

From green hydrogen to electricity: A review on recent advances, challenges, and opportunities on Power-to-Hydrogen-to-Power systems

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Abstract

The energy sector is responsible for around two-thirds of greenhouse gas emissions, mainly relying on fossil fuels. Thus, the industry must make substantial changes as part of the global energy transition toward a carbon-neutral society. Green hydrogen has the potential to boost the transition to clean and renewable energy while providing stability and reliability to power grids. This paper reviews the most recent developments of Power-to-Hydrogen-to-Power (P2H2P) systems: conversion of power to hydrogen, its storage, transport, and re-electrification, with emphasis on their technical characteristics, novel modeling approaches, and implementation challenges. The main opportunities to exploit the potential of P2H2P are associated with cost efficiency and innovation, sector coupling, and reduction of grid dependence. In such a way, P2H2P systems would become cost-competitive while decarbonizing sectors. Furthermore, the gradual maturity of technology and political support would encourage the development of sustainable energies for zero-emission economies.

Keywords: Green hydrogen, Energy systems, Power-to-X, Power-to-Hydrogen-to-Power, P2H2P

Word count: 12286

List of Abbreviations

AC	Alternating Current
AEL	Alkaline Electrolyzer
AFC	Alkaline Fuel Cell
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditure
CGH ₂	Compressed gas hydrogen
DC	Direct Current
DMFC	Direct Methanol Fuel Cell
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gases
ICEV	Internal Combustion Engine Vehicle
LCOH	Levelized cost of hydrogen
LH ₂	Liquified hydrogen
LOHC	Liquid organic hydrogen carrier
MCFC	Molten carbonate Fuel Cell
MH	Metal hydride
NIMBY	Not In My Back Yard
OPEX	Operational Expenditure
OSM	OpenStreetMap
P2G	Power-to-Gas
P2H	Power-to-Hydrogen
P2H2P	Power-to-Hydrogen-to-Power
P2X	Power-to-X
P2X2P	Power-to-X-to-Power
PAFC	Phosphoric acid Fuel Cell
PEMEL	Proton-exchange Membrane Electrolyzer
PEMFC	Proton-exchange Membrane Fuel Cell
RES	Renewable Energy Sources
SOEL	Solid-Oxide Electrolyzer
SOFC	Solid-Oxide Fuel Cell

1. Introduction

The energy transition comprises a global effort to reduce the anthropogenic emissions of greenhouse gases (GHG) while maintaining the standard of living of societies. However, countries deploy their energy transition strategies at different scales and extents. Recent projections anticipate a 2.5 °C increase in global average temperature by the end of this century under current measures (Stated Policies Scenario), which is 1 °C above with the Net Zero Emissions Scenario [1]. It is, therefore, of utmost importance to accelerate the expansion of renewable energies, the electrification of sectors, and the development of sustainable substitutes for feedstocks in hard-to-abate sectors. The United Nations has suggested specific actions such as the rapid deployment of available energy transition solutions, the redirection of energy financing towards the transition, and the adaption of policies and regulations to ensure the achievement of Sustainable Development Goal 7, “Affordable and Clean Energy”, and decarbonized energy systems by 2050 [2]. Following this, the EU Renewable Energy Directive proposes to increase the renewable share in the European energy mix from 32% to 40% by 2030 [3]. In contrast, the US Inflation Reduction Act allocates nearly 370 billion dollars for developing clean technologies and infrastructure [3]. These guidelines, among other policies, foster renewable hydrogen production, as it is both an energy carrier and a feedstock for industry. In addition, hydrogen can improve power grid stability by acting as an energy buffer with long-term storage capabilities, thus balancing the power supply and demand. Such a process is denoted as Power-to-Hydrogen-to-Power (P2H2P). It consists of converting power to hydrogen, its storage, transport, and subsequent reconversion to power.

P2H2P systems have already been considered in several studies. Genovese et al. [4] presented a review study on potential hydrogen applications in Europe, including the renewable energy storage option to enhance the power grid stability and reliability. The energy storage application can vary depending on the renewable energy potential and requirements of the energy system, yielding different scales, technologies, and operating conditions of P2H2P. For instance, Zhang et al. [5] tested the performance of a renewable energy system with on-site energy storage alternatives: hydrogen (P2H2P) or lithium battery, while Schöne et al. [6] proposed a P2H2P system for an off-grid community that typically uses diesel generators. In both cases, P2H2P proved to be economically viable while improving the stability and reliability of the power system, thus becoming a suitable alternative to conventional energy systems. Besides off-grid studies, P2H2P can enhance existing power plants, especially for managing peak load and low load periods of consumption. Alirahmi et al. [7] investigated this concept for a geothermal power plant that integrates a P2H2P system, leading to an optimized exergy efficiency and cost rate. Such studies require large datasets, mainly due to the volatile aspect of renewable energies, multiple models to describe process

units (electrolyzers, compressors, fuel cells, turbines, etc.), and optimization objectives. In addition, power grid models are essential for the development of energy systems that advantageously integrate Power-to-X (P2X) and P2H2P and quantify their benefit to the overall system.

Despite the advantages of P2H2P systems described above, hydrogen production from electricity remains limited, accounting for roughly 0.04% of total production in 2021 [8]. This occurs because P2H2P-dedicated technology has not yet achieved the technology and manufacturing readiness level for large-scale applications. In response to the global strategies towards the energy transition, companies such as Siemens [9], [10], General Electric [11], Linde [12], and Kawasaki Heavy Industries [13], [14] are consistently engaged in developing new processes and equipment or innovating, improving, and adapting existing ones. As a result, this paper aims to review the most recent developments in large-scale P2H2P systems from both scientific and industrial perspectives, focusing on all the stages of the process, including:

- Power grid models considering P2H2P in recent contributions;
- Green hydrogen production through water electrolysis (AEL, PEMEL), its purification (deoxidation, dehydration), and compression;
- Hydrogen storage in pressure vessels, salt caverns, aquifers, and depleted reservoirs;
- Hydrogen transport as a compressed gas, liquified and in liquid organic carriers by different means: pipes, roads, and maritime;
- Re-electrification of hydrogen through gas turbines and fuel cells.

While recent reviews have also emphasized the importance of integrating hydrogen into power systems, these tend to dwell on specific stages of the P2H2P system. For instance, Yue et al. [15] analyzed the advancements in hydrogen technologies and their application in power systems, focusing solely on hydrogen production, storage, and re-electrification. Similarly, Dawood et al. [16] presented an outline of hydrogen-based energy systems, exclusively discussing the pathways and associated technologies for production, storage, and utilization. Going beyond these approaches, Ishaq et al. [17] and Nazir et al. [18], [19] delve into a broader scope, reviewing not only conventional and renewable hydrogen production methods but also examining hydrogen utilization, storage, transportation, and distribution. Nevertheless, these reviews often neglect specific crucial steps, such as purification and compression, despite their significance in meeting quality requirements for subsequent storage and transportation stages post-production. Other reviews exclusively target single stages of P2H2P, such as purification [20], underground storage [21], compression [22], [23], or re-electrification in gas turbines [24]. The novelty of this review lies in its holistic approach to addressing the entire

spectrum of processes involved in P2H2P systems, ensuring a complete understanding of the integration of hydrogen into power systems, and analyzing the challenges and opportunities associated with the implementation of these technologies.

The present review article is organized as follows: the most recent advancements in the components of a P2H2P system (power grid modeling; green hydrogen production, storage, transport; and re-electrification) are presented in Chapters 2 to 4, emphasizing their technical features and limitations. In Chapter 5, the challenges for the implementation of P2H2P have been identified in terms of (i) modeling and simulation limitations, (ii) capital and operating costs, (iii) safety and operating constraints, (iv) environmental impact, and (v) social acceptance. Finally, Chapter 6 discusses a few research opportunities to enhance green hydrogen production systems as a decarbonization strategy for the energy transition.

2. Power grid modeling

The Power-to-Hydrogen (P2H) concept describes using renewable energy sources (RES), such as wind or solar, to produce hydrogen as an energy carrier. In line with the energy transition, this work focuses on green hydrogen production through RES-powered water electrolysis. RES are volatile and intermittent, impacting the power grid and P2H operation. Therefore, using a suitable power grid representation is crucial to evaluate and understand these effects thoroughly. However, there are several models of the power grid with distinct levels of interactions between generation, demand, and grid operation. Based on this, power grid models are classified into four different types: *single-node model*, *transshipment model*, *DC model*, and *AC power flow model* [25]. As the simplest, most straightforward representation, the single-node model assumes an unconstrained electrical grid. On the other hand, the AC power flow model is the most realistic representation of the power grid, considering active and reactive power flows. *Table 1* summarizes the data requirements for each model type.

Table 1. Grid data requirement for each grid model type [25]

	<i>Single-node Model</i>	<i>Transshipment Model</i>	<i>DC Model</i>	<i>AC power flow Model</i>
Data requirements				
- Active power data generation and demand	X	X ^a	X ^a	X ^b
- Abstract grid topology: nodes, power lines, and regions		X	X	X
- Net transfer capacities of power lines		X	X	X

- Resistance and thermal limit current of power lines	X	X
- Reactive behavior of power lines		X
- Global frequencies		X
- Nominal voltage levels		X
- Characteristic of transformers		X

^a Spatially differentiated between nodes or regions

^b Specified by their reactive power or voltage behavior

Power grid modeling endeavors different tools vital in understanding their complex dynamics and far-reaching implications. These tools use three well-defined procedures: (i) grid representation and data collection, (ii) model enhancement and reduction, and (iii) simulation and analysis. This structured classification assists in emphasizing the crucial role of each component in creating precise and insightful power grid models.

2.1. Grid Representation and Data Collection

Modeling power systems require grid data to produce valid and accurate results. Nonetheless, neither grid nor power data are always accessible or transparent [25]. Therefore, this is a challenge that needs to be addressed for an accurate simulation of the power grid. In this context, OpenStreetMap (OSM) has demonstrated its utility as a valuable database for constructing power grid models using openly accessible and public data [25].

OSM [26] was created as an initiative for a free and accessible geographic database. Geo-referenced features that can be mapped, e.g., buildings, roads, and power plants, are collected by volunteer contributors. The database is complemented with license-free maps and public or proprietary-donated databases. The main downside of the OSM is that since it is a “free and editable map of the world” [27], data is constantly being updated or modified without guaranteeing it is correct, complete, or accurate.

SciGrid [28] and *osmTGmod* [29] are two different approaches for grid representation based on OSM data. Both approaches use OSM power relations data, but *osmTGmod* extends its scope by applying heuristics to the missing non-relations data. According to Medjroubi et al. [25], *osmTGmod* is more suitable for delivering lower voltage grids or for regions with limited power data. At the same time, *SciGrid* proved to be most effective for high-voltage grids. Even though the OSM database is not a power database, these approaches yielded acceptable models for power grid simulation.

With further validation, availability, and transparency, open grid models may become the standard for modeling energy systems. Considering this, the comparison tool *AutoGridComp* [30] holds the potential to aid the selection of the most fitting open-source grid representation model. This tool, developed as an open-source solution, facilitates the comparison between various open-source power grid models and, if available, against the official grid model. It assesses the accuracy and completeness of the models within three layers: mathematical characterization, visual representation, and electrical characterization. Thus, *AutoGridComp* is a functional tool that complements and improves grid derivation methods, i.e., *SciGrid*, *osmTGmod*, *GridKit*, etc.

2.2. Model Enhancement and Reduction

Although more input data makes a model more accurate and realistic, its simulation comes with additional complexity regarding the “computational efforts for solving mathematical problems” [31]. The assessment of complex energy models revealed that more accurate results are not guaranteed [31]. Instead, the conservative approach involves balancing accuracy and complexity to use computational resources efficiently.

Grid model reduction methods are frequently used to obtain sufficiently accurate results while reducing the simulation burden. A promising option is the reduction of the spatial resolution of the grid. Implementing a network clustering approach, as proposed in [32], [33], reduces the number of buses, enhancing grid representation with major transmission corridors. An alternative reduction method, the ED-reduction method [34], additionally considers electrical, political borders, and region-specific renewable potentials as parameters. A comparison of a grid scaled down to 68% of the original nodes showed that the root-mean-square error (RMSE) for the ED method (approx. 5%) was lower in contrast to the method proposed in [32], [33] (approx. 23%). This trend underscores the ongoing progress within the modeling community, focused on refining grid reduction methods to augment grid model representation, especially since evaluating power system models has a significant role in the energy transition.

Reducing the spatial resolution of a grid model leads to a proportional decrease in solving time, whereas decreasing the temporal resolution yields an exponential reduction [31]. A major challenge for power grid modeling is the selection of a proper temporal resolution to avoid an over- or underestimation of the RES share [35]. Hoevenaars & Crawford [36] examined the efficacy of renewable-based power systems modeling using steps from 1 second to 1 hour, obtaining comparable results for output inaccuracy. Therefore, 1-hour time steps achieve a sufficient representation while reducing the computational complexity of grid power models. Moreover, Shirizadeh & Quirion [37] showed the possibility of further reducing the time to an eight-hourly resolution for a grid model with sector coupling in France. Even though the errors

obtained were negligible, they suggest that a *smarter sub-sampling* could further enhance its performance. Based on this, a complexity reduction should be first regarding the temporal resolution, followed by the spatial resolution.

2.3. Simulation and Analysis

Several programs have recently been developed for power system simulation (see *Table 2*). Most are written in Python, which is free and easy to learn. PyPSA [38] stands out as a tool distinguished by its extensive repertoire of features. In comparison to PYPOWER [39] and pandapower [40], PyPSA offers multi-period unit commitment, investment optimization, and energy system coupling [38]. This last feature makes PyPSA a valuable simulation software for P2X applications, i.e., gas, heating, transport, etc.

Table 2. Comparison of selected features for Python-based tools (Adapted from [38])

Features	Software Version	pandapower 1.4.0	PYPOWER 5.1.2	PyPSA 0.11.0
<i>Grid Analysis</i>				
- Power Flow		X	X	X
- Continuation Power Flow				
- Dynamic Analysis				
<i>Economic Analysis</i>				
- Transport model		X	X	X
- Linear Optimal Power Flow (OPF)		X	X	X
- Security-Constrained Linear OPF				X
- Non-linear OPF		X	X	
- Multi-period Optimization				X
- Unit commitment				X
- Investment Optimization				X
- Energy System Coupling				X

Power grid modeling is the primary component of P2H2P systems. The simulation of these models can help optimize the production and conversion of renewable energy into green hydrogen. However, since RES are volatile, its behavior is not accurately depicted in most cases. A suitable power grid model is vital in P2H system modeling to represent RES intermittent supply. Such a model would provide a better understanding of the renewable capacity for the follow-up RES conversion process into hydrogen. *Chapters 5 and 6* further discuss this.

3. Green hydrogen production

Hydrogen is mainly produced via steam methane reforming and coal gasification. 78.7% of the total hydrogen production in 2020 came from natural gas and coal [41], raising it to 81.7% in 2021 [8]. This classification is referred to as *grey* or, if carbon capture is involved, *blue* hydrogen. The current trend towards decarbonization encourages hydrogen production from water electrolysis with RES, labeled as *green* because of the absence of carbon by-products. Depending on its end-use application, different technologies for its storage and transport have been developed in recent years. The general supply chain for green hydrogen, which consists of the technologies for production, storage, and transport, is summarized in *Figure 1*.

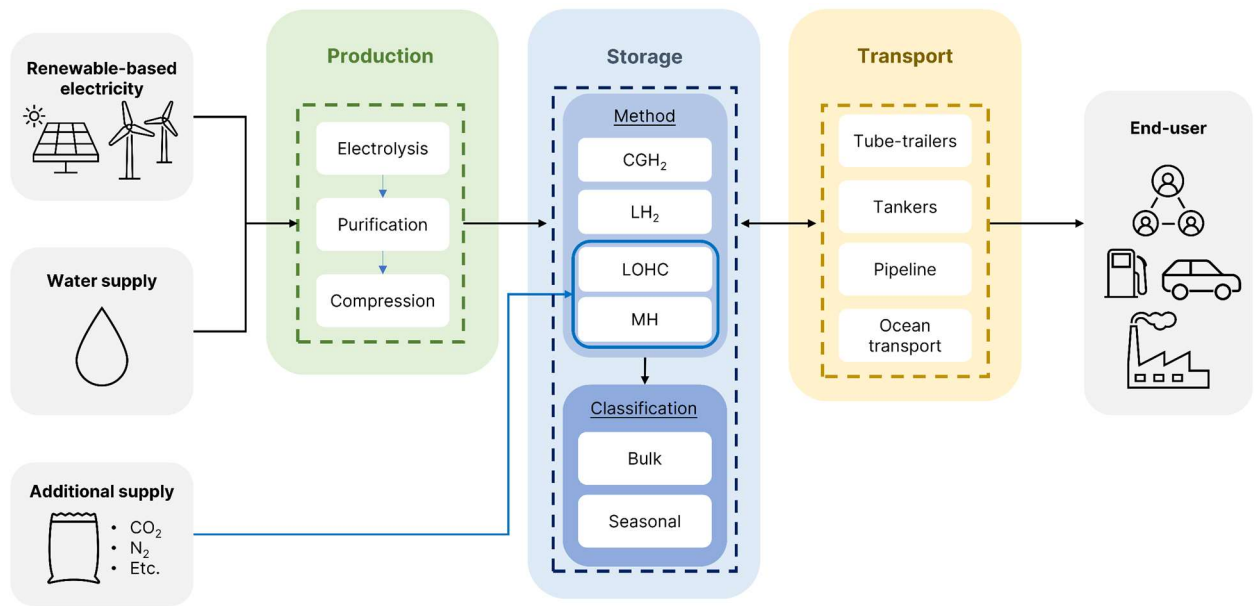
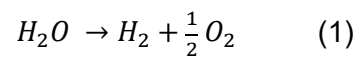


Figure 1. Schematic representation of green hydrogen supply chain based on the scope of this review.

3.1. Water Electrolysis

A water electrolysis cell comprises two electrodes, an anode and a cathode, that are in contact with the electrolyte. The RES power supply conducts current to the cell and, when a sufficiently high voltage is applied, water breaks down into hydrogen and oxygen at the cathode and anode, respectively. Different reactions can take place at the electrodes depending on the electrolyte and electrolysis technology, as shown in *Figure 2*. Nonetheless, the overall reaction is always:



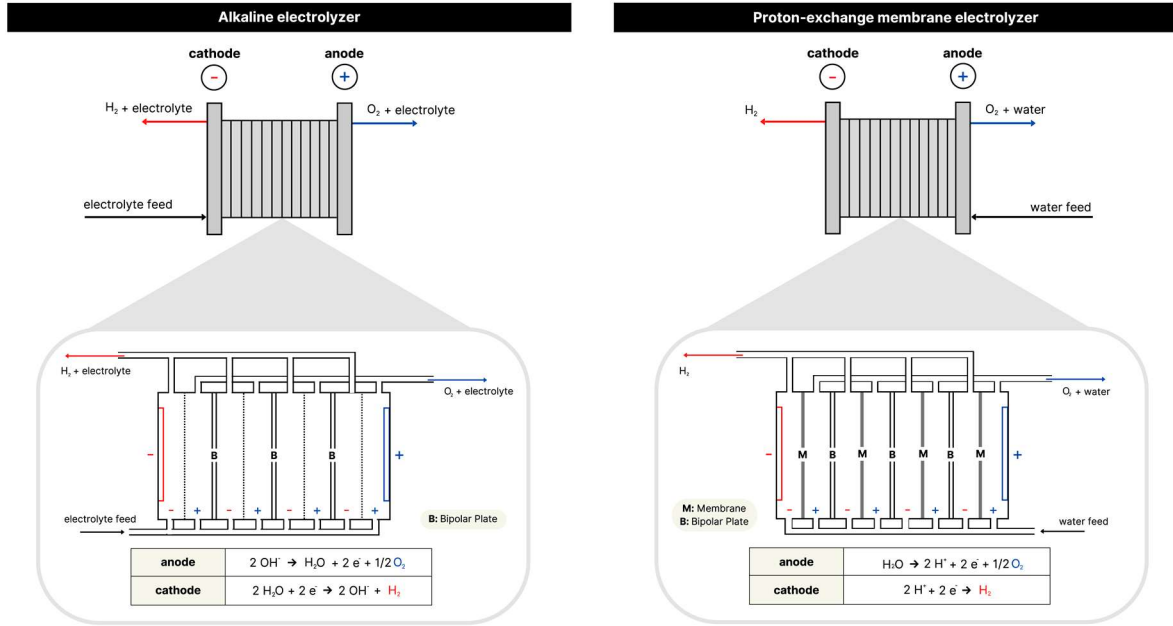


Figure 2. Bipolar configuration of the exemplary designs of an alkaline electrolyzer (left) and proton-exchange membrane electrolyzer (right).

There are three principal types of electrolyzers: Alkaline (AEL), Proton-exchange Membrane (PEMEL), and Solid-Oxide (SOEL). However, since SOEL is the least developed technology [42], it still requires significant technological advancement before commercial utilization becomes feasible. A comparison between the more mature technologies is presented in *Table 3*.

Recent P2H2P studies [7], [43]–[47] use PEMEL technology for the P2H section. The advantages of PEMEL support this, as they encompass the production of high-purity hydrogen and high ramp rates to follow volatile renewable energies [48]. Besides, PEMEL plants are more attractive for industrial applications due to their compact design [49]. With future research and development on less-expensive material-based catalysts, PEMEL capital costs are expected to reduce and therefore be cost-competitive. Nevertheless, AEL remains the dominant technology for water electrolysis because of its availability for larger-scale applications, use of low-cost electrode materials, and lower CAPEX.

Table 3. Comparison of AEL and PEMEL technical characteristics [48]–[52]

	<i>AEL</i>	<i>PEMEL</i>
Characteristics		
Electrolyte	20 – 30% NaOH or KOH	Solid sulphonated polystyrene membrane
Electrode materials	Ni, Fe	Pt, Pd, Ir, Ru
Temperature (°C)	40 – 90	20 – 100
Pressure (bar)	< 30	< 200
Current density (A/cm ²)	0.2 – 0.4	1 – 3
Efficiency (% LHV)	62 – 82	67 – 82
Energy consumption (kWh/Nm ³)	4.5 – 5.5	4.0 – 5.0
TRL	9	9
Production capacity (Nm ³ /h)	< 1400	< 400
Hydrogen purity (%)	> 99.5	> 99.99
CAPEX (\$/kW _e) ^a	400 – 850	650 – 1500

^a Future estimate by 2030

Since AEL is already used in the industry, it is possible to validate mathematical models with process data. Sakas et al. [53] performed a dynamic mass-and-energy simulation of a 3 MW industrial alkaline water electrolyzer plant using MATLAB. The proposed electrochemical and thermal models represented the dynamic behavior of the plant with 98% accuracy. A steady-state analysis was also used to identify power losses during plant operation. Thus, this model can be used to predict the energy and mass flows of industrial AEL systems in P2H2P applications and, as the authors suggest, be helpful for scaled-up optimization studies.

A crucial factor for green hydrogen production is the cost gap with other fossil-based options, i.e., grey or blue hydrogen. According to IEA [41], hydrogen production from natural gas costs around 0.5 – 1.7 \$/kg depending on the regional gas price, while using renewable electricity raises its costs to 3 – 8 \$/kg. Considering this, Jang, Cho, et al. [54] and Jang, Choi, et al. [55] analyzed the effect of pressure and temperature on AEL performance to optimize its cost operation. Jang, Cho, et al. [54] results showed that operating pressures around 20 bar made the system more efficient while obtaining high-purity hydrogen (> 99.99%). This suggests that further purification might not be necessary, cutting down both CAPEX and OPEX. Alternatively, Jang, Choi, et al. [55] demonstrated that a higher operating temperature (around 80°C) increases the stack and system efficiency only in the relatively high current density. Holm et al.'s [56] economic analysis of water electrolysis gains support from these findings as high-temperature and high-pressure operation enhances electrode kinetics and reduces compression requirements.

On the same path of making green hydrogen cost-competitive, Varela et al. [57] proposed an alkaline water electrolysis scheduling model to determine optimal production schedules that balance efficient hydrogen production and energy availability with operation and investment costs. The model allows for determining the optimal number of stacks to install, being a valuable tool in large-scale P2X applications. Integrating all of the models mentioned above could facilitate a more comprehensive study of AEL systems, which is a critical step for enhancing the energy transition scenario.

3.2. Purification

The hydrogen gas exiting the stack is mixed with the electrolyte and oxygen traces. In some cases, nitrogen traces may be present as it is commonly used to purge electrolyzers [58]. Depending on the end-use application, this hydrogen gas must be purified to meet specific quality standards. According to Du et al. [59], there are two types of purification methods: physical and chemical. Their main difference is the selectivity for impurities removal. Whereas physical purification techniques simultaneously remove many compounds, i.e., O_2 , water, N_2 ; chemical methods remove a specific impurity. For a green hydrogen facility to operate securely, both purification methods are necessary [20]. *Figure 3* presents the classification of the different hydrogen purification methods, and their technical characteristics are summarized in *Table 4*. From this classification, catalytic purification and adsorption are the most common technologies in large-scale applications [60], and thus are further discussed in this section.

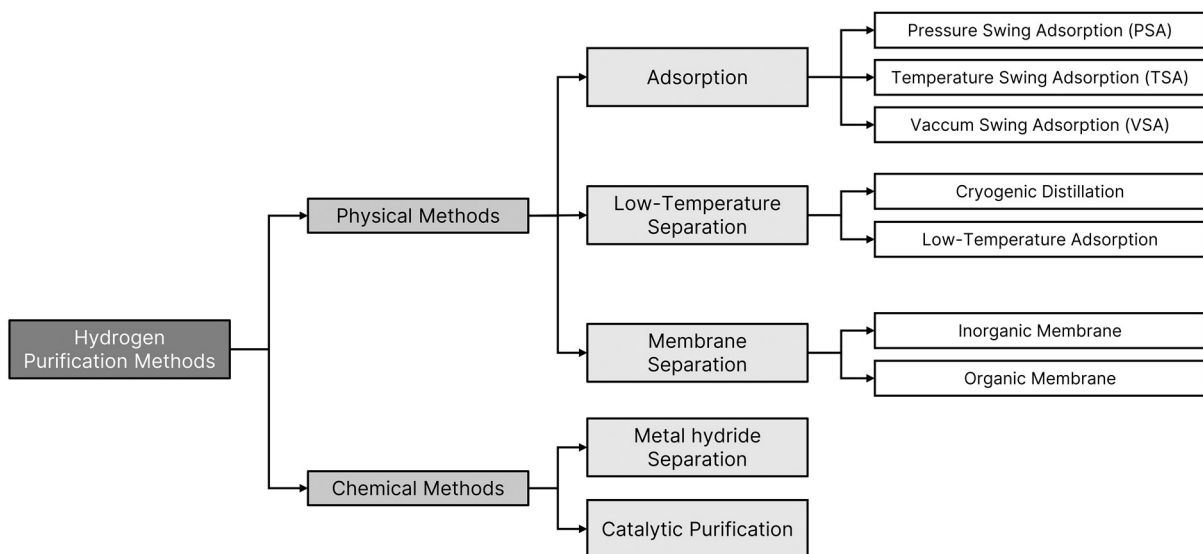
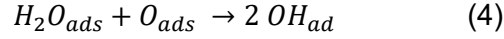
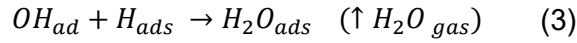
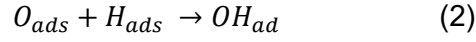


Figure 3. Classification of hydrogen purification technologies [59]

Table 4. Comparison between hydrogen purification methods [20], [59], [60]

	<i>Adsorption</i>	<i>Low-temperature Separation</i>	<i>Membrane Separation</i>	<i>Metal hydride Separation</i>	<i>Catalytic Purification</i>
Principle	Capturing impurities through a solid adsorbent	Impurity separation based on differences in volatility	Selectively permeating impurities through a membrane	Reversible absorption and desorption of H ₂ in a metal alloy	Catalyzed chemical reactions for impurity removal
Scale of use	Large	Medium to large	Small	Small to medium	Small to large
Hydrogen purity	99.999	> 99	> 99	> 99.9	> 99.9995
Advantages	Effective for various impurities, continuous operation	High H ₂ recovery	Flexible operation, low energy consumption, high selectivity	Safe hydrogen storage, minimal impurity presence	High selectivity
Disadvantages	Adsorbent regeneration, pressure drop	High energy consumption, further purification is required	Limited to specific impurities, membrane fouling	Slow kinetics during absorption, metal hydride degradation	Catalyst deactivation, potential catalyst poisoning

Oxygen is a crucial impurity to remove since concentrations above 4% would reach the lower explosive level and cause an explosion [61]. Catalytic purification selectively removes O₂ through a recombination reaction with H₂ (*Equations 2 – 4* [62]). An adiabatic reactor with a fixed catalyst layer is commonly used [60]. The global reaction is strongly exothermic ($\Delta H = -242 \frac{kJ}{mol}$) and produces water [20]. Because of this, the operation is often carried out before a condensation drying step [58].



Pd and Pt metals are the most common catalyst materials because of their strong affinity to absorb H_2 and O_2 molecules at their surface. However, these materials have some disadvantages [20]. An excess in water formation deactivates the catalytic activity of Pd and Pd-Pt-based catalysts by forming a water film around its surface. On the other hand, Pd is easily embrittled by H_2 at low temperatures. Consequently, research has been emphasizing enhancing catalyst characteristics, particularly improving its stability and hydrogen conversion. For example, G. J. Kim et al. [63] studied Pt/TiO₂, Pd/TiO₂, and Pt-Pd/TiO₂ catalysts. The highest hydrogen conversion (90%) was obtained with a 0.1%Pt-0.9%Pd/TiO₂ catalyst. Whereas Lalik et al. [64] investigated the effect of humidity on Al₂O₃ and SiO₂ supported Pd, Pt, and Pd-Pt catalysts. The results indicated that Pd catalyst had lower deactivation, which could quickly be restored by increasing the reactor temperature. Nevertheless, a gas stream with low H_2 content was used to test each catalyst effect in both studies. Therefore, future research should use a high H_2 concentration with O_2 traces gas instead for a suitable representation of the AEL hydrogen product.

The International Organization for Standardization (ISO) [65] established a maximum concentration of 5 ppm of water as a fuel quality requirement for hydrogen. Since hydrogen from AEL is saturated with water [58], a drying step is needed to reach this specification. The typical method for this is adsorption, which is available for large-scale processes with high economic performance [20]. Furthermore, hydrogen can be purified from other impurities because adsorption is a non-selective removal method.

As schematized in *Figure 3*, adsorption technologies are divided into PSA, TSA, or VSA. This classification relies on the regeneration of the adsorbent through pressure reduction, heat application, or under vacuum conditions. PSA is usually the preferred technology for its simple equipment, high-performance system, and prevention of safety hazards, i.e., hot spot prevention [58]. However, VSA has recently gained attention for its more useful advantages, including reduced energy consumption and improved hydrogen purity [66], [67].

The most frequent adsorbents used in gas purification are zeolites, activated carbon, silica gel, and activated alumina. Most studies are focused only on CO₂ removal using new adsorbents or modifying existing ones. For example, He et al. [68] proposed an activated carbon adsorbent with a nickel foam coating for a rapid PSA (RPSA). This material exhibited improved CO₂ adsorption, making it suitable for industrial applications. Furthermore, Brea et al. [69] synthesized CaX and MgX zeolites to evaluate their performance on a PSA unit. These

adsorbents purified a feed gas mixture containing H₂/CH₄/CO/CO₂ to above 99.99% hydrogen. The fact that hydrogen is still primarily produced from fossil fuel sources, where carbon-based byproducts are produced, supports this research trend. Nevertheless, such byproducts are not present in green hydrogen production. Hence, future research should focus on removing the specific impurities associated with green hydrogen.

3.3. Compression

Compression is the last step in hydrogen production before conversion for storage and further transport. This section introduces current hydrogen compression technology.

Sdanghi et al.[22] divide hydrogen compression into two main categories: mechanical and non-mechanical. The first group includes *reciprocating*, *diaphragm*, *centrifugal*, *linear*, and *liquid* compressors. On the contrary, *cryogenic*, *metal hydride*, *electrochemical* and *adsorption* compressors are part of the non-mechanical classification. Most of these have a maximum flow capacity of less than 1000 Nm³/h [23], and therefore are not suitable for large-scale hydrogen production. The compressors currently used for this purpose are reciprocating and centrifugal [23], whose comparison is presented in *Table 5*.

Table 5. Comparison between reciprocating and centrifugal compressors [22], [23]

	<i>Reciprocating Compressor</i>	<i>Centrifugal Compressor</i>
Method of compression	Positive displacement	Dynamic
Max Flow (Nm ³ /h)	4800	50000
Max Discharge Pressure (MPa)	85.9	84.7
Max Discharge Temperature	135°C – 150°C (Latest trend < 120°C)	200°C – 230°C
Single-stage Pressure ratio (X:1)	4.5 – 5.0 (low P) 2.0 – 2.5 (P _{in} > 70 bar)	1.05 – 1.20

Reciprocating compressors are appropriate for low-flow applications and can generate high pressures on a single stage. As these are positive displacement machines, gas density and molecular weight do not comprise the compression process [70]. On the other hand, centrifugal compressors are suitable for higher flow rates but have lower single-stage pressure ratios. The Bernoulli principle describes the operation of this type of compressor as simplified in *Equation 5* [23]. Therefore, the discharge pressure depends not only on the gas velocity but also on the gas density, which in this case is low since hydrogen has a density of about one-eighth of natural gas [71].

$$\Delta P = \frac{1}{2} (\rho_{in} v_{in}^2 - \rho_{out} v_{out}^2) \quad (5)$$

Discharge pressure and flow rate are the main factors considered when selecting the proper type of compressor. If higher discharge pressures are required, a multiple-stage compression with intercooling and the same compression ratio per stage is advised [72]. Since compression is an energy-intensive process, operating costs account for most of the cost of a hydrogen compressor rather than capital costs. Because of that, the compression stage dominates hydrogen's delivery cost in the supply chain if its production is not considered [73]. Khan et al.'s [72] work is a significant guide to conducting a techno-economic analysis to evaluate hydrogen compression technologies, power requirements, and associated costs.

Hydrogen compression is significantly challenging due to its low molecular weight and density [72]. Besides, when hydrogen undergoes expansion at a temperature above its inversion point (-80°C), it heats instead of cooling down as usual, an aspect that would complicate a safe compression [70]. This, along with maximum discharge temperature constraint, hydrogen embrittlement, and contamination with lubricants, represents the main issues that must be addressed in the future for large-scale H_2 production.

Regarding the existing hydrogen compression technology, lubricant contamination can be avoided on most centrifugal compressors as they are generally oil-free, whereas this is only possible with a particular type of dry or oil-free reciprocating compressor [23]. The other mentioned issues are primarily concerned with securing safety controls and extending the life span of the equipment. Higher discharge temperatures can cause problems with any sealing elements [23]. On the other hand, materials like low-alloy steels, nickel, and titanium alloys are prone to hydrogen embrittlement [74]. Both scenarios could end in hydrogen leakage and its corresponding risks, i.e., explosion, asphyxiation, and exposure to extremely low temperatures [75].

The recent development of new technologies is vital to safe, efficient, and low-cost hydrogen compression. For example, Linde's [12] patented *Ionic Liquid Compressor* has the advantage of preventing risks for hydrogen contamination and increasing energy efficiency by using an ionic liquid as a lubricant and a coolant. On the other hand, *Metal Hydrides Compressors* can be powered with waste industrial heat or renewable-based electricity [22], potentially reducing operational costs. However, these technologies have not yet reached the level of industrial-scale production, which should be the main focus of future research.

3.4. Process diagram of hydrogen production and purification

Figure 4 shows the process diagram of a hydrogen production plant by alkaline water electrolysis. Electrolyzers can be powered either through on-grid or off-grid connections. Given their direct current (DC) electricity use, on-grid connections necessitate the initial use of alternating current (AC)/DC rectifiers. In contrast, off-grid connections require the initial use of DC/DC converters. This DC source is fed to the alkaline electrolyzer composed of several stacks arranged in series with a bipolar configuration [53], as shown in Figure 2. Due to the efforts towards decarbonization, green hydrogen plants should have high installed power capacities. For that, several stacks must compose an electrolyzer or several electrolyzers must be placed in a parallel arrangement (see Figure 4).

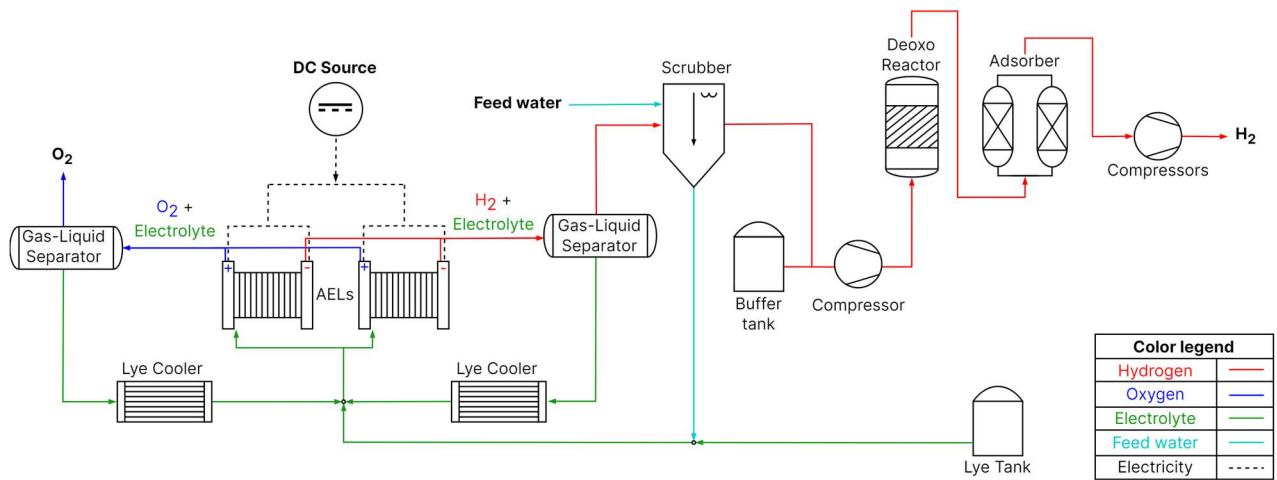


Figure 4. Hydrogen production process diagram [53], [54], [76]

In alkaline electrolyzers, the water splitting reaction (*Equation 1*) occurs in the catalyst layer of the electrodes generating H_2 gas at the cathode-side and O_2 gas at the anode-side. A mixture of the electrolyte solution and O_2 is collected from the anodes and then separated in a horizontal gas-liquid separator. Simultaneously, the electrolyte solution and H_2 mixture is collected from the cathodes and separated in another horizontal gas-liquid vessel. The liquid streams from these separators are recirculated back to the electrolyzers before passing through shell-and-tube heat exchangers. Heat exchangers act as *coolers* removing heat from the electrolyte solution to maintain a constant temperature in the electrolyzer. The O_2 -rich gas stream from one separator is vented to the atmosphere, while the H_2 -rich gas stream leaving the other separator undergoes purification and compression stages.

The scrubber removes residual traces from the electrolyte. It cools down the hydrogen stream with feed water, which is then recirculated and mixed with the electrolyte solution fed to the electrolyzers [76]. The scrubbed gas stream that exits the scrubber enters the buffer tank and

is released intermittently into the Deoxo Reactor. According to Sakas et al. [53], intermediate storage is necessary for industrial applications to control the hydrogen concentration and the oxygen flow in the reactor, which would otherwise increase the deoxidizer temperature at unfavorable conditions. Following deoxidation, an adsorption stage occurs, in which the gas stream undergoes drying, yielding a 99.999% pure hydrogen gas. Finally, this pure hydrogen gas is compressed according to the application requirement before being stored and transported to the end-consumer.

It is important to mention that the proposed process diagram focuses on using compressed gas hydrogen for storage. In the following section, different storage methods are presented, each requiring specific conversion processes.

3.5. *Hydrogen Storage*

Green hydrogen is produced and stored on-site, transported, and then stored close to the delivery site before being delivered to the final customer [18] (see also *Figure 1*). This dual storage is due, in part, to the fact that green hydrogen production facilities are usually located in remote areas where RES is available. Moreover, RES intermittency and availability constraint H_2 production. Therefore, storage is crucial in the hydrogen supply chain to regulate the stock based on user demand.

Hydrogen can be stored through physical-based or material-based methods. Their main difference is that material-based methods store hydrogen indirectly into another compound, while physical-based methods store it directly. In this review, the physical methods covered are compressed gas (CGH_2) and liquified (LH_2) hydrogen. Liquid-organic hydrogen carrier (LOHC) and metal hydride (MH) are material-based methods. A comparison between these methods is shown in *Table 6*.

Hydrogen is mainly stored as compressed gas because its technology is commercially available and, compared to liquified H_2 , it does not involve high costs. However, since hydrogen gas has a low volumetric density, storing it results difficult and expensive due to large space requirements. This issue could be addressed by storing hydrogen in liquid or solid forms, offering an advantage as H_2 has the highest gravimetric density (~ 120 MJ/kg) compared to other fuels [77], thus more energy could be stored in less space.

Table 6. Comparison between hydrogen physical-based and material-based methods [18], [77], [78]

<i>Method</i>	<i>Description</i>	<i>Advantages</i>	<i>Disadvantages</i>
Compressed Gas	H ₂ compressed gas form (350 – 700 bar)	<ul style="list-style-type: none"> - Large gravimetric density - Commercially available - Fast filling and high release rate 	<ul style="list-style-type: none"> - Low volumetric density - Large space requirement - Safety concerns from high-pressurized tanks
Liquified	H ₂ liquified form (-253°C at 1 atm)	<ul style="list-style-type: none"> - Large gravimetric and volumetric density - Commercially available - Low/medium pressure 	<ul style="list-style-type: none"> - Higher energy consumption (30% of the final energy) - Loss of H₂ due to evaporation - High cost of H₂ liquefaction
Liquid-organic carrier	Unsaturated organic compounds that absorb H ₂ through chemical reactions	<ul style="list-style-type: none"> - Large gravimetric and volumetric density - Stable at ambient conditions 	<ul style="list-style-type: none"> - Poor on-board/off-board regenerability - High system costs
Metal hydride	Metals that absorb H ₂ to form a stable compound	<ul style="list-style-type: none"> - Large gravimetric and volumetric density - Highly stable at ambient temperature 	<ul style="list-style-type: none"> - Slow kinetics (filling time) - High activation barriers (adsorption/desorption) - Higher system costs

LOHC carriers include cycloalkanes and n-heterocycles with an approximate hydrogen storage capacity of 6 % w/w [18]. They have recently gained attention in Power-to-X-to-Power (P2X2P) applications with long-distance transport and long-term storage, i.e., terrestrial transportation and the aviation industry [79]. Some promising LOHC candidates are ethylene glycol, with H₂ storage capability of 6.5% w/w [80], and dimethyl ether as a circular hydrogen carrier with the potential for carbon sequestration [81]. The main advantage of LOHCs is their stability at ambient temperature compared to LH₂, which exhibits H₂ losses due to evaporation under the same conditions. Moreover, LOHC has similar properties to crude oil-based liquids [82]. Therefore, existing crude oil infrastructure can be adapted for LOHC. However, as 43% of hydrogen is lost during LOHC conversion, this storage option still needs to improve its regenerability to recover the stored hydrogen fully [8].

MH is another promising option for hydrogen storage. According to the Fraunhofer Institute [83], metal hydrides offer multiple advantages over CGH₂ or LH₂ technologies, including safety, no boil-off, low operation pressure, performance, and simplicity of use. Magnesium (Mg) and magnesium-based hydrides have drawn attention recently because hydrogen adsorption can be achieved in a one-step reaction process [77]. Besides, Mg is abundant on Earth. Nevertheless, issues like controlling the desorption rate and higher system costs prevent MH from being a feasible option in the short run.

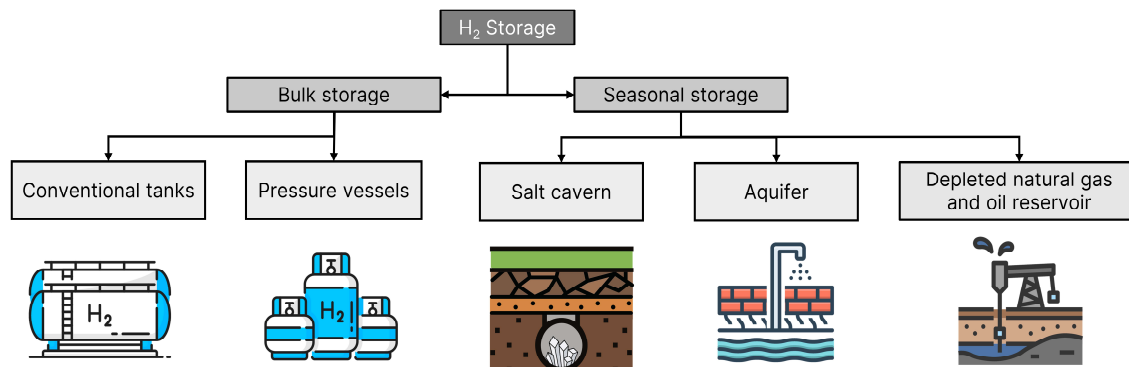


Figure 5. Classification of hydrogen storage according to the time frame for use

Due to RES volatility, green hydrogen faces peak and low production periods. Depending on the intended time frame for hydrogen utilization, its storage can be classified as bulk or seasonal (see *Figure 5*). In the short to medium run, hydrogen is bulk-stored in *pressure vessels* or *conventional tanks* for immediate use. On the other hand, seasonal storage stores hydrogen over time for periods when its production is insufficient to meet demand. Hydrogen demand will most likely increase in the following years because of the current trend toward decarbonization. For example, in 2021, this showed a 5% increase from the previous year, and nearly 94 million tons of hydrogen were demanded [8]. To keep up with this increasing demand, hydrogen surplus from the peak periods can be seasonal-stored as CGH₂ in *salt caverns*, *aquifers*, or *depleted natural gas reservoirs* as a provision for the low periods. This underground storage of larger volumes of hydrogen is a more efficient, low-cost, and flexible method than bulk storage, which otherwise would require a large number of tanks or vessels to store the same volume [18].

Pressure vessels are containers that store gas or liquid at pressures different from ambient conditions. There are four types of pressure vessels for CGH₂ storage (see *Table 7*). Type I vessels are primarily used for industrial applications due to their large storage capacity and cheaper cost. However, these vessels are the heaviest and have the lowest mass storage efficiency (about 1% wt. of H₂ stored) and thus require an ample space for hydrogen storage

[84]. Besides, as it is a pure metallic vessel, it is susceptible to hydrogen embrittlement which increases the risk of failure by burst or gas leak [84]. The target characteristics for hydrogen energy systems are safe storage with high-weight efficiency. For that, research has focused on developing vessels (Types II, III, and IV) with various parts made of different materials, e.g., composite or polymer, to be compatible with high-pressure requirements. The most common materials for the metallic parts are aluminum (6061 or 7060) and carbon or low-alloy steel; for the composite parts are glass, aramid, and carbon fiber; and the polymer parts are mostly polyethylene or polyamide-based [84], [85]. These vessels are essential for large-scale bulk hydrogen storage, so future research should focus on reducing their cost, which is the current drawback to its implementation.

Table 7. Comparison of pressure vessels used for compressed-hydrogen storage [84]–[86]

	<i>Type I</i>		<i>Type II</i>		<i>Type III</i>		<i>Type IV</i>	
Description	Metallic vessel		Thick metal liner partially wrapped with a thin fiber-resin composite vessel		Thin metal liner wrapped with a fiber-resin composite vessel		Polymer liner wrapped with a fiber-resin composite vessel	
Pressure limit (bar)	500		No limitation		450		1000	
Advantages	-	Large storage capacity	-	Lightweight (30 – 40% less of Type I)	-	Lightweight (half of Type II)	-	Prevents hydrogen embrittlement
	-	Not expensive	-	Highest pressure tolerance			-	Allows optimal pressure distribution
							-	Lightest weight
Disadvantages	-	High weight	-	Expensive (twice that of Type I)	-	Expensive (twice that of Type II)	-	Too expensive (approximately 5 times that of Type I)
	-	Poor storage efficiency	-	Hydrogen embrittlement	-	Hydrogen embrittlement		
	-	Hydrogen embrittlement						

As mentioned, LOHC or LH₂ are liquid forms to store hydrogen. Nevertheless, LH₂ is not a stable liquid at ambient conditions as LOHC. Because of this, LH₂ is stored in *insulated* pressure vessels with an external protective jacket to prevent accidents in case of leakage or rupture of the inner vessel [86]. To reduce thermal conductivity and minimize evaporation losses, an insulation multi-layer of materials such as alumina-coated polyester sheets, aluminum foil, glass fiber, silica, or perlite particles is placed between these vessel walls [84], [87]. Cylindrical tanks are used for small LH₂ volume storage, whereas spherical tanks are

more suitable for large-volume applications. Since hydrogen boil-off makes long-term storage of LH_2 challenging, it is best used in [84]. For this purpose, spherical tanks are preferred for their large capacity and lowest boil-off rate (below 0.1% per day) [87]. On the contrary, as LOHC and MH are known compounds, e.g., formic acid, ethylene glycol, and MgH_2 , conventional tanks are used for their storage. It is worth mentioning that some compounds have certain specifications for the tank material to prevent corrosion. Robust materials like carbon or stainless steel are generally used for this constraint.

Since lower electricity prices for flexible operation cannot balance the investment costs for liquefaction, liquid hydrogen does not offer advantages as a seasonal storage medium [88]. Based on this, seasonal hydrogen storage as compressed hydrogen is a viable option. Of the seasonal geological storage formations in *Figure 5*, the salt caverns are considered the future for hydrogen storage [89]. Even though depleted reservoirs have significantly higher capacity than salt caverns, there exists a risk of H_2 contamination with natural gas traces [90]. This scenario will not benefit high-purity hydrogen applications as a purification process would be required before the end-user delivery. On the other hand, aquifers have proven to be a more viable storage option for CH_4 than H_2 , due to hydrogen losses caused by the presence of microorganisms and its significant solubility in water [90]. A more detailed comparison is presented in *Table 8*.

Table 8. Comparison of geological formations for seasonal storage (Adapted from [21])

	<i>Salt cavern</i>	<i>Aquifer</i>	<i>Depleted reservoir</i>
Storage Capacity	Based on cavern size	High	High
Discharge rate	High	Low	Average
Initial cost	High	Average	Average
Cyclic cost	Low	Average	Average
Seismic risk	Low	High	Average
Chemical conversion rate	Low	High	Average
Leakage risks	Low	High	High

Salt caverns are in the capacity range of $1 \times 10^6 \text{ m}^3$ for hydrogen storage, and their optimal storage pressure is between 175 – 200 bar [90]. Hydrogen gas must be purified and compressed before being injected into the cavern. Among its advantages are the sealing rock layers around the salt structures that prevent hydrogen leakage and contamination due to their

impermeability and inert nature [91]. Furthermore, salt caverns offer a more flexible operation with high injection and discharge rates than aquifers or depleted reservoirs [92]. In addition, storing hydrogen in salt caverns can be 1% of the cost of storing the same energy as electricity [93]. The existing caverns in Kiel, Teeside, Clemens Dome, Moss Bluff, and Spindletop (see *Table 9*) have demonstrated for decades that salt caverns are a technically feasible option for hydrogen storage.

Prioritizing green hydrogen to meet the expanding demand would necessitate increased seasonal storage to supply the low-peak RES periods. Since underground storage is demographically limited, finding suitable locations near production or delivery sites is difficult [18]. Based on this, Caglayan et al. [94] assessed the technical potential of subsurface salt structures for hydrogen storage in terms of size, land eligibility, and capacity using the open-source model *Geospatial Land Availability for Energy Systems* developed by Ryberg et al. [95]. Taking Europe as a case study, the estimated hydrogen storage potential was about 84.8 PWh_{H2}, including onshore and offshore locations, with Germany alone having the highest storage potential at 9.4 PWh_{H2}. This evaluation can be complemented by the modeling approach presented by Williams et al. [96], in which the authors assess the feasibility of new salt caverns based on the geological distribution of bedded halite formations. Nevertheless, both studies neglect detailed geological and techno-economic evaluations, crucial in determining salt caverns' overall potential. Future work must address these aspects to prove the technological feasibility at a scale of seasonal storage in general. Porous reservoir rocks, i.e., aquifers and depleted reservoirs, should also be the focus of future research as they would provide hydrogen network support in areas lacking suitable bedded salt resources [96].

Table 9. Characteristics of existing salt caverns for hydrogen storage [97], [98]

	Site				
	<i>Kiel, Germany</i>	<i>Teeside, UK</i>	<i>Clemens Dome, USA</i>	<i>Moss Bluff, USA</i>	<i>Spindletop, USA</i>
Operating since	1971	1972	1983	2007	2014
Operated by	Not reported	Sabir Petroleum	Conoco Phillips	Praxair	Air Liquide
Pressure (bar)	80 – 100	45	70 – 137	55 – 152	68 – 202
Capacity (m ³)	32,000	210,000	580,000	566,000	906,000
H ₂ storage (%)	60	95	95	95	95
Status	Closed	Operating	Operating	Operating	Operating

3.6. Hydrogen Transport

Hydrogen can be transported depending on the quantity and distance through road, pipelines, or maritime [18] (see *Table 10*). Transporting hydrogen as compressed gas is recommended for small volumes and short distances. On the other hand, liquid or solid storage forms are preferred for more significant amounts over longer distances. The reasons for these transport preferences—influenced by hydrogen physical properties and economic factors—were discussed in the previous section.

Table 10. Comparison between hydrogen transport methods [14], [18]

	<i>Tube trailers</i>	<i>Tankers</i>	<i>Pipelines</i>	<i>Maritime</i>
Description	Trailers with staked long gas Type 1 cylinder	Trailers with a single long cylinder	Line of connected pipes	Ships with double-walled vacuum tanks
Transport via	Road	Road	Pipe	Maritime
H ₂ storage form	CGH ₂	LH ₂	CGH ₂	LH ₂
Max Capacity	540 kg/trailer	4000 kg/tanker	8900 kg/h	~10,000,000 kg/ship
Advantages	<ul style="list-style-type: none"> – Technology available – Not expensive 	<ul style="list-style-type: none"> – Technology available – Larger distances than tube-trailers (4000 km) 	<ul style="list-style-type: none"> – Continuous large-scale distribution – Low transport cost 	<ul style="list-style-type: none"> – International transport
Disadvantages	<ul style="list-style-type: none"> – Travel for a short distance (200 to 300 km) – Steel cylinders capacity limitation (1% wt. for H₂ storage) 	<ul style="list-style-type: none"> – High capital and operational costs due to liquefaction requirements – H₂ boil-off 	<ul style="list-style-type: none"> – Lack of H₂ dedicated pipelines 	<ul style="list-style-type: none"> – H₂ boil-off – Lack of development in specialized ships due to low H₂ market

Tube-trailers and tankers are an already established technology for hydrogen transport [18]. One of the disadvantages of tube trailers is the low weight efficiency, which is around 1% wt. for H₂ storage. However, composite-based vessels have been developed to overcome this limitation, increasing the maximum capacity to 900 kg of hydrogen per trailer [99]. On the other hand, the main downsides of tankers are higher capital and operational costs due to

liquefaction requirements that could add around 2-3 \$/kg of H₂ to the final cost [100]. Besides, this type of transport demands careful scheduling to prevent excess H₂ boil-off before delivery to the end-user. Nevertheless, tankers can transport approximately to ten times more hydrogen than tube-trailers [18].

Another option is to transport hydrogen in LOHC or MH. MH can be transported via tube-trailers in specialized containers with up to 7% wt. of H₂ storage. The main advantage of this alternative is that the transport is less hazardous, and the chance of leakage is minor since hydrides require heat to release hydrogen [18]. Nonetheless, one of its disadvantages is its high weight and, thus, high transportation costs [101]. In contrast, LOHC is in tankers with a 6 – 8% wt hydrogen storage density without high pressure or high insulated vessel requirements [18]. However, the additional hydrogenation and dehydrogenation steps continue to render this alternative not cost-competitive. Moreover, approximately 41% of energy available is lost along the LOHCs supply chain, particularly during the dehydrogenation process, where most hydrogen is lost (see *Figure 6*).

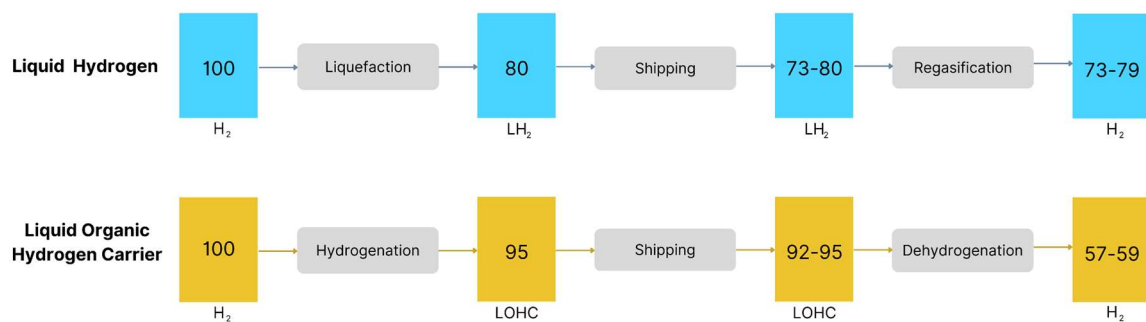


Figure 6. Energy available along the conversion and transport chain in hydrogen equivalent terms

Note. Adapted from *Energy available along the conversion and transport chain in hydrogen equivalent terms, 2030* [Figure], by [8]. CC BY 4.0.

Transport logistics from the production site to seasonal storage areas and ultimately to the delivery site are critical considerations in large-scale hydrogen production. The most promising transport methods are pipelines, which offer a continuous large-scale distribution. Besides, transportation costs would lower because of the long distances and large volumes transported. Transporting hydrogen by pipeline can cost a tenth of what it costs to transport electricity [102]. Moreover, transport costs can be reduced to 1.9 – 2.8 \$/kg with a pipeline scenario instead of to 3.3 \$/kg with the compression-storage-distribution scenario [15]. The

main drawback of this option is the lack of hydrogen-dedicated pipelines, as there is only a 5000-kilometer network connecting Asia, Europe, and North America (compared to the 3-million-kilometer network for natural gas) [102]. This calls for the construction of new infrastructure or the modification of the existing one.

Khan et al. [103] described how to conduct a techno-economic analysis for new hydrogen pipelines, including aspects such as sizing and cost estimation. According to them, a H₂ gas pipeline system consists of transmission and distribution pipelines. *Transmission pipelines* are large pipes that move gas over long distances at high pressures (10 – 120 bar). *Distribution pipelines* are smaller pipes that deliver the gas to the end-consumer at lower pressures (2 – 10 bar). The design, construction, and operation of hydrogen pipelines present more challenges than for other gases or liquids due to the characteristics of hydrogen, which can cause embrittlement and safety concerns [103]. For example, natural gas transmission pipelines are typically made of materials like high-strength steels, which are more prone to hydrogen embrittlement. Besides, H₂ is an odorless gas, so odorization would be necessary to detect leakages easily. Nevertheless, an odorant has not been approved yet for H₂ [103]. Moreover, because of its low volumetric energy density, H₂ volumetric flow rates for a given pipeline are significantly higher than natural gas. Therefore, future research should address these concerns and focus on developing appropriate coatings, inhibitors, and odorants for protecting hydrogen pipelines from corrosion and ensuring safe hydrogen transport.

Pipelines require significant capital investment. Hydrogen pipeline investment costs can be around 110-150% of fossil gas pipelines [102]. For an initial transition period, hydrogen demand is not attractive enough to private investors, so government support might be needed for its construction. An alternative for the short run is blending hydrogen into natural gas pipeline networks. Cerniauskas et al. [104] evaluated this option in a case study in Germany and concluded that pipeline reassignment could save at least 60% on hydrogen delivery costs. Nowadays, it is possible to introduce around 5 – 10% vol. of H₂ into natural gas pipelines in the USA and up to 10% in Germany without significantly affecting end users or the pipeline infrastructure [105]. The main disadvantage of this alternative lies in the necessity to employ on-site separation/purification technology for fulfilling hydrogen quality prerequisites before consumption, which raises both capital and operational costs. Because of this, this is more likely to be used in future Power-to-Gas (P2G) systems to reduce natural gas consumption. For instance, Gu et al. [106] evaluated the product gas quality of H₂ blending in natural gas pipelines using dynamic simulation to optimize H₂ injection while maintaining quality standards for PtG applications like gas turbines.

Another promising transport method is ships. Ships offer international transport of large LH₂ capacities, allowing hydrogen to be delivered to countries with limited renewable energy resources, such as Japan. The main challenge is keeping hydrogen below -253°C to avoid H₂ boil-off during long travel times. In 2019, Kawasaki Heavy Industries developed a 1250 m³ double-walled tank using glass fiber-reinforced plastic for a pilot hydrogen supply chain project between Australia and Japan, proving that LH₂ tanker construction is feasible [107]. Moreover in 2022, an innovative Kawasaki design for a larger vessel (160,000 m³ of LH₂) was approved for construction [108]. The proposed ship design includes dual-fuel engines that can be powered by the boil-off H₂ from its storage tanks, thus, creating a potential for LH₂ as a maritime fuel. However, the time gap between those projects demonstrates that the development of specialized vessels is still limited, mainly due to the current small H₂ market.

Currently, transporting pure hydrogen by ship is expensive and inefficient. An alternative for this is to ship hydrogen indirectly through LOHC. The advantages of this option are supported by LOHC stability at ambient conditions, enabling the repurposing of existing ships for its transportation. This strategy can also be an alternative for an initial H₂ transition. However, once the H₂ market develops and grows, pure hydrogen supply chains are expected to be developed.

4. Hydrogen re-electrification

Hydrogen is an energy carrier that currently allows renewable energy to be stored and distributed. Such an alternative has gained attention as a method to compensate for the volatility of renewables. This concept is denominated *P2H2P*, in which hydrogen produced from renewable sources is converted back into electrical energy instead of being used as a raw material for X applications, i.e., Power-to-Chemicals, Power-to-Gas, Power-to-Food, etc. To utilize the energy stored in the hydrogen molecules, hydrogen is re-electrified in gas turbines or fuel cells. This chapter presents these technologies.

4.1. Gas Turbines

Gas turbines involve three main sections: a compressor, a combustion chamber, and a turbine. The compressor draws and pressurizes air into the combustion chamber, where it mixes with a steady stream of fuel before undergoing combustion. The combustion product is a high-temperature and high-pressure gas stream that expands through the turbine and spins a generator to produce electricity. Most fuels used in gas turbines are fossil-based, i.e., natural gas, propane, butane, syngas, etc.

In the path towards decarbonization, hydrogen as a fuel for gas turbines is promising. This is because gas turbines represent a dispatchable power source that allows a flexible generation

capacity to maintain the power grid stable [9]. In other words, gas turbines can adjust their power output supply to match electricity demand, especially during low periods of renewable energy production. Therefore, gas turbines are more suitable for stationary applications. Besides, using hydrogen for combustion can significantly reduce greenhouse gas emissions [24]. Based on this potential, manufacturing companies like Siemens and General Electric seek to design gas turbines that run only on hydrogen. In fact, in 2020, a consortium led by Siemens Energy implemented the project HYFLEPOWER as the first industrial P2X2P demonstrator with an advanced H₂ gas turbine [9].

Although hydrogen combustion does not contribute to CO₂ emissions, it comes with associated challenges that require attention. Since hydrogen is one-third less dense than methane, three times the volume flow is required to provide the same energy input [109]. This represents a challenge for existing gas turbines that run on methane. If hydrogen is used as the primary fuel to obtain the same power output, compressors must be adapted to operate with greater flow rates. Besides, the flame speed of hydrogen is one order of magnitude faster than methane, 170 cm/s, and 38.3 cm/s, respectively [109]. Gas turbine combustors are designed for a defined range of flame speeds; therefore, current ones may not be suitable for hydrogen-only operation. Furthermore, hydrogen's high flame speed and short auto-ignition delay time increase the possibility of NO_x emissions and could cause flame flashback [24]. Other safety-related challenges include hydrogen having low luminosity flame, is more flammable, and can diffuse through sealings [109]. These concerns require an improvement in the flame detection system, a reinforcement of the sealing system with welded connections, and even a plant layout review to minimize safety risks. Since gas turbines have more than 30 years of life, those built today will most likely still be in operation in the 2050s [9]. Anticipating net zero CO₂ emissions by then [8], current gas turbines, which run on natural gas, will operate on pure hydrogen shortly. Manufacturers should consider the previously mentioned issues in their designs to build equipment ready for the hydrogen transition scenario.

In the short run, green hydrogen cannot be turbines' primary fuel for power generation. Its production remains expensive, costing around 3 to 10 times more than natural gas, which is the currently used fuel for this purpose [109]. Operating with green hydrogen would increase the cost of electricity by the same magnitude, which is not economically competitive. An alternative for the initial transition period is to blend hydrogen with natural gas into gas turbines to reduce CO₂ emissions to a certain extent. In this regard, it is worth mentioning that the key factor in determining emissions for a fuel blend is the relative heat input from the constituents rather than the volumetric contribution [109]. Since gas turbines require a constant heat input and H₂ has the lowest volumetric energy density, a mixture based on a heat input contains

less hydrogen compared to higher energy-density fuels. For example, to reach a 50% reduction in CO₂ emissions, a mix with 77% v/v hydrogen is needed for co-combustion [9], but it represents a blend of 50% hydrogen and 50% methane by heat content. As it was mentioned, this is still not cost-competitive because of green hydrogen's high production costs; therefore, hydrogen could be blended in smaller quantities to have an acceptable economic impact while still reducing the carbon footprint.

4.2. *Fuel cells*

Fuel cells directly convert the chemical energy of hydrogen into electricity, achieving significantly higher efficiencies of 60 – 80% compared to the combustion in gas turbines [110]. The reason is that gas turbines convert the energy stored in hydrogen into mechanical energy and then into electricity. Consequently, the thermodynamic efficiency of hydrogen-based internal combustion engines is around 20-25% [111]. Because of their higher efficiency, fuel cells are the preferred technology since they maximize the potential benefit of hydrogen as an energy carrier.

A fuel cell can be composed of several individual cells, which involve an anode, a cathode, and an electrolyte [112]. A fuel cell system works the opposite of an electrolyzer: hydrogen and oxygen molecules are supplied to the anodes and cathodes, respectively, and water, electricity, and heat are produced in the overall reaction. This process is facilitated by a catalyst layer in the electrodes, usually carbon-supported platinum (Pt/C) [15]. The electrolyte is located between the electrodes, and its main function is to act as a membrane that allows ion exchange. Hydrogen and oxygen do not mix within a fuel cell, unlike gas turbines or internal combustion engines; therefore, combustion does not occur, and CO₂ emissions are not produced [112].

Fuel cell systems are classified according to the electrolyte membrane used (see *Table 11*). Solid-Oxide (SOFC) and Molten carbonate (MCFC) are high-temperature fuel cells with advantages and disadvantages. On the one hand, these fuel cells can handle a variety of fuels in addition to hydrogen [104]. On the other hand, some major significant issues, such as durability and slow start-up, limit their application range. Alkaline (AFC) and Phosphoric acid (PAFC) are liquid membrane fuel cells. AFC has been the most developed technology and is mainly used in space applications [113]. PAFCs are more modern fuel cells typically used for stationary power generation. Both challenges need to be addressed in future studies to leverage these technologies in the energy transition scenario. While AFC has lower costs, it is also sensible to CO₂ in the air, affecting its performance and reducing its life span. On the other hand, PAFC has an increased tolerance for fuel impurities and has proven to be 85%

more efficient when used in electricity and heat co-generation systems [113]; however, they are more expensive since a higher catalyst loading is required.

Proton Exchange Membrane fuel cells (PEMFC) are low-temperature fuel cells that use a solid polymer as an electrolyte. PEMFC has gained attention in recent P2X2P studies [7], [45], [114], [115] for its quick start-up and better durability in stationary applications as compared to the previously mentioned technologies. Another advantage of PEMFC is that they have very high performance and power density for the size of the vehicle engine, making them also appropriate for mobility applications [112]. Direct Methanol fuel cells (DMFC) are a type of PEMFC that use pure methanol as fuel. DMFC are particularly suitable for portable and small-scale applications due to their simplicity and ability to utilize liquid methanol directly, eliminating the need for hydrogen storage [116]. However, DMFCs also face challenges related to methanol crossover and efficiency that must be addressed to fully leverage their potential in various energy transition scenarios [117].

Table 11. Comparison between fuel cell technologies [15], [110], [112], [116]–[119]

	<i>PEMFC</i>	<i>SOFC</i>	<i>AFC</i>	<i>MCFC</i>	<i>PAFC</i>	<i>DMFC</i>
Membrane	Solid polymer electrolyte (Nafion)	Yttria-stabilized zirconia	KOH solution soaked in a porous matrix	A molten mixture of alkali metal carbonates	Phosphoric acid soaked in a porous matrix	Solid polymer electrolyte (Nafion)
Operating temperature	< 120 °C	500 – 1000 °C	< 100 °C	600 – 700 °C	150 – 200 °C	70 – 90 °C
Stack voltage efficiency	50 – 60%	60 – 80%	~60 %	60 – 80%	> 80%	40 - 60%
Typical stack size	< 1 kW – 100 kW	1 kW – 2 MW	1 – 100 kW	300 kW – 3 MW	5 – 400 kW	< 0.2 kW
Fuel	H ₂	H ₂ , CO, CH ₄ , other	H ₂	H ₂ , CO, CH ₄ , other	H ₂	CH ₃ OH
Cell voltage	1.1	0.8 – 1.0	1.0	0.7 – 1.0	1.1	0.6 – 0.9
Advantages	Fast start-up and load following, low temperature, solid electrolyte	High efficiency, solid electrolyte, and fuel flexibility	Most developed technology, fast start-up, lower cost	High efficiency, fuel flexibility	High efficiency with heat co-generation, increased tolerance to fuel impurities	Easier and safer to handle, higher energy density, quick refueling, fast start-up

Disadvantages	Expensive catalyst, sensitivity to fuel impurities	Slow start-up time, issues with cell components breakdown and corrosion	Used mostly for space applications, electrolyte management, CO ₂ sensitivity	Slow start-up time, issues with cell components breakdown and corrosion	Expensive catalyst, slow start-up time	Expensive catalyst, methanol crossover, impurity management
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A single PEMFC can generate a voltage of 1.1 V. The stack voltage can be upgraded by increasing the number of cells in a series configuration, as shown in *Figure 7*. Like the electrolyzers, fuel cell stacks can be connected in parallel to increase the output current. This is important because power requirements are different depending on the application: electric vehicle ranges from 20 to 250 kW, residential applications between 100 W to 1 kW, and stationary applications can be from 100 kW to 2 MW [120]. Thus, a fuel cell system can be designed and configured based on voltage and power requirements.

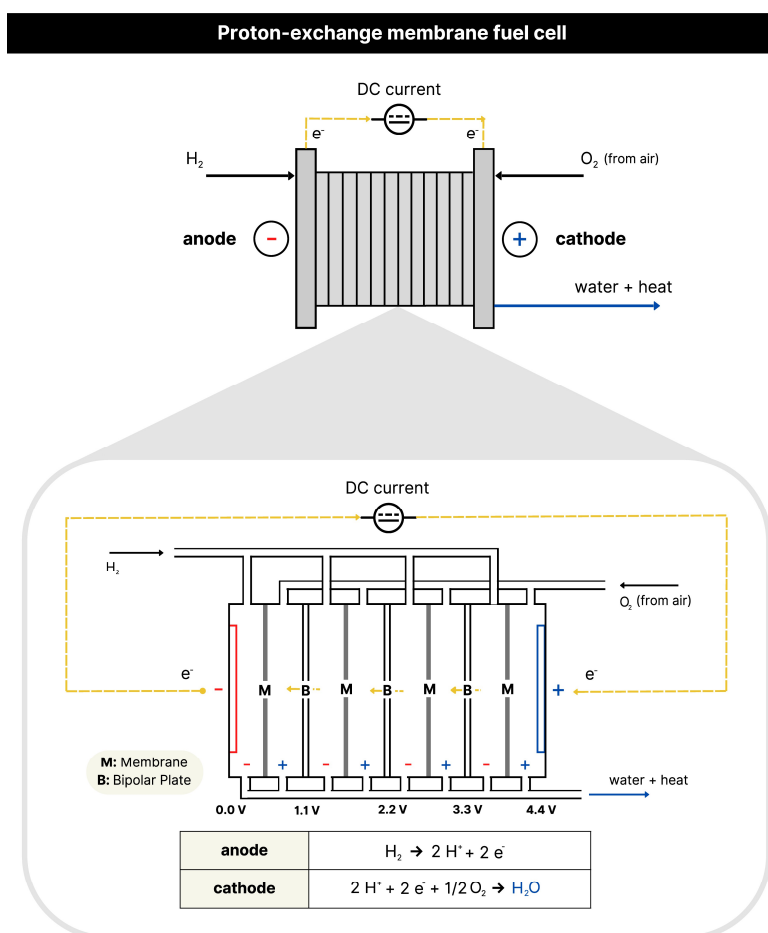


Figure 7. Bipolar configuration of the exemplary design of a proton-exchange membrane fuel cell.

The mobility sector is the primary application of PEMFCs. By 2019, there were over 19000 PEM fuel cell electric vehicles (FCEV) worldwide, of which approximately 8000 were in the U.S. and around 3600 in Japan [121]. By 2022, just in the U.S. and Japan, there were over 21000 FCEVs sold [122], which shows the increasing trend of PEMFC in the mobility sector. Besides lightweight vehicles, PEM fuel cell electric buses are another mobility application that has recently gained attention, especially for use in congested areas where pollution concerns are more critical [121]. Furthermore, buses also provide more space and mechanical protection for the hydrogen tank. Even though FCEVs are more efficient than conventional vehicles (ICEV), the economic aspect still restrains its market share. For example, Winker et al. [123] compared battery electric vehicles (BEV), ICEV, and FCEV by simulating a case study of the food retail sector in Berlin. The study concluded that FCEVs had 22 – 57 % higher costs, mainly from the current cost of hydrogen for refueling, making them a not yet cost-competitive option.

In stationary applications, PEMFCs have found utilization as backup power generation sources connected to the grid. For example, project HAEOLUS proposed a P2H2P system in a remote area in Norway with limited access to the power grid. This project demonstrated the flexible integration of a renewable energy source: a 45 MW wind farm, into the grid with a 100 kW PEMFC. Another stationary application is the co-generation systems for residential purposes. As mentioned, heat is also a product of hydrogen re-electrification in fuel cells. In fact, it represents between 45 – 60% of the total energy stored in hydrogen [124]. This heat has the potential to be repurposed for heating or cooling applications, which would increase the system's overall energy efficiency by up to 95 % [15]. Japan and Europe are the leaders in commercializing micro-cogeneration PEMFC unit installations on homes and small enterprises that provide electricity and heat for services like hot water and room heating.

Even though PEMFC has several advantages, it also presents some disadvantages. These include its sensitivity to fuel impurities and the expensive catalyst required for high loading as it is a low-temperature fuel cell. Besides, the heat generated inside the stack must be effectively removed to maintain its performance and extend its life span [124]. However, some of these have already been addressed. Regarding fuel impurities, the ISO [65] specified the minimum quality requirements of hydrogen as a fuel for vehicular and stationary applications. Based on this, the purification technologies presented in *Section 3.2* were developed or further improved. As for the heat produced in the stack, co-generation, and tri-generation systems were proposed as an opportunity for heat recovery and utilization.

Due to the growing interest in PEMFC, several models have been developed to represent their operational performance. Omran et al. [125] proposed a steady-state model in MATLAB to calculate the output power and efficiency of a PEMFC system with variable load. This model was compared with experimental tests obtaining errors of less than 9%. Ahmadi & Khoshnevisan [126] developed a dynamic model of a FCEV to simulate its performance and conduct a life cycle assessment mainly focusing on fuel cell degradation. Similarly, Maleki Bagherabadi et al. [127] presented a dynamic model of a PEMFC for marine power systems. This model serves as a valuable tool for simulation approaches and design optimization applications. A cost-competitive PEMFC with high performance could be achieved by integrating a techno-economic analysis with these models. For example, Mei et al. [128] performed a multi-objective optimization and thermodynamic analysis of a PEMFC to maximize output power and efficiency while minimizing environmental impacts and costs. This approach facilitates achieving optimal operating conditions for varying current densities and a diverse number of cells.

5. Challenges

The previous chapters provide insights into the characteristics of P2H2P systems based on contributions from academia and industry. There, some limitations were hinted at regarding P2H2P modeling and implementation. This chapter takes an in-depth look at these challenges from the point of view of (i) modeling and simulation limitations, (ii) capital and operating costs, (iii) safety and operating constraints, (iv) environmental impact, and (v) social acceptance.

5.1. Modeling and simulation limitations

Most P2X systems are modeled under steady-state conditions. In these models, the power output and other operating conditions are held constant as if they were a conventional energy system; thus, control and optimization are implemented based on deterministic methods. This results in an overestimation or underestimation of RES-based energy systems, as it overlooks the differences arising from the volatility of RES and operational constraints. Besides, steady-state model simulation is only valid under the specific conditions they were developed. In the case of these systems, these conditions can significantly change in a matter of hours. Therefore, steady-state models should be left only for preliminary analysis.

The number of models for P2X2P systems has increased over the years, but most still assume steady-state conditions, i.e., [7], [44], [45], [129], [130]. A suitable approach to represent the behavior of these systems would be through a dynamic model to manage time-dependent variables like renewable energy supply and demand. For example, Ho et al. [43] proposed a dynamic simulation of a P2H2P system, except that the primary energy source is a nuclear reactor instead of RES. In this case, the P2H2P system worked as a power backup: hydrogen

was produced with PEMEL and stored as a compressed gas in a salt cavern when electrical grid demand was low, and then re-electrified with a Brayton cycle (gas turbine) when the demand was higher than what the main source could supply. Nevertheless, the potential of P2H2P systems is not only to work as a backup for power generation but also to decarbonize other X applications such as ammonia or methanol production, the steel industry, and the mobility sector. For that, variables like energy demand, hydrogen for X-product demand, and even the CO₂ market must be considered, given their inherent unpredictability.

A dynamic supply chain model of a P2H2P system faces several challenges. On the one hand, since this is a more complex model, it increases the computational burden of its simulation. On the other hand, because data often is not accessible or transparent, fluctuations in RES, energy demand, hydrogen demand, and even grid models could not be accurately assessed. This aspect should be addressed explicitly as an integrated dynamic model, which would help evaluate the potential of implementing a P2H2P system. Moreover, a techno-economic, exergy, and environmental impact analysis on such models would allow a more thorough feasibility evaluation, whereas optimization strategies would improve efficiency.

5.2. Levelized costs of green hydrogen

The levelized cost of hydrogen (LCOH) strongly depends on equipment investment and operating costs [131]. In fact, P2H2P projects require significant capital investment. According to a recent report, the CAPEX of an AEL electrolyzer ranges from 500 - 1400 \$/kW, while PEMEL could cost up to twice as much [132]. This is evident in hydrogen production costs of 4.5 – 6.5 \$/kg for PEMEL technology, which is significantly higher than the AEL cost of 3.5 – 5.7 \$/kg [15]. Although electrolyzer costs have decreased by 60% since 2010 [133], capital cost improvements are still needed to make green hydrogen competitive with grey hydrogen.

Both capital and operating costs of the hydrogen supply chain's storage and transport steps impact its final cost. Compression for CGH₂ adds around 1 – 1.5 \$/kg H₂ to the total cost of production, whereas the liquefaction process for LH₂ is between 2 – 3 \$/kg H₂ [102]. In the case of LOHC, it depends on the selected hydrogen carrier. For example, the cost to convert hydrogen into formic acid and then extract it back is approximately 0.03 \$/kg H₂. In contrast, N-Ethyl-Carbazole-dodecahydro-N-ethylcarbazole (NEC-H12-NEC) costs around 43.6 \$/kg H₂ [134]. On the other hand, the investment component is the significant cost in the pipeline scenario. Hydrogen pipeline investment costs can be around 110 - 150% of fossil gas pipelines and about 10 – 25% to repurpose fossil gas pipelines for hydrogen transport [102]. The estimated total investment cost for the 2040 European Hydrogen Backbone ranges between \$87 and \$156 billion, including new pipelines and the reuse of existing natural gas pipelines [135]. If both conversion and transport costs remain high, it will be economically unviable to

transport green hydrogen [102]. This scenario would limit the advancement of the energy transition, as P2H projects would only be pursued in areas characterized by substantial demand.

Similar is the case with fuel cell technology for hydrogen re-electrification. The capital cost of fuel cells remains high and depends on the scale of the application. For example, micro-cogeneration fuel cells of 0.3 – 0.5 kW cost about 10900 \$/kW, medium-size fuel cells of 5 – 400 kW for building installations cost around 8170 \$/kW, while large-scale industrial applications of 0.4 – 30 MW cost between 2180 – 3270 \$/kW [15]. This pricing structure also influences the cost of FCEVs, which can cost 1.5 to 2 times more than ICEVs [136]. Besides, since green hydrogen costs are 2 - 3 times higher than grey hydrogen [133], it would be more expensive to refuel both stationary and mobility applications with green hydrogen. To put it in perspective, electricity from hydrogen costs around 3 to 10 times more than natural gas [109]. Whereas hydrogen as a fuel for mobility was 8.50 – 10.80 \$/kg higher than gasoline in 2021 [137].

According to Agora Industry [131], a comprehensive estimation of LCOH requires incorporating additional aspects such as total energy demand (including auxiliary power), costs for buildings and foundations, and costs for stack degradation and replacement. However, it is imperative for this economic assessment to also encompass variables like the dynamics of electricity generation and demand, considering temporal and spatial resolutions, along with technical constraints inherent to the power grid, electrolyzers, and fuel cells. Several tools address one or multiple of these parameters to undergo this analysis. For example, H2FAST [138] is an open-source Excel spreadsheet that facilitates rapid yet comprehensive financial analysis of hydrogen systems. Additionally, the tool RODeO [139] comprises an open-source script designed as a mixed-integer linear programming model, enabling the exploration of optimal system design and operation for hydrogen energy systems. The main purpose of these tools is to estimate costs, with the LCOH serving as a key performance indicator. However, there remains a need for further enhancement of these models to incorporate a broader array of parameters, thereby enabling a more holistic representation of systems across diverse regions with varying electrical grid configurations and greater model flexibility.

5.3. Safety and operating constraints

Hydrogen is the lightest fuel (2.016 g/mol), has an extremely low boiling point (-253°C at 1 atm), a low volumetric energy density (10.8 MJ/Nm³), a low flammability limit in both air (4%) and oxygen (4%) and a fast flame speed (170 cm/s). Besides, hydrogen dissolves in many metals [61], [140].

Because of these physical properties, there are some challenges regarding the safety of hydrogen supply chain operations. Hydrogen can diffuse through the sealings of compressors, gas turbines, pipelines, storage tanks, etc., which are generally impermeable to other gases. If this leakage exceeds the flammability limit, the risk of an explosion would be imminent. Besides the leaking out, hydrogen dissolution on metals degrades their mechanical properties, a phenomenon known as hydrogen *embrittlement*. Constant contact with hydrogen can cause adverse effects on metals, despite their high strength. In fact, failure due to hydrogen embrittlement always happens at low-stress levels with brittle fractures [141]. These two issues must be considered within the design of P2H2P systems since they can potentially affect plant procedures resulting in economic losses and safety risks.

Other challenges to overcome are associated with operational constraints. For example, due to hydrogen's low volumetric energy density, more volumetric flow would be needed to produce the same power output in gas turbines compared to other fuels. Since gas turbines are designed for a defined capacity of fuel feed, the equivalent hydrogen feed of conventional fuels may not be on the same order of magnitude. This mismatch could result in equipment damage or performance alterations unless suitable adaptations are implemented. Another example is the conversion of the different storage methods. Hydrogen liquefaction is an energy-intensive process, and suitable materials for low-temperature and high-pressure operations would be needed. Similar is the case for most LOHC hydrogenation and dehydrogenation reactions which require high temperatures and pressures [85]. Although LH₂ and LOHC have the potential to be efficient storage methods, their large-scale adoption encounters obstacles due to the existing technology limitations.

To address the safety concerns associated with P2H2P systems, the scientific and industrial community should consider the following:

- Improved Sealing and Monitoring, to prevent hydrogen leakage beyond flammability limits with develop advanced sealing techniques and rigorous monitoring systems (gas/pressure/temperature sensors, hydrogen detection paints or odorants, leak detection solutions, etc.);
- Material Research, to ensure the structural integrity of components by identifying materials that are resistant to hydrogen embrittlement;
- Safety Protocols, to establish comprehensive training and guidelines for working with hydrogen, particularly in high-risk environments;
- Innovative Storage Technologies, to mitigate risks while improving safety and efficiency with the research and development of innovative storage technologies;

- Industry Standards, to develop standardized safety measures and practices for hydrogen-related operations.

By implementing these recommendations, the safety concerns associated with hydrogen supply chain operations can be effectively addressed, promoting the sustainable and secure integration of hydrogen into energy systems.

5.4. Environmental impact

In 2021, the European Commission set a target for the European Union (EU) industrial and mobility sector to consume around 11 million tons of green hydrogen annually from 2030 onwards [1]. Since the EU's current production is approximately 7 million tons of hydrogen annually, mostly grey hydrogen [1], hydrogen production should replace its energy source with renewables and almost double by 2030. This proposal is too ambitious to be realistically scaled up in the mid-future without facing the challenge of running out of resources if not effectively managed. In the case of water, theoretically, 9.012 L is consumed to produce 1 kg of hydrogen, but its consumption can be up to 25% higher [142]. In fact, PEMEL electrolysis and SOEL electrolysis use 18 L and 9.1 L of water per kilogram of hydrogen produced, respectively [143]. Thus, large water sources are required for this energy transition scenario, especially considering the climate change in the upcoming decades with its effect of increasing droughts. Hence, the water availability may further restrict green hydrogen production at electrolyzer locations. Something similar occurs with rare materials mainly used as electrode catalysts in fuel cell systems and electrolyzers. Nowadays, electrolyzers and fuel cells are manufactured in small volumes, but large-scale manufacturing is expected to emerge soon. With this, the consumption of nickel, titanium, palladium, and platinum will exponentially increase. For example, by 2030, around 7% of the total platinum supply will be required for fuel cell use in Europe [15].

Green hydrogen can reduce carbon emissions, which account for most greenhouse gases in the energy transition scenario. Nevertheless, hydrogen is an indirect greenhouse gas that can considerably reduce the benefits of decarbonization [144]. Because the effects of hydrogen on global warming are short-lived compared to other greenhouse gases, its significance is being neglected and underestimated, even though it is a tiny molecule that easily escapes into the atmosphere. In fact, hydrogen leakage from its supply chain ranges from 0.2 to 10% [15]. These emissions can undermine the potential of the hydrogen economy as a climate change mitigation strategy [144].

According to CertifHy, for hydrogen to be categorized as “green”, CO₂ emissions from its production must be 60% less than grey hydrogen production [145]. However, displaced

emissions could occur if the energy utilized for the green hydrogen supply chain is not produced sustainably. For electrolytic hydrogen to emit less CO₂ than grey hydrogen, the electricity powering electrolyzers must have an emission factor below 190 g CO₂/kWh [102]. Nevertheless, the existing grid shares fossil and renewable energies and thus cannot always guarantee minimal emissions. Additionally, transporting and converting hydrogen, particularly into LOHC, can produce more CO₂ emissions [146]. For instance, a diesel-powered trailer transporting CH₂ would produce around 3 kg CO₂/kg H₂ traveling 400 kilometers [147]. In contrast, emissions from a pipeline moving 40 tons per day over 400 kilometers would be 0.1 kg CO₂/kg H₂ [147]. On the other hand, liquid hydrogen reduces the CO₂ contribution per kilogram of hydrogen delivered but is subject to additional emissions during the liquefaction process. These displaced emissions represent a barrier that challenges the scaled-up of the hydrogen supply chain; thus, strategies are needed to minimize the sustainability issues.

5.5. *Social acceptance*

The widespread adoption of P2H2P systems is a key element in the trend toward decarbonization. To accomplish this, the research community, government, and industry have recognized the vital role of societal acceptance in accelerating hydrogen technology deployment [148]. Perceived costs and risks, limited environmental knowledge, and proximity to hydrogen facilities are some of the most influential elements of social acceptance [148] related to the general public's lack of prior knowledge. For example, Schönauer & Glanz [149] analyzed the social acceptance of project ELEGANCE in Germany. Although the results initially confirmed a positive perception of hydrogen, it started to decrease when it came to large-scale infrastructure construction near residential areas, a phenomenon denominated "Not In My Back Yard" (NIMBY). This is because of their negative connotations regarding their safety and environmental effects on large hydrogen infrastructures such as pipelines or salt caverns. According to Emodi et al.'s study [148], more than 60% of the countries considered had low hydrogen awareness and consumers' low willingness to pay for a still-uncompetitive hydrogen price, which may increase the adoption gap for green hydrogen. Thus, public and private policy incentives are needed to increase the diffusion of hydrogen energy technologies and citizen participation in the energy transition [150], especially since stakeholders agree that besides infrastructure availability, affordability, regional skill capability development, and preservation of biodiversity, local community engagement along with safety and disruptive benefits to the community are essential for a thriving hydrogen industry [148].

6. Opportunities

Based on the existing contributions and current challenges, significant opportunities have been recognized to exploit the potential of P2H2P systems in the upcoming years. Making the most of these opportunities would boost the deployment of hydrogen energy systems, an essential aspect of achieving the global transition towards zero-emission economies.

6.1. Cost Efficiency and Innovation

The gradual maturity of hydrogen technology, as well as economies of scale, are significant advantages in making P2H2P systems cost-competitive. Finding innovative solutions and strategies to lead to more efficient processes, reduced expenses, and overall improved economic viability of green hydrogen technologies is imperative.

Research and development (R&D) is a crucial area where cost reduction should be prioritized. Continuous research and development of the green hydrogen technologies presented, along with large-scale infrastructure implementation, can result in lower LCOH and increased technological readiness. One approach is to prioritize research focused on improving electrolysis processes' efficiency, thereby achieving higher hydrogen production rates with lowered energy consumption and, ultimately, lower overall costs. This could involve the investigation of novel catalysts and materials that enhance the efficiency of electrolyzers. Furthermore, researching cost-effective compression and liquefaction technologies is essential for efficient hydrogen storage and transport. Investigating innovative storage materials and methods that reduce losses during storage and distribution can help to cut associated expenses even further. As an alternative, investigate the emerging and promising technologies for storage, such as LOHC, by identifying carriers that strike a balance between cost and performance, optimizing the overall efficiency and cost-effectiveness of the conversion and extraction process. Moreover, R&D efforts should focus on reducing the capital costs of fuel cells across all scales, from micro-cogeneration to large industrial applications. Enhancing the durability and lifespan of fuel cells is equally essential, prolonging their operational life.

Collaboration between academia and industry is vital in designing hydrogen pipelines that ensure safe and efficient transport while minimizing investment costs. Exploring opportunities to repurpose existing natural gas pipelines for hydrogen transport can also significantly reduce the need for entirely new infrastructure, positively impacting costs. Advancements in manufacturing techniques and automation should also be encouraged, as they can potentially drive down production costs significantly.

Another effective strategy for cost reduction and improved competitiveness is fostering hydrogen market growth to achieve economies of scale. The installation of green hydrogen projects is dominated by the cost of the electrolyzer stack itself [151]. AEL stack accounts for

roughly 45% of the total cost at lower manufacturing rates, but at larger rates, it can drop below 30%. In contrast, in the case of PEM electrolyzers, the scale-up would allow a cost reduction of approximately 50% [133]. Furthermore, technological advances such as increasing the active area of the stack or improving LOHC conversion technology can lead to additional cost savings [15], [152]. These strategies would reduce the costs of green hydrogen projects by 40% in the short term and up to 80% in the long term [133]. As a result, hydrogen is expected to cost 1.54 \$/kg, distributed as 0.90 \$/kg for electricity, 0.27 \$/kg for CAPEX, 0.22 \$/kg for water, and 0.14 \$/kg for OPEX by 2030 [151].

In this 2030 scenario, electricity would remain a crucial parameter, accounting for about 60% of the cost of hydrogen. Fossil-based electricity is vulnerable to geopolitical crises, leading to sudden, unpredictable price spikes [153]. For example, the current geopolitical situation involving Russia, the largest exporter of natural gas, has driven up gas prices by more than 300% [151], impacting the price of electricity. As a result, the price of grey hydrogen, produced by steam methane reforming, has increased from its prior value of 1.50 \$/kg H₂ to around 3.30 \$/kg H₂ [151].

The gradual maturity of renewable energy technologies and the expansion and commissioning of power plants with higher generating capacity can lead to lower long-term energy costs and greater price stability [153]. With this, green hydrogen will be cheaper in the near future and thus would be the only choice to return to the 1.50 \$/kg H₂ benchmark.

By focusing on these aspects and actively pursuing innovations and collaborations, the hydrogen sector can work towards reducing the LCOH. These efforts are crucial for achieving the cost-competitive green hydrogen production goal, enabling its integration into energy systems on a larger scale and facilitating the energy transition.

6.2. *Sector coupling*

Recent novel studies have described opportunities to maximize the potential of green hydrogen applications, its technology, and the supply chain. L. Wang et al. [129] and Mukelabai et al. [130] proposed a reversible SOFC for different P2X2P applications. The main advantage is that solid oxide technology uses a unique ceramic material system that allows for a reversible operation. In contrast, PEMEL and AEL require different catalysts or active materials for the fuel cell and electrolyzer mode. Besides, since SOFC can operate with a different range of chemicals, dehydrogenation or purification would not be required for re-electrification. This dual configuration is expected to lower both CAPEX and OPEX of P2X2P systems, improving their cost-competitiveness while guaranteeing efficiency. On the other hand, Tukenmez et al. [47] and Skordoulis et al. [44] proposed multigeneration systems for their P2X (Hydrogen and Ammonia) and Hydrogen-to-Power sections, respectively. When

compared to a single-generation system, this multigeneration design boosted energy efficiency while decreasing carbon emissions, demonstrating to be an opportunity with great potential for future sector coupling between electricity, heat supply, transport, and industry. In this regard, it is worth mentioning that there is an opportunity for the chloralkali industry to produce electricity via fuel cells because there is a considerable amount of hydrogen as a by-product. Verhage et al. [114] and Campanari et al. [115] studied PEMFC power plants fed with by-product hydrogen from the electrolysis of brine in the Netherlands and China, respectively. Although there is still room for this process to improve and reach a certain degree of technological readiness, it has been demonstrated that this by-product can be employed to partially cover utilities like electricity and heat for the chemical plant.

Depleted reservoirs, one of the seasonal storage options mentioned, may not have the same potential as salt caverns due to the risk of hydrogen contamination with natural gas traces. Nevertheless, it is still possible to reuse these reservoirs as the hydrogen from this underground storage can be used for heating purposes [90]. Gu et al. [106] studied the impact of hydrogen injection into natural gas pipelines based on the Wobbe Index and Combustion Potential as two interchangeability indexes. This research opens up the possibility of repurposing natural gas pipelines to transport hydrogen/natural gas mixture from depleted reservoirs without requiring new investment while guaranteeing gas quality for heating applications.

6.3. *Reduction in grid dependency*

The existing grid shares fossil and renewable energies. However, fossil fuels are often the predominant source of electricity generation. For instance, 61% of the electricity generated in the U.S. in 2021 came from coal, natural gas, and petroleum [154]. If this electricity is used in hydrogen production from water electrolysis, the process will rely on fossil fuel resources which is not the aim of the energy transition scenario. Based on this, Bartels et al. [155] analyzed production strategies for a flexible operation of water electrolysis facilities using renewable energy capacity as the main source and the power grid as backup. This approach has the potential to minimize grid consumption and carbon emissions. Compensation schemes and policies are other strategies that would further reduce grid dependence by encouraging both grid operators and consumers to prefer renewable sources over fossil-fuel alternatives. Sánchez et al. [156] proposed an optimal design of the hydrogen supply chain, particularly selecting efficient storage and transport methods. This strategy would facilitate a more effective match of facility demand and renewable supply, thus minimizing the grid backup requirements.

7. Conclusion

Green hydrogen does not produce carbon byproducts, making it a key element in decarbonization strategies for the current energy transition scenario. Many efforts have been made to accelerate the energy transition at a global scale. This paper reviews the most recent developments of P2H2P systems regarding power grid modeling, hydrogen production via water electrolysis, storage, transport, and re-electrification technologies. The potential of different types of electrolyzers and fuel cells is acknowledged, and so is the potential of LOHC for bulk storage and salt caverns for seasonal storage. The current models for P2H2P systems that have been proposed are still unsuitable for simulating their dynamic behavior. In addition, levelized cost for producing green hydrogen, operating and safety constraints, and the absence of a thorough environmental impact assessment continue to limit the social acceptance and widespread use of green hydrogen in large-scale applications. Cost efficiency and innovation, sector coupling, and reduction of grid dependence are opportunities to exploit the potential of P2H2P systems. Together with mature technology and policies encouraging the development of hydrogen energy systems, these prospects would be critical in achieving the global transition to sustainable energy and zero-emission economies.

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