investments by prioritizing sites in proximity to existing infrastructure such as gas pipelines, power plants, and other end users. Specifically, government policies should prioritize replacement of existing brown and black hydrogen production, and end uses with green and blue hydrogen systems.

Source: Compiled by authors.

B. Regulations and Standards

As an evolving amalgamation of technologies, regulations, and standards on the production and utilization of green hydrogen are not yet in place, although existing standards for hydrogen from fossil fuels do provide a foundation on which to build. Individual countries have developed their own standards and regulations or even unwritten or unclear rules. There is a need to develop uniform standards, agree on operational rules, and harmonize safety standards, to stimulate and foster the deployment of the hydrogen market. The current informal “color” scheme of hydrogen needs to evolve to an internationally agreed system that certifies the GHG content of hydrogen produced.

To date, there is no commonly agreed standard for green hydrogen, indicating that the differences in defining, interpreting, and describing green hydrogen from country to country has a negative effect on standardization. Having a globally (or even regionally) agreed definition would pave the way for the development of a standard, thus allowing for a legislative framework to be produced, and provide different incentives.

Different levels of standards can be divided into three groups: (i) national standards (i.e., the United Kingdom, the US, Germany, France, etc.); regional standards (i.e., EU); and international standards (i.e., International Standards Organization, International Electrotechnical Commission). Usually, national and regional standards feed into international ones.

Generally, standards are directly interlinked to a piece of legislation, again, national, regional, or global. Global standards are more difficult to implement than regional or national standards in that they must be linked to national legislations to be enforceable.

A standard focused on tradeable guarantees of origin is critical to define the GHG content of hydrogen. Guarantees of origin could be of similar nature to the renewable energy industry. The aim is to provide the appropriate securities to the purchasers that they are buying green hydrogen and not highly polluting hydrogen. The CertifHy²¹ certification is the first scheme to issue guarantees of origin for low-carbon hydrogen.

²¹ CertifHy. CertifHy Enters into Phase 3 to build a H₂ GO Market As Well As a H₂ Certification Scheme for REDII.

Currently, several organizations develop new national and international standards. However, substantial challenges face the standardization community, as different organizations developing a standard have their own definitions and their own system boundary. This has been causing inconsistencies between the different standards, and when legislative frameworks are created based on the standards, these may not be able to reach cross-border trading, limiting the outreach and international trading for green hydrogen.

For instance, CEN-CENELEC/TC 6²² aims to develop an international green hydrogen standard. The TC 6 focuses its efforts on defining the terminologies, how to deal with guarantees of origin, and safety. It also aims at investigating crosscutting issues including, but not limited to, operational conditions, training, education, and social aspects. The TC 6 has opted to use the CertifHy as a starting point to their work.

In France, Afhypac is developing a standard focused on the production of hydrogen. The system boundary is at the point of production, meaning hydrogen must be from a 100% renewable source. The type of work is driven by a working group all motivated by guarantees of origin.

TÜV SÜD, in Germany, is working to develop a German national standard. The overall aim is to reduce emissions, and the baseline is hydrogen from steam-methane reforming (SMR). To qualify for the scheme, the technology being used should demonstrate a decrease of CO₂ emissions between 35% to 75% (production process dependent). The system boundary is the point of use. The standard includes renewable electrolysis, SMR, biomethane, and pyro-reforming of glycerin.

The California Low-Carbon Fuel Standard is a mechanism developed for the transport fuels focused on carbon content of fuels including alternative fuels (such as ethanol). In 2018, the California Air Resources Board defined that renewable hydrogen within California can be produced from some feedstocks including (i) water electrolysis and other aqueous solutions using renewable power, (ii) catalytic cracking or SMR of biomethane, and (iii) thermochemical conversion of biomass (this includes the organic portion of local municipal solid waste).

The definition of the California Air Resources Board differs from Europe, creating major issues between EU and California legislation as related to the minimum carbon intensity for compressed hydrogen. In California, this is set at 76.1 grams carbon dioxide equivalent per megajoule for on-site reforming with renewable feedstocks (i.e., biomass), and this is much higher than the allowed threshold in the EU CertifHy scheme. Such a difference in carbon tolerance and the difference in accounting methodologies means that guarantees of origins' trading between both the US and the EU is currently not possible. This is why the definition of green hydrogen is so important and that a consensus must be reached internationally (or at least, at a regional setup).

C. Road Maps and Targets

Road maps and national strategies are essential documents that play a key role in the deployment of new technologies. They provide dates, time frames, strategic directions, areas to prioritize, and targets to be met for a given industry. They also identify distinctive niches (e.g., car, truck, combined heat and power, etc.) in the different sectors (e.g., industry, transport, building, etc.) that could create an initial potential for mass markets, for a given country or region. Without a regional or an economic vision, it is difficult to develop local hydrogen strategies, especially if the country aims to export hydrogen in the future. National target values and time frames are important to foster the regional and/or global development of a carbon-neutral economy with hydrogen and value chain.

²² CEN is the European Committee for Standardization and collaborates with ISO, while CENELEC is the European Committee for Electrotechnical standardization and collaborates with IEC—TC6 is Technical Committee 6.

These road maps are also important to understand what the industry wants and needs from governments in policies, legislation, regulation, codes, and standards, permitting and planning, as well as financial support to begin technological development and deployment. They provide a clear set of objectives with short, medium-, and long-term time frames. The aim is to converge toward a given vision, such as an Asia-wide hydrogen vision.

For many countries, road map objectives will vary, at times significantly. One of the Australia's main objectives, for instance, is to export hydrogen to other countries, as it has substantial natural resources that it can use to produce green hydrogen. Japan and the Republic of Korea, by contrast, do not have enough natural resources to do so in quantities sufficient to supply their national markets, and therefore need to import the gas in large quantities. The individual road maps for these three countries will therefore differ and diverge on their main principles and purposes. However, a bottleneck exists among them in the lack of a common road map to reveal these different needs and define delivery time frames, hence lowering technical, financial, and economic risks for all.

Table 10 and Table 11 are snapshots of targets and government initiatives.

Table 10: Hydrogen Targets and Government Initiatives in Europe

Country / Region	Date	Targets, Initiatives, and Commitments
European Union	2023	(i) The Communication European Hydrogen Bank (COM [2023]156), published on 16 March 2023, describes its concept, tasks, and structure. (ii) The main objective of the facility is to unlock private investments in hydrogen value chains, both domestically and in developing countries, by connecting renewable energy supply to European Union (EU) demand and addressing the initial investment challenges. (iii) It will establish an initial market for renewable hydrogen, offering new growth opportunities and jobs (European Commission 2023).
European Union and Norway	2023	In April 2023, the EU and Norway aim to work together to develop infrastructure to capture and store carbon dioxide (CO ₂) emissions and scale up renewable hydrogen production in Europe, according to a draft "alliance" plan (Abnett 2023).
European Union	2022	(i) Through the European Clean Hydrogen Alliance, develop an investment agenda to stimulate the rollout of production and use of hydrogen, and build a concrete pipeline of projects. (ii) The hydrogen pipeline includes over 750 projects collected under the Clean Hydrogen Alliance (European Commission 2022).
European Union	2022	(i) Support strategic investments in clean hydrogen in the context of the European Commission's recovery plan, through the Strategic European Investment Window of InvestEU. (ii) The scoreboard reveals that 15 EU countries have included hydrogen in their recovery and resilience plans, amounting to €9.3 billion (European Commission 2022).
European Union	2022	(i) Establish the proposed Clean Hydrogen Partnership, focusing on renewable hydrogen production, storage, transport, distribution, and key components for priority end uses of clean hydrogen at a competitive price. (ii) The Clean Hydrogen Partnership has been launched with €1 billion from the EU's Horizon research funding and €1 billion from industry partners (European Commission 2022).
European Union	2022	(i) Steer the development of key pilot projects that support hydrogen value chains, in coordination with the SET Plan. (ii) Hydrogen has been integrated into Implementation Working Group on Renewable Fuels under the SET Plan activities.
European Union	2022	(i) Promote cooperation with Southern and Eastern Neighbourhood partners and Energy Community countries, notably Ukraine, on renewable electricity and hydrogen. (ii) Joint communication on the Southern Neighbourhood with hydrogen production as new strategic priority, and hydrogen workshop under the Eastern Partnership (European Commission 2022).

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Table 10 *continued*

Country / Region	Date	Targets, Initiatives, and Commitments	
European Union	2022	(i)	Develop a benchmark for euro-denominated transactions.
		(ii)	Hydrogen included in the communication on “European economic and financial system: fostering openness, strength and resilience” (European Commission 2022).
European Union	2022	(i)	With the publication of the REPowerEU plan in May 2022, the European Commission complements the implementation of the EU hydrogen strategy to further increase the European ambitions for renewable hydrogen as an important energy carrier to move away from the Russian Federation’s fossil fuel imports.
		(ii)	The European Commission outlines a “hydrogen accelerator” concept to scale up the deployment of renewable hydrogen, which will contribute to accelerating the energy transition and decarbonizing the EU’s energy system.
		(iii)	The ambition is to produce 10 million tons and import 10 million tons of renewable hydrogen in the EU by 2030 (European Commission 2023).
European Union	2020	(i)	Launch a 100-megawatt (MW) electrolyzer and a Green Airports and Ports call for proposals as part of the European Green Deal call under Horizon 2020.
		(ii)	The Horizon2020 call resulted in the financing of three 100 MW renewable hydrogen electrolyzers in Germany, the Netherlands, and Portugal (European Commission 2022).
Germany	2020	(i)	The German national hydrogen strategy has a goal of 5 gigawatts (GW) production capacity by 2030 and 10 GW by 2040.
		(ii)	Significant funding has been earmarked for research and technology transfer from lab to market, including separate funding for industry.
		(iii)	Recognizing the limitations to producing the hydrogen needed within Germany, a budget of €2 billion has been proposed for fostering international partnerships (European Parliament 2021).
Netherlands	2020	The Dutch national plan includes producing blue hydrogen from gas with CCS; the northern Netherlands region, however, has opted for 100% renewable hydrogen in its regional hydrogen strategy (European Parliament 2021).	

Source: Compiled by authors.

Table 11: Hydrogen Targets and Government Initiatives in Asia and Australia

Country	Date	Target	
Australia	2019	(i)	Australia launched the Australia’s National Hydrogen Strategy.
		(ii)	The strategy provided 57 measures including infrastructure, mobility, research and development, and regulations.
		(iii)	The strategy is to be the world leader in hydrogen production and exports (COAG Energy Council 2019).
India	2022	(i)	By 2030, India plans to develop green hydrogen production capacity of at least 5 million tons per year with an associated renewable energy capacity addition of about 125 gigawatts in the country (Government of India 2022).
		(ii)	India has set a goal for its largest fleet operator, the state-owned Shipping Corp of India, to retrofit at least two ships to run on green hydrogen-based fuels by 2027 (Singh and Verma 2023).
		(iii)	India aims to end imports of ammonia-based fertilizer by 2034–2035 and replace them with locally produced green ammonia-based soil nutrients (Singh and Verma 2023).
Japan	2019	Japan has set a goal to increase its hydrogen supply to 3 million tons by 2030 from its current 2 million tons. Furthermore, Japan aims to expand hydrogen production to 20 million tons by 2050 (Reuters 2023). The government will aim to generate \$113 billion from both the public and private sectors over the next 15 years to achieve the goal (Japan Times 2023).	

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Table 11 *continued*

Country	Date	Target
People's Republic of China (PRC)	2022	The Government of the PRC developed a Hydrogen Industry Development Plan for the period 2021–2035. The government has set a target to bring 50,000 fuel cell vehicles on the road by 2025 and build hydrogen fueling stations. Furthermore, the plan sets a target for green hydrogen production using renewable energy at 100,000–200,000 tons per year by 2023 (IEA 2023).
Republic of Korea	2019–2021	(i) The Republic of Korea is pursuing a hydrogen economy for economic growth and industrial competitiveness more than for climate change objectives. In particular, the Republic of Korea sees hydrogen as a potential driver of economic growth worth suggest to include note on forex rate USD to won and 420,000 new jobs. (ii) The Republic of Korea has robust targets for hydrogen usage that it seeks to achieve by 2040. For consumption, the Republic of Korea aims to expand its annual market from 130,000 tons at present to 5.26 million tons per year. For the transportation sector, the Republic of Korea's New Deal (announced in 2020) sets the 2040 fuel cell electric vehicle (FCEV) target to nearly 3 million, including 2.9 million domestically manufactured FCEVs, 30,000 fuel cell trucks, and 40,000 fuel cell buses. In 2020, the Republic of Korea led the world in FCEV installation, with over 10,000 FCEVs on the road, thereby doubling the national stock from 2019. (iii) The Republic of Korea adopted the Hydrogen Economy Roadmap in 2019. To lay the legal foundations for the government's promotion of hydrogen and the implementation of safety standards for facilities, the Korean National Assembly passed the Hydrogen Economy Promotion and Hydrogen Safety Management Law in January 2020. The hydrogen law, which went into effect in 2021, stipulates several important industrial strategy elements, such as supporting hydrogen-focused companies through research and development subsidies, loans, and tax exemptions (Center for Strategies & International Studies 2021).

Source: Compiled by authors.

V. OPPORTUNITIES FOR DEVELOPING MEMBER COUNTRIES

A. National Energy Transition Road Maps, Strategies, and Targets

In the last 5 years, there has been a considerable increase in the number of government announcements regarding hydrogen, enhancing its importance for meeting national climate commitments. Several DMCs have published dedicated hydrogen policies, strategies, and road maps at national, regional, and city levels such as in the PRC, Japan, Republic of Korea, and India. ADB can play a key role by supporting hydrogen-related policies, enhancing knowledge and technical expertise, and developing pilot projects across the hydrogen supply chain and covering all related infrastructure from production to transmission and distribution to demand-use. For example, the ongoing Energy Storage and Green Hydrogen Sector Development Program in Georgia, through investment and policy support, will strengthen electricity grid security; improve the regulatory framework; and pave the way for greater private sector participation in the development of energy storage and renewable energy including wind, solar, and green hydrogen. The program supports the government's goals of reforming the energy sector, enhancing cross-border electricity trading, and improving the efficiency of the transmission network, as reflected in the ADB country partnership strategy for Georgia, 2019–2023 (ADB 2022). Furthermore, both private and state-owned oil and gas companies (e.g., Pertamina in Indonesia, Sinopec in the PRC, and Adani and Reliance in India) and heavy industries (e.g., Arcelor Mittal) are developing decarbonization plans and seeking support for development of hydrogen projects. ADB could play an important role in providing

both technical and financial support including de-risking of projects for first movers. Equity investment in hydrogen related firms could also be considered such as electrolyzer manufacturing.

Meeting the Paris Agreement targets will require trillions of dollars of investments in electrolyzer systems; wind, solar, other renewable energy, and hydrogen storage; and other supporting infrastructure including ports to pipelines. According to the IEA, global annual investments in low-carbon hydrogen stand at about \$500 million but would need to increase at least tenfold in a net-zero scenario by 2030. By 2050, in a net-zero scenario, 500 million tons of hydrogen per year would need to be produced, of which 300 million tons would come from electricity (i.e., green hydrogen) and 200 million tons would come from fossil fuels with carbon capture, utilization, and storage.²³

B. Overview of Opportunities in Developing Member Countries

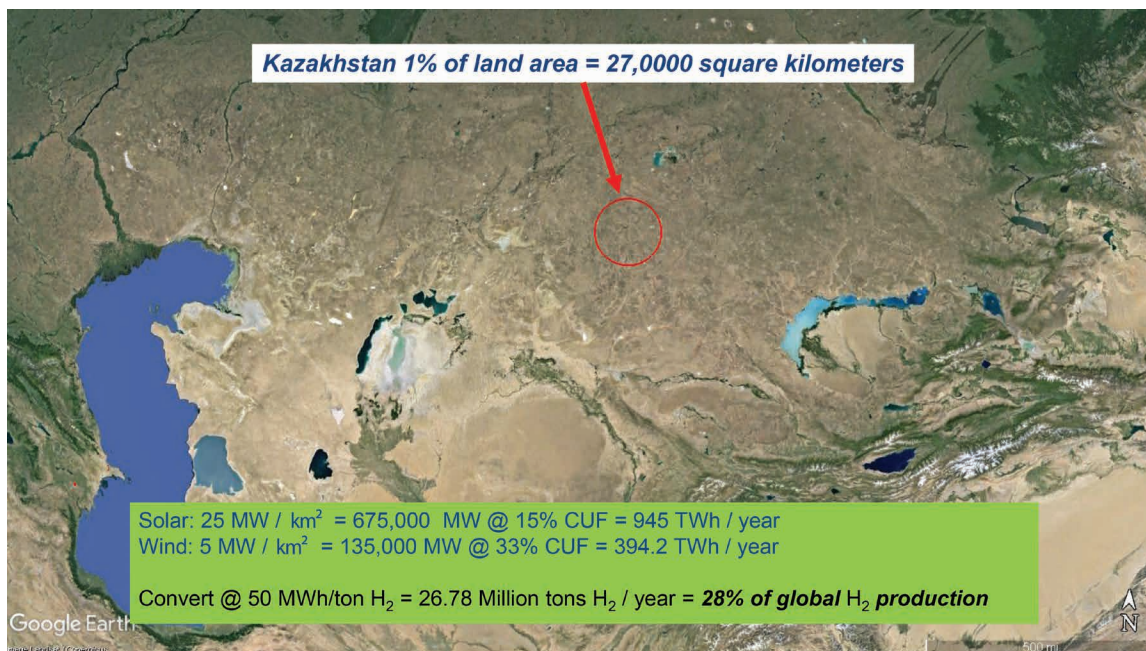
Renewable energy resource availability and accessibility, along with water availability, are critical for gigawatt-scale green hydrogen production, and hydropower, solar, and wind (including offshore wind) appear to be the most attractive with respect to scalability. Across Asia and the Pacific, different regions, subregions, and countries have different potential opportunities. Gigawatt-scale is possible, especially in the context of onshore solar and wind energy development given that many DMCs have abundant solar and/or wind resources (e.g., the PRC, India, Kazakhstan, Mongolia, Pakistan), and hydropower (e.g., Georgia and Nepal). Existing wind farms may be candidates for repowering and/or augmentation with solar, and vice versa, with additional renewable energy output used for hydrogen production. At the megawatt and kilowatt scale, integrating hydrogen with intermittent renewable energy may be a cost-effective solution for displacing diesel in remote areas where electricity is provided by diesel generation, e.g., in Indonesia, Maldives, other Pacific island countries, and the Philippines.²⁴ In all cases of green hydrogen production, the potential use and value of the oxygen by-product should be considered.

Central and West Asia DMCs have abundant hydropower, solar, and wind resources that are more than sufficient to achieve 100% renewable electricity. Private sector solar and wind projects in Azerbaijan, Kazakhstan, and Uzbekistan are routinely reaching financial closure with offtake prices of less than \$40/MWh, which implies a levelized cost of hydrogen production of around \$3.5/kg (Figure 8). Incorporating a cost of carbon of \$50/ton CO₂e would effectively close the cost gap with gray hydrogen (depending on local natural gas prices).

In Azerbaijan, Kazakhstan, Turkmenistan, and Uzbekistan, green hydrogen could be used for grid balancing, converting surplus solar and wind to hydrogen, which could then be blended in the existing natural gas pipeline network (this scenario would require rehabilitation of pipelines to minimize gas leakage). For example, using only 1% of the land area in Kazakhstan for solar and wind development, with 25 MW of solar per square kilometer and 5 MW of wind per square kilometer at capacity utilization factor (CUF) of 15% and 33%, respectively, would produce 1,339.2 million MWh/year of electricity. Converting at 50 MWh/ton hydrogen would yield 26.78 million tons per year of green hydrogen, which is 28% of current world hydrogen supply (Figure 20). It is important to note that the solar and wind could be collocated to minimize impacts on land use, and the power densities noted allow ample space for agriculture and livestock activities and other land uses. Solar and wind farms could be sited adjacent to existing high-voltage transmission lines, and electrolyzers could be sited independently of solar and wind to minimize distance to existing natural gas pipelines. In this “power-to-X” scenario, hydrogen provides grid balancing services and earns revenue from sale into the natural gas supply network.

²³ The potential for blue hydrogen is difficult to quantify given the limited growth of carbon capture, utilization, and storage deployment globally.

²⁴ For examples of commercial project development, see: HDF Energy. Renewable Electricity Always Available.

Figure 20: Kazakhstan Solar + Wind to Hydrogen Potential

CUF = capacity utilization factor, km² = square kilometer, H₂ = hydrogen, MW = megawatt, MWh = megawatt-hour, TWh = terawatt-hour.

Source: D. Millison; photo from Google Earth.

India was an early adopter of green hydrogen, with a 106 MW plant installed in 1958 (Buttler and Hartmut 2018). A hydrogen trading market already exists in India, albeit mostly for gray hydrogen. India has a national road map for green hydrogen development with a target of producing 6 million tons per year by 2030, mostly intended to displace existing fossil-based hydrogen. The World Bank is supporting green hydrogen supply chain development under a low-carbon programmatic development policy operation with \$1.5 billion in funding (World Bank 2023). India has mature solar and wind markets, with gigawatt-scale solar development dating back to the early 2010s (and earlier for wind). India has been successful in public-private partnerships for solar parks, wherein government leads development to create shovel-ready projects, which are then tendered to private sector for implementation.

Opportunities exist in India to repower older wind farms which are fully amortized and depreciated, and utilize new surplus electricity for hydrogen production. There are more than 6,000 MW of installed wind capacity, which is more than 15 years old comprising 300 kW class turbines. These wind farms could be selectively augmented with larger wind turbines under updated power purchase agreements, with the 300 kW class turbines dedicated to hydrogen production. This would be relatively modest in scale, i.e., 6,000 MW of wind at 33% CUF would be sufficient to produce only 300,000 tons of hydrogen per year. However, if the electricity input cost is taken at the marginal cost of production, the cost of hydrogen production might be less than \$2/kg.

Nepal has abundant hydropower as well as solar and wind resources and is already experiencing seasonal electricity surpluses from hydropower. ADB supported a preliminary assessment of converting some of the surplus power to hydrogen for potential use as transport fuel and for production of green ammonia. Nepal has no indigenous petroleum or natural gas resources, and imports 100% of refined petroleum products and most of the other industrial and agricultural chemicals used in local markets. The value proposition for Nepal is based on reducing imports of these materials which would also improve balance of trade.

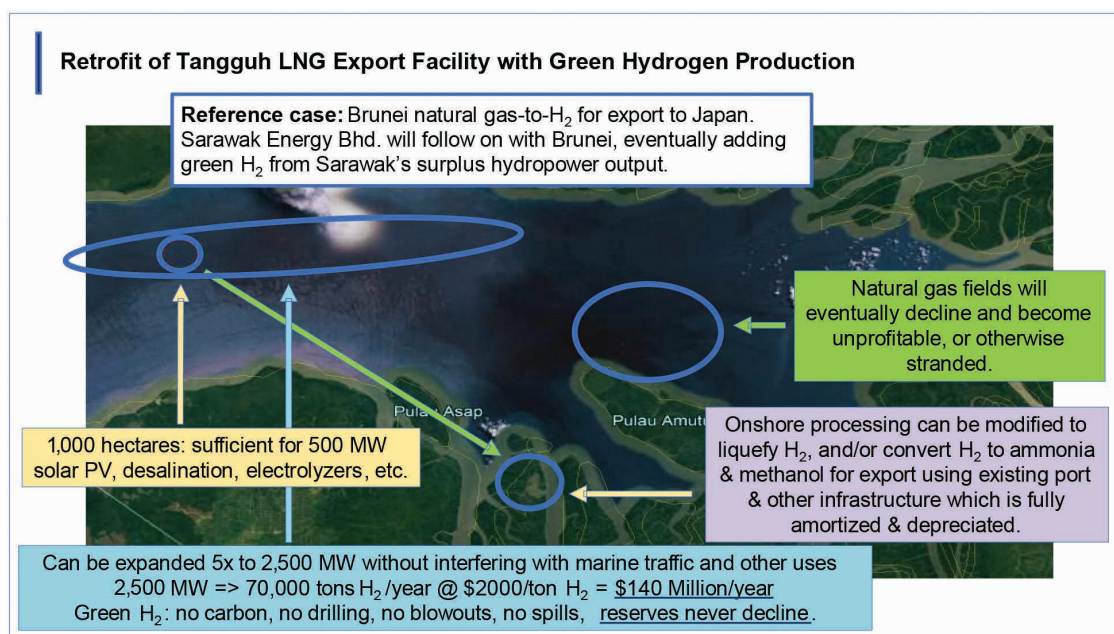
East Asia has enormous undeveloped solar and wind potential suitable for green hydrogen production. Development in Mongolia may be constrained by lack of water and lack of local demand for hydrogen, but opportunities for hydrogen exports to the PRC may be viable (Young 2023).

The PRC has systematically pursued green hydrogen to utilize surplus renewable energy output and has focused more on transport applications than most other ADB DMCs (e.g., using curtailed wind power for hydrogen production to use in fuel cell buses). The PRC Hydrogen Industry Development Plan (2021–2035) targets green hydrogen production of 100,000–200,000 tons per year by 2023. One of the world’s largest projects commissioned is in the PRC, where green hydrogen will replace gray hydrogen in an existing petroleum refining and chemical manufacturing complex (footnote 44). The PRC appears to be the first ADB DMC to pursue floating wind for hydrogen production with integral marine aquaculture (Hydrogen Central 2023).

Southeast Asia’s hydropower potential is estimated to be more than 300,000 MW, although developing more than 5%–10% of this would be environmentally unsustainable without significant changes in hydropower design philosophy. Wind potential is also substantial, with total possible installations of well over 416,000 MW (Shukla and Sudhakar 2017). Harnessing 10% of the hydropower potential at 60% CUF would be sufficient to produce 3.3 million tons per year green hydrogen. Harnessing 10% of the wind potential at 33% CUF would be sufficient for 2.3 million tons per year green hydrogen. Commercial green hydrogen production is expected to begin by 2027 in Sarawak state of Malaysia (Ling 2023).

In Indonesia, a potential shortcut to green hydrogen production and exports could be to retrofit the existing Tangguh liquefied natural gas (LNG) export facility with renewable energy for hydrogen production. Figure 21 illustrates the possibility of installing floating solar in the general vicinity of the existing offshore natural gas fields and augmenting the existing LNG facility with electrolyzers and other processing facilities to produce hydrogen and or green ammonia or other hydrogen derivatives. Such a project may be possible if existing LNG buyers were willing to commit to long-term hydrogen offtake agreements on an agreed price formula (similar to the business model for traditional LNG export projects).

Figure 21: Indonesia Tangguh Hydrogen Production Scenario



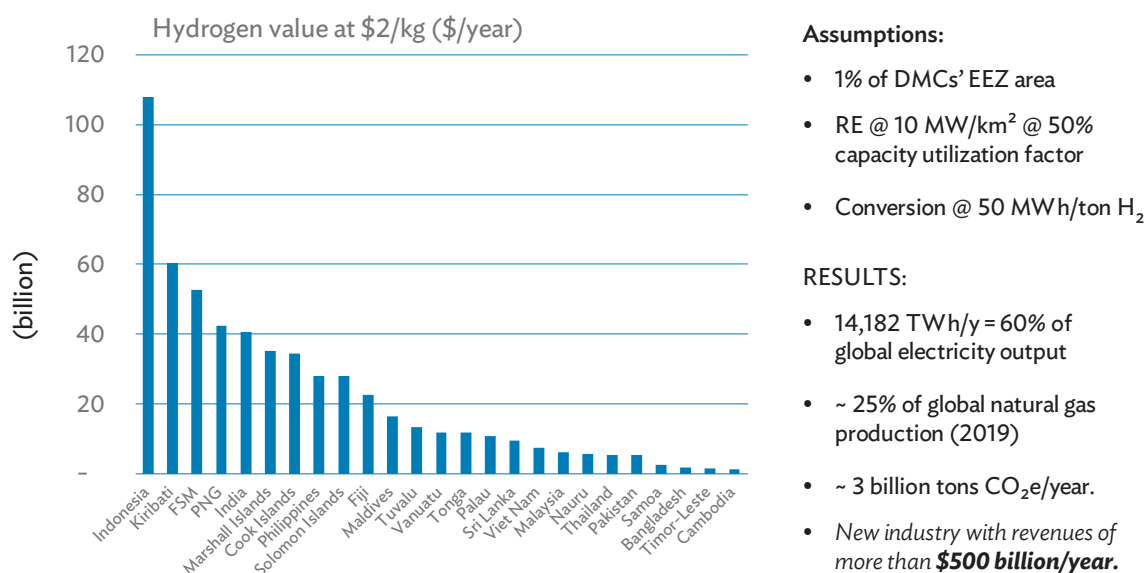
H₂ = hydrogen, LNG = liquefied natural gas, MW = megawatt, PV = photovoltaic.

Source: D. Millison.

Offshore renewable energy can also play an important role, given that much of the renewable energy potential in exclusive economic zones of DMCs cannot be monetized readily via transmission connections to land. This is particularly true for DMCs in the Pacific region, where the renewable energy potential is orders of magnitude larger than total energy consumption. For example, utilizing 1% of the exclusive economic zone area of DMCs for wind power at a density of 10 MW per square kilometer translates to more than 3,000 GW of generation capacity; at a capacity factor of 50%, electricity output would be more than 14,000 TWh per year, which is more than 60% of total world electricity consumption. Conversion at 50 MWh/ton hydrogen would produce more than 280 million tons of hydrogen per year (about three times current global hydrogen production), which has the energy equivalent of 1.1 trillion liters of gasoline. At a target price of \$2/kg, the gross revenue would be more than \$567 billion/year, as shown in Figure 22.

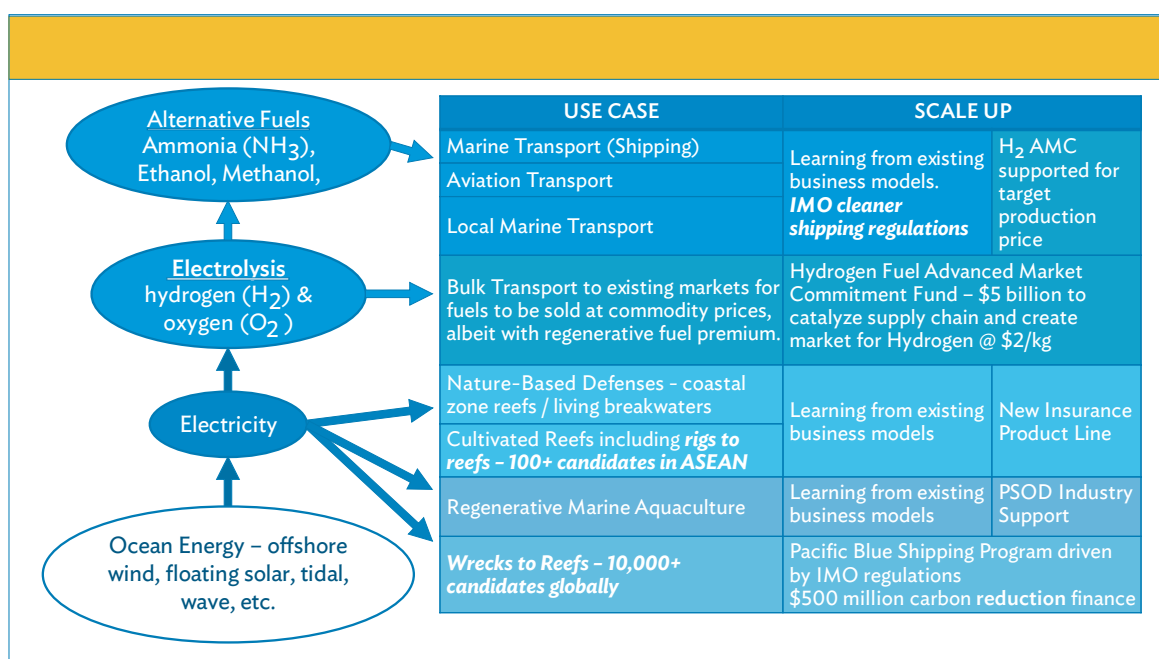
The theoretical offshore renewable energy potential points to development scenarios that are ocean health centric, i.e., with colocated marine aquaculture and ecotourism possibilities. An early pilot project has been announced in the PRC, where hydrogen will be produced from floating wind which also hosts marine aquaculture. Integration of seaweed farming with offshore wind is also beginning to happen offshore Norway and the United Kingdom (Casey 2023). ADB has been investigating an integrated approach to offshore renewable energy development under technical assistance for marine aquaculture, reefs, renewable energy, and ecotourism for ecosystem services (MARES, RETA 6619). The central organizing principle of “power to X” is consistent to the general conception of green hydrogen from surplus renewable electricity, with applications consistent with merit order earlier discussed. The marine “power-to-X” use cases are illustrated in Figure 23. The integration of marine aquaculture with green hydrogen production from offshore renewable energy will help preserve and restore marine ecosystem services, i.e., the hydrogen produced is not just green—it is “regenerative.”

Figure 22: Offshore Renewable Energy to Hydrogen Potential in Select ADB Developing Member Countries



ADB = Asian Development Bank, CO₂e = carbon dioxide equivalent, DMC = developing member country, EEZ = exclusive economic zone, FSM = Federated States of Micronesia, H₂ = hydrogen, km² = square kilometer, MW = megawatt, MWh = megawatt-hour, PNG = Papua New Guinea, RE = renewable energy, TWh = terawatt-hour, y = year.

Source: D. Millison.

Figure 23: Offshore Renewable Energy Monetization with “Power-to-X” Business Model

ASEAN = Association of Southeast Asian Nations, IMO = International Maritime Organization, kg = kilogram, PSOD = Asian Development Bank Private Sector Operations Department.

Source: D. Millison.

C. Future Policy Considerations

Policymakers should consider the following:

- (i) Prepare a hydrogen road map with the time frame (near term, midterm, long term), target values, and attractive applications in the different sectors (e.g., industry, transport) that could create an initial potential for mass markets.
- (ii) Depending on the country's capabilities and strategy, a specific road map should be developed to (i) produce and export hydrogen, (ii) manufacture appliances and hydrogen applications, and/or (iii) import hydrogen fuel to displace fossil fuels and reduce emissions. The road map could foster regional development and international supply chains where applicable.

As discussed, in the macroeconomic context, renewable energy resources are sufficient to produce hydrogen in large enough quantities to completely replace natural gas use and displace other fossil fuel use at scale. It is still a big task to convert a country from a hydrocarbon-fueled system to a carbon-neutral economy. The targets and government initiatives in Table 10 and Table 11 show that governments understand the steps needed to move toward a hydrocarbon-free economy.

Asia and the Pacific could benefit from subregional road maps (e.g., road maps for Southeast Asia, South Asia, Pacific island countries) to support intercountry cooperation and deployment of hydrogen systems. Most ADB DMCs have the renewable energy resources necessary for large-scale hydrogen production, but monetizing those resources requires applying “power-to-X” business models instead

of developing projects around power purchase agreements. More partnerships are required to develop hydrogen highways among these countries.

D. Hydrogen Trading Market Potential

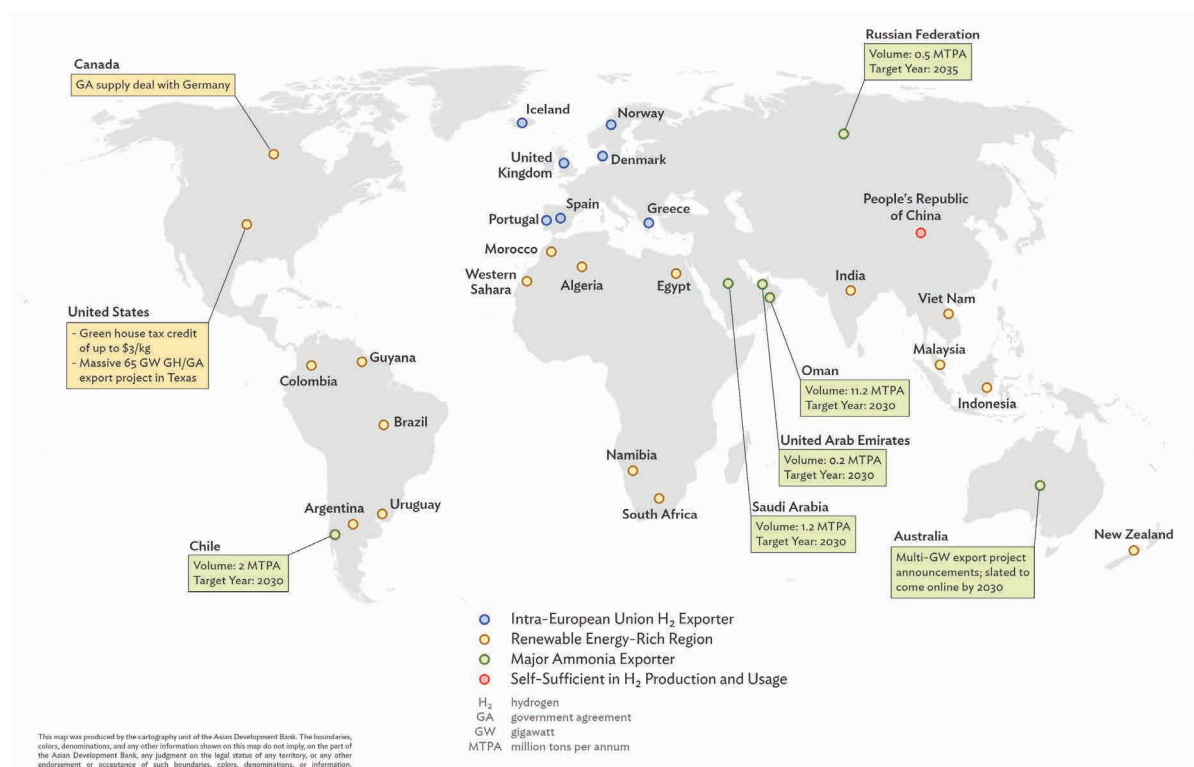
Analogous to natural gas trading hubs, the nature of hydrogen production, storage, and transportation enables a potential market opportunity where the production and consumption can be decoupled, creating hydrogen hubs in strategic locations. The hydrogen hub enables a price discovery mechanism and improve the utilization and contribution of hydrogen to the economy. An Asian hydrogen trading hub will be good for ADB's DMCs and the region at large. Based on experience with other commodities such as LNG, a transition toward liquidity in hub pricing will be challenging. It will require cooperation by multinational governments, together with diligent oversight by regulators. LNG trading hubs in Asia have enabled better options for price discovery, risk management, and supply chain planning. From economic history, it can be expected that most current market incumbents will oppose the hydrogen hub to maintain their market power and dominance. The business case for regional hydrogen hubs in DMCs includes the following benefits:

- (i) Enabling easier hydrogen procurement through more transparent prices and open markets.
- (ii) Boosting environmental benefits of hydrogen by increasing its use in large metropolitan areas and accelerate fossil fuel switching.
- (iii) Contributing toward greater utilization of a country's unused energy, like hydroelectricity and wind power.
- (iv) Integrating regional and global hydrogen supply chains to address climate change mitigation at scale.
- (v) Facilitating efficient and responsive market operations.
- (vi) Reducing risk aversion of established and emergent hydrogen companies to empower investment decisions.
- (vii) Expanding greater economic integration and cooperation between Asian countries.
- (viii) Encouraging intra-regional trade and infrastructure synergies while setting a shared political agenda to make hydrogen more accessible.

Although green hydrogen has potential advantages for reducing GHG carbon emissions, the merit order shown in Figure 18 should be respected. A key role of governments is to identify the opportunities consistent with technical, financial, and economic rationale to determine "best-use" cases. ADB's DMCs should undertake science-based assessments of integrating green hydrogen within their economies while formulating policies for their larger national interests.

Hydrogen corridors are developing across all continents indicating that green hydrogen could be a globally traded commodity. Figure 24 highlights the following points:

- (i) The PRC is the leading global hydrogen market with annual production of 20 million tons.
- (ii) Australia announced plans to become a "future hydrogen export powerhouse."
- (iii) Chile, Oman, the Russian Federation, and Saudi Arabia plan to be the top ammonia exporters.
- (iv) Northern and Southern Africa, the US, Canada, and Brazil are emerging exporters of green ammonia.

Figure 24: Hydrogen Corridors Across All Continents

EU = European Union, H₂ = hydrogen, GA = government agreement, GH = greenhouse, GW = gigawatt, MTPA = million tons per annum, RE = renewable energy, US = United States, UAE = United Arab Emirates.

Source: ADB. 2021. *Study of Hydrogen Trading Market Final Report*. ADB internal report, conceptual study only.

1. Potential Hydrogen Hubs in Asia

Regional stakeholders should continue to keep an active watch on clean hydrogen technologies, hydrogen supply and application, carbon capture and storage, and transitions toward clean sources of energy. Examples of potential hydrogen hubs in ADB's DMCs, as assessed in the Hydrogen Market Study (ADB 2021) include Shanghai, PRC; Gwadar, Pakistan; Khorgos, Kazakhstan; and Vientiane, Lao People's Democratic Republic.

- (i) Shanghai, PRC: A deep seaport and river port with established storage and distribution infrastructure to the domestic PRC market, and a mature financial trading hub framework.
- (ii) Gwadar, Pakistan: A seaport with pipeline and rail access, can be an import–export terminal linking Pakistan's potential rich solar and/or wind produced green hydrogen supply, and a hub for supply to and from the PRC, Middle East, Australia, and the rest of Asia.
- (iii) Khorgos, Kazakhstan: A land terminal connecting the PRC, the Russian Federation, and Europe (including Rotterdam, an existing hydrogen hub gateway) with potentially abundant green hydrogen produced from considerable solar and wind resources in Kazakhstan and Uzbekistan.

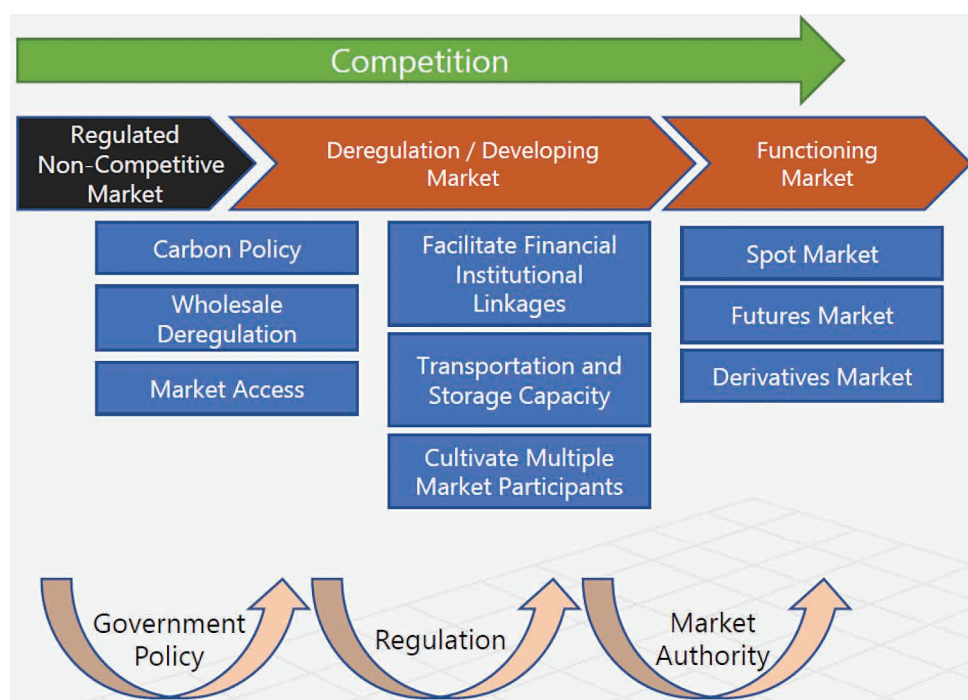
- (iv) Lao People's Democratic Republic: Could become the hub to leverage vast seasonal hydroelectric resources to produce green hydrogen and supply domestic requirements and be a hub for neighboring countries like Viet Nam, Cambodia, Thailand, and the PRC.

2. Pillars for Hydrogen Trading Hubs

Hydrogen trading and physical hubs can be established based on similar commodity markets. As shown in Figure 25, the hydrogen market would be overseen by a market authority. The three prongs required for the strategy are:

- (i) Government policy to set the climate for transition to a competitive market.
- (ii) Regulations to promote market access, price deregulation, and financial security.
- (iii) Competition authority to ensure that futures and spot markets remove anti-competitiveness.

Figure 25: Transition from Noncompetitive to Trading Hub



Source: ADB 2021.

VI. THE WAY FORWARD

This paper aims to help decision-makers navigate the green hydrogen value chain and understand what is required for successful implementation and reap the potential rewards in the energy transition.

Green hydrogen will play an essential role in the energy mix for countries that seek to reach their climate goals, specifically for hard-to-decarbonize segments such as heavy industrial processes and shipping. Hydrogen is a scarce and valuable resource today, making it important that priority is given in industries that are hard to decarbonize as opposed to other sectors such as transport where it is cheaper and more efficient to electrify. The merit order for green hydrogen deployment begins with replacement of established fossil hydrogen production and use, followed by displacement of fossil fuels in heavy, hard-to-decarbonize, industries.

Green hydrogen is expected to grow in Asia and the Pacific, with most projects being initiated in developed and emerging economies. Uptake of green hydrogen in developing countries is expected to be slower due to the up-front cost barriers, limited renewable energy capacity, and lack of supporting policies and technical expertise to make the green hydrogen supply chain financially viable. Developing pilot projects will be an important first step and government leadership and decision-making are critical at this stage. Strong government support is needed in site allocation, permitting, and control of hydrogen projects. Furthermore, governments should assist in securing long-term offtake agreements for early projects to enable project financing.

If green hydrogen is deemed an area for development by any of ADB's DMCs, a road map should be developed that sets targets and identifies attractive applications in the different sectors (e.g., industry, transport) that could create an initial potential for mass markets. This will mitigate risk for the private sector's market-in and technology development. Any road map developed should be clear in translating policy objectives in terms of scale, public sector funding support, creation and expansion of distribution value chains, and competitive trading among market players.

ADB can provide support to DMCs in implementation of green hydrogen projects through:

- (i) Knowledge sharing (workshop, handbook, and other knowledge products): Policymakers' and industry players' awareness of the latest trends and technologies and capacity building on safety.
- (ii) Support government policy development: Strategy, road map, and regulatory framework for hydrogen energy development.
- (iii) Enhance hydrogen trading platforms: Promote international hydrogen supply chain with competitive market and trading hubs through stakeholder engagement and policy dialogues.
- (iv) Support pilot and scaling up: Pilot hydrogen technologies and business models for demonstration and scaling-up (feasibility study with consultants).
- (v) Support finance: Finance hydrogen energy projects, including production, transportation and distribution infrastructure, as well as market applications.

ADB can provide various types of assistance in different parts of the hydrogen merit order (Table 2). A summary of ADB-supported activities is presented in Table 12, which is not exhaustive.

Table 12: ADB Hydrogen Activities as of May 2023

ADB Operation	Description	Status / Outcome	ADB Department / Division	Available Reports / Other Notes
Technical Assistance (TA) 9742	Solar hydrogen market assessment and project identification with International Solar Alliance	Consultant mobilized in March 2022	South Asia Department (SARD) / SARD Energy Division (SAEN)	Online Green Hydrogen Center of Excellence: https://isa-ghic.org/
TA 6966	Preparing Energy Storage and Hydrogen Sector Development Program (Georgia)	Ongoing	Central and West Asia Department (CWRD)/ CWRD Energy Division (CWEN)	https://www.adb.org/projects/54448-002/main
TA 6619	Marine Renewable Energy to H ₂ ("power to X") with embedded regenerative marine activities. The TA seeks to determine the planning, policy, and development guidelines for Ocean States to exploit their marine resources in a regenerative manner.	February 2023 High-Level Investor Forum	Sustainable Development and Climate Change Department (SDCC)/ SDCC Energy Sector Group (ENE)	TA paper Dataroom Blogs – Rigs2reefs Ocean Acidification and spotlight at ACEF 2021
TA 9690	Technical assistance support to conduct pre-feasibility study on application of low-carbon alternative fuels (hydrogen, ammonia, and methanol) for maritime transport sector in Indonesia	Completed in the first quarter, 2023	SDCC ENE, Southeast Asia Department Energy Division (SEEN), and Indonesia Resident Mission (RM)	TA consultants' report
TA 9690	Pakistan Renewable Hydrogen Energy – Pre-feasibility Study	Study completed in October 2021	SDCC ENE	TA consultants' report Press release
TA 8944 Subproject A	HDF Energy project in Sumba, Indonesia: solar + batteries + hydrogen for 24/7 renewable electricity	Preliminary due diligence conducted by ADB consultants in 2020–2021	SDCC ENE	Confidential
TA 9686	Study of Turquoise Hydrogen or Methane Pyrolysis	Report completed	SDCC ENE	Consultant's report
Not applicable	Nepal analysis on Hydropower to Hydrogen	Study completed and published August 2020	SARD / SAEN	Publication DevAsia Blog
TA 9690	Study of Hydrogen Trading Market	Consultant report 31 March 2021	SDCC ENE	Conceptual study only
Proposed TA	India: Supporting Green Hydrogen Through High Technology – Support Government of India announced the National Hydrogen Energy Mission to draw up a road map for using green hydrogen as an energy source	Processing	SARD /SAEN	TA paper

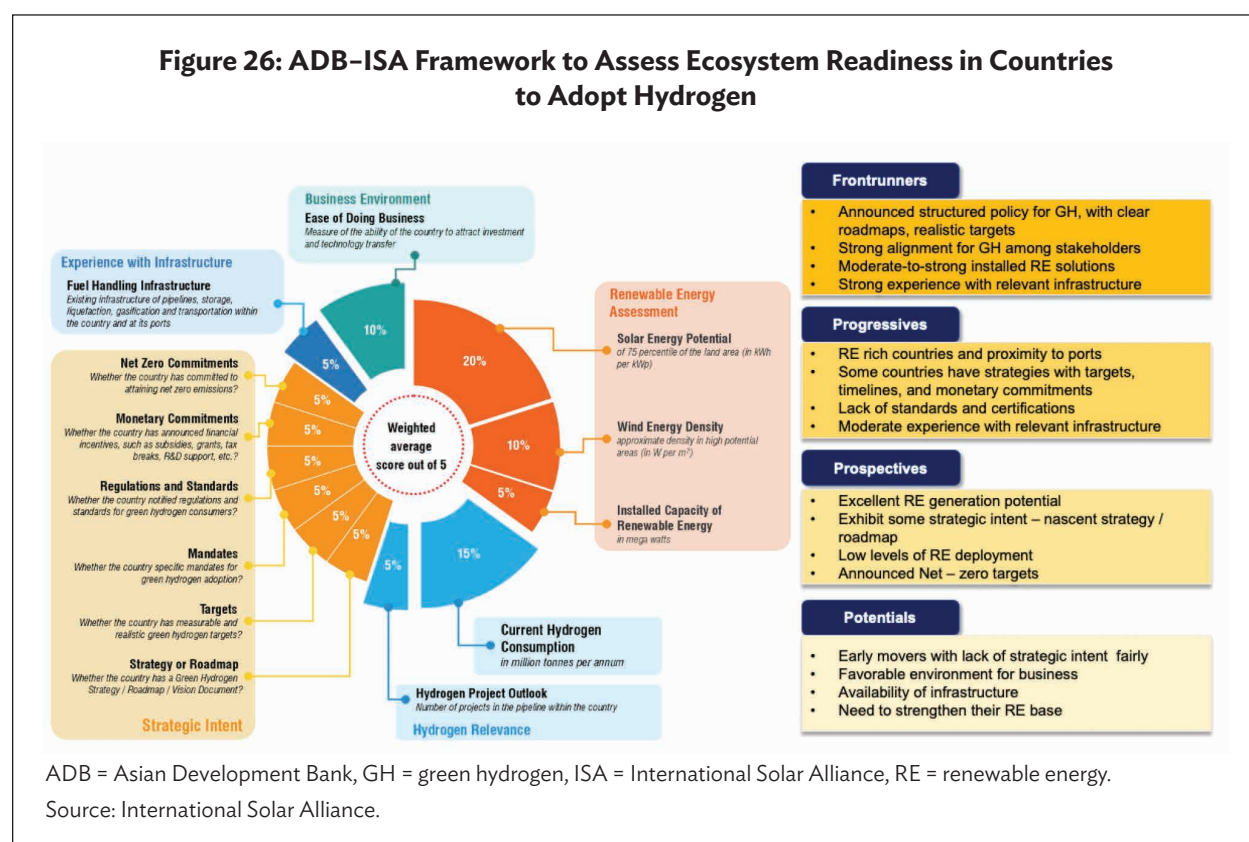
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Table 12 continued

ADB Operation	Description	Status / Outcome	ADB Department / Division	Available Reports / Other Notes
Proposed TA	Feasibility study on Turquoise Hydrogen in the petrochemical sector study in northeast of India	Concept stage	SAEN	55173-001: Supporting Green Hydrogen Through High Technology Asian Development Bank (adb.org)
TA 9309-PRC and Loan 3629-PRC	Fuel cell bus deployment with green hydrogen in Zhangjiakou City for possible financing via ensuing financial intermediation financial intermediation loan	Appraised during project preparation in 2017	East Asia Department (EARD) / East Asia Sustainable Infrastructure (EASI)	51181-001: Air Quality Improvement in the Greater Beijing–Tianjin–Hebei Region—Regional Emission-Reduction and Pollution-Control Facility Asian Development Bank (adb.org)

ADB = Asian Development Bank, PRC = People's Republic of China.
Source: Compiled by authors.

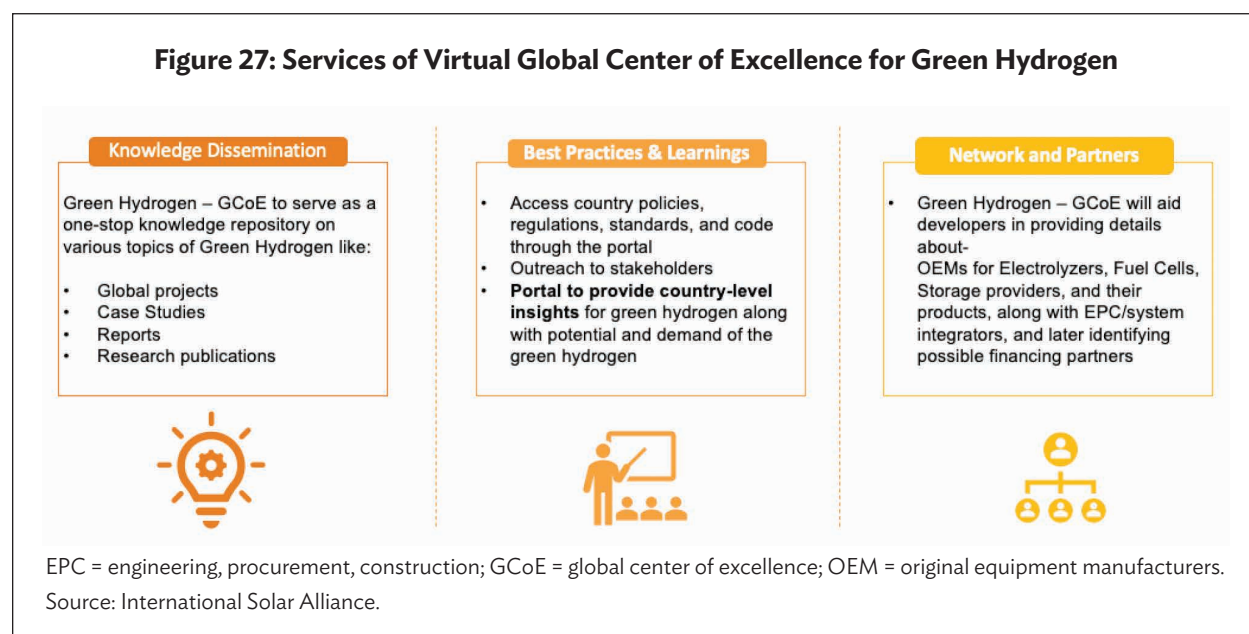
ADB has been organizing knowledge-sharing workshops, producing publications, and working papers and conducting pre-feasibility studies and due diligence on green hydrogen projects in India, Indonesia, Maldives, the Marshall Islands, Pakistan, Palau, the PRC, Malaysia, and Thailand. Furthermore, ADB has been collaborating with the International Solar Alliance (ISA) in developing ecosystems for countries to be ready for green hydrogen. Figure 26 illustrates a framework ADB and ISA developed to help countries assess ecosystem readiness for adoption of hydrogen.



Countries can take the following steps to develop a green hydrogen industry in a holistic process:

- (i) Stakeholder discussions on Ecosystem Readiness Framework.
- (ii) Deep-dive country-level consultations to assess green hydrogen for accelerating deployment.
- (iii) Assess viability of current global solar hydrogen sector in countries.
- (iv) Develop a road map for production/deployment of renewable energy-based hydrogen across countries through 2030, 2040, and 2050.
- (v) Identify ready-to-invest opportunities across various end-use sectors across countries and provide recommendations.
- (vi) Identify stakeholders across peer organizations and industry associations.

Countries can seek support from the ADB–ISA Virtual Global Center of Excellence for Green Hydrogen, a one-stop platform that provides country-level insights and addresses the knowledge needs of all stakeholders as shown in Figure 27.



Conclusions

Hydrogen is emerging as a scalable and flexible clean energy system that is based on the ability to convert renewable energy to electricity (electrons) to hydrogen (protons), which can be stored indefinitely or converted into other molecules. Hydrogen-derived chemicals (molecules) can be transported in bulk as is the case for crude oil, natural gas, and refined petroleum products. Like fossil fuels, which are formed by a combination of solar, biomass, geothermal energy, and geologic time, hydrogen is an energy carrier. Green hydrogen development is primarily a “power-to-X” proposition, which is not the same as renewable energy development built around power purchase agreements.

Hydrogen appears to be a scalable solution for both time-shifting and location-shifting of renewable energy. Floating solar in existing hydropower reservoirs and offshore wind appear to be the most readily scalable pathways to gigawatt-scale green hydrogen production.

As of 2021, hydrogen accounted for about 1.8% of global GHG emissions. Green hydrogen can decarbonize the existing hydrogen supply chains, but expanding green hydrogen production beyond the current

global supply needs to be carefully considered as hydrogen has a 100-year global warming potential of 11.6 (i.e., almost 12 times worse than CO₂). This global warming potential should be considered along with the fact that hydrogen is lighter than air and floats up into and above the atmosphere (as is the case with helium). In layman's terms green hydrogen development must ensure that "the cure is not worse than the disease."

One kg of hydrogen has energy equivalent of 1 gallon (3.94 liters) of gasoline. Although \$2/kg is typically referenced as a price benchmark, \$4/kg is at par with gasoline prices in many countries. The cost-effectiveness of green hydrogen production depends on electricity input costs, electrolyzer costs, and electrolyzer load factors, and green hydrogen production may be commercially viable today at \$4/kg. The use of intermittent versus "baseload" renewable energy does not dictate the commercial viability of green hydrogen production. The cost of green hydrogen production is expected to decline as electrolyzer costs decline and electrolyzer efficiencies increase. A key value proposition of green hydrogen is cost certainty versus the price volatility of fossil-based hydrogen.

From a policy perspective, green hydrogen is energy-intensive and is not the solution to all. Green hydrogen development must be considered in the broader context of renewable energy development and the need for accelerating the global energy transition.

The viability of green hydrogen projects depends primarily on electrolyzer costs, local energy costs, specific end-use applications, and willingness of hydrogen buyers to commit to long-term offtake agreements (like traditional LNG export projects). Hydrogen supply chain development is expected to continue globally, and as global electrolyzer manufacturing capacity increases a virtuous cycle of development may emerge. A key rate-limiting factor for scaling up of green hydrogen production is the availability of critical metals, specifically iridium and platinum, for use in electrolyzers.

A well-planned development of a green hydrogen supply chain can minimize the economic and social costs of transitioning to a low-carbon economy. This can only be achieved through crosscutting discussions with the various stakeholders including local and national authorities, private sector manufacturers, planners, developers, hydrogen gas companies, natural gas companies, media, educational institutions, training organizations, and hydrogen safety research institutions. ADB can help its DMCs facilitate the needed discussions and decision-making to bring down the barriers that are hindering development of a green hydrogen industry. The Virtual Global Center of Excellence for Green Hydrogen serves as an online resource that is supported by ADB and can be used by any of ADB's DMCs to understand green hydrogen and decide where to begin in developing this industry.

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Emerging Hydrogen Energy Technology and Global Momentum

This paper provides an overview of the emerging hydrogen economy to help decision-makers navigate the green hydrogen value chain, understand what is required for successful implementation, and reap the potential rewards in the energy transition. Green hydrogen is a “power-to-X” business proposition based on selling molecules rather than selling electrons. The financial viability of green hydrogen production depends primarily on electrolyzer costs, local electricity input costs, specific end-use applications, and willingness of hydrogen buyers to commit to long-term offtake agreements. As global electrolyzer manufacturing capacity increases, a virtuous cycle of development may emerge.

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