IntechOpen *Journals*

Green Energy and Environmental Technology

REVIEW PAPER

A Comprehensive Review on The Potential of Green Hydrogen in Empowering the Low-Carbon Economy: Development Status, Ongoing Trends and Key Challenges

Ayatte. I. Atteya[1,2,*], Dallia Ali[1], Mamdud Hossain[1] and Nazmi Sellami[3]

1 School of Engineering, Robert Gordon University RGU, Scotland, UK
2 College of Engineering and Technology, Arab Academy for Science, Technology and Maritime Transport AASTMT, Alexandria, Egypt
3 School of Engineering and The Built Environment, Edinburgh Napier University, Scotland, UK
*Corresponding author. E-mail: a.atteya@rgu.ac.uk

Citation
Ayatte. I. Atteya, Dallia Ali, Mamdud Hossain and Nazmi Sellami (2023), A Comprehensive Review on The Potential of Green Hydrogen in Empowering the Low-Carbon Economy: Development Status, Ongoing Trends and Key Challenges. *Green Energy and Environmental Technology* 2(1), 1–53.

DOI
https://doi.org/10.5772/geet.23

Received: 31 May 2023
Accepted: 13 December 2023
Published: 28 December 2023

Abstract

Green hydrogen is currently considered a key element for delivering free-carbon energy. This paper provides an extensive assessment of the potential of green hydrogen technology as a pathway to the low-carbon economy while highlighting the major technical challenges to its implementation. A detailed overview of green hydrogen production, storage technologies, transportation infrastructures and green hydrogen implementations is provided. Status of the ongoing trends for repurposing the existing gas grid infrastructures to transport the hydrogen safely across Europe is presented in this work, with 48 sample projects statistically reviewed and classified based on the key challenges being addressed. The potential of green hydrogen in decarbonizing the energy sector and the associated technical challenges are widely reviewed and critically assessed. Detailed discussions have been provided on the optimal sizing of renewable hydrogen energy systems, real-world modelling of hydrogen energy storage elements and the smart energy management strategies for the application of hydrogen electrolysers as smart controllable loads. Some prospects are given on how digital key trends of blockchain technologies could support the growth of green hydrogen markets together with emphasis on the raised research questions. Further assessment is presented on the potential of green hydrogen versus blue hydrogen while reflecting on future directions and policy recommendations for planning a successful energy transition. Finally, some future insights and near-term policy recommendations are provided for promoting the use of green hydrogen production while supporting the green hydrogen industry.

Keywords: green hydrogen production, hydrogen energy storage, hydrogen transportation, hydrogen end-use applications, optimal sizing, smart energy management

1. Introduction

The ongoing growth in global energy demands and the continuous increase in Greenhouse Gas (GHG) emissions have accelerated the need for setting zero-carbon pathways [1–3]. In-line with multiple international agreements held for tackling climate change, including the Sustainability Development Goals (SDGs), the United Nations Conference on Housing and Sustainable Urban Development (Habitat III), and the 26th Conference of Parties (COP26) [4–6]; there is an increasing effort towards the transition from a fossil-fuel to a Zero-Carbon energy system by 2050. The achievement of this ambition requires significant changes in the energy supply and demand. According to the latest BP Statistical Review of World Energy [7, 8], the fossil-fuel resources constituted around 84% of the global energy consumption in 2020, the renewable energy accounted for approximately 12%, and nuclear sources covered the remaining 4%. With the continuing population growth, the energy demand is expected to rise by 16% towards 2050 and the share of renewable energy mix is required to increase by around 3–5 times its current amount to meet the highly-ambitious goal of carbon-neutrality by 2050 [9]. While the integration of renewable energy is a key element in the energy transition picture, the implications and associated challenges call for a concerted effort. The admission of these unpredictable power sources into the grid is subject to significant variability due to their intermittent nature, requiring the central generators to cover any transient variations between the renewable power input and consumer demand. The need to cover such variations will increase the operation of large fossil-fuel plants in "**spinning-reserve**" mode, which is expensive and carbon-intensive, thus hindering the renewable potential [10]. Therefore, to accommodate the intermittency of renewable power and ensure energy system security and flexibility, adequate energy storage is required. Hydrogen, as a free-carbon energy carrier, offers a clean storage opportunity that supports the renewable energy integration and helps empowering the energy transition target. Being on the roadmap of delivering a full sustainable development [11], Hydrogen acts as a versatile, clean and sustainable energy storage medium, that provides zero-emissions at the point of end-use, paving the way for energy diversity and unlocking multiple barriers towards an affordable low-carbon future [9, 12]. Hydrogen can be produced either from fossil-fuels, renewables or nuclear energy [13]. For a deep understanding of hydrogen production processes, a colour code nomenclature is commonly used to classify it into five different shades: grey hydrogen, black hydrogen, blue hydrogen, green hydrogen, and pink hydrogen. Grey hydrogen is produced from natural gas or methane through the process of

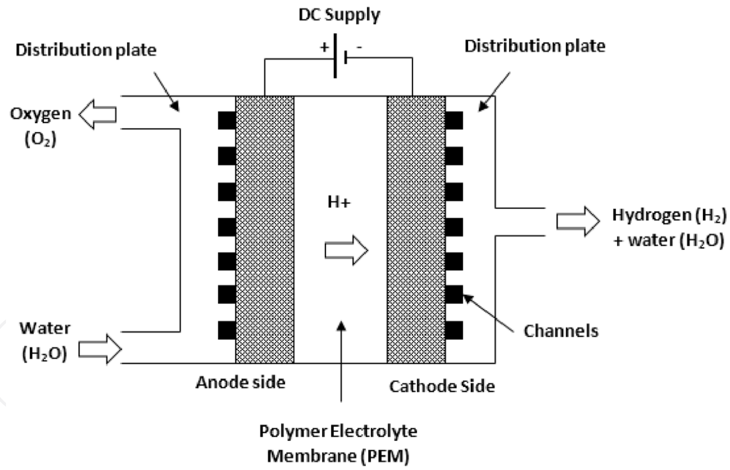
Steam Methane Reforming (SMR) without capturing the associated carbon-dioxide (CO_2) emissions, thus making it unsuitable for the route to zero-carbon emissions [14]. Similarly, black hydrogen is environmentally-unfriendly as it is harvested from black coal using gasification process [14, 15]. Blue hydrogen, like Grey hydrogen is produced industrially through the steam reforming of natural gas or methane, but utilizes Carbon Capture and Storage (CCS) technology to negate CO_2 emissions [16]. Although blue hydrogen is considered as one of the proposed solutions towards the vision of low-carbon economy, CCS doesn't completely eliminate the GHG emissions. CCS technologies are expected to reach maximum efficiencies of 85–95%, thus around 5–15% of CO_2 emissions would still be released to the atmosphere. Moreover, the process of hydrogen generation by steam reforming uses methane which is more potent than CO_2 and has higher global warming impact on a 100-year timescale [17, 18]. Therefore, although blue hydrogen can reduce CO_2 emissions by CCS, it cannot guarantee a fully net-zero carbon future. Additionally, blue hydrogen is subjected to some limitations due to the impact of volatile energy prices of fossil-fuels, and the additional costs related to carbon capture, transport, and monitoring. These factors have restricted the deployment of blue hydrogen technologies [18]. Alternatively, Green hydrogen is generated with zero-carbon emissions by using renewable energy in powering water electrolysis and thus considered the most suitable type to the Net-Zero mission [18, 19]. Pink hydrogen refers to the hydrogen generated by water electrolysis powered from nuclear energy. This is still an emerging technology, and there are no examples yet of established large-scale hydrogen facilities based on nuclear reactors [20]. Furthermore, the cost of electrolysis used to extract the hydrogen from nuclear energy, as estimated by the International Energy Agency (IEA) [21], is around 3–5 times the cost of any other electrolysis units. Among the aforementioned types, green hydrogen is gaining much attention being an emissions-free energy vector while absorbing the intermittency of renewable energy resources, thus providing energy system security and reliability [22]. It offers a viable potential solution that can fulfil the requirements of a clean energy transition through sector-coupling synergies, thus securing the flexibility and resilience of power system [23]. In addition, the downward trend of renewable energy prices as reported by the IEA [21], will highly endorse the vision of green hydrogen economy, making green hydrogen highly-competitive with other low-carbon alternatives. However, green hydrogen still poses many challenges to researchers, investors and policy makers to unlock its full potential for empowering the low-carbon economy. A critical assessment of the limitations, research gaps and technical challenges facing the implementation of green hydrogen technologies could increasingly help practitioners and regulatory bodies to evaluate the possible opportunities for upscaling the technology development. It has been noticed that recent review studies tended to focus on specific hydrogen storage technologies [13, 24], while relatively less attention has been given to the competitiveness of different hydrogen storage options and their impact on hydrogen transportation. The current development status and the ongoing trends of hydrogen transportation are not fully covered in review papers and only few discussions are available [25, 26] with lack in detailed assessment of the key barriers currently facing the maturity of technology. The role of green hydrogen in decarbonising the power sector can be found in a number of references [22, 23, 27, 28], however these lack emphasis and in-depth analysis of the technical challenges associated with the integration of renewable hydrogen energy storage systems with the electricity grid which includes, the optimal sizing of grid-connected hydrogen storage components, optimal scheduling of their operation when integrated with renewables in the utility grid, and accurate dynamic modelling that can reflect the operation of Real-World green hydrogen energy storage technologies within the electricity grid. Eriksson *et al.* [29], have reviewed the optimization algorithms and energy modelling tools used for integrating the hydrogen storage technologies with hybrid renewable energy systems, focusing on the design performance and the capabilities of reviewed approaches. However, the formulation of optimal sizing problem of hybrid renewable hydrogen energy systems was not critically assessed. The correlation between the mathematical modelling used for simulating the internal working of hydrogen storage technologies and the optimal sizing of hybrid renewable hydrogen energy systems is still not evaluated in literature and requires in-depth analysis and discussions for improvements. The flexibility of hydrogen electrolysers for providing ancillary services is reviewed in terms of load range, time response and ramp-up and down rates [30, 31], but lacks detailed discussion on the economic viability of hydrogen electrolysers as smart controllable loads and the control strategy optimization of green hydrogen production planning in response to the grid market.

This paper aims to fill these gaps by providing a comprehensive review on the technical challenges facing the implementation of green hydrogen from production to end-use applications while discussing the research gaps in renewable hydrogen energy systems grid integration. An extensive assessment of the most established green hydrogen production technologies is given in this paper, in which the maturity of technology, the techno-economic performance characteristics, the suitability of applications and the deployment level of ready-to-commercialise water electrolysers are all evaluated not only based on review articles but also on organisational reports, industry market surveys and recent real-world green hydrogen production plants. The impact of different hydrogen storage systems on the modes of hydrogen transportation is widely surveyed in this paper together with the key challenges facing the deployment of hydrogen transportation infrastructures. The ongoing trend of repurposing the existing gas grid for hydrogen transportation is statistically reviewed with 48 sample projects running across Europe examined to reflect on Europe current development status in addressing the key challenges facing the hydrogen implementation. The potential of green hydrogen in decarbonizing the energy sector is critically reviewed in this work, where the authors have evaluated the current conducted literature from a technical perspective and presented an in-depth analysis and discussions regarding the sizing, modelling, scheduling, and smart energy management strategies of green hydrogen energy storage system components within four key areas of developments; this includes: (1) grid balancing, (2) frequency regulation, (3) large-scale integration of renewables and (4) electrification of remote areas. Furthermore, new insights are provided regarding the digitization of green hydrogen markets with recent trends of blockchain technologies and the key barriers facing the associated smart energy management systems with decentralized trading of green hydrogen energy. Further assessment is carried out on the competitiveness of green hydrogen versus blue hydrogen, providing the readers with a deep understanding of their potentials, limitations, socio-economic impacts and challenges, while addressing future directions and policy recommendations for planning a successful clean energy transition. Finally, the future of green hydrogen economy is further discussed providing near-term policy recommendations for supporting the green hydrogen industry.

The rest of this paper is organized as follows: Section 2 widely reviews Green Hydrogen Energy Storage Systems covering green hydrogen production, storage technologies, transportation infrastructures and hydrogen implementations. Section 3 explores the potential and technical challenges of green hydrogen in decarbonizing the energy sector. Section 4 discusses possible implementation of blockchain digital key advancements for supporting the growth of decentralized green hydrogen markets. Section 5 assesses the competitiveness of green hydrogen versus blue hydrogen for succeeding a clean energy transition. Section 6 provides some future insights and near-term policy recommendations for supporting the green hydrogen industry.

2. *Green hydrogen energy storage systems*

A typical Green Hydrogen Energy Storage System (HESS) mainly involves two stages; the first comprises the process of transforming the renewable energy into green hydrogen through water electrolysis [10] and the second involves the storage of green hydrogen in multiple forms [13, 32], to be used when needed in a wide range of applications including electricity generation, heating facilities, fuel-cell electric vehicles and industry purposes. An extensive survey on the technologies implemented for green hydrogen production, storage and implementations is given in the following subsections.



$$Anode: H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^-;\ Cathode: 2H^+ + 2e^- \rightarrow H_2; Overall: H_2O \rightarrow H_2 + \frac{1}{2}O_2$$

Figure 1. Schematic diagram of basic water electrolysis (PEM).

2.1. Green hydrogen production

Green hydrogen production is an electrochemical energy conversion process in which the electrolyser is powered by renewable electricity to split the water molecules into hydrogen and oxygen with zero-carbon emissions. Figure 1 shows a basic water electrolysis unit consisting of an anode and a cathode immersed in an electrolyte solution and separated by a porous diaphragm or a proton exchange membrane (PEM) that permits only positively-charged ions to pass through it. The electrolytic solution can either be pure water (H_2O) or potassium hydroxide (KOH), depending on the type of electrolysis technology used. Considering pure water electrolysis, when a DC source is connected across the anode and cathode, the water dissociates into positively-charged hydrogen ions (protons), electrons, and oxygen gas. The hydrogen protons cross the membrane towards the cathode side, while the electrons transfer towards the anode through the external power circuit (electricity). At the cathode side, the hydrogen protons recombine with the hydrogen electrons in pairs to form hydrogen (H_2) gas [33, 34]. The technologies used for water electrolysis can be classified into three main categories: Alkaline (ALK) electrolysers, Polymer Electrolyte Membrane (PEM) electrolysers, and Solid-Oxide Electrolysis Cells (SOECs). Table 1 summarizes the techno-economic characteristics and key design constraints for the three types. A detailed overview on each technology outlook, considerations, and performance is given in the following subsections.

2.1.1. Alkaline (ALK) electrolysers

Alkaline electrolysis is a mature and commercialized technology that has been industrially used since the 20th century for non-energy purposes [21, 35]. It utilizes Potassium Hydroxide (KOH) as the electrolytic solution to separate the hydrogen

Table 1. Techno-economic characteristics of commercial hydrogen electrolysis technologies [21, 30, 35, 36].

Criteria	ALK electrolysers		PEM electrolysers		SOECs electrolysers	
	2019	2030	2019	2030	2019	2030
Electrical efficiency (%LHV)	63–70%	65–71%	56–60%	63–68%	74–81%	77–84%
Energy consumption (kWh/Nm^3)	4.2–4.8		4.4–5.0		3.0	
Operating pressure (bar)	1–30	—	30–80	—	1.0	—
Operating temperature (°C)	60–80	—	50–80	—	650–1000	—
Stack lifetime (operating hours)	60,000–90,000	90,000–100,000	30,000–90,000	60,000–90,000	10,000–30,000	40,000–60,000
Annual efficiency degradation rate	0.25–1.5%		0.5–2.5%		3–50%	
Load range (% nominal load)	10–110%	—	0–160%	—	20–100%	—
Current density (A/cm^2)	0.25–0.45	—	1.0–2.0	—	0.3–1.0	—
Hydrogen production rate (Nm^3/h)	1400	—	400	—	<10	—
CAPEX (USD/kW)	500–1400	400–850	1100–1800	650–1500	2800–5600	800–2800
Overall system lifetime (years)	25–30	30	20–30	30	20	—

from oxygen molecules. Indeed, the maturity development and the high production volumes of ALK electrolysers have contributed to relatively lower capital expenditure (CAPEX) costs compared to other technologies listed in Table 1 [30, 35]. Moreover, ALK electrolysers are more suitable for large-scale capacity applications [23] and several examples exist of power plant capacities ranging from 100–200 MW, particularly in countries with abundant hydropower supply resources. The most common historical examples include; Aswan dam in Egypt built in 1960 with a rated capacity of 165 MW and hydrogen production rate of around 40,000 Nm^3/h, Nangal dam in India established in 1958 with a hydrogen production rate of 26,000 Nm^3/h, Cominco in Canada constructed in 1939 with a hydrogen production rate of 17,000 Nm^3/h, Rjukan in Norway established 1926 with a hydrogen production rate of 27,000 Nm^3/h, and Kwekwe in Zimbabwe installed in 1921 with a hydrogen production rate of 21,000 Nm^3/h [30, 37–39]. A recent market survey [30, 40–43] of commercially available large-scale electrolysers by technology type from different suppliers across the world is illustrated in Figure 2, showing that current ALK electrolysis are manufactured at a rated power of up to 6 MW, equivalent to 1400 Nm^3/h. Table 2 shows some examples of worldwide recent hydrogen production plants based on different electrolysis technologies. A large-scale example of ALK-based production plant has just started operation 2020 in Japan with a capacity of 10-MW, on the behalf of Fukushima Hydrogen Energy Research Field (FH2R) project [44, 45]. The commissioning of several green hydrogen demonstration projects is also taking place in China. In December 2021, "Baofeng Energy Group" has launched the operation of the World's largest 150-MW ALK electrolyser powered with 200-MW solar panels in Central China, with a production rate of more than 20,000 tons of hydrogen per year [46]. An upcoming record will also take place with Sinopec Chinese oil company beginning the construction of 260-MW of ALK electrolyser in Northern China, integrated with 300-MW of solar and wind energy supply to be fully operational by 2023 [46]. In terms of lifetime, ALK electrolysers are showing superior performance than other technological counterparts with a minimum stack lifetime currently rated at 60,000 h [21], twice that of PEM electrolysers and six times longer than that of SOECs electrolysers. It is also predicted for ALK electrolysis to maintain an outstanding stack lifespan that can reach up to 100,000 operating hours in 2030 [21, 35]. However, the electrolyser stack lifetime can be affected by the increase in overloads and the declining efficiencies due to the cells voltage degradation rates [30]. The literature has reported annual efficiency degradation rates of 0.25–1.5% for commercial ALK electrolysers, compared to 0.5–2.5% for PEM electrolysers [47]. This means that the rate at which the efficiency of ALK electrolysis is subject to decrease per annum is approximately half the rate at which PEM electrolysis efficiencies tend to fall down, resulting in relatively longer lifespan for the former. For the overall system lifetime, this includes a number of stack swaps or replacements under continuous operation [36], it can be seen from Table 1 that ALK electrolysers have slightly longer system lifespan that can endure up to 25–30 years, compared to 20–30 years for PEM electrolysis, and 20 years for SOECs technologies [30, 36]. Further manufacturing insights have estimated that commercial ALK electrolysis typically require a stack replacement or partial overhauls after a period ranging from 8–15 years [30].

2.1.2. Polymer electrolyte membrane (PEM) electrolysers

PEM electrolysers are more compact and less dense than ALK electrolysers, making them potentially suitable in urban areas. They utilize pure water as the electrolytic solution, thus avoiding the recycling process of KOH solution employed with ALK electrolysis [21]. PEM electrolysers are rapidly emerging as they offer more flexibility in the load range operation than ALK electrolysis, making them more attractive for market stakeholders, as well as for grid balancing and frequency regulation services [35]. They are able to operate beyond 100% and up to 160% of nominal load, as well as operating in stand-by mode with minimal consumption [21,

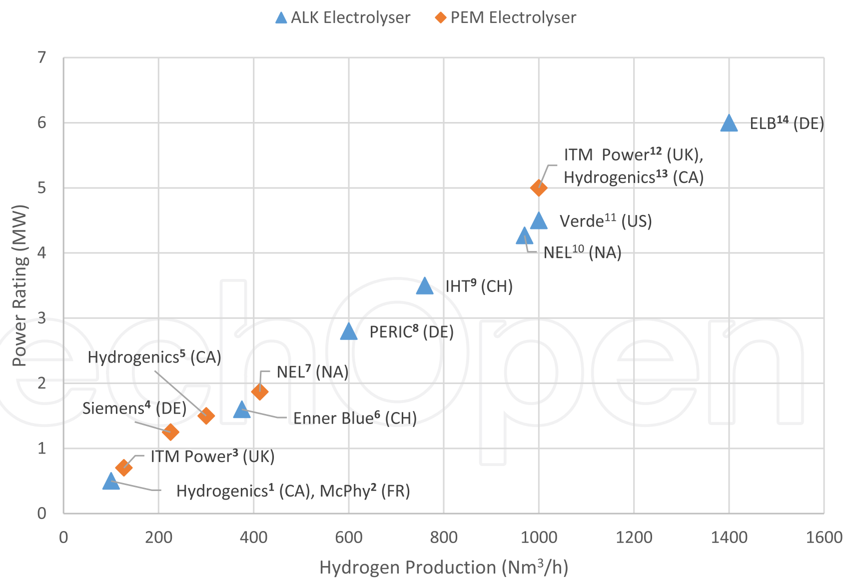


Figure 2. Market survey of worldwide large-scale commercial electrolysers by technology type and manufacturer. [1]Hydrogenics series HySTAT 100-10 [42], [2]McPhy series McLyzer [30] (both McPhy and hydrogenics products are available at same capacity of 0.5-MW electrolysis systems), [3]ITM Power series HGAS1SP [30, 43], [4]Siemens series Silyzer 200 [41], [5]Hydrogenics series HyLYZER 300-30 [30, 42], [6]Enner Blue Module L-size [30], [7]NEL series MC400 [40], [8]PERIC series ZDQ-600 [30], [9]IHT series S-556 [30], [10]NEL series A1000 [40], [11]Verde series Verde-1000 [30], [12]ITM Power series 2GEP Skid [43], [13]Hydrogenics series HyLYZER 1000-30 [42] (both Hydrogenics and ITM Power products are available at same capacity of 5-MW electrolysis systems), [14]ELB series LURGI SE [30].

35]. Thus, with the ability to regulate PEM electrolysis upstream and downstream rated load, they can provide frequency regulation services while supplying hydrogen for multiple endeavours as industry, transportation or injection into gas grid [35]. As illustrated in Table 1, ALK technologies are less flexible than PEM electrolysis, and their load range is limited at 110% of rated load as they were traditionally manufactured to operate at constant load for steady-state applications [21, 35]. Therefore, there is a room for improvement in the economics of PEM technologies due to their flexibility and the opportunity to earn extra revenues from grid operators and several customers, thus compensating for their high CAPEX compared to that of ALK electrolysis [35]. Furthermore, PEM technologies are designed to operate under higher pressures ranging from 30–80 bar and can reach up to 100–200 bar with additional compressors, compared to 1–30 bar for ALK electrolysis. This makes them appropriate for decentralized production and mobility applications requiring high pressure as refuelling stations [21, 23]. However, the operation under excessive pressures results in higher degradation rates for PEM facilities than ALK electrolysis as discussed earlier in Section 2.1.1. In terms of efficiency, as indicated by

Table 2. Worldwide examples of recent hydrogen production plants by technology type.

Technology type	Project plant name	Country	Capacity range	Year
ALK technology	Baofeng project [46]	Ningxia autonomous region, central China	150-MW ALK unit	2021
	FH2R [45]	Namie town, Fukushima, Japan	10-MW ALK unit	2020
	Audi E-Gas [55]	Wertle, Germany	6 MW, 3 ALK units, rated 2 MW each	2013
	EON demonstration plant [30]	Falkenhagen, Germany	2 MW ALK unit	2013
	George Olah Plant [30]	Svartsengi, Iceland	6 MW ALK unit	2012
PEM technology	Air Liquide Hydrogen project [48]	Bécancour, Quebec, Canada	20MW, 4 PEM-modules	2021
	H_2 Future [49]	Voestalpine, Linz, Austria	6 MW PEM module	2019
	BIG HIT [22]	Orkney islands, Scotland, UK	1.5 MW, 2 PEM modules, (1 MW and 0.5 MW)	2018
	Energiepark Mainz [30, 50]	Mainz, Germany	6 MW, 3 PEM-Stacks, rated 2 MW each	2015
	HyBalance [51]	Hobro, Denmark	1 MW, 1 unit	2015
	H2BER [55]	Berlin, Germany	0.5 MW, 1 unit	2014
SOECs technology	Sunfire prototype [54]	California, USA	140 kW at part-load 250 kW at full-load	2016

Table 1, PEM technologies have a rated stack efficiency based on lower heating value (LHV) of 56–60%$_{LHV}$ at energy consumption rates of 4.4–5.0 kWh/Nm^3, while ALK electrolysis are 63–70%$_{LHV}$ more efficient at similar energy consumption values of 4.2–4.8 kWh/Nm^3 [21, 30]. Other factors such as the utilities consumption and losses associated to rectifiers or additional compressors also impact the overall system performance. Figure 3 demonstrates the techno-economic performance of each electrolyser technology type in terms of its electrical efficiency and CAPEX versus the range of suitable applications according to its operating pressure level (with more focus on the PEM and ALK technologies given that the SOECs are still under-development). Such demonstration can aid appropriate selection of electrolyser technology suited for a required application. It should be noted that the electrolysis technologies could achieve better performance in terms of stack efficiency under reduced load operation [35]. Further literature has indicated that the opportunity for PEM electrolysis to achieve improved efficiencies at part-load operation is higher than that for ALK electrolysis [23]. This was justified by figuring out the overall efficiency of an ALK-based industrial project which has slightly increased from 53%$_{LHV}$ at full-load to 55%$_{LHV}$ at 40% of rated load, achieving only a 2% increase when operated below the half-load range [30]. On the other hand, the results of a PEM-based Siemens project, namely "Energiepark Mainz", have indicated that the total efficiency at higher heating value (HHV) has improved from 58%$_{HHV}$ at full-load to 65%$_{HHV}$ at nearly 60% of nominal load, attaining a 7% of increase at reduced load operation [23, 30]. PEM technologies are also characterized by higher current densities ranging from 1–2 A/cm^2, which are equivalent to hydrogen production volumes of up to 8.4 Nm^3 per cell area [30]. In contrast, ALK electrolysers have much lower current densities rated at 0.25–0.45 A/cm^2, corresponding to a maximum hydrogen production volume of 1.9 Nm^3 per cell area, less than quarter the PEM electrolysis value. In terms of deployment level, PEM technologies have recently achieved a promising development through a number of demonstration projects in the MW-scale, as illustrated in Table 2. Typical examples include; Air Liquide Hydrogen project in Quebec, Canada, renovated in 2021 and currently holding the world's largest capacity of 20-MW PEM electrolysis [48]; H_2Future in Austria, successfully rolled out in 2019 with 6-MW PEM Electrolysis [49]; BIG-HIT project in Orkney, Scotland, inaugurated in 2018 with a total installed capacity of 1.5-MW of PEM electrolysers [22]; Energiepark Mainz project in Germany, commissioned in 2015 with 6-MW PEM electrolysis [30, 50]; and HyBalance project in Hobro, Denmark, launched in 2015 with 1-MW PEM electrolyser capable to generate 230 Nm^3/h of hydrogen [51]. Interestingly, this scaling-up investment in PEM technologies will contribute to their future cost reductions, thus bypassing the main challenge of PEM electrolysis.

2.1.3. Solid oxide electrolysis cells (SOECs)

SOEC, is still a pre-commercialized technology that has been only investigated at laboratory-scale or small-scale demonstration projects. It utilizes solid-ions conducting ceramics as the electrolyte solution and produces hydrogen by steam conversion [52]. SOECs operate under very high temperatures ranging from 650–1000 °C, making them most suitable to be integrated with energy resources that provide higher amount of heat as nuclear energy, geothermal or concentrated solar power (CSP) plants [21, 35]. The downside of SOEC is that they are subject to substantially higher degradation rates compared to ALK and PEM electrolysis, that can reach up to 50% per annum, due to their increased operating temperatures [30]. In terms of flexibility, SOECs offer reversible operation of up to −100/+100% of load range. This means that they can be switched between electrolysis mode to generate hydrogen and fuel cell mode to generate back electricity, thus providing flexibility in stabilizing the grid while producing hydrogen for energy storage [21, 30]. Moreover,

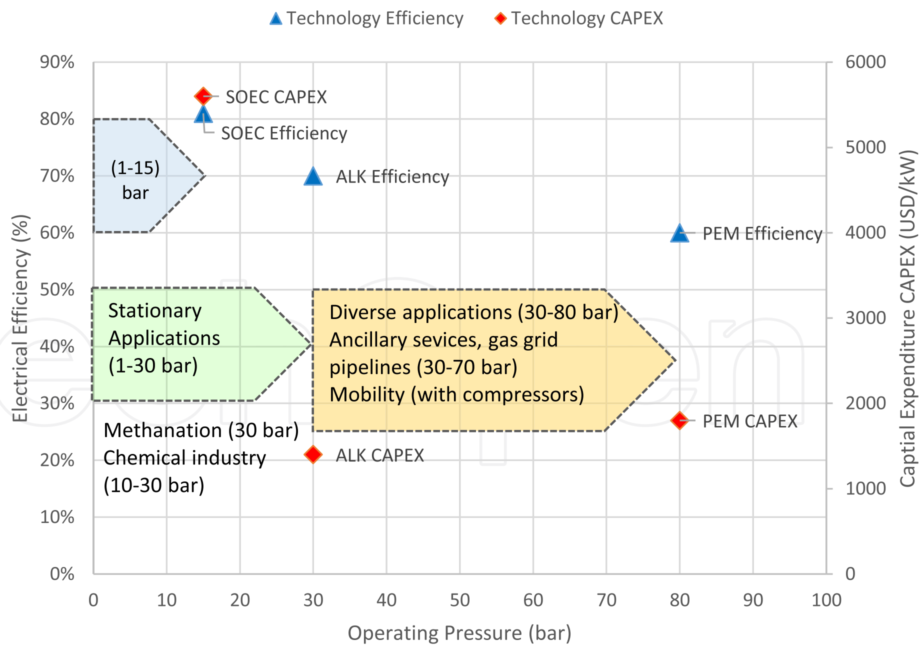


Figure 3. Techno-economic performance of electrolysers technologies versus the range of suitable applications according to operating pressure level.

as can be seen from Table 1, compared to ALK and PEM technologies SOECs feature the highest conversion efficiency rated at 74–81%$_{LHV}$ [21] at estimated average energy consumption of around 3.0 kWh/Nm^3, excluding other losses [30]. The efficiency privilege for SOECs is a result of steam conversion, and other factors related to improved thermodynamics and internal heat recycling. From another prospective, SOECs are facing some limitations correspondent to their relatively lower current densities of 1 A/cm^2 at most [30] and their short-term stack lifetime limited at 30,000 h as estimated by the IEA [21]. These restrictions are mainly due to their higher degradation issues with respect to other technologies. In practice, the longest lifetime of SOECs is above 11,000 h [53], based on experimental validation in the European Institution for Energy Research (EIFER). Regarding their capacity range, SOECs are available in a few kilowatts range as the technology is still in the development phase. An example of SOEC large capacity module is the one installed in the US Navy micro-grid test facility in California that has been delivered by Sunfire technology in 2016. It has a capacity range of 140 kW under part-load operation and a raised efficiency of up to 85% [54]. A key challenge that need to be addressed in SOEC is their significantly higher CAPEX compared to other technologies, it's around three times more than that of PEM electrolysis and over five times more than that of ALK electrolysis [21]. A route for their CAPEX reductions exists as the technology reaches up the deployment level.

2.2. Green hydrogen storage and transportation

Green Hydrogen storage plays a crucial role in driving the route for green energy transition and delivering a full sustainable development. The current on-board hydrogen storage technologies mainly involve three categories: gaseous storage systems, liquid storage systems and solid-state storage systems [13]. The competitiveness of the available storage mediums depends on the size of hydrogen to be stored, the duration required for hydrogen storage, and the scale of end-use applications [13, 21].

2.2.1. Gaseous hydrogen storage and transportation

Gaseous storage systems are more suitable for long-term storage and energy conversion applications. This is typically relevant to the use of hydrogen as energy storage vector to compensate for seasonal variations or shortfalls in energy supply, as well as for residential and commercial heating [21]. The scale of end-use application mainly depends on the type of hydrogen storage system and the modes of hydrogen transportation. In the gaseous state, hydrogen is stored as highly-compressed gas in either storage vessels or underground storage systems, reaching pressure levels of 35–70 MPa for fuel-cell applications [13, 56]. It should be noted that the hydrogen gas is characterized by a very low density of 0.089 kg/m^3, leading to relatively higher opportunities of hydrogen leakage even when stored under high pressures in containing vessels [57]. Thus, heavy steel and aluminium cylinders are widely used for gaseous hydrogen storage, providing robust design to withstand high-pressures and prevent gas leakage, however this highly impacts the quantity of hydrogen being transported [58]. Pressurized hydrogen gas can be transported either by tube trailers or via pipelines [59]. Tube trailers are used for hydrogen transportation by road where the compressed gas cylinders are stacked together and mounted on a trailer or truck, this therefore is more suitable for short-distance and small-scale applications due to the limitations of transport capacity [60]. The weight of storage vessels is key factor in determining the transport capacity per truck. The more the weight of storage cylinders, the less the transport capacity per truck which is the case of heavy steel storage vessels. A single truck carrying capacity is limited to 420 kg of hydrogen when loaded with steel cylinders at 200 bars [59]. An increased carrying capacity up to 720 kg of hydrogen at same pressure could be achieved by using Carbon-Fibre-Reinforced-Polymer (CFRP) cylinders as they offer a lightweight solution with high strength materials [60, 61]. However, this technology is still-under development [58], and may incur additional cost on the future of hydrogen in empowering the low-carbon economy. For long-term and large-scale applications, underground storage systems with geological formations such as salt caverns or depleted natural gas and oil reservoirs, are more appropriate for longer-term hydrogen storage. Salt caverns are more effective as they offer high efficiency, minimal risks of hydrogen contamination and lower operational costs [13, 21], while the gas residuals in depleted gas reservoirs may affect the hydrogen purity. The depth of salt caverns highly impacts the hydrogen storage capacity [62]. Deeper depths allow more pressurized hydrogen to be stored, thus more advantageous for large-scale hydrogen storage while preventing leakage under high pressures and preserving the hydrogen for longer periods of time. The most common examples include three salt caverns located in Teesside, UK, that can store up to 1-kilo tons of hydrogen. The largest salt cavern storage system currently exists in the United States and can store from 10-20 kilo tons of hydrogen energy [21]. The most established and cost-effective transportation way for pressurized hydrogen gas on-ground or underground would be via pipelines in the same manner natural gas is being transported. However, hydrogen behaves differently from natural gas and this could lead to several problems with the existing natural gas infrastructures, this involves extreme safety measures to abate hydrogen attack with high-strength metals or alloys, hydrogen embrittlement, opportunities of breaking the welds in existing pipelines and hydrogen leakage from valves and joints [63]. As mentioned earlier, the hydrogen gas features a very low volumetric energy density and thus lower viscosity, requiring the hydrogen flow rate in existing pipelines to be much faster than natural gas to avoid hydrogen higher mobility and opportunities of gas escapes [62]. Further, adopting rigorous risk assessments is essential to avoid hydrogen ignitions, explosions or damage to human life when exposed to overpressures or accumulated in poor ventilated areas [25]. Installing new pipelines that are more suitable for transporting the hydrogen gas is currently in its infancy phase, however too costly and only available in locations where the hydrogen gas is being produced next to large retailers and industry consumers. The longest operating hydrogen pipeline exists along the Gulf Coast region in the United States [61]. To enable a cost-effective and low-carbon economy across Europe, a currently ongoing trend in the European nations is to repurpose or retrofit the existing natural gas pipelines to transport the hydrogen safely, given that the European infrastructure for natural gas is already installed [25]. However, the route to establish the technology is challenging. To reflect on the current development status of repurposing the existing gas grid infrastructures in European nations, 48 sample projects recently running across Europe are examined in this paper. Statistics of the considered projects running from 2019–2022 onwards is presented in Figure 4. Four exemplar regions, UK, Germany, Netherlands and Belgium, have been considered for the illustration. The considered gas grid repurposing projects include Research and Innovation, Research and Development (R&D), and on-site demonstration projects. As illustrated in Figure 4, the total number of ongoing projects for repurposing existing gas infrastructures reached the highest record by the year of 2021 (33 projects), with more than 40% of considered projects running across the UK [64–77], and the remaining proportion fairly distributed between

Germany [65, 78–89], Netherlands and Belgium [65, 90–94]. Similar efforts are currently underway and further planned for 2022 onwards [67, 74–77, 86–89, 92–94]. However, the number of ongoing projects is not the only indicator of the nations' development towards establishing the technology, but also the challenges being addressed can identify where nations are standing up from the maturity of technology. From the analysis of the considered projects, it can be concluded that the main challenges being addressed among nations through the launched projects include the following 7 main categories: (1) techno-economic evaluation of existing gas grids, (2) safety measures of hydrogen transportation in existing gas grids, (3) blending hydrogen with natural gas up to 20%, (4) blending hydrogen with natural gas up to 100%, (5) developing hydrogen sensor technology, (6) adopting hydrogen for residential/commercial heating, (7) hydrogen deblending from mixtures with natural gas. To demonstrate the development status of European nations in addressing these challenges, Figure 5 shows the considered project samples classified according to the challenges being addressed using the scope of each project and the related tasks or phases, where each project can address more than one challenge. It should be noted that the development status towards addressing a specific challenge cannot guarantee that the problem has been fully resolved, however could give indication to which extent the challenge is being addressed and highlights the potential research gaps remaining to unlock all barriers. The first challenge considered involves technical and economic evaluation of existing gas grids to identify the optimal requirements, scenarios and conditions under which the hydrogen can be transported safely and selecting the most suitable locations for expanding the hydrogen network. This has been highly addressed within the UK which has launched a number of research and innovation projects for reviewing and assessing the technical and economic feasibility of hydrogen transportation within its existing gas transmission systems mainly across North of England [74–76], Scotland [67], and South Wales [25]. The fact that nations can build up on international knowledge and lessons learned from other research experiences might clarify some ambiguity regarding the progress of other nations in assessing the techno-economic viability of repurposing existing gas infrastructures [85]. The second challenge which constituted a major concern among all considered nations is to ensure the safety of hydrogen transportation within existing gas infrastructures. Investigating this challenge included activities for researching and testing the compatibility of various materials used with existing gas networks (steel pipes, valves, regulators, heat exchangers … etc) for hydrogen flow, and analysing how the change in gas characteristics can impact the behaviour of such materials for recommendations to further improvements or replacements needed [70, 83]. Activities like developing integrity management systems for security aspects of pipelines with high hydrogen content and establishing standardized risk assessments for hydrogen related hazards [70, 78–80, 90, 91] have also been included under the safety measures for hydrogen transportation with existing gas infrastructures. Figure 5 shows an increased weight from the total number of launched projects towards addressing this challenge compared to other challenges, thus reflecting extensive efforts and relatively progressed state of considered nations in filling this gap. Potential examples in this field included HYPOS projects in Germany [78–80], and H21 programme in UK [70] which involved a series of small projects aiming to review and test the safety of existing gas networks with some projects delivered in 2021 [70], and others currently running for upgrading the existing gas pipelines with essential modifications needed. Serving as strong pillar for the next development phases, the code of standards and safety case reviews provided within the delivered projects allowed for trial investigations to blend the hydrogen with natural gas in incremental concentrations while maintaining the safety measures outlined for hydrogen related hazards [25, 69]. Overall, a moderate progress has been seen among the considered nations in addressing this issue, with potential results confirming the operational safety of gas pipelines and end-uses applications for hydrogen blends up to 20%–30% [25]. Blending up to 100% hydrogen is currently under research [65, 76, 81, 86, 95] to combat damaging overpressures and risks of explosions estimated for hydrogen blends over 50% [25, 96]. Further research is needed regarding developing sensor technologies to detect gas leakage in pipelines with rich hydrogen content, hydrogen flow metering and measurement accuracy [79, 84], hydrogen deblending from admixtures with natural gas [66, 76] and developing certified hydrogen domestic gas appliances such as boilers, cookers and gas fires to adopt the hydrogen for heating [68] and enable residential end-users to shift into "low-carbon" or in the near future "pure hydrogen" network. An initiative kick started to address this issue via Hy4Heat project in UK [68], which in collaboration with industrial experts, has developed prototypes for hydrogen 'ready-to-use' appliances and auxiliary components required for installation in the existing natural gas appliances, and accordingly proceed to the next stage of community trials. While hydrogen is likely to dominate the gas grid infrastructures in the near to medium term future, there are still more questions to answer, particularly on the scale of investment required to switch from natural gas to low-carbon or pure hydrogen network. Transitioning to a hydrogen gas grid would require a vast number of repurposing of the existing gas pipelines to deploy the hydrogen for heating in homes, buildings and businesses by 2050 and realize the Zero-Carbon ambition. However, the scale of mass production required, the uncertainty regarding people awareness and level of public engagement together with continuous population growth and increasing energy demands are all highlighting significant milestones for nations to reach the maturity of technology.

2.2.2. *Liquid hydrogen storage and transportation*

Liquid storage systems are more suitable for short-term storage and applications requiring high energy density, where the hydrogen is used as fuel for driving the

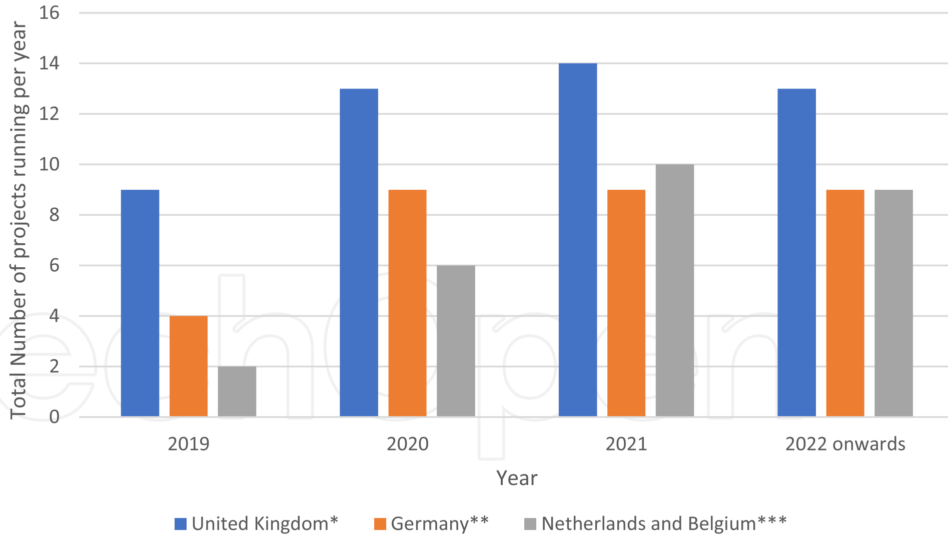


Figure 4. Statistics of ongoing projects across Europe for repurposing existing gas infrastructure to transport hydrogen. *Considered projects in UK include: Liverpool-Manchester Hydrogen (L-M) Cluster (2017–2025) [64, 65], HG2V (2018—2021) [65, 66], Hy4Heat (2018–2022) [25, 67, 68], Aberdeen Vision as part from Acorn Hydrogen project (2018–2025) [25, 69], H21-NIC (2018-present) [70], H21-NIA series 292, 348 (2018–2021) [70], HyDeploy (2019–2022) [25, 65], Future of LTS (2019–2020) [65, 67], HyNet (2020–2027) [25, 71, 72], Zero 2050 South Wales (2020) [25], Gas Goes Green (2020–2050) [73], H100 Fife (2020–2027) [65], H21-NIA 275 Compatibility of H2 services (2021) [70], HyNTS (2021–2023) [25, 74, 75], Project Union (2021–2033) [76], Future Grid (2022–2045) [67, 76], East Coast NGN (2022–2032) [77], H21-NIA 302 Wider Networks H2 impacts (2022-Present) [70]. **Considered projects in Germany include: HYPOS: PIMS (2016–2019) [78], HYPOS: HyPROS (2017–2020) [79], HYPOS: INES (2018–2021) [80], Ohringer-H2-Island (2019–2023) [81], HyPipe Bavaria (2020–2050) [82], H_2 gas grid Compendium (2020) [65, 83], H2 infrastructure Worldwide (2020–2021) [85], H2 measurement accuracy (2020–2021) [84], H2HoWi (2020–2023) [65], SyWest H2 (2020–2022) [65], H2BoMess (2021–2023) [65], H2vorOrt (2021–2050) [65, 86], TransHyDE (2021–2025) [65, 87], HH-WIN (2022 onwards) [88], HyPerLink (2025–2030) [89]. ***Considered projects in Netherlands and Belgium [65, 90–94] include: H2 Sensor Technology (2018–2020) [90], Marcogaz project (2018–2019), HyDelta (2020–2022), Hydrogen Street (2020–2025), HyWay27 (2020–2021), GERG HIPS (2020–2021), H2&CO_2 Backbone (2020–2026), HyTransPort RTM (2021–2024), Metrology for decarbonizing gas grid (2021), SeaH2land (2021-present), H2DeltaNetwork (2021–2025), HyFit (2021–2023), H2 Transmission Backbone (2024–2030), H2opZee (2022-present).

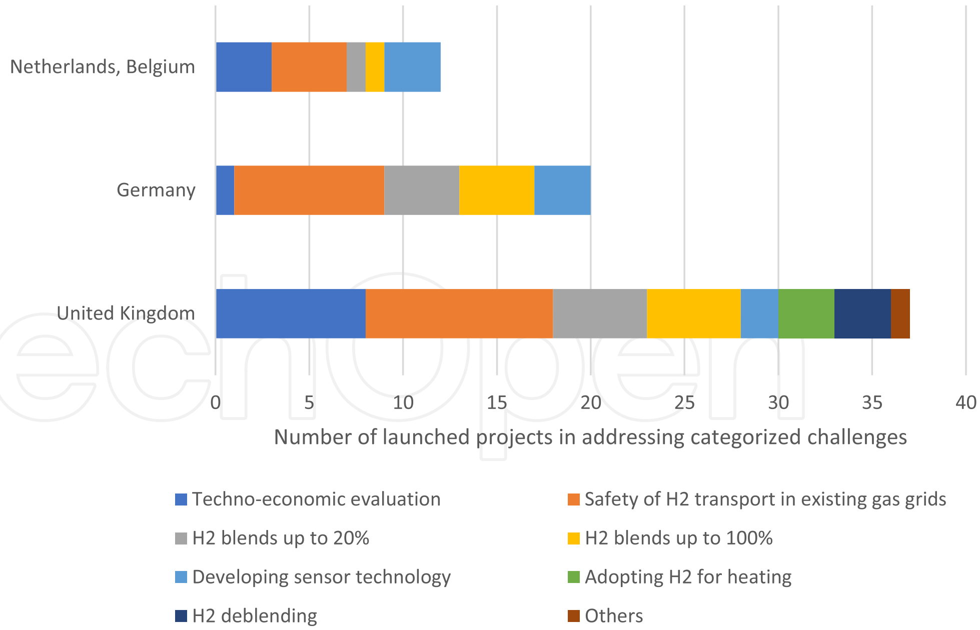


Figure 5. Development status of considered European Nations in addressing categorized challenges*.* Total number of projects that address all categorized challenges differ from total number of actual projects as each project can address more than one challenge (only projects with announced plans have been considered).

mobility sector, or as renewable energy carrier for international hydrogen transport. The density of liquified hydrogen (LH2) is around 70 kg/m^3 at 1 bar, thus allowing huge storage densities to be achieved at the atmospheric pressure [24, 57]. In the liquid state, hydrogen is stored in super-insulated cryogenic tanks, where the fluid is cooled down to $-253\ ^{\circ}$C [59, 61]. To maintain the fluid at cryogenic temperatures, double-wallet storage tanks, occupied with vacuums between walls and provided with high insulation materials, are commonly used to minimize the heat transfer [13, 24]. In terms of weight, liquid hydrogen tanks offer compact size design and less space requirements due to the higher fluid density at lower storage pressures. Compared to gaseous hydrogen storage, liquid hydrogen tanks feature reduced wall thickness as advantage of low storage pressures, surrounded by thick layer of insulation with insulation mass relatively low compared to the mass of the tank, and thus much lighter weight than the heavy steel cylinders used for compressed hydrogen gas [60]. However, hydrogen liquefaction process consumes higher energy input due to the extremely low boiling point of LH2, with more than 30% of hydrogen content consumed in the liquefication process, resulting in higher fuel costs per unit mass when compared to gaseous hydrogen storage. Table 3 summarizes the key design considerations and limitations of liquid hydrogen storage compared to gaseous hydrogen storage. Another concern related to the cooling process of LH2, is the energy loss due to the evaporation of liquid hydrogen, known as "boil-off". The hydrogen boil-off can be defined as the loss of hydrogen over time owing to the pressure build-up inside the storage vessels, thus restricting the use of liquid storage tanks for applications requiring the preserved hydrogen to be consumed over short-term periods [13, 24]. For automotive applications, where the vehicle weight is a major design driver affecting the vehicle performance and fuel costs, LH2 became more economically viable as it allows weight savings, less tank volumes and less fuel consumption over long distances [26, 60]. LH2 can be transported by road liquid trucks or by sea shipments. Transporting the hydrogen as liquid requires higher operating costs than gaseous hydrogen as more energy is consumed for liquification (typically 10 kWh per kg of liquid hydrogen), however it is more advantageous in terms of hydrogen transport capacity. A single liquid truck can carry ten times more hydrogen than gaseous hydrogen truck due to its increased fluid density, and thus dominates over gaseous tube trailers for long-distance applications [59–61]. For liquid hydrogen transportation by sea shipments, this is often relevant to international hydrogen transport at large-scale where hydrogen is used as renewable energy carrier, offering cost-effective and highly efficient way to distribute renewable energy across regions. Today the need for international energy trading is escalating as result of variations in renewable potential and energy demands across border regions. For instance, Japan is considered a poor country in wind and solar energy resources and thus importing renewable power would be a more feasible solution for accommodating the shortage in their renewable potential. For European countries where the demand for green energy transition is increasing, importing low-cost solar energy from Middle Eastern regions become more economically attractive, while allowing developing countries to raise their scale of investment. The privilege of high energy density allows for LH2 to be shipped offshore, carrying large quantities of renewable energy from countries with high renewable potential to countries with less renewable potential at relatively low cost and high efficiency [9]. A single ship could carry up to 10,000 tons of hydrogen, thus making LH2 maritime shipping the most suitable option for very large-scale and long-range international transport [60]. Recently, a World-Class LH2 carrier ship by the Japanese corporation "Kawasaki Heavy Industries", has just got approval to transport large amounts of cryogenic LH2 with a carrying capacity of 40,000 m^3 (approximately 2800 tons) per tank [97, 98]. Despite serving as affordable cross-border energy infrastructure, key transportation hurdles exist against the widespread adoption of large-scale LH2 cargo containment systems for maritime shipping, this includes low boiling-off point, difficulty in designing robust insulation systems, safety concerns and special ship designs. Research gaps exist in developing heat transfer models for well-insulated storage tanks as well as the selection of appropriate insulation materials to maintain the boiling-off temperature of LH2 at −253 °C and avoid the loss of fuel due to temperature difference between the inner storage tank and outside ambient temperature. Even though with adopting high-vacuum insulation systems to control the boil-off loss of liquid hydrogen within acceptable limits, upscaling the technology to a level suitable for shipping offshore will be further challenging. This is because the target vacuum required to develop a World-Class LH2 cargo container, as large as LNG tank, is expected to slow down the evacuation process while significantly increasing cost expenditures as result of additional outer tank requirements beyond the manufacturing practices [26]. Further research is needed to address the techno-economic viability of these insulation strategies for large-scale LH2 tanks to enable the technology development. Additionally, hydrogen safety issues like high flammability risk, contamination with air and hydrogen embrittlement need to be considered when designing the controlling valves and support systems for LH2 containers. Mostly, the associated valves and joints are made of high strength materials, which need to be properly designed to avoid the phenomenon of "cryogenic embrittlement", defined as the reduction in materials strength when exposed to LH2 [26]. It should be noted that there is lack of experimental work on LH2 embrittlement, which needs to be addressed through proper research and lab-scale testing. In terms of ship design, LH2 carrier ships become less attractive when compared to the well-established Liquified Natural Gas (LNG) ships, as the density of the former fluid remains lower than that of the later even in the liquid state, meaning more space is required and thus greater ship sizes compared to those already established for LNG [99]. While hydrogen transportation by sea shipments offers cost-effective way to distribute renewable energy across border regions, the need for customized ship designs to carry LH2 cargo containers imposes extra cost on shipowners against the widespread adoption of LH2 carrier ships. The specialized ship design requirements together with sophisticated operational conditions for LH2 cargo containment systems gave rise to alternative options of liquid hydrogen carriers such as green ammonia (NH_3). The advantage of ammonia route over LH2 sea shipments is that ammonia is a well-established chemical fertilizer, and thus doesn't require specialized ship designs as the technology for transporting it is already mature [100]. Additionally, ammonia features higher hydrogen storage density compared to LH2, thus providing an easy pathway for long-distance hydrogen transportation at relatively low cost. However, the cost of hydrogen release at the delivery point maybe as expensive as the cost of hydrogen liquefication, in addition to the risk of air pollutants emissions as nitrogen oxides [26]. For these reasons, the large-scale deployment and transportation of ammonia is subject to authorities' regulations.

2.2.3. Solid-state hydrogen storage

Conventional hydrogen storage systems using gas compression or liquefaction require bulky storage spaces, thus raising the attention towards solid-state hydrogen storage. Solid-state storage involves the reaction of hydrogen molecules with either

Table 3. Design considerations and limitations of gaseous hydrogen storage versus liquid hydrogen storage.

Criteria	Gaseous hydrogen storage	Liquid hydrogen storage
Suitability	Long-term storage and energy conversion applications	Short-term storage and high energy density applications
Storage requirements	High-strength materials	High-insulation materials
Transportation modes	• Tube trailers (road trucks) • Pipelines	•Road liquid trucks •Sea shipments
Transportation hurdles	• By trucks: heavy weight and limited transport capacity • By pipelines: building new hydrogen pipelines is too costly and limited to specific locations, technical issues for repurposing the existing gas grid pipelines (safety concerns, H_2 blends with natural gas, H_2 deblending and developing new H_2 sensors)	•By trucks: higher operating costs, boil-off concern •By sea shipments: sophisticated operating conditions for large-scale LH_2 cargo containment systems and specialized ship designs

pure or alloying metals to produce metal hydrides at ambient pressures and temperatures, giving them a superior degree of safety against hydrogen gas leakage or liquid evaporation [13]. Moreover, solid-state storage systems allow the hydrogen to be stored at higher volumetric energy densities and offer improved storage efficiency and easy process of hydrogen release. A demonstration example with innovative solid-state hydrogen storage that is capable to store more than 1 ton of hydrogen energy, under the name of "INGRID" project, is launched in Southern Italy by a consortium of seven European partners to support over 3500 MW of renewable energy [101].

2.3. Green hydrogen implementations

Green hydrogen is recognized by its ability to become a clean energy carrier in the supply chain through fuel-cells technology. In the following subsections, the fundamental prospects of fuel-cells generators and combined heat and power (CHP) technologies are briefly discussed.

2.3.1. Fuel-cells generator technology

A fuel-cell is a device used to convert the chemical energy stored as hydrogen into electrical energy. The complete set-up of a fuel-cell energy system involves two primary components: a fuel-cell stack and a power conditioning subsystem [102]. Other auxiliary parts may include pumps, blowers, compressors, and condensers.

Like the hydrogen electrolyser in construction, a single fuel-cell module consists of an electrolytic membrane sandwiched between two electrodes. The hydrogen is fed into the anode while the oxygen is supplied through the cathode, forming a balanced number of dissociated protons and electrons among the two electrodes. The membrane permits only positively-charged ions to pass through it [103], thus protons cross the membrane towards the cathode while the free electrons exit the anode to the cathode through an external wire between both electrodes, resulting in a current flow through the wire [104]. At the cathode side, the oxygen gas in air reacts with the hydrogen protons and electrons, producing only water and heat as by-products with zero-carbon emissions. A single fuel-cell operating voltage is between 0.55–0.80 volts [102], and thus a fuel-cell stack connects multiple fuel-cells in series to achieve a higher voltage for practical applications. The operating current can be determined by the active area of individual cells [103], where a single cell area is typically ranging from 100 cm^2 to around 1 m^2 based on the fuel-cell type and the application power rating. The rated current can be controlled by increasing the surface area of the individual cells [102]. A power conditioning subsystem is required since the fuel-cell stack produces DC output power that needs to be regulated before serving the AC load demands. The typical DC output voltage of a fuel-cell stack is relatively low in magnitude, within a range less than 50 V per stack, and thus implies the use of a DC–DC converter to boost it to a voltage suitable for connection to the DC/AC converter (200–400 V) needed for serving the load [105, 106]. In addition, the use of DC–DC converter allows providing the low input current ripples demanded by the fuel cell stacks for grid interface. However, the reduction of current ripples involves the operation at higher frequencies which further increases the switching losses, reduces the efficiency and adds more penalties in terms size and cost of converter topologies. Following the DC voltage stepping-up and regulation, a DC/AC converter is used to transform the boosted DC voltage into AC output voltage with an adjustable frequency profile. These are mainly employed to provide power quality improvement for grid interface together with lower harmonic distortion, lower switching losses and higher efficiencies [107]. One of the challenges facing the implementation of these converters is the instability in providing DC link voltage in response to dynamic changes of grid events (fast load changes or grid faults) leading to harmonic distortion of output waveforms. Therefore, controllers are used to maintain a balanced DC voltage for lowering distortion or unwanted voltage stresses [108]. Figure 6 illustrates the architecture of the fuel-cell power conditioning subsystem. The hydrogen fuel-cells market has rapidly expanded in the last few years due to their ability to provide an emissions-free source of electricity. The world's largest hydrogen fuel-cell power plant, by Hanwha Energy production company, came into reality in South Korea in July 2020 with 114 fuel-cells capable of generating up to 400,000 MWh of electricity per year [109].

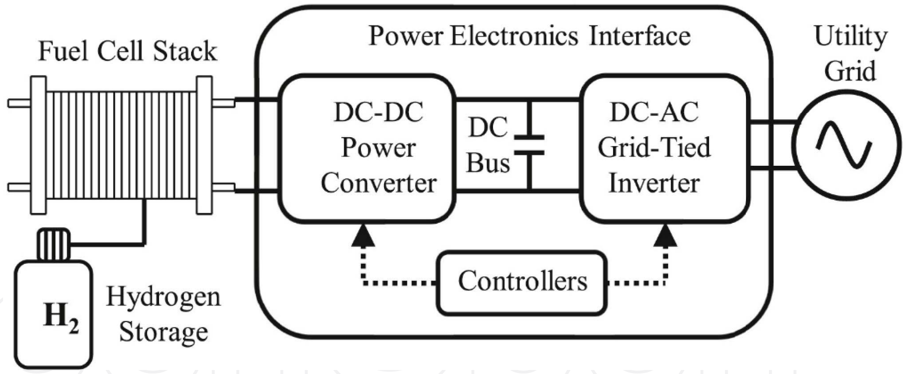


Figure 6. Power conditioning subsystem for fuel cell technologies [105].

2.3.2. Fuel cells combined heat and power (CHP) technology

Fuel-cells can also be configured into Combined-Heat-and-Power (CHP) technology, through which electricity is locally generated and the emitted heat is captured and used for heating purposes. A fuel-cell based CHP unit comprises a fuel-cell energy system and a heat exchanger acting as the recovery module for the wasted heat [110]. Most of the heat is retrieved from the cooling system of fuel-cell stack and the exhaust steam gases resulting from the condensation of water by-product. The type of fuel-cell and the operating temperature indicate the quality of heat and the scale of end-use application [102]. For a PEM-based fuel-cell, the cooling system allows the stack to be condensed at approximately 80 °C, thus making CHP schemes more suitable for residential/commercial heating and hot water applications [110]. A valuable advantage of CHP fuel-cells is their ability to provide higher operating efficiencies when compared to fuel-cells electrical generators, due to the process of heat recovering. For instance, the net electrical efficiency of PEM fuel cells is estimated at around 35% while the system efficiency could surge up to 85% when operating as CHP module due to coupling the electricity production with heat recovery [102, 110]. The fuel-cell CHP technology continues to attain a widespread deployment across the globe. Japan is successfully leading the world in installing fuel-cell micro-CHP modules since 2009, reaching up 289,125 units across the country in 2019, and is planning to achieve more than 5 million households by 2030. In addition, Japanese products are constituting the dominant share of domestic fuel-cell CHP facilities in the global market, with a production capacity typically rated between 200–700 W [9, 111].

3. Challenges of green hydrogen technologies in the energy supply sector

Hydrogen as an energy carrier offers a greater flexibility in decarbonizing the energy supply sector by storing, transporting and generating clean electrical power.

However, the strategic efforts required to enable the technology development bring major technical challenges. In this section, a critical review of the challenges facing the implementation of green hydrogen technologies for decarbonizing the energy supply sector is presented within four key areas of development: grid balancing, frequency regulation, large-scale integration of renewables and electrification of remote areas.

3.1. Challenges of green hydrogen in grid balancing services

Green Hydrogen Energy Storage holds the potential of stabilizing the utility grid by mitigating the seasonal variation of renewable energy systems. It can be used to store the intermittent renewable energy during the hours of peak generation and off-peak demand, then convert this back into electricity via fuel-cell technology to cover the energy needed during the hours of off-peak generation and peak-load demand. This in turn will reduce the need for fossil-fuel spinning-reserve used for peak-demand support and ensures the energy system security and flexibility while integrating more renewable sources, thus helping to decarbonize the electricity grid [22, 112]. The aforementioned process and the improvement of a power plant generation profile when supported with energy storage system at the point of common coupling is demonstrated in [113]. From another prospective, the integration of Hydrogen Energy Storage technologies within the electricity grid adds more complexity in several ways. The optimal sizing of system components including electrolysers, storage tanks and fuel-cells together with the optimal scheduling of their operation with the rest of system, and the ability to identify their economic viability when integrated with renewable energies are all considered main technical challenges and core-component research topics. Figure 7 illustrates a schematic diagram of the key factors involved in the optimal sizing problem of renewable hydrogen energy systems, which can be divided into three main categories: problem formulation, optimal sizing approach and modelling the operational management of system components. Optimizing the capacity of grid-integrated energy system can be formulated by defining a set of decision variables within a certain search space, seeking to find the best size configuration of system components which can minimize a given objective function, while satisfying a set of predefined constraints. For renewable hydrogen energy systems, the objective function often deals with the economics in form of the Annualized Cost of System (ACS) [104], Levelized Cost of Energy (LCOE) [114], or Net Present Cost (NPC) [115] while considering CAPEX, OPEX, replacements costs, salvage values, revenues, incentives, efficiency and lifetime of the technology. It should be noted that most of research studies consider the cost function of the renewable energy system coupled with the integrated storage technology [104, 114, 116–119]. To allow analysing the economics of a hydrogen storage system compared to onboard storage alternatives, it is recommended to evaluate the cost of the storage subsystem solely

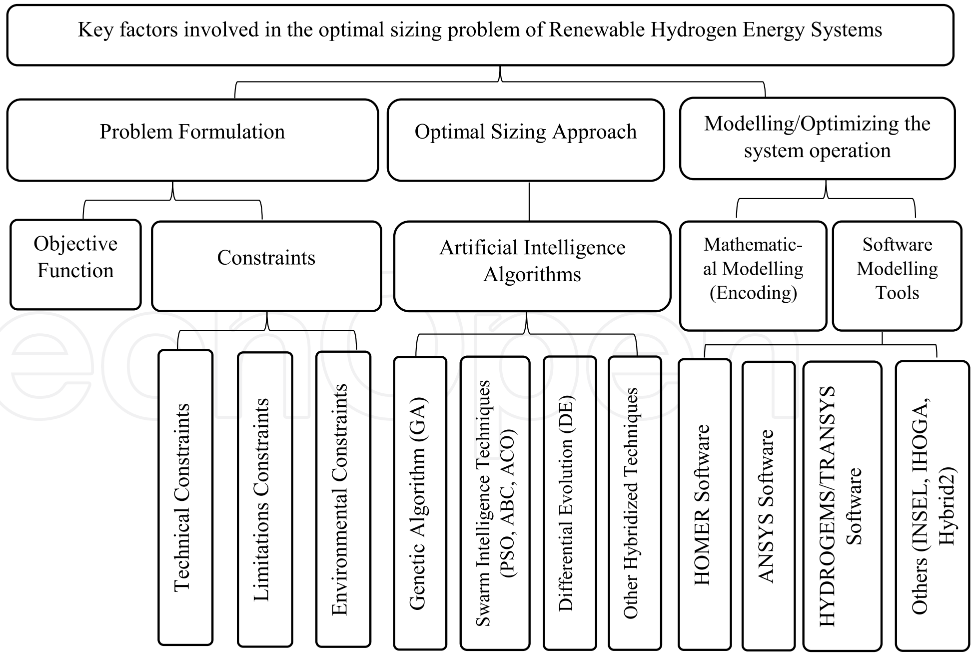


Figure 7. Schematic diagram illustrating key factors involved in the optimal sizing problem of renewable hydrogen energy systems.

per unit energy stored [29]. In the size optimization problem of renewable hydrogen energy systems, the objective function is subjected to a set of operational constraints, which can be divided into technical criteria, boundary limitations and environmental constraints [29]. The technical criteria measure the ability of an energy system to serve a load demand over a given time interval. This is often measured by Loss of Power Supply Probability (LPSP) [104, 117, 120], defined as the ratio of deficiency in feeding the energy demand over a given period of time. Other studies reported the Loss of Hydrogen Supply Probability (LHSP) [116], which similarly defines the ratio of deficiency in meeting the hydrogen demand over a given period of time. The aforementioned probabilities should tend to zero to indicate the effectiveness of the integrated hydrogen storage system in compensating the intermittency of renewable energy and serving the load demand. The evaluation of technical criteria involves modelling the energy management between the system components and integrating it with the size optimization process for minimizing the cost function, this in turn adds higher degree of sophistication. The limitation constraints define a set of boundary levels for the electrolyser, hydrogen tank and fuel-cell rated capacity, as well as the rate of charge and discharge of the storage vessel [29, 104, 116, 120]. Further limitations that need consideration in the optimization problem are the nominal flow rate of hydrogen generation, the nominal flow rate of hydrogen consumption and the target pressures and temperatures while charging and discharging the hydrogen tank. Regarding the environmental criteria, these introduce restrictions to limit the amount of GHG emissions resulting from an energy system configuration [29]. Recent research studies [115, 121–123] have demonstrated that environmental issues are commonly addressed through an assessment-based approach, and often not taken as part of the optimization problem. A common practice is to evaluate the amount of pollutant emissions displaced by the optimal size of a system configuration. Although this is essential in assessing the feasibility of energy systems' optimal sizing, restricting the amount of carbon footprint throughout the optimization process is recommended to guarantee minimized fossil-fuel spinning-reserves for grid-balancing applications. This has been addressed in few research studies in terms of Non-Renewable Usage (NRU) which defines the contribution of fossil-fuel to total energy provided [116], or conversely in terms of Renewable Usage (RU) defining the contribution of renewable energy sources in feeding the load demand [114, 116]. It can be deduced from conducted literature review that there is a room for improvement in formulating the optimal sizing problem of renewable hydrogen energy systems for grid integration. After formulating the optimization problem, a key barrier in optimizing the size of hydrogen energy storage components is the approach to find a global optimum solution which mainly depends on the mathematical modelling methodology and the optimization algorithm used. Artificial Intelligence (AI) algorithms, like Genetic Algorithm (GA) [124], Particle Swarm Optimization (PSO) [104, 116], Ant Colony Optimization (ACO) [125], and Differential Evolution (DE) [117], have been widely used for the optimal sizing of energy storage technologies integrated with renewable energy systems. These are population-based algorithms, where the population of candidate solutions are generated within a certain search space and works by improving each candidate solution in terms of a fitness function towards the global optimum solution. Recent literature has demonstrated that hybridized AI techniques can achieve better performance in optimizing the size of renewable hydrogen energy systems in terms of fitness function and computational time [104, 117]. While previous research studies have focused on enhancing the performance of optimization algorithms, they didn't take into account the internal working of hydrogen storage components which represents a major deviation from finding a solution that can fit into the real-world of hydrogen storage technologies. Accurate dynamic modelling is essential for hydrogen storage elements and represents a key-component in assessing the feasibility of the techno-economic optimization. ANSYS, HOMER and HYDROGEMS are the most compatible commercially available software tools for modelling the hydrogen storage systems. ANSYS is a simulation tool that works on optimizing the energy efficiency and thermal management of electrolysers and fuel-cell stacks, however lacks an optimization tool for the entire operation of renewable hydrogen energy systems [29]. HOMER is commonly used in the literature, providing the ability to simulate and optimize the size and the entire operation of grid-connected hybrid renewable energy systems from a techno-economic prospective before investment [115, 118, 119, 121]. However, this tool neglects the transient dynamic behaviour of hydrogen electrolysis when coupled with a renewable energy source. For grid balancing applications, an integrated electrolyser will be switching on and off in response to the intermittent nature of renewable energy sources, thus affecting the efficiency at which a quantity of hydrogen is being produced. HOMER software performs the optimal sizing of renewable hydrogen energy systems, considering an average value of electrolysis efficiency without modelling the impact of transient dynamic response of hydrogen electrolysers [126]. This in turn introduces a shortcoming in quantifying the real amount of hydrogen being produced by an electrolyser when used for grid balancing applications. An accurate mathematical modelling of hydrogen storage technologies can be found in HYDROGEMS toolbox, available as part from TRANSYS software, which provides a set of pre-programmed models that consider the thermal compensation, mechanical properties and thermodynamics of electrolysers, storage systems and fuel-cells [29, 126]. However, it lacks a design optimization feature for the size and internal workings of hydrogen subsystems. Moreover, the parameters of the pre-programmed models are based on manufacturers specifications and cannot be tuned to simulate an optimal operation of hydrogen storage solutions. Developing a model that can accurately simulate and optimize the size and the operation of real-world grid-integrated hydrogen storage technologies is currently a challenging milestone. Other challenges include: the application of Model Predictive Control (MPC) to address the degradation issues of hydrogen equipment when optimizing their operation along their lifecycles [127], forecasting the uncertainties in renewable energy and load demand for the optimal scheduling of renewable hydrogen energy systems [23], reducing forecast errors to enhance the economic viability of hydrogen electrolysers and fuel-cells when participating in the electricity market [128], and the application of Maximum Power Point Tracking (MPPT) for the energy management of solar-based hydrogen energy storage systems [129].

3.2. Challenges of green hydrogen in frequency regulation services

Another way to address the intermittency of renewable energy sources (RES) is the participation of hydrogen electrolysers in providing frequency regulation services for the electricity market. The integration of intermittent weather-dependant RES into the grid creates a huge imbalance between energy production and consumer demands, requiring the grid operators to manage any frequency disturbances. As mentioned earlier, PEM and ALK electrolysers can be operated in either part-load or over-load conditions and thus can be used to regulate the frequency up or down by adjusting their load operating point. An experimental analysis conducted by the U.S. National Renewable Energy Laboratory (NREL) has demonstrated how fast a hydrogen electrolyser can provide a system recovery in less than one second [28, 31].

The fast response of electrolysers makes them eligible to serve the regulation market which requires to takes an action within the 15-min average energy consumption [31]. In order for hydrogen electrolysers to participate in the ancillary services market, the commitment of their operational strategy should be done in accordance to grid requirements based on Demand Side Management (DSM) techniques. This involves a trading arrangement between hydrogen market stakeholders and local Distribution Network Operators (DNOs) in a beneficial way that allows increasing hydrogen production during the hours of low energy tariffs, and conversely decreasing hydrogen production during the hours of high energy tariffs while satisfying a hydrogen demand [130]. An important consideration for business owners when targeting the regulation market, is the oversizing of hydrogen electrolysers and storage capacity to ensure greater flexibility in providing ancillary services while supplying the hydrogen customers at minimal load operation [31]. This in turn increases the capital expenditures of hydrogen power plants, however analysing the incoming revenues and incentives from grid operators can identify the economic viability of hydrogen electrolysers for participating in the regulation market. In terms of green hydrogen production, a feasibility study [131] has demonstrated how profitable for RES owners to integrate hydrogen electrolysers in coordination with the grid. On the analysis of this research, it can be concluded that integrating hydrogen electrolysers brings more profit to RES owners due to the hydrogen sale, while the additional profit from participating in the regulation market depends on how much time the frequency control is to be activated or deactivated throughout the year. This is subject to variability of load energy consumption, thus necessitating the need to perform load forecasting studies in the decision making of hydrogen electrolysers as frequency regulators. Other important factors include the selling prices of hydrogen and excess electricity which depend on the volatile energy market. The more the income from the excess power generated, the more profitable the activation of frequency control. Conversely, the more the income from the hydrogen sale, the more profitable the deactivation of frequency control. It should be noted that the operation and maintenance costs need to be considered when analysing the cost-effectiveness of hydrogen electrolysers for frequency regulation services. From a technical perspective, the application of hydrogen electrolysers as smart controllable loads involves the integration of an intelligent control system communicating between the hydrogen generators and DNOs in accordance to the price signals [132]. The need to establish a set of communication protocols to realize the operation of hydrogen electrolysers in response to the grid market is one of the challenging issues. Another challenge is the need to develop an optimization module to adjust the desired operating level for hydrogen electrolysers to fulfil the grid requirements while feeding a hydrogen demand at an affordable price. This involves optimal planning of hydrogen production based on optimal energy management strategy to allow maximizing the opportunities of hydrogen stakeholders to gain profits from providing ancillary services, thus promoting the use of hydrogen electrolysers as frequency regulators. Higher degree of sophistication exists when it comes to green hydrogen production, as increased opportunities for prosumers to earn extra revenues come in place when selling renewable surplus electricity to the grid during hours of high-energy prices, thus obstructing the decision making on whether renewable surplus power can be fed into the grid or absorbed as green hydrogen for feeding a certain demand. The integration of a smart Energy Management System (EMS) is then crucial to optimize the percentage loading of hydrogen electrolysers to a level that can allow feeding a hydrogen demand while maximizing earned revenues from grid feed-in renewable surplus electricity, and thus facilitating the process of the decision making [133, 134]. Figure 8 shows a schematic that demonstrates the aforementioned smart energy management strategy of hydrogen production planning and storage in response to the grid market. In this illustration, the smart EMS receives real-time data of grid energy prices, RES and load demand forecasts to indicate the optimal percentage of electricity to be consumed by the electrolyser from renewable surplus power and that from the electricity grid for satisfying a certain demand while serving the regulation market, as well as the optimal percentage of grid feed-in renewable surplus electricity which can maximize extra revenues. This concept falls under the optimal scheduling or dispatching of microgrids and multi-energy systems which is key feature towards the deployment of smart grids and is particularly relevant to the application of green hydrogen electrolysers as smart controllable loads [135, 136]. Recently emerging AI control schemes which have been seen potentially effective in handling these problems are EMSs based on Machine Learning (ML) algorithms, like Reinforcement Learning (RL) and Deep Reinforcement Learning (DRL) [137]. Within the context of energy management, cutting-edge ML algorithms are capable to handle non-linearities and uncertainties facing the optimal scheduling problems including RES forecasts, load forecasts and dynamic grid pricing mechanism, in addition to being able to acquire large and updated data sets in real-time, thus reducing forecasting errors [138]. Advanced fields of RL and DRL work by assigning a virtual agent that interacts with an environment based on state-space observations, makes a decision that impacts the states of the environment and updates its decisions based on a reward and penalty scheme [139]. The more rewards the agent receives, the more oriented its self-learning towards recognising optimum decisions. Several research studies [140–145] have adopted RL and DRL for the control strategy optimization of microgrids and multi-energy systems. Up to date, only few studies [146, 147] have investigated their application in hydrogen production planning and the operational management of hydrogen storage systems. Overall, acceptable results have been achieved for the optimal control strategy of microgrids integrating green hydrogen storage using DRL-based EMS [146], considering variability of RES portfolio and load demand profile. However, the assumption of fixed wholesale electricity price is inconsistent with real-world volatile energy market, thus significantly bypassing key barriers facing the assigned agent while solving the optimal scheduling problem. This shortcoming has been resolved by A. Dreher *et al.* [147] by optimizing hydrogen production and storage of a grid-connected industrial CHP plant while considering volatile grid pricing, renewable generation and load demand forecasts. Despite the promising quality of results achieved by this study for controlling the operation of hydrogen electrolysers in response to grid signals under realistic scenarios, some challenges still exist. One of the key challenges to address is the trade-off between maximizing revenues from the operation of hydrogen electrolysers as smart controllable loads and maximizing the green hydrogen production and storage for meeting a hydrogen demand that realize the net-zero carbon ambition. Further research is required to improve the performance of newly emerging algorithms for handling such contradictory objectives, as well as analysing their strengths and weaknesses against other AI evolutionary algorithms commonly used for optimizing multi-objective functions in power system applications like Non-Sorted Genetic Algorithm (NSGA) and ε-constraint method. Moreover, the process of optimal control strategy for hydrogen production and storage in response to the regulation market must take place every 15-min interval to accommodate any change in energy consumption [132]. Therefore, real-time simulations are mandatory to verify the time response of the associated controller per cycle, which represents a critical parameter in assessing the functionality of hydrogen electrolysers for providing frequency regulation services. The response time of the smart control strategy falls under the electrolyser balance of plant (BOP), which involves other transducers to control the pressure, temperature and fluid aspects under different operating conditions [31, 132]. Research conducted at NREL disregards the BOP parameters when estimating the time taken for an electrolyser to ramp up or down, which increasingly affects the full capability of hydrogen electrolysers in responding to large frequency deviations. To guarantee successful operation in responding to grid events, future research work needs to focus on developing a mathematical model that can precisely evaluate the performance of hydrogen electrolysers under different load profiles while considering the BOP parameters.

3.3. Challenges of green hydrogen in enabling large-scale integration of renewables

The integration of RES into the grid provides genuinely green energy at the points of entry, however results in transient mismatches between generation and consumption as stated earlier, which hinders the renewable potential and introduces a key barrier against the large-scale integration of renewables in constrained power networks. Grid operators have to manage this imbalance by imposing financial penalties on RES owners for extra power generated during hours of off-peak

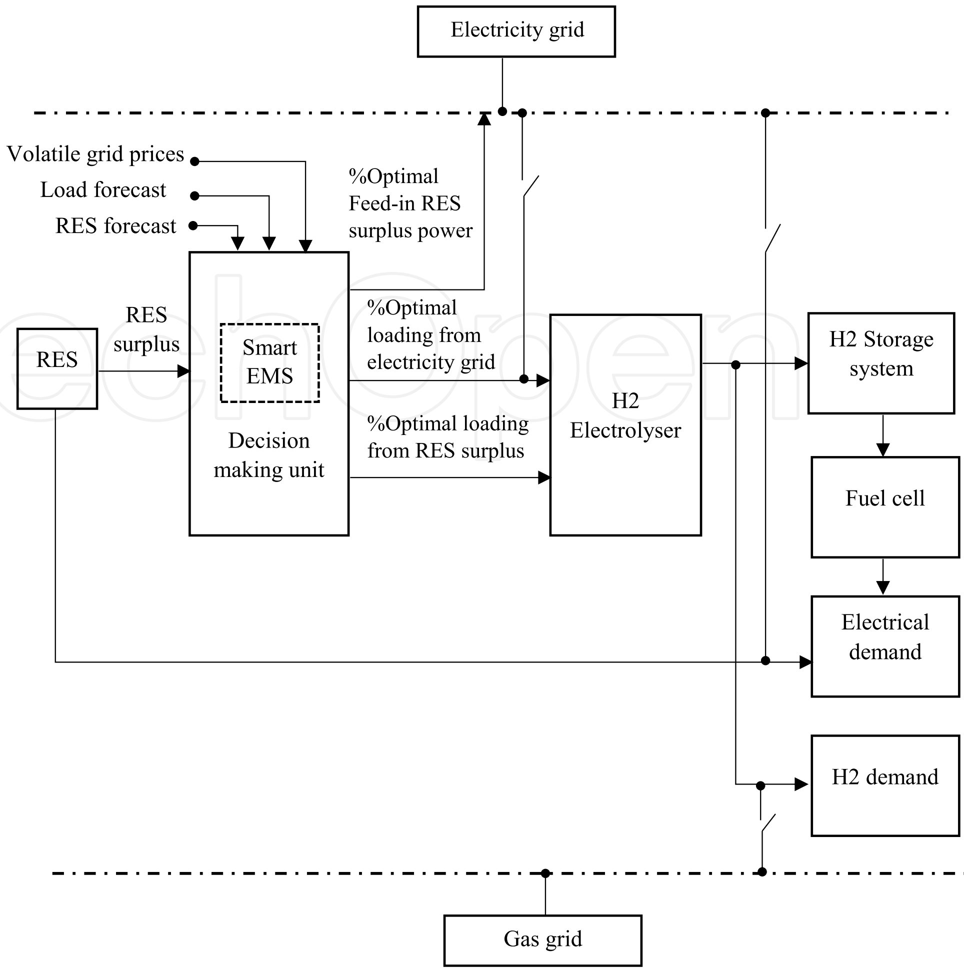


Figure 8. Smart energy management strategy for the application of hydrogen electrolysers as smart controllable loads.

demand and in turn, pay them compensations for the legislation of these rules [148]. An example of this has occurred in Scotland in April 2014, when severe windy conditions took place and disabled the Scottish grid from absorbing all the generated power from wind. In this scenario, the utility grid operators have paid extremely massive compensations that reached approximately £890,000 in just few hours to six wind farms owners for moving their wind energy output off the grid [10]. Hydrogen, as an energy storage medium, can unlock this barrier by offering grid balancing and frequency regulation services as explained earlier in Sections 3.1 and 3.2, thus avoiding financial losses and facilitating the large-scale integration of renewable energy to meet zero-carbon emissions goals. Furthermore, hydrogen can play a meaningful role in maximizing the capacity of renewables by avoiding the energy curtailment scenarios. For instance, in Germany alone, renewables constitute around 90% of the total installed capacity; leading to an expected curtailment of over 170 TWh by 2050 [9]. Instead of being curtailed, this huge energy surplus can be absorbed in powering about 60 GW hydrogen electrolysis capacity [9]. Another study has reported that an installed capacity between 3300 and 7800 GWh of solar and wind in California is projected to be curtailed between 2017 and 2025 and if all the excess instead of being curtailed is stored as hydrogen to be blended with natural gas, then it would be enough for powering up to 187,000 homes [60]. Therefore, hydrogen can valorise the excess of renewable electricity and thus allow their high penetration putting a step forward towards the targeted 2050 zero-carbon ambition. However, the application of hydrogen storage for capturing the surplus of renewable energy requires the gas to be compressed and filled in large-scale gaseous storage systems. The transient behaviour of filling a pressurized hydrogen tank can identify the maximum filling capacity, and thus the quantity of renewable energy being absorbed [149]. During the process of hydrogen filling, the storage vessel experiences a pressure build-up and temperature rise, allowing termination of the filling process when maximum working pressure and temperature is reached, thus restricting the amount of surplus electricity being captured by the electrolyser. Moreover, the process of compressing the hydrogen gas commonly occurs in multiple phases through cascaded high-pressure storage mechanisms [148]. Thus, developing mass transfer models is essential to quantify the mass of hydrogen being transferred through the cascaded phases during high compression, and thus estimate the pressure and temperature increments inside the storage vessels. Many researchers have studied the transient behaviour of filling pressurized hydrogen tanks as well as cascaded hydrogen storage systems [148–150], however they have investigated the application of thermodynamic modelling for fuelling hydrogen vehicles. A research gap exists in modelling the filling phase of hydrogen storage vessels running back a renewable energy source. Addressing this issue will help quantifying the maximum filling capacity of hydrogen storage systems for accommodating surplus renewable electricity.

3.4. Challenges of green hydrogen in the electrification of remote areas

Green hydrogen offers a competitive emissions-free alternative for the electrification of remote areas. Rural villages or islands, usually don't have access to the electricity grid as the extension of existing power networks to reach the isolated zones would be too costly [102]. Consequently, the local supply in remote areas usually relies on diesel generators which are increasingly expensive and carbon-intensive [151]. Stand-alone Green Hydrogen-based microgrids offer an environmentally friendly full off-grid autonomy for isolated areas. A fully integrated green hydrogen-based microgrid involves renewable energy sources, electrolysers, hydrogen storage and fuel-cells to compensate for renewable energy fluctuations. The most common examples include; the autonomous wind-hydrogen system installed at the island of Utsira in Norway, providing full grid independence for 2–3 days to 10 households [152]; the Hydrogen-based system serving the West Beacon

Farm in Loughborough, UK [153], and the Smart Autonomous Green Energy System (SAGES) located in Reunion island, France, based on solar panels in conjunction with hydrogen storage and batteries [154]. The major challenge for off-grid hydrogen-based energy systems is the ability to evaluate the economic feasibility of hybrid configuration while maintaining optimal operating conditions and satisfying the load demand requirements. Being grid-isolated necessitates the need to avoid excessive on/off switching of electrolysers and fuel cells to minimize their rate of degradation. Therefore, the usage of batteries as daily energy buffers in conjunction with hydrogen storage solutions is recommended in rural areas to achieve better system performance and lifespan. The integration of EMS is then crucial to guarantee optimal coordination of various system components, improved roundtrip efficiency and cost-effectiveness. Recent efforts have been carried out to achieve this challenging task under the EU-Horizon funded project (2018–2021), "REMOTE", aiming to showcase the techno-economic feasibility of isolated hydrogen-based microgrids in different locations across Europe including Italy, Greece and Norway [155]. More research effort in this prospect is still needed to allow wide commercialization of hydrogen-based solutions for remote areas and off-grid islands.

4. Digital trends of blockchain technologies for supporting green hydrogen markets

With the world moving towards a low-carbon economy, there is an increasing need to track emissions and green energy flows among value chains from the supply points to demand centres via secure, transparent and standardized scheme. This is where lies the importance of certification mechanisms. A certification can guarantee the origin of a green or low-carbon gas like hydrogen and tracks its flow throughout the supply chain to facilitate its trading as global commodity in the energy market [156]. Through green gas certificate schemes, green hydrogen producers are audited by a central authority that is responsible of verifying the on-site production of green gas, its quantity and quality to be approved for certification, and its trade among other parties (consumers or prosumers). The certified information can be then forwarded to consumers as 'guarantee of origin' for billing purposes and authorities finally keep record of green energy consumed and the corresponding emissions phased out. An example of this certification is CertifHy scheme, aiming to issue certificates of origin for green and blue hydrogen gases within the feedstock industry [157]. While green gas certificate schemes can play a key role in supporting the growth of a green hydrogen market, it requires the involvement of many intermediaries, making the certification process time-consuming and posing other challenges of labour, cost and scalability. Digital key advancements as Blockchain technologies could potentially simplify the process and speed-up the trading of

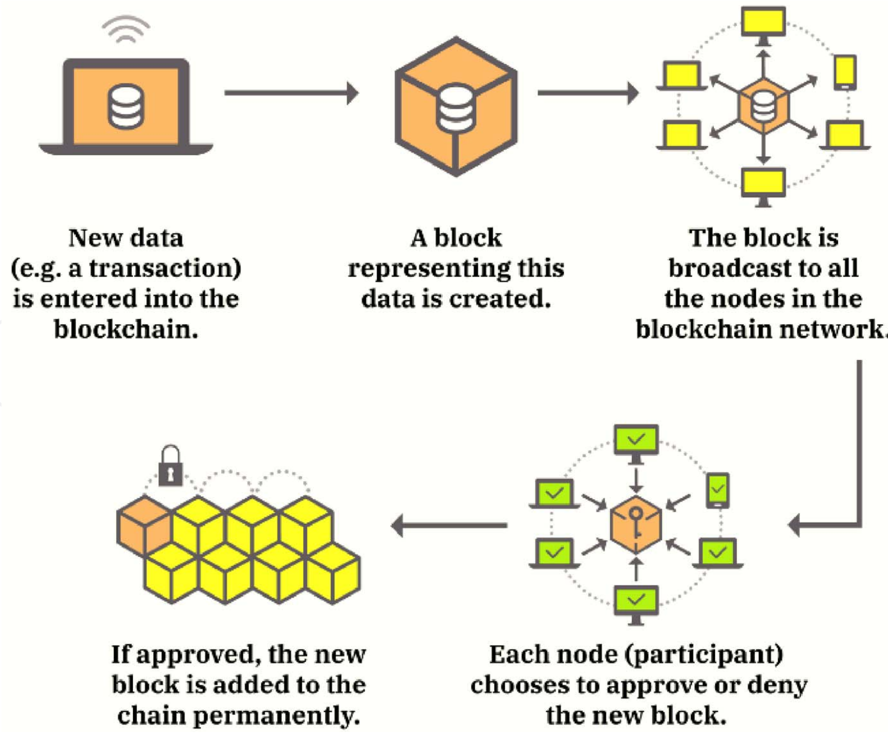


Figure 9. The working principle of blockchain technologies.

green hydrogen energy among the supply chain without intermediaries or central authorities. Blockchain can be defined as a shared, decentralized and immutable digital ledger that enables the safe recording of digital transactions and the self-execution of smart contracts among participants in a secure and transparent environment [158]. In terms of energy market, it is a continuous log of energy transactions managed and controlled by a distributed network of independent computers known as "nodes". Each node belongs to a market participant interested in buying or selling energy units. In the event of requesting a new energy transaction, each node validates the transaction using consensus protocols or algorithms [159]. In case of a valid transaction, a smart contract is self-created using computer codes providing the terms of agreements between the buyer, seller and the amount of energy transacted [160]. Once confirmed, the new transaction is combined with other synchronized energy transactions and added to the shared ledger as a new block of data. This new block is finally integrated with previous blocks using cryptographic security in a way that cannot be altered, forming a chain of energy records that indicate the chronological order of energy transaction events [159]. Figure 9 illustrates the working principle of blockchain technologies. With the automatic feature of smart contracts, blockchain technologies can change how a green hydrogen market is being regulated without the involvement of third-parties, thus facilitating green hydrogen trading among the supply chain while helping policy makers to track the green gas transactions and address the high number of certificates [156, 158]. As the world is navigating towards digitalization and the energy sector is being transformed from 'centralized' to 'decentralized' networks, blockchain schemes could be seen as potential solutions allowing for Peer-to-Peer (P2P) energy trading of green hydrogen while providing participants with a high level of transparency and cyber security that can highly supports a broader access to green hydrogen markets. However, the implementation of blockchain-based energy markets implies a higher degree of complexity. Blockchain-based energy markets in collaboration with AI algorithms need to have real-time access to blockchain participants accounts via smart meters, for optimizing and securing an energy bidding strategy that can fulfil all requirements of a market participant in the most efficient and cost-effective way, for managing energy transactions. All market participants interested in buying and selling energy units can place their orders into an open log book. With access to real-time data, a smart EMS is able to forecast a participant energy supply or demand over a given period of time and accordingly interacts with a pricing mechanism to find the best energy bid or offer [161]. In this way, blockchain technologies allow for green energy producers to maximize their revenues while minimizing consumers energy bills, thus fostering the decarbonization, decentralization and digitization of the energy sector. In addition, blockchain-based energy markets could potentially reduce the energy transactions fees with the removal of intermediaries, while supporting the utility grids during hours of peak-demand and avoiding expensive spinning reserves [159]. Blockchain technologies are currently seen evolving in decentralized energy trading. Potential examples include the Brooklyn Microgrid in New York, US [161]. A study has further demonstrated that decentralized energy trading accounted for the largest share of blockchain recent initiatives [159]. While recent research studies [162–164] focused on the use of blockchain technologies for P2P electricity trading, less attention has been given to the application of blockchain schemes for green hydrogen markets. Apart from scalability issues, speed and security concerns from malicious attacks, coupling P2P electricity trading for creating a green hydrogen market further increases the challenges of blockchain technology. With other new players joining the digital platform, green electricity consumers become afterwards green hydrogen producers (like hydrogen refuelling stations) seeking to increase revenues from hydrogen sales. On the other hand, hydrogen consumers (like FCEVs drivers) are seeking to minimize costs of fuel consumption, thus making the process of finding the best energy bidding more challenging. Developing dynamic hydrogen pricing mechanisms based on real-time data of decentralized renewable electricity and hydrogen demand side management is then essential for coupling P2P electricity trading with green hydrogen markets [165]. In the electricity bidding, the smart EMS should seek to maximize the revenue of renewable energy supplier, while minimizing the cost of electricity purchased for green hydrogen producers and this condition is met whenever the highest bidding price of electricity consumer matches the lowest bidding price of electricity supplier. Similarly, in the hydrogen bidding, the smart EMS should seek to maximize the revenue of green hydrogen producer, while minimizing the cost of fuel consumption for green hydrogen consumer and this condition is met whenever the highest bidding price of hydrogen consumer matches the lowest bidding price of hydrogen producer [165]. Thus, the bidding price of hydrogen sale highly depends on the bidding price of electricity purchase to generate the profit with same market participant changing two different roles in the energy market. As result, a hydrogen pricing mechanism needs to be integrated and linked to decentralized electricity pricing mechanism for securing a green hydrogen bidding. Furthermore, the hydrogen storage capacity needs to be considered when securing the electricity bidding of green hydrogen producers. The current research status of blockchain-based hydrogen markets is seen very limited and reflects potential research gap in the knowledge. Another critical issue to solve is the ability of blockchain-based energy markets to coordinate with centralized utility grids to ensure balancing supply with demand all times [159]. Risks arise from the probability of local decentralized multi-energy sources to disrupt the structure of energy system and might even contribute to grid defection. More research is needed to unlock the full potential of blockchain technologies and support its implementation with green hydrogen markets.

5. Green hydrogen versus blue hydrogen

In light of controversial debate between green hydrogen and blue hydrogen technologies, it is essential to differentiate between their production methods and analyse their merits, demerits, socio-economic impacts and challenges in order to assess their competitiveness towards a clean energy transition while discussing further insights and policy recommendations. Table 4 summarizes the key characteristics of green hydrogen versus blue hydrogen. Blue hydrogen refers to hydrogen produced from fossil fuels when coupled with CCS technology to negate CO_2 emissions. The majority of global hydrogen production today is harvested from natural gas or methane (Grey hydrogen), using either Steam Methane Reforming (SMR), or Autothermal Reforming (ATR) [21]. SMR is considered the most established technology to produce hydrogen from natural gas. The process of SMR undergoes three stages: the first one involves reacting methane with high-temperature steam under catalytic action to produce mainly hydrogen and carbon monoxide. The hydrogen fuel and carbon dioxide are then generated by water–gas shift reaction and hydrogen fuel is finally purified to separate carbon dioxide and other impurities using purification techniques [166]. The separated CO_2 emissions can be either stored via CCS technology, utilised via CCU technology, or both stored and utilised via Carbon Capture Storage and Utilization (CCUS) technologies [157]. CCUS technologies can be coupled with SMR at maximum efficiencies between 85–90%, and there are other indications for achieving reductions up to 95% in GHG emissions [157, 167]. Thus, blue hydrogen is considered "low-carbon" fuel, but not fully free-carbon emissions as around 5–15% of CO_2 would still be emitted to the atmosphere. Figure 10 illustrates the carbon intensity of hydrogen produced by different methods from fossil fuels, showing that the carbon intensity of blue hydrogen from natural gas and coal is minimized to around 1–2 kg CO_2/kg H_2 when coupled with CCUS at 90% efficiency [21, 167]. From the illustrated chart, it is evident that extremely low-carbon footprint can be achieved with CCUS technologies compared to conventional grey and black hydrogen production from fossil fuels, however there is still room for intensive CO_2 emissions at large-scale of blue hydrogen production. According to IEA, the global demand for pure hydrogen has reached around 70 million tons in recent years, with 76% produced from natural gas and about 23% from coal [21]. From Figure 10, the carbon intensities of blue hydrogen production from natural gas and coal are 1 and 2 kg CO_2/kg H_2 respectively. Using these values and assuming blue hydrogen will be used to meet the aforementioned global demand with CCUS technologies at 90% capture rate, it would still be responsible for around 85 $MtCO_2$/yr. $[(0.76 \times 70MtH2 \times 10^3 \times 1) + (0.23 \times 70MtH2 \times 10^3 \times 2)]$ of which approx. 53 $MtCO_2$ would account for emissions of blue hydrogen from natural gas and nearly 32 $MtCO_2$ would account for emissions of blue hydrogen from coal. While blue hydrogen is expected to reduce the carbon footprint about ten times below the announced global emissions in recent years from black and grey hydrogen production (approx. 830 $MtCO_2$/yr. emitted) [21], it would still emit millions of CO_2 tons per annum compared to the fully free-carbon green hydrogen produced by renewable energy. Moreover, there is a risk of CO_2 leakage from CCS infrastructures on the long-term. Similar to underground hydrogen storage, the captured CO_2 emissions can be stored in depleted gas reservoirs with geological formations at large storage capacities. While this is advantageous for capturing large amounts of CO_2 emissions, this is not a periodic storage as the captured emissions are intended to be permanently stored underground given the goals of clean energy transition. Risks can arise from corrosion of caprocks and dissolution of caprock minerals when reacting with CO_2, thus increasing opportunities of CO_2 leakage over time [62]. In terms of production efficiency, green hydrogen becomes less competitive when compared to blue hydrogen, with commercial electrolysis technologies reaching efficiencies up to 60–70% as discussed earlier [21, 30], versus up to 85% efficiency for blue hydrogen production [157]. There are opportunities for green hydrogen to highly compete with blue hydrogen production efficiencies using SOECs facilities, however this is still an emerging technology in early-stage of development. Regarding the technology maturity, water electrolysis technologies are well-established worldwide as listed earlier in Table 2, with ALK electrolysers already commercialized and historically deployed for industrial use, while PEM technologies recently achieved promising levels of up-scaling development. On the contrary, CCUS technology is still immature and as result associated with high capital costs. There are only few CCUS projects operating worldwide mainly across the United States and Canada [167], however the technology is not operational yet across Europe [157]. Several challenges are hindering the development of CCUS technologies, including the need to establish suitable infrastructures for transporting the captured CO_2 to underground storage sites and the need to monitor the stored CO_2 emissions over time to avoid the risk of possible leakage and the impact on ecological environment [157]. In the meantime, more research and development are necessary to address CO_2 transportation and monitoring. The lack of sufficient CCUS projects, the safety concerns of such unfamiliar technology and the associated high capital costs are all key factors currently demotivating stakeholders against the development of CCUS technologies. However, opening a market for the captured CO_2 to serve as hydrocarbon resource for industry instead of undesirable pollutant, might encourage enterprises to invest in CCUS technologies. Apart from the technical barriers facing CCUS investments, blue hydrogen cannot mitigate the intermittency of renewables and thus cannot support the goals of energy system decarbonization. In contrast, green hydrogen is powerful enough to decarbonize the energy supply chain and holds a major potential for capturing the surplus of renewable energy, balancing generation with consumption and supporting the large-scale integration of renewables. The key challenge for green hydrogen is its high production cost compared to blue hydrogen. Figure 11 demonstrates the variations in hydrogen production costs across different regions and the projections of cost reductions by 2030 [21, 167, 168]. As can be seen from the illustrated chart, green hydrogen production is currently too costly compared to blue hydrogen production, with prices reaching up to 6–7 USD/kg for green hydrogen compared to only 1.5–2.0 USD/kg for blue hydrogen. Two major drivers are impacting the costs of green hydrogen production including the costs of renewable electricity and the costs of water electrolysers [167]. The latter can be mitigated with mature technologies and the ongoing scaling-up investments of ready-to-commercialize counterparts, while the former presents the key to unlock the economic barrier of green hydrogen. However, the downward trend in renewable energy prices along with the high penetration of renewables are projected to substantially bring down the costs of green hydrogen production by 2030 as seen in Figure 11, allowing green hydrogen to reach parity with blue hydrogen in regions with high renewable potential [168]. Scaling up the investments in renewable energy is therefore crucial to mitigate the cost challenge of green hydrogen production. Further, the legislation of carbon taxes is beneficial for promoting the use of renewable energy resources. While planning for large-scale solar parks and wind farms is increasingly important to enhance the future vision of green hydrogen, it could raise some socio-ecological concerns regarding the loss of lands and the migration of livelihoods following the construction of onshore renewables as well as the impact on marine life and seabirds when planning for offshore renewables [166, 169]. Such factors need to be considered and well supported with government policies and research activities to ensure climate justice along with clean energy transition. Following the assessment of green route versus blue route and the challenges facing each technology, it is then favourable to take advantage from every potential to accelerate the clean energy transition. Blue hydrogen is low-carbon fuel that features higher production efficiency and lower production cost, however, lacks sufficient CCUS projects and cannot support the goals of energy system decarbonization. Green hydrogen is a fully free-carbon fuel with well-established technologies worldwide and holds a great potential in decarbonizing the energy supply sector, however less efficient and associated with significantly higher production costs. Thus, the transition to green hydrogen on the long-term is likely to occur through blue hydrogen on the near to medium term. Considering the projections of cost reduction in green hydrogen production with the continuous decline in renewable electricity prices and given the green hydrogen potential in accommodating the intermittency of renewables and its associated environmental-friendly impact, green hydrogen is therefore expected to be the winner on the long-run. However, this is not projected to take place prior 2030 [168]. Thus, blue hydrogen can pave the way for green hydrogen until the latter becomes cost-competitive enough. Assigning blue hydrogen for supporting the 'hard-to-abate' sectors like heavy-duty transport or energy-intensive industries, is recommended in the near future to help reducing the demand on green hydrogen and renewable electricity until sufficient renewable potential can dominate the energy supply sector [157]. Additionally, the usage of blue hydrogen in heavy industry can strongly support the development of CCUS technology by making profit from the captured CO_2, thus helping to promote CCUS investments. In conclusion, to help succeeding the planning strategy for a clean energy transition, a collaborative approach needs to be adopted between governments, research communities and public societies. Government support can be provided through the introduction of carbon taxes, incentives and financial subsidies for scaling-up the investments in renewable energy, bringing down the costs of renewable electricity and thus accelerating the cost competitiveness of green hydrogen production [167]. Furthermore, strong government policies are required to prevent investment practices intending to immigrate human activities to capitalize on the return of renewables and green hydrogen boom [166]. Research activities need to address the challenges facing CCUS technologies to enable blue hydrogen paving the way for green hydrogen transition. Meanwhile, further research is needed regarding the environmental impact of offshore renewables on marine life to address design recommendations and allow a safe exploitation of available offshore renewable potential [169]. The role of public engagement is also increasingly important for the

Table 4. Comparison of green hydrogen versus blue hydrogen.

Criteria	Green hydrogen	Blue hydrogen
Carbon footprint [157, 167]	Fully free-carbon fuel (Net zero-carbon emissions)	Low-carbon fuel (85–95% zero-carbon emissions)
Production efficiency [21, 30, 157]	Up to 60–70%	Up to 85%
Technology maturity [157, 167]	Water electrolysis technology is mature (ALK technology is already commercialized, PEM technology is ready for commercial scale)	CCUS technology is immature (Few CCUS facilities exists in North America, CCUS is not operational yet in Europe)
Production Cost [21, 167, 168]	2.5–7.0 USD/kg·H2	1.5–2.0 USD/kg·H2
Socio-ecological impact [62, 166, 169]	Loss of lands and immigration of human activities with onshore renewables—Impact on marine life and seabirds with offshore renewables.	Impact on ecosystem from CO_2 stored underground and risks of CO_2 leakage from caprocks on long-term

success of the planning strategy. Finally, raising people awareness on DSM techniques and the incoming revenues from renewables and green hydrogen can help promoting the reliance on renewable electricity, and thus significantly accelerating the route to green hydrogen transition.

6. Future insights and policy recommendations for supporting green hydrogen industry

The upcoming share of clean hydrogen energy (green & blue hydrogen) is expected to foresee a noticeable increase from negligeable rates in 2020 to around 15% from total hydrogen supply in 2030 [170]. However, clean hydrogen still not expected to dominate the hydrogen supply by 2030. One major reason is the cost of green hydrogen production which is impacted by the costs of renewable electricity and the costs of electrolysers as mentioned earlier. Increasing the operating hours of electrolysers can help declining the impact of their high CAPEX, however could translate into high electricity costs particularly when renewables are not yet dominating the energy supply which is the case forecasted for 2030 [171]. To demonstrate this, a realistic offshore wind farm located off the east coast of Aberdeen in Scotland, is used as numerical example. The farm is known as "European Offshore Wind Deployment Centre (EOWDC)" and consists of 11 wind turbines with a total installed capacity up to 93.2 MW [172]. As shown in Table 5, the annual output energy of the wind farm during hours of high availability is estimated

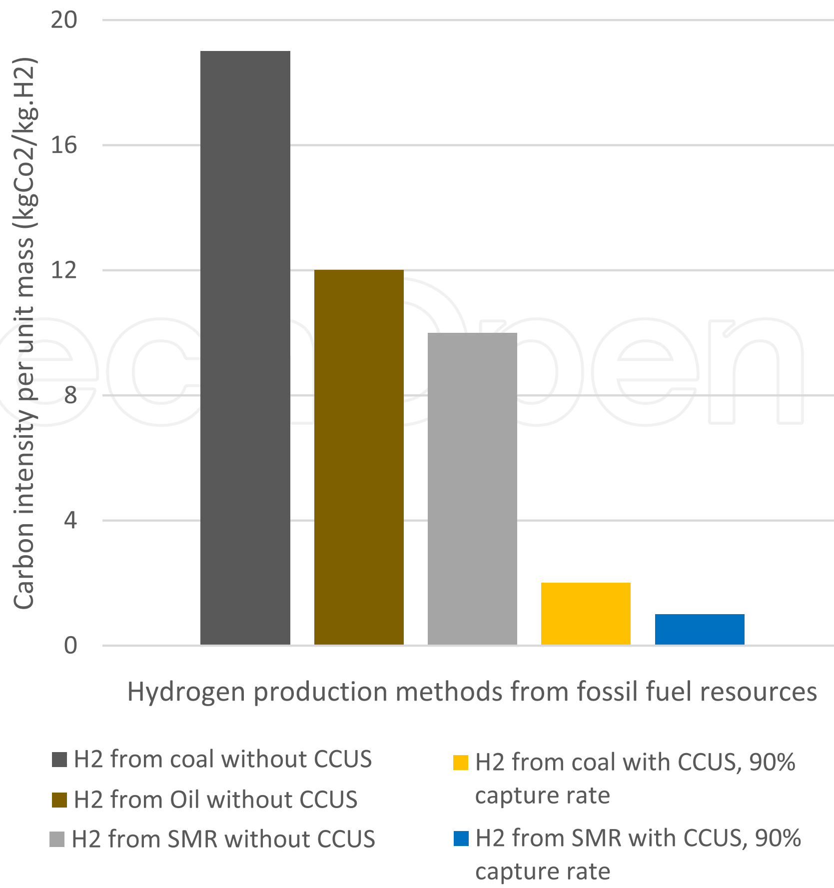


Figure 10. Carbon intensity of different hydrogen production methods from fossil fuel resources.

to be 32,6572.8 MWh considering 40% offshore wind load factor [173]. The estimated capacity can supply and thus decarbonize around 172 buildings each of 1898 MWh average annual consumption. Assuming an eco-friendly electrolyser is going to be installed by 2030 to capture 40% of offshore wind capacity for 8000 h a year, therefore the energy input to this electrolyser is estimated to be 119,296 MWh, resulting in 15-MW of electrolysis rated capacity. The sized capacity is enough to supply and thus decarbonize around 62 buildings out of the 172 buildings mentioned above. As can be seen from Table 6 [174, 175], a large-scale PEM electrolyser of a full-load energy consumption rated at 5.4 kWh/Nm^3 can be selected. The hydrogen production flow rate at full-load capacity is equivalent to around 2778 Nm^3/h, which lies within the nominal flow rate of the sized electrolyser. Assuming the price of electricity from offshore wind is 30$/MWh as expected for 2030 [168], the electricity bills would cost more than 3.5 million dollars a year for operating the sized electrolyser 8000 h to cover all the 62 buildings. The operation of electrolysers at full-load hours is then challenging and might fall below sufficient hydrogen production levels for the near future, thus highlighting the need for near-term

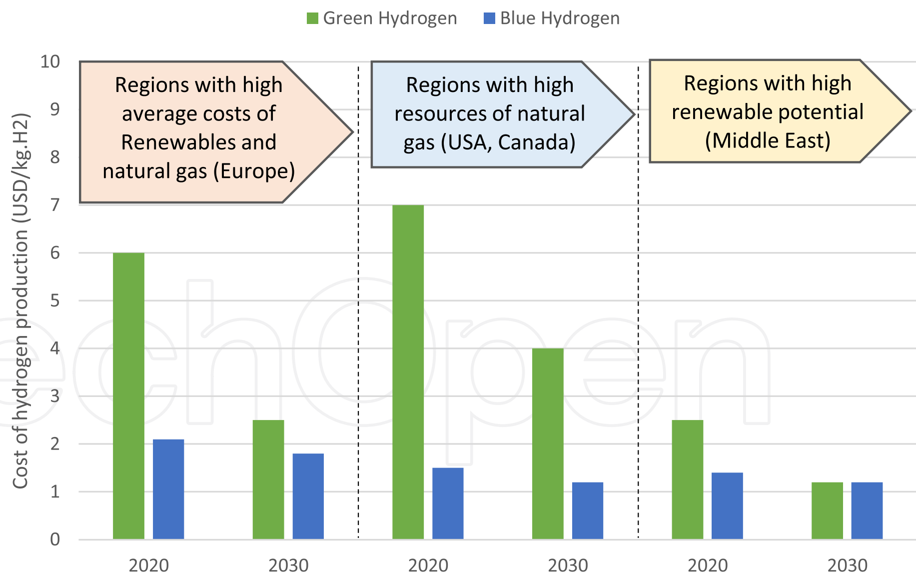


Figure 11. Projections of hydrogen productions costs across different regions.

Table 5. Calculated annual energy output of EOWDC wind farm and its potential in decarbonizing the building sector.

Parameter	Rating
The wind farm total installed capacity	93.2 MW
Offshore wind average load factor	0.4
Annual wind farm output energy	32,6572.8 MWh
Average annual building consumption	1,898.119 MWh
Number of buildings that the wind farm, supported with backup green H2 storage system, can power (decarbonise)	172 buildings

policy recommendations to promote the use of green hydrogen production. Pricing carbon emissions is highly recommended to narrow down the gap between the electricity costs of green hydrogen production from renewables and those of grey hydrogen production from fossil fuels. Also, improving electrolysis efficiency can allow boosting green hydrogen production when partly operated for serving higher hydrogen demand at low cost. Increasing off-grid electrolysers capacities dedicated for green hydrogen production could be another solution to enable greening the total hydrogen supply in the near future, putting the World on track to the Net Zero-Carbon ambition.

Table 6. Specifications of the hydrogen generator (electrolyser) proposed to support EOWDC wind farm.

Parameter	Specification
Electrolyser type	PEM
Nominal input power	15 MW
Nominal hydrogen flow rate	3000 Nm^3/h
AC power consumption	5.0–5.4 kWh/Nm^3

7. Conclusion

This paper provides a comprehensive survey on green hydrogen energy and evaluates its potential as a sustainable solution for empowering the low-carbon economy, while highlighting key technical challenges to its implementation. The conducted survey has reflected on the current development status of green hydrogen production technologies, showing technological advances in making green hydrogen more commercialised and cost-effective while highlighting their suitability of applications and key design characteristics for addressing their operating performance issues. This paper has also pointed out on the main types of hydrogen storage systems, the relevant modes of hydrogen transportation and the key transportation hurdles facing the technology development. The review of green hydrogen implementations within the key areas of grid balancing, frequency regulation, large-scale integration of renewables and electrification of remote areas have demonstrated their promising ability to decarbonize the energy supply sector, however the process of transforming this potential into reality is challenging. For grid balancing services, a critical assessment of the current literature has highlighted the lack of design considerations for formulating the optimal sizing problem of renewable hydrogen energy storage systems and the shortcomings of available software tools for modelling the real-world operational management of hydrogen energy storage elements to ensure the feasibility of optimal sizing solution for grid integration. In the regulation market, it was found that it is critical to determine the conditions under which the electrolysers became more economically attractive for investors to serve as smart controllable loads. Additionally, the ability to develop smart energy management systems to optimize the operating level of hydrogen generators in accordance with grid requirements was found as key factor impacting the decision making of hydrogen electrolysers participation in ancillary service market. The trends of digital key advancements as blockchain technologies for accelerating the growth of green hydrogen markets are further discussed. These evolving technologies are seen as potential solutions for facilitating decentralized trading of green hydrogen energy among the supply chain, however their implementation with green hydrogen markets poses challenging research questions that blockchain schemes cannot address alone and need further developments in AI algorithms and predictive analysis to resolve the raised questions. This paper has also evaluated the potential of green hydrogen versus blue hydrogen and concluded that green hydrogen route dominates over blue route in terms of environmental impact, technology maturity and potential in decarbonizing the energy supply sector. However, green hydrogen is currently facing higher production costs, and thus blue hydrogen is likely to be used as a short-term transitional fuel towards the green hydrogen dominance on the long-term. The prospects of this work are to foster upcoming research efforts firstly to improve the electrolysers' operating efficiencies for boosting green hydrogen production levels in the near future; secondly to develop new modelling approaches that can enable the real-world application of renewable hydrogen storage systems in the energy sector. Progressive efforts are also demanded for imposing rigorous measures to promote the use of green hydrogen energy in today's market.

Declaration of competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

This research is part of studentship (no. ENG20-02) which is funded by School of Engineering at Robert Gordon University, Aberdeen.

References

1 Østergaard PA, Maestosib PC. Tools, technologies and systems integration for the smart and sustainable cities to come. *Int J Sustain Energy Plan Manag*. 2019;**24**: 1–6.

2 Narayanan A, Mets K, Strobbe M, Develder C. Feasibility of 100% renewable energy-based electricity production for cities with storage and flexibility. *Renew Energy*. 2019;**134**: 698–709.

3 Maestosi PC, Civiero P, Massa G. European Union funding research development and innovation projects on smart cities: the state of the art in 2019. *Int J Sustain Energy Plan Manag*. 2019;**24**: 7–20.

4 Osborn D, Cutter A, Ullah F. Universal sustainable development goals. *Understanding the Transformational Challenge for Developed Countries*. 2015;**2**(1):1–25.

5 Habitat UN. *New Urban Agenda: Habitat III: Quito 17–20 October 2016*. Nairobi: United Nations; 2017.

6 COP26: The Negotiations Explained. Glasgow Climate Change Conference – October–November 2021, UK: United Nations Climate Change, 2021.

7 BP. *Statistical review of world energy*. London, UK: 2021.

8 Ritchie H. Which sources does our global energy come from? How much is low-carbon?: Our World in Data; 2021 [cited 2021 November 30]. Available from: https://ourworldindata.org/sources-global-energy?country=.

9 Council H. *How hydrogen empowers the energy transition*. 2017. Available from https://hydrogencouncil.com/en/study-how-hydrogen-empowers/.

10 Ali DM. Energy capacity and economic viability assessment of the renewable hydrogen energy storage as a balancing mechanism in addressing the electric system integration issues inherent with variable renewable energy resources. In: *IET Conference on Reliability of Transmission and Distribution Networks (RTDN 2011): 22–24 Nov. 2011*: 2011. p. 1–7.

11 Cox J. *Aberdeen city and Shire strategic development plan*. Aberdeen City and Shire: 2020.

12 Morrison J. *Powering Aberdeen: Aberdeen's sustainable energy action plan*. Aberdeen City Council; 2016.

13 Abe JO, Popoola API, Ajenifuja E, Popoola OM. Hydrogen energy, economy and storage: review and recommendation. *Int J Hydrogen Energy*. 2019;**44**(29):15072–15086.

14 Group NG. The hydrogen colour spectrum UK2021. Available from: https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum.

15 Dodgshun J. Hydrogen: clearing up the colours: from green hydrogen to black — what hydrogen colours mean for the climate: Enapter; 2020 [30 Sept]. Available from: https://www.enapter.com/hydrogen-clearing-up-the-colours.

16 Chisholm G, Cronin L. *Hydrogen from water electrolysis. Storing energy*. School of Chemistry, University of Glasgow, Glasgow, United Kingdom: 2016.

17 Commision E. Methane emissions 2021 [10 February]. Available from: https://ec.europa.eu/energy/topics/oil-gas-and-coal/methane-emissions_en.

18 IRENA. *Green hydrogen: a guide to policy making*. Abu Dhabi: International Renewable Energy Agency; 2020.

19 Jenny Laing AS. *Aberdeen city region hydrogen strategy & action plan*. Aberdeen City Council, H2 Aberdeen; 2015.

20 Evans S, Gabbatiss J. In-depth Q&A: does the world need hydrogen to solve climate change? 2020 [30 November]. Available from: https://www.carbonbrief.org/in-depth-qa-does-the-world-need-hydrogen-to-solve-climate-change.

21 IEA. *The future of hydrogen: seizing today's opportunities*. International Energy Agency; 2019.

22 Widera B. Renewable hydrogen implementations for combined energy storage, transportation and stationary applications. *Therm Sci Eng Progr*. 2020;**16**: 100460.

23 Parra D, Valverde L, Pino FJ, Patel MK. A review on the role, cost and value of hydrogen energy systems for deep decarbonisation. *Renew Sustain Energy Rev*. 2019;**101**: 279–294.

24 Andersson J, Grönkvist S. Large-scale storage of hydrogen. *Int J Hydrogen Energy*. 2019;**44**(23):11901–11919.

25 Mahajan D, Tan K, Venkatesh T, Kileti P, Clayton CR. Hydrogen blending in gas pipeline networks — a review. *Energies [Internet]*. 2022;**15**(10):3582. Available from https://doi.org/10.3390/en15103582.

26 Ratnakar RR, Gupta N, Zhang K, van Doorne C, Fesmire J, Dindoruk B, et al. Hydrogen supply chain and challenges in large-scale LH2 storage and transportation. *Int J Hydrogen Energy*. 2021;**46**(47):24149–24168.

27 IRENA. *Innovation landscape for a renewable-powered future: solutions to integrate variable renewables*. Abu Dhabi: International Renewable Energy Agency; 2019.

28 IRENA. *Innovation lanscape brief: renewable power-to-hydrogen*. Abu Dhabi: International Renewable Energy Agency; 2019.

29 Eriksson ELV, Gray EM. Optimization and integration of hybrid renewable energy hydrogen fuel cell energy systems – a critical review. *Appl Energy*. 2017;**202**: 348–364.

30 Buttler A, Spliethoff H. Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: a review. *Renew Sustain Energy Rev*. 2018;**82**: 2440–2454.

31 Eichman J, Peters M. *Novel electrolyzer applications: providing more than just hydrogen*. Golden, CO (United States): NREL; 2014.

32 Kleperis J, Fylenko V, Vanags M, Volkovs A, Lesnicenoks P, Grinberga L, et al. *Energy storage solutions for small and medium-sized self-sufficient alternative energy objects*. Renewable Energy & Innovative Technologies; Blugaria: Bulgarian Chemical Communications; 2016. p. 290–296.

33 Shiva Kumar S, Himabindu V. Hydrogen production by PEM water electrolysis – a review. *Mater Sci Energy Technol*. 2019;**2**(3):442–454.

34 Sood S, Prakash O, Boukerdja M, Dieulot J-Y, Ould-Bouamama B, Bressel M, et al. Generic dynamical model of PEM electrolyser under intermittent sources. *Energies*. 2020;**13**(24):6556.

35 IRENA. *Hydrogen from renewable power: technology outlook for the energy transition*. Abu Dhabi: International Renewable Energy Agency; 2018.

36 Bertuccioli L, Chan A, Hart D, Lehner F, Madden B, Standen E. *Development of water electrolysis in the European Union. E4tech Sàrl with Element Energy Ltd for the fuel cells and hydrogen joint undertaking*. 2014.

37 Zeng K, Zhang D. Recent progress in alkaline water electrolysis for hydrogen production and applications. *Progr Energy Combust Sci*. 2010;**36**(3):307–326.

38 Santos D, Sequeira C, Figueiredo J. Hydrogen production by alkaline water electrolysis. *Química Nova*. 2012;**36**: 1176–1193.

39 Yan XL, Hino R. In: Lee S, editor. *Nuclear hydrogen production handbook*. Ohio, USA: CRC Press; 2011.

40 Nel. The World's most efficient and reliable electrolysers. Nel Hydrogen Electrolysers, 2019.

41 Siemens. Overview of the PEM Silyzer family. Siemens Energy NEB, GIZ Workshop, 2020.

42 Thomas D. State of play and developments of power-to-hydrogen technologies. *Hydrogenics*. 2019;.

43 ITM, POWER. World-class turn-key electrolysers from 600 kW to 100 MW. Available from: https://itm-power.com/products.

44 Robbins J. Green hydrogen is taking off around the globe – its supporters say it could play an important role in decarbonisation, but sceptics question its safety and practicality: BBC; 2020 [13 November]. Available from: https://www.bbc.com/future/article/20201112-the-green-hydrogen-revolution-in-renewable-energy.

45 Lee A. Japan opens world's largest green-hydrogen plant near Fukushima disaster site 2020 [9 March]. Available from: https://www.rechargenews.com/transition/japan-opens-worlds-largest-green-hydrogen-plant-near-fukushima-disaster-site/2-1-769361.

46 FuelCellsWorks. The world's largest green hydrogen project with a 150-MW electrolyser comes online in China 2022 [cited 2022 February]. Available from: https://fuelcellsworks.com/news/the-worlds-largest-green-hydrogen-project-with-a-150mw-electrolyser-comes-online-in-china-el-periodico-de-la-energia/#:~:text=The%20Baofeng%20project%20held%20the,yuan%2C%20about%20200%20million%20euros.

47 Felgenhauer M, Hamacher T. State-of-the-art of commercial electrolyzers and on-site hydrogen generation for logistic vehicles in south Carolina. *Int J Hydrogen Energy*. 2015;**40**: 2084–2090.

48 Sampson J. Air liquide inaugurates 8.2 tonnes per day low-carbon hydrogen unit in Québec. *H2 View*. 2021;.

49 Collins L. World's largest green-hydrogen plant begins operation in Austria 2019 [18 November]. Available from: https://www.rechargenews.com/transition/worlds-largest-green-hydrogen-plant-begins-operation-in-austria/2-1-708381.

50 Siemens. Energy park Mainz: a project for the industry FCH JU stakeholder forum; 2015.

51 HyBalance project in Denmark to demo green hydrogen energy. *Fuel Cells Bull*. 2016;**2016**(3):8–9.

52 Schmidt O, Gambhir A, Staffell I, Hawkes A, Nelson J, Few S. Future cost and performance of water electrolysis: an expert elicitation study. *Int J Hydrogen Energy*. 2017;**42**(52):30470–30492.

53 Schefold J, Brisse A, Poepke H. Long-term steam electrolysis with electrolyte-supported solid oxide cells. *Electrochim Acta*. 2015;**179**: 161–168.

54 Sunfire takes significant steps to clean energy on demand using solid oxide technology. *Fuel Cells Bull*. 2016;**2016**(3):12–14.

55 Koita A, Payman A, Camara MB, Dakyo B, Hissel D. Hydrogen vector in the exploitation of a wind farm. In: *2018 Thirteenth International Conference on Ecological Vehicles and Renewable Energies (EVER); 10–12 April 2018*. 2018. p. 1–6.

56 Pesonen O, Alakunnas T. *Energy storage: a missing piece of the puzzle for the self-sufficient living*. Lapland: University of Applied Sciences; 2017.

57 Prachi P, Mahesh W, Aneesh G. A review on solid state hydrogen storage material. *Adv Energy Power*. 2016;**4**(2):11–22.

58 Yue M, Lambert H, Pahon E, Roche R, Jemei S, Hissel D. Hydrogen energy systems: a critical review of technologies, applications, trends and challenges. *Renew Sustain Energy Rev*. 2021;**146**: 111180.

59 Rödl A, Wulf C, Kaltschmitt M. Chapter 3 - assessment of selected hydrogen supply chains—factors determining the overall GHG emissions. In: Azzaro-Pantel C, editor. *Hydrogen supply chains*. Academic Press; 2018. p. 81–109.

60 Tashie-Lewis BC, Nnabuife SG. Hydrogen production, distribution, storage and power conversion in a hydrogen economy - a technology review. *Chem Eng J Adv*. 2021;**8**: 100172.

61 Dagdougui H, Sacile R, Bersani C, Ouammi A. *Hydrogen storage and distribution: implementation scenarios*. 2018. p. 37–52.

62 Zivar D, Kumar S, Foroozesh J. Underground hydrogen storage: a comprehensive review. *Int J Hydrogen Energy*. 2021;**46**(45):23436–23462.

63 Sequeira C. *Hydrogen storage and transportation*. E Scholarly Community Encyclopedia; 2021.

64 Cadent. *The Liverpool-Manchester hydrogen cluster: a low cost, deliverable project*. Progressive Energy Ltd; 2017.

65 ENTSOG. Hydrogen project visualization platform, Overview of hydrogen projects along the emerging value-chain in Europe. Available from: https://h2-project-visualisation-platform.entsog.eu/.

66 Cadent. Hydrogen grid to vehicle (HG2V); network purity for transport. Available from: https://smarter.energynetworks.org/projects/nia_cad0022.

67 UK hydrogen strategy. HM government; 2021. Available from https://www.gov.uk/government/publications/uk-hydrogen-strategy.

68 BEIS. *Hy4Heat report final progress report*. Department for Business, Energy and Industrial Strategy; 2022.

69 SGN, Nationalgrid, Dot PB, DNV.GL. Aberdeen Vision Project. 2020.

70 Networks NG. Pioneering a UK hydrogen network. Available from: https://h21.green/projects/.

71 Cadent. The HyNet north west hydrogen pipeline will help unlock an energy revolution to decarbonise the north west.

72 Eni. HyNet north west: CO_2 storage in the UK, the first low GHG emissions industrial cluster in the world under development in the Liverpool Bay which we are involved in for CCS activities. Available from: https://www.eni.com/en-IT/operations/united-kingdom-hynet-north-west.html.

73 ENA. *Gas goes green: developing the pathway to net zero*. ENA Energy Networks and Association; 2021.

74 Ofgem. Network innovation competition: full submission application. 2020.

75 Nationalgrid. *HyNTS: hydrogen in the NTS*. United Kingdom: Nationalgrid.

76 Project Union. Gas transmission and metering; 2022.

77 East Coast Hydrogen Feasibility Report. Northern gas networks, Cadent, Nationalgrid; 2021.

78 HYPOS. H2 PIMS: Pipeline integrity management zur Weiternutzung der bestehenden Erdgasinfrastruktur für Wasserstoff. Hydrogen Power Storage and Solutions East Germany E.V.

79 HYPOS. HyProS: Prozess- und Sicherheitssensorik für das Wasserstoff-Qualitätsmanagement. Hydrogen Power Storage and Solutions East Germany E.V.

80 HYPOS-Projekt INES erfolgreich abgeschlossen [press release]. Hydrogen Power Storage and Solutions East Germany E.V. 22 Jul 2021.

81 Dialogik. Netzlabor (Gridlab) Hydrogen-Island. Available from: https://www.dialogik-expert.de/en/projects/netzlabor-gridlab-hydrogen-island.

82 Zuruck. Bayernets participates in BMWi's expression of interest procedure for hydrogen technologies. 2021 23 Feb.

83 DVGW. Hydrogen Research Projects. Deutscher Verein des Gas- und Wasserfaches e.V; 2020.

84 DVGW. H2-Messrichtigkeit: Untersuchung des Verhaltens von Haushaltszählern im Verbund mit Hausdruckregelgeräten bei Nutzung von H2-beaufschlagten Gasen. Deutscher Verein des Gas- und Wasserfaches e.V; 2022.

85 DVGW. H2-Infrastrukturen weltweit: Studie zur Erfassung von H2-Verteilnetzen/Infrastrukturen. Deutscher Verein des Gas- und Wasserfaches e.V; 2020.

86 DVGW. H2vorOrt – Gasnnetzgebiets-transformationsplan. Deutscher Verein des Gas- und Wasserfaches e.V; 2022.

87 How the TransHyDE flagship project aims to develop a hydrogen transport infrastructure: Federal MInistry of Education and Research. Available from: https://www.wasserstoff-leitprojekte.de/projects/transhyde.

88 Hamburgnews. HH-Win hydrogen network in Port of Hamburg gets approval 2022 [cited 2022 August]. Available from: https://www.hamburg-news.hamburg/en/standort/hh-win-hydrogen-network-port-hamburg-gets-approval.

89 GasunieDeutschland. Project HyPerLink. Available from: https://www.gasunie.de/en/the-company/gasunie-deutschland/project-hyperlink#:~:text=HyPerLink%20will%20largely%20be%20realized,610%20km.

90 TkiNieuwGas. Overview of hydrogen projects in the Netherlands. 2020.

91 HyDelta. Research programme 2022. Available from: https://hydelta.nl/research-programme.

92 Hynetwork. Rotterdam: The hydrogen pipeline for the port of Rotterdam. Available from: https://www.hynetwork.nl/voor-de-omgeving/rotterdam.

93 GreenCarCongress. Ørsted proposes to develop one of the world's largest renewable hydrogen plants: SeaH2Land 2021. Available from: https://www.greencarcongress.com/2021/04/20210402-orsted.html.

94 RWE. H2opZee: Demonstration project for green hydrogen in the Netherlands 2022. Available from: https://www.rwe.com/en/research-and-development/hydrogen-projects/h2opzee.

95 ENA. SGN receives the go-ahead to build the world's-first hydrogen heating network 2020 [1 December]. Available from: https://www.energynetworks.org/newsroom/sgn-receives-the-go-ahead-to-build-the-worlds-first-hydrogen-heating-network.

96 Melaina MW, Antonia O, Penev M. *Blending hydrogen into natural gas pipeline networks: a review of key issues*. National Renewable Energy Laborarory NREL; 2013.

97 Heynes G. Kawasaki obtains AiP for world's largest containment for a liquefied hydrogen carrier. H2 View. 2021 7 May.

98 Bahtić F. KHI gets ClassNK's AiP for world's largest liquefied hydrogen carrier CCS 2021 [7 May]. Available from: https://www.offshore-energy.biz/khi-gets-classnks-aip-for-worlds-largest-liquefied-hydrogen-carrier-ccs/.

99 Alkhaledi AN, Sampath S, Pilidis P. A hydrogen fuelled LH2 tanker ship design. *Ships Offshore Struct*. 2022;**17**(7):1555–1564.

100 Burger R. Hydrogen transportation | the key to unlocking the clean hydrogen economy Focus. 2021 4 Nov.

101 INGRID 39 MWh grid-connected renewable energy storage project. *Fuel Cells Bull*. 2012;**2012**(8):9.

102 Darrow K, Tidball R, Wang J, Hampson A. Section 6: technology characterization: fuel cells. In: *Catalog of CHP technologies*. 2015.

103 Ali D, Aklil-D'Halluin DD. Modeling a proton exchange membrane (PEM) fuel cell system as a hybrid power supply for standalone applications. In: *2011 Asia-Pacific Power and Energy Engineering Conference; 25–28 March 2011*. 2011. p. 1–5.

104 Singh S, Chauhan P, Singh N. Capacity optimization of grid connected solar/fuel cell energy system using hybrid ABC-PSO algorithm. *Int J Hydrogen Energy*. 2020;**45**(16):10070–10088.

105 Mayo-Maldonado JC, Valdez-Resendiz JE, Sanchez VM, Rosas-Caro JC, Claudio-Sanchez A, Chan Puc F. A novel PEMFC power conditioning system based on the interleaved high gain boost converter. *Int J Hydrogen Energy*. 2019;**44**(24):12508–12514.

106 EG&G Technical Services I. *Fuel cell handbook*. Seventh ed. U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory; 2004.

107 İnci M, Türksoy Ö. Review of fuel cells to grid interface: configurations, technical challenges and trends. *J Cleaner Prod*. 2019;**213**: 1353–1370.

108 Guo R, Li Q, Zhao N. An overview of grid-connected fuel cell system for grid support. *Energy Rep*. 2022;**8**: 884–892.

109 FuelCellWorks. Hanwha's groundbreaking power plants shows how hydrogen can fuel a circular economy 2020 [16 August]. Available from: https://fuelcellsworks.com/news/hanwhas-groundbreaking-power-plant-shows-how-hydrogen-can-fuel-a-circular-economy/.

110 Olabi AG, Wilberforce T, Sayed ET, Elsaid K, Abdelkareem MA. Prospects of fuel cell combined heat and power systems. *Energies*. 2020;**13**(16):4104.

111 Arias J. *Hydrogen and fuel cells in Japan*. Tokyo EU-Japan Centre for Industrial Cooperation; 2019.

112 Lin R-H, Zhao Y-Y, Wu B-D. Toward a hydrogen society: Hydrogen and smart grid integration. *Int J Hydrogen Energy*. 2020;**45**(39):20164–20175.

113 Akinyele DO, Rayudu RK. Review of energy storage technologies for sustainable power networks. *Sustain Energy Technol Assess*. 2014;**8**: 74–91.

114 Gharibi M, Askarzadeh A. Size and power exchange optimization of a grid-connected diesel generator-photovoltaic-fuel cell hybrid energy system considering reliability, cost and renewability. *Int J Hydrogen Energy*. 2019;**44**(47):25428–25441.

115 Okundamiya MS. Size optimization of a hybrid photovoltaic/fuel cell grid connected power system including hydrogen storage. *Int J Hydrogen Energy*. 2021;**46**(59):30539–30546.

116 Mokhtara C, Negrou B, Settou N, Bouferrouk A, Yao Y. Design optimization of grid-connected PV-hydrogen for energy prosumers considering sector-coupling paradigm: case study of a university building in Algeria. *Int J Hydrogen Energy*. 2020;**46**(75):37564–37582.

117 Optimal sizing of a hybrid renewable system. In: Sánchez V, Ramirez JM, Arriaga G, editors. *2010 IEEE International Conference on Industrial Technology; 2010 14–17 March*. 2010.

118 Optimal sizing and energy management of a grid-connected microgrid using HOMER software. In: Shahinzadeh H, Moazzami M, Fathi SH, Gharehpetian GB, editors. *2016 Smart Grids Conference (SGC); 2016 20–21 Dec.* 2016.

119 Solar PV-hydrogen fuel cell system for electrification of a remote village in Bangladesh. In: Hossain KK, Jamal T, editors. *2015 International Conference on Advances in Electrical Engineering (ICAEE); 2015 17–19 Dec.* 2015.

120 Optimal sizing of hybrid PV/T-fuel cell CHP system using a heuristic optimization algorithm. In: Bernoosi F, Nazari ME, editors. *2019 International Power System Conference (PSC); 2019 9–11 Dec.*. 2019.

121 Akhtari MR, Baneshi M. Techno-economic assessment and optimization of a hybrid renewable co-supply of electricity, heat and hydrogen system to enhance performance by recovering excess electricity for a large energy consumer. *Energy Conversion Manage*. 2019;**188**: 131–141.

122 Memon SA, Upadhyay DS, Patel RN. Optimal configuration of solar and wind-based hybrid renewable energy system with and without energy storage including environmental and social criteria: a case study. *J Energy Storage*. 2021;**44**: 103446.

123 Li J, Liu P, Li Z. Optimal design of a hybrid renewable energy system with grid connection and comparison of techno-economic performances with an off-grid system: a case study of west China. *Comput Chem Eng*. 2022;**159**: 107657.

124 Sizing methods for stand-alone hybrid systems based on renewable energies and hydrogen. In: Castañeda M, Fernández LM, Sánchez H, Cano A, Jurado F, editors. *2012 16th IEEE Mediterranean Electrotechnical Conference; 2012 25–28 March*. 2012.

125 Fetanat A, Khorasaninejad E. Size optimization for hybrid photovoltaic–wind energy system using ant colony optimization for continuous domains based integer programming. *Appl Soft Comput*. 2015;**31**: 196–209.

126 Ali D, Gazey R, Aklil D. Developing a thermally compensated electrolyser model coupled with pressurised hydrogen storage for modelling the energy efficiency of hydrogen energy storage systems and identifying their operation performance issues. *Renew Sustain Energy Rev*. 2016;**66**: 27–37.

127 Fernández FJV, Segura Manzano F, Andújar Márquez JM, Calderón Godoy AJ. Extended model predictive controller to develop energy management systems in renewable source-based smart microgrids with hydrogen as backup. *Theoret Foundat Case Study. Sustainabil*. 2020;**12**(21):8969.

128 Grueger F, Möhrke F, Robinius M, Stolten D. Early power to gas applications: reducing wind farm forecast errors and providing secondary control reserve. *Appl Energy*. 2017;**192**: 551–562.

129 Abadlia I, Adjabi M, Bouzeria H. Sliding mode based power control of grid-connected photovoltaic-hydrogen hybrid system. *Int J Hydrogen Energy*. 2017;**42**(47):28171–28182.

130 Ali DMM. Hydrogen energy storage. In: Demirkan MT, Attia A, editors. *Energy storage devices*. London: IntechOpen; 2019.

131 Jovan DJ, Dolanc G. Can green hydrogen production be economically viable under current market conditions. *Energies*. 2020;**13**(24):6599.

132 Mohanpurkar M, Luo Y, Terlip D, Dias F, Harrison K, Eichman J, et al. Electrolyzers enhancing flexibility in electric grids. *Energies*. 2017;**10**(11):1836.

133 Carr S, Zhang F, Liu F, Du Z, Maddy J. Optimal operation of a hydrogen refuelling station combined with wind power in the electricity market. *Int J Hydrogen Energy*. 2016;**41**(46):21057–21066.

134 Flamm B, Peter C, Büchi FN, Lygeros J. Electrolyzer modeling and real-time control for optimized production of hydrogen gas. *Appl Energy*. 2021;**281**: 116031.

135 Optimal scheduling of hydrogen energy storage integrated energy system based on mixed integer second-order cone. In: Wan L, Zhang W, Xu Z, editors. *12th IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC); 2020 20–23 Sept.* 2020.

136 Klyapovskiy S, Zheng Y, You S, Bindner HW. Optimal operation of the hydrogen-based energy management system with P2X demand response and ammonia plant. *Appl Energy*. 2021;**304**: 117559.

137 Zhou Y. Advances of machine learning in multi-energy district communities–mechanisms, applications and perspectives. *Energy AI*. 2022;**10**: 100187.

138 Rangel-Martinez D, Nigam KDP, Ricardez-Sandoval LA. Machine learning on sustainable energy: a review and outlook on renewable energy systems, catalysis, smart grid and energy storage. *Chem Eng Res Des*. 2021;**174**: 414–441.

139 Venkatasatish R, Dhanamjayulu C. Reinforcement learning based energy management systems and hydrogen refuelling stations for fuel cell electric vehicles: an overview. *Int J Hydrogen Energy*. 2022;**47**(64):27646–27670.

140 Mbuwir BV, Ruelens F, Spiessens F, Deconinck G. Battery energy management in a microgrid using batch reinforcement learning. *Energies*. 2017;**10**(11):1846.

141 Huang X, Hong SH, Yu M, Ding Y, Jiang J. Demand response management for industrial facilities: a deep reinforcement learning approach. *IEEE Access*. 2019;**7**: 82194–82205.

142 Lin L, Guan X, Peng Y, Wang N, Maharjan S, Ohtsuki T. Deep reinforcement learning for economic dispatch of virtual power plant in internet of energy. *IEEE IOT J*. 2020;**7**(7):6288–6301.

143 Zhou S, Hu Z, Gu W, Jiang M, Chen M, Hong Q, et al. Combined heat and power system intelligent economic dispatch: a deep reinforcement learning approach. *Int J Electr Power Energy Syst*. 2020;**120**: 106016.

144 Ye Y, Qiu D, Wu X, Strbac G, Ward J. Model-free real-time autonomous control for a residential multi-energy system using deep reinforcement learning. *IEEE Trans Smart Grid*. 2020;**11**(4):3068–3082.

145 Lu R, Hong SH, Yu M. Demand response for home energy management using reinforcement learning and artificial neural network. *IEEE Trans Smart Grid*. 2019;**10**(6):6629–6639.

146 Tomin N, Zhukov A, Domyshev A. Deep reinforcement learning for energy microgrids management considering flexible energy sources. *EPJ Web Conf*. 2019;**217**: 01016.

147 Dreher A, Bexten T, Sieker T, Lehna M, Schütt J, Scholz C, et al. AI agents envisioning the future: forecast-based operation of renewable energy storage systems using hydrogen with deep reinforcement learning. *Energy Convers Manage*. 2022;**258**: 115401.

148 Gazey RN. *Sizing hybrid green hydrogen energy generation and storage systems (HGHES) to enable an increase in renewable penetration for stabilising the grid*. Robert Gordon University (RGU); 2014. Available from http://openair.rgu.ac.uk.

149 Hosseini M, Dincer I, Naterer GF, Rosen MA. Thermodynamic analysis of filling compressed gaseous hydrogen storage tanks. *Int J Hydrogen Energy*. 2012;**37**(6):5063–5071.

150 Xiao J, Bi C, Bénard P, Chahine R, Zong Y, Luo M, et al. Neural network based optimization for cascade filling process of on-board hydrogen tank. *Int J Hydrogen Energy*. 2021;**46**(3):2936–2951.

151 Luta DN, Raji AK. Potential benefits of renewable fuel cell systems for rural communities' power supply. In: *International Conference for Research, Innovation and Development for Africa:* EAI. 2018.

152 Ulleberg Ø, Nakken T, Eté A. The wind/hydrogen demonstration system at Utsira in Norway: evaluation of system performance using operational data and updated hydrogen energy system modeling tools. *Int J Hydrogen Energy*. 2010;**35**(5):1841–1852.

153 In: Gammon R, Roy A, Barton JP, Little M, editors. *Hydrogen and renewables integration (HARI)*. 2006.

154 Cowan V, Chrometzka T. How to light up remote areas with clean hydrogen energy 2019 [13 December]. Available from: https://development.asia/explainer/how-light-remote-areas-clean-hydrogen-energy.

155 Marocco P, Ferrero D, Gandiglio M, Ortiz MM, Sundseth K, Lanzini A, et al. A study of the techno-economic feasibility of H2-based energy storage systems in remote areas. *Energy Convers Manage*. 2020;**211**: 112768.

156 Mould K, Silva F, Knott SF, O'Regan B. A comparative analysis of biogas and hydrogen, and the impact of the certificates and blockchain new paradigms. *Int J Hydrogen Energy*. 2022;**47**(93):39303–39318.

157 Lagioia G, Spinelli MP, Amicarelli V. Blue and green hydrogen energy to meet European Union decarbonisation objectives. An overview of perspectives and the current state of affairs. *Int J Hydrogen Energy*. 2022;**48**(4):1304–1322.

158 Blasio ND, Hua C. *The role of blockchain in green hydrogen value chains. Policy brief*. Harvard Kennedy School Blefer Center for Science and International Affairs; 2021.

159 Andoni M, Robu V, Flynn D, Abram S, Geach D, Jenkins D, et al. Blockchain technology in the energy sector: a systematic review of challenges and opportunities. *Renew Sustain Energy Rev*. 2019;**100**: 143–174.

160 Zhao F, Guo X, Chan WK. Individual green certificates on blockchain: a simulation approach. *Sustainability [Internet]*. 2020;**12**(9):3942. Available from: https://doi.org/10.3390/su12093942.

161 Mengelkamp E, Gärttner J, Rock K, Kessler S, Orsini L, Weinhardt C. Designing microgrid energy markets: a case study: the Brooklyn microgrid. *Appl Energy*. 2018;**210**: 870–880.

162 Hosseinnezhad V, Hayes B, O'regan B, Siano P. Practical insights to design a blockchain-based energy trading platform. *IEEE Access*. 2021;**9**: 154827–154844.

163 Verma P, O'Regan B, Hayes B, Thakur S, Breslin JG. EnerPort: Irish blockchain project for peer- to-peer energy trading. *Energy Inform*. 2018;**1**(1):14.

164 Tsao Y-C, Thanh V-V. Toward sustainable microgrids with blockchain technology-based peer-to-peer energy trading mechanism: a fuzzy meta-heuristic approach. *Renew Sustain Energy Rev*. 2021;**136**: 110452.

165 Wang L, Jiao S, Xie Y, Xia S, Zhang D, Zhang Y, et al. Two-way dynamic pricing mechanism of hydrogen filling stations in electric-hydrogen coupling system enhanced by blockchain. *Energy*. 2022;**239**: 122194.

166 Li K. Technological challenges and socio-ecological impacts of green hydrogen boom. 2022 September.

167 Yu M, Wang K, Vredenburg H. Insights into low-carbon hydrogen production methods: green, blue and aqua hydrogen. *Int J Hydrogen Energy*. 2021;**46**(41):21261–21273.

168 Path to hydrogen competitiveness. A cost prespective. Hydrogen Council; 2020.

169 Bergström L, Kautsky L, Malm T, Rosenberg R, Wahlberg M, Capetillo NÅ, et al. Effects of offshore wind farms on marine wildlife – a generalized impact assessment. *Environ Res Lett*. 2014;**9**: 034012.

170 IEA. *Global hydrogen review 2021*. International Energy Agency; 2021.

171 DNV. *Energy transition outlook 2022: a global and regional forecast to 2050*. Det Norske Veritas Group; 2022.

172 AREG. The European offshore wind deployment centre (EOWDC): Aberdeen renewable energy group. Available from: https://www.aberdeenrenewables.com/portfolio/eowdc/.

173 BEIS. *Digest of UK energy statistics: load factors for renewable electricity (DUKES 6.5)*. Department for Business, Energy and Industrial Strategy; 2020.

174 Thomas D. *Large scale PEM electrolysis: technology status and upscaling strategies*. Brussels: Hydrogenics; 2019.

175 Smeets F, Thomas D. *HyBalance: state-of-the-art PEM electrolysis paving the way to multi-MW renewable hydrogen systems*. Oevel, Belgium: Hydrogenics Europe N.V.; 2017.