

## Article

# Reliable and Economically Viable Green Hydrogen Infrastructures—Challenges and Applications

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## Abstract

The smart grid concept is based on the full integration of different types of energy sources and intelligent devices. Due to the short- and long-term volatility of these sources, new flexibility measures are necessary to ensure the smart grid operates stably and reliably. One option is to convert renewable energy into hydrogen, especially during periods of generation overcapacity, in order that the hydrogen that is produced can be stored effectively and used “just in time” to stabilize the power system by undergoing a reverse conversion process in gas turbines or fuel cells which then supply power to the network. On the other hand, in order to achieve a sustainable general energy system (GES), it is necessary to replace other forms of fossil energy use, such as that used for heating and other industrial processes. Research indicates that a comprehensive hydrogen supply infrastructure is required. This infrastructure would include electrolyzers, conversion stations, pipelines, storage facilities, and hydrogen gas turbines and/or fuel cell power stations. Some studies in Germany suggest that the existing gas infrastructure could be used for this purpose. Further, nuclear and coal power plants are not considered reserve power plants (as in the German case), and an additional 20–30 GW of generation capacity in H<sub>2</sub>-operated gas turbines and strong H<sub>2</sub> transportation infrastructure will be required over the next 10 years. The novelty of the approach presented in this article lies in the development of a unified modeling framework that enables the simultaneous and coherent representation of both economic and technical aspects of hydrogen production systems which will be used for planning and pre-decision making. From the technical perspective, the model, based on the black box approach, captures the key operational characteristics of hydrogen production, including energy consumption, system efficiency, and operational constraints. In parallel, the economic layer incorporates capital expenditures (CAPEX), operational expenditures (OPEX), and cost-related performance indicators, allowing for a direct linkage between technical operation and economic outcomes. This paper describes the systematic transformation from today’s power system to one that includes a hydrogen economy, with a particular focus on practical experiences and developments, especially in the German energy system. It discusses the components of this new system in depth, focusing on current challenges and applications. Some scaled current applications demonstrate the state of the art in this area, including not only technical requirements (reliability, risks) and possibilities, but also economic aspects (cost, business models, impact factors).



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**Keywords:** hydrogen technologies; hydrogen infrastructure; electrolyzer; hydrogen storage; energy hub; modeling; simulation; business models; H<sub>2</sub> project development; risks; costs; CAPEX; OPEX; H<sub>2</sub> use cases

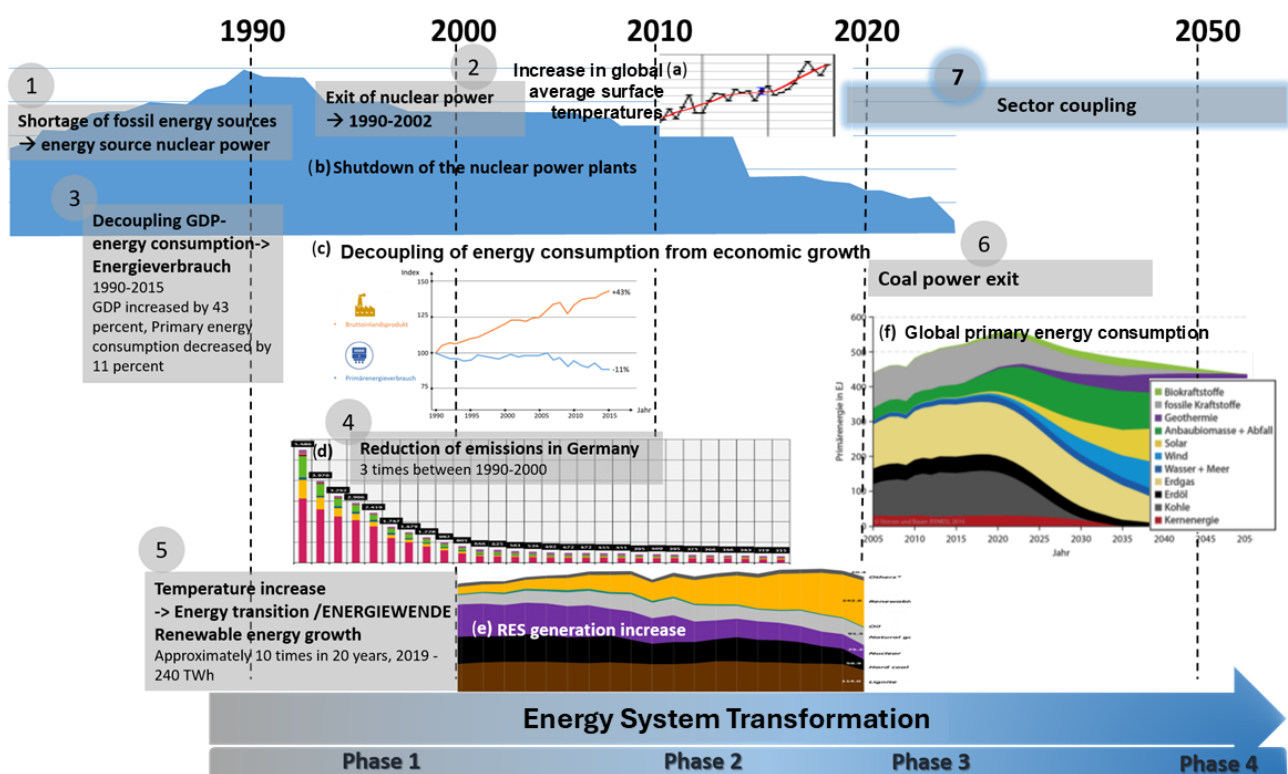
## 1. Introduction

Reducing or avoiding greenhouse gas emissions and the associated limitation of global warming or the so-called climate risk index are some of the most important current goals of the global community. Regarding other considerations and the economic situation, the desire of many countries to be less dependent on their own energy supplies, the limited and geographically constrained availability of fossil fuels, and the globally uncertain and highly dynamic markets and prices, are further increasing the need for energy independence, taking into account the possibilities for the various forms of energy for different applications.

A sustainable and economically viable transformation to a so-called general energy system (GES), considering all usable forms of final energy such as electricity, heat, and gas for different consumer groups such as industry, commerce, households, and transport, is essential and must be viewed as a very long-term process [1].

Various levels of government, including the European Union (EU) and individual countries such as Germany, already have sustainability strategies in place. These strategies outline methods for reducing greenhouse gases and establish different timelines for achieving greenhouse gas neutrality.

The EU, for example, wants to achieve greenhouse gas neutrality by 2045 with its “Green Deal” program. In some federal states in Germany, such as Saxony-Anhalt, there are concrete sub-strategies, such as the hydrogen strategy, for implementing the energy transition, also known as the energy transformation, which is a lengthy process that began in the 20th century and continues to this day (see Figure 1).



**Figure 1.** Energy transition—the path to the sustainable GES of the future [1]. Reproduced with permission from Przemyslaw Komarnicki, Zbigniew Antoni Styczynski, Michael Kranhold, General Energy System (GES) of the Future, Sector Coupling through Electricity and Hydrogen; published by Springer Fachmedien Wiesbaden, 2024.

Generation by renewable energy plants, transport and distribution via the power grids, flexible loads, and storage (stationary and mobile) play a decisive role in the supply of the electrical energy of the future and will continue to be expanded [2–4]. On the other hand,

other sustainable and necessary forms of energy use, such as green heat for households or green gases for industry, are not being developed and integrated into the system in a way that is comparable to renewable electricity generation. In 2024, the shares of renewable energies in the electricity sector in Germany were 54.4%, 18.1% in the heating sector, and 7.2% in the transport sector [5]. This development can certainly be explained by the initial focus on the electricity sector in the 2000s, as well as through the Renewable Energy Sources Act (EEG). Nevertheless, profound energy transformation is also necessary in the household and commercial sectors (especially heating) as well as in industry, including energy-intensive industries such as chemicals and steel (especially as a substitute for gas supplies) [6]. In the future, this will be possible through so-called sector coupling—Phase 3 Measure 7 on Figure 1 of the overall energy transformation from around 2020, which basically produces sustainable, further usable forms of energy such as hydrogen from green electricity through various processes.

Sector coupling, currently one of the most important measures for driving forward the energy transition, particularly in other sectors, is a bundle of technical and organizational measures that will result in the majority of the energy consumed in the future being generated from renewable sources. In order to use this renewable energy (mostly wind or solar energy) effectively, it is first converted into electrical energy in highly efficient plants. Depending on demand, green electricity or products made from green electricity through Power-to-X processes are made available to the sectors that use them [7]. Power-to-X distinguishes between the following areas, which represent a direct link and dependency between renewable energy and all sectors [8]:

- Power-to-Gas: Generation of energy gases from surplus renewable electricity through electrolysis and, if necessary, subsequent methanation (production of renewable natural gas by attaching hydrogen atoms to carbon atoms) as a central coupling element [9].
- Power-to-Heat: Use of surplus electricity in the heating market through the using controllable heating elements in local heat storage systems and district heating systems, or the connection of heat pumps [10].
- Power-to-Chemicals: Use of surplus electricity in industry for the targeted production of basic chemicals for chemical products [11].
- Power-to-Liquids: Process for producing fuels from surplus electricity via electrolysis/hydrogen production to usable basic chemicals (methanol) or fuels from synthetic hydrocarbons (dimethyl ester, kerosene, etc.) [12].
- Power-to-Mobility: Use of surplus electricity to charge electric vehicles, which, in theory, would also enable the battery content to be fed back into the grid [13,14]; alternative use of methane produced from Power-to-Gas processes for CNG and LNG mobility or hydrogen for mobility.

Power-to-Gas technology, which enables green hydrogen production based on renewable energy generation and water, is one of the most important branches, particularly for industry, transport, and private households, in making them more sustainable and less dependent on energy imports. Hydrogen is already an indispensable raw material today and is also necessary as an energy source in various industrial processes. In the future, climate-friendly hydrogen is expected to replace fossil fuels to drive decarbonization forward and, especially for energy-intensive and gas-based industries, it often offers the only way to advance energy transition. In the chemical industry, it is used as a means of producing ammonia (for fertilizers), methanol, and other chemicals, and, in petroleum refineries, it is necessary for use in the “cracking” of hydrocarbons. In steel production, it can already be used as an additive to natural gas in direct iron reduction to produce emission-free steel in the future (complete gas replacement is also relevant for other industries such as copper). In addition, hydrogen enables the provision of high-temperature heat for energy-intensive industries and building heating and can be used

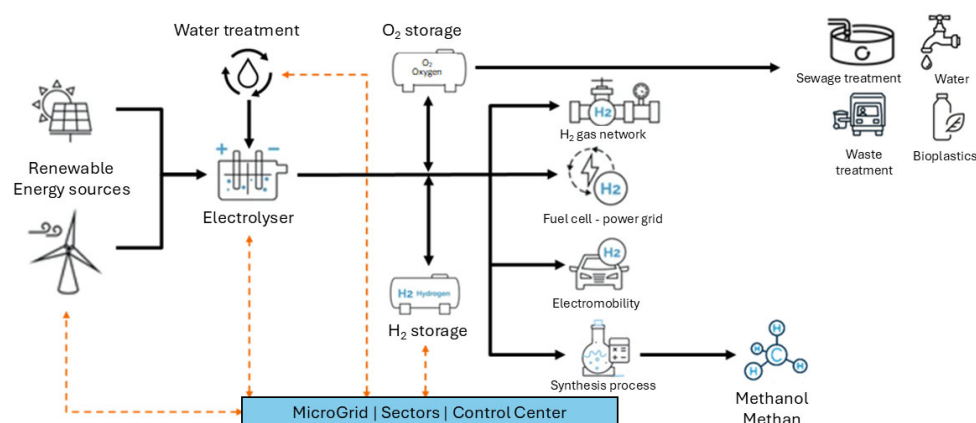
directly in the transport sector as a propellant (hydrogen mobility) [15] or as a substrate for the production of synthetic fuels. Since hydrogen is versatile, it could play a crucial role in the industrial, heating, and transportation sectors in the future (emission reduction), and is generally produced in a relatively costly and complex manner using renewable electricity and water. It is necessary to take a closer look at this challenge from both a technical application perspective (production process, transport and storage, safety and reliability) and economic perspective (costs, profits, business and operating models).

The novelty of the approach presented in this article lies in the development of a unified modeling framework that enables the simultaneous and coherent representation of both economic and technical aspects of hydrogen production systems for planning process and pre-decision making. From the technical perspective, the model captures the key operational characteristics of hydrogen production, including energy consumption, system efficiency, and operational constraints. In parallel, the economic layer incorporates capital expenditures (CAPEX), operational expenditures (OPEX), and cost-related performance indicators, allowing for a direct linkage between technical operation and economic outcomes. This paper describes the systematic transformation from today's power system to one that includes a hydrogen economy, with a particular focus on real-world experiences and developments observed in the German energy system. A key contribution of the proposed methodology is its ability to support a comprehensive assessment of investments, particularly in complex energy systems where hydrogen production is coupled with external infrastructures or stakeholders. By explicitly linking technical parameters with economic variables, the model facilitates the identification and quantification of investment-related risks, such as exposure to electricity price volatility, efficiency degradation, operational uncertainty, and cost overruns. This risk-aware modeling capability allows decision-makers to evaluate not only expected performance but also potential downside scenarios. Therefore, it is possible to satisfactorily assess hydrogen investment planning using simple black box modeling methods.

Section 1 presents the current state of energy transformation. Section 2 describes the elements that are included in hydrogen infrastructure from a technical point of view. Section 3 describes the model used and presents test scenarios for simulation. Section 4 contains a discussion on the development of hydrogen infrastructure. Section 5 summarizes the simulation results.

## 2. Hydrogen Infrastructure—Technical Requirements and Technologies

The hydrogen system can serve as an example of a cross-sector infrastructure (see Figure 2). It encompasses electricity generation, water treatment, hydrogen production facilities, transport, storage, and possible further processing facilities such as a synthesis reactor for methanol production. Due to the different energy conversion processes and the dynamics of the individual technologies and plants (sector-specific and cross-sector), it is very complex [16].

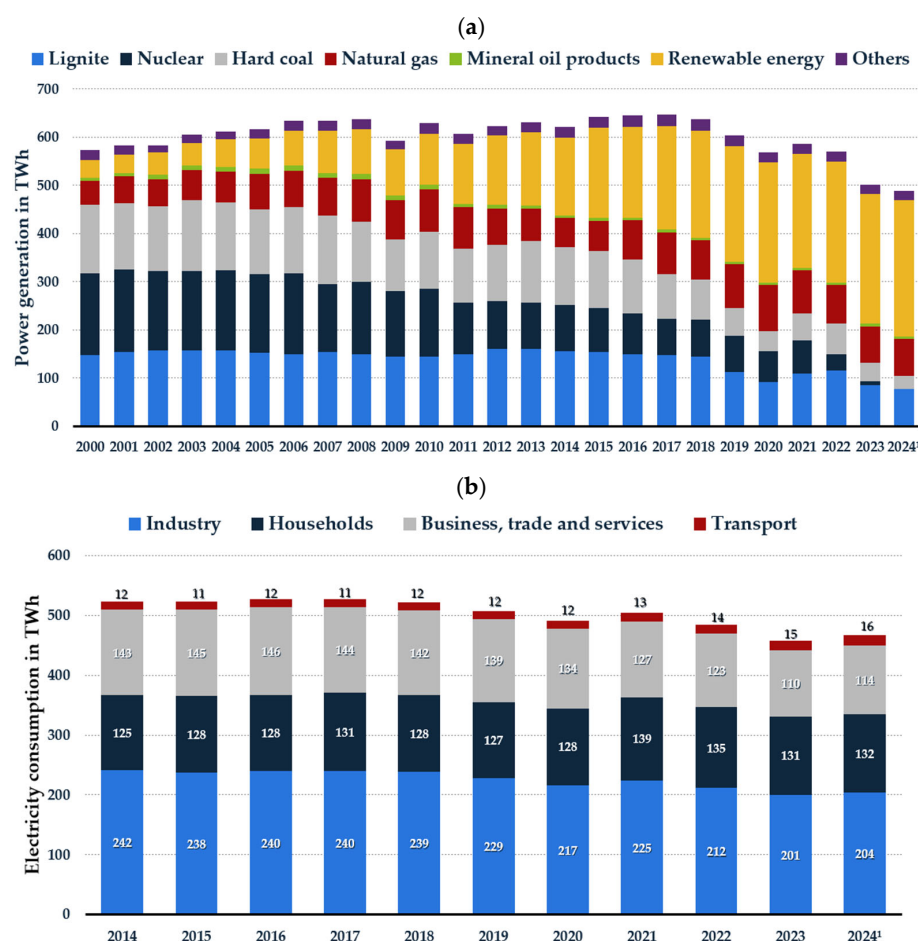


**Figure 2.** Overall hydrogen infrastructure from production to consumption or further processing.

## 2.1. Renewable Electricity Generation

Hydrogen can be produced in various ways: steam reforming, methane pyrolysis, and electrolysis. Detailed manufacturing methods are described in [17–19]. Decentralized and fossil-fuel-independent and sustainable (green) hydrogen production is essentially based on the electrolysis process, in which renewable electricity is used to split treated water.

In order to meet the demand for renewable energies (photovoltaics, wind, biomass, hydropower) for direct use (electricity) or indirect processing (Power-to-X technologies), massive expansion is still required. The EU has set itself the goal of increasing the share of renewable energies to 45% by 2030 and reducing greenhouse gas emissions by 90% compared to 1990 levels by 2040. The expansion of renewable energies has been increasing continuously since 2000, especially photovoltaics and wind (onshore and offshore), although energy consumption is relatively high, which can be explained by increasing device efficiency but also by the number of consumers/devices, as shown by the Figure 3, using Germany as an example. This does not take into account the demand for electrolyze capacity (electricity capacity) and transport (electromobility), which will lead to challenges in meeting demand, depending on time and costs.



**Figure 3.** (a) Gross electricity generation by energy source 2000–2024 in TWh [20] and (b) electricity consumption by consumer group 2014–2024 in TWh in Germany [21]. <sup>1</sup> preliminary.

## 2.2. Water Treatment for Electrolysis

All water electrolyzers operate based on two fundamentally different charge transport mechanisms: Type I conductivity, which corresponds to electronic conduction by electrons, and Type II conductivity, which corresponds to ionic conduction through the electrolyte. The spatial separation of these two transport mechanisms is the core design principle of

every electrolyzer system. Type I conductivity is required in the electronically conducting components of the stack, such as bipolar plates, current collectors, gas diffusion layers, and external circuitry. These components must provide highly conductive and corrosion-resistant pathways for electrons in order to minimize ohmic losses. Type II conductivity, in contrast, is confined to the electrolyte phase, which must selectively conduct ions between the anode and cathode while blocking electron transport and preventing the crossover of hydrogen and oxygen. The concrete realization of Type II conductivity differs significantly between the three main electrolyser technologies. In alkaline electrolyzers, ionic conduction is provided by hydroxide ions ( $\text{OH}^-$ ) migrating through a liquid alkaline electrolyte, typically a concentrated KOH solution, and a porous diaphragm. In proton exchange membrane electrolyzers, protons ( $\text{H}^+$ ) are transported through a dense polymer membrane such as Nafion, which simultaneously serves as electrolyte and gas separator. In solid oxide electrolyzers, oxide ions ( $\text{O}^{2-}$ ) migrate through a ceramic electrolyte, usually yttria-stabilized zirconia, at temperatures above 650 °C. These technology-specific implementations of Type II conductivity impose very different system requirements. The liquid electrolyte in AES requires relatively low current densities and limits dynamic operation, while the dense polymer membrane in PEM enables high current densities, high differential pressures, and excellent load-following capability. In SOEC systems, the ceramic electrolyte demands very high operating temperatures to achieve sufficient ionic conductivity, which enables very high electrical efficiencies but severely limits start-up speed and operational flexibility. In all three technologies, failure to maintain a strict separation between Type I and Type II conductivity leads to critical performance losses. Electronic leakage through the electrolyte would cause internal short-circuiting, while ionic conduction through metallic components would result in parasitic currents and corrosion. Consequently, each electrolyzer technology is fundamentally defined by how it realizes and controls the interaction between electronic and ionic charge transport.

In order to produce green hydrogen, it is necessary to provide not only electricity from renewable energy sources but also suitable water, known as ultrapure water. The treatment of ultrapure water takes place in several stages. Typically, pre-treatment begins in stage 1, e.g., with reverse osmosis in a reverse osmosis plant, with the aim of roughly removing ions, germs, and molecules so that the water treated here has a significantly lower conductivity. In stage 2—fine cleaning—(e.g., deionization or electrodeionization EDI), the pure water is further treated to remove any remaining dissolved salts and ions, resulting in ultrapure water with low conductivity (often below 0.1  $\mu\text{S}/\text{cm}$ ) and very high specific resistance (above 18.2  $\text{M}\Omega/\text{cm}$ ). A final and optional polishing stage with mixed bed resins (mixed bed ion exchangers) may be necessary to achieve the highest degrees of purity and remove the last traces of impurities. Ultrapure water of the highest quality is necessary for an electrolyzer in order to avoid malfunctions, corrosion, and long-term damage (including the service life of the membranes) and is also a prerequisite for stable and efficient operation of the electrolysis [5]. In addition to ultrapure water for the electrolysis process, additional water is required to ensure the cooling of the electrolyzers. It can be noted that, in order to produce 1 kg of hydrogen by electrolysis, between 12 and 30 L of raw water (groundwater, drinking water, seawater) are required (9 to 10 L of ultrapure water as raw material and the need for cooling water and water necessary for the treatment of the raw water), which must certainly be taken into account in the overall assessment of the hydrogen infrastructure.

### 2.3. Electrolyzer

Electrolysis is a process in which water is directly split into hydrogen and oxygen molecules under the influence of an electric current supplied from an external power source. The charge carriers in the electrolysis process are anions and cations. At the negative electrode (cathode), hydrogen is released in a reduction process, while, at the positive electrode (anode),

oxygen is released in an oxidation process. It should be noted that the reactions occurring during electrolysis are the reverse of those occurring in electrochemical fuel cells. Technical devices capable of conducting these reactions in a controlled manner are called electrolyzers.

The current scale of actual hydrogen production and implementation of hydrogen technologies remains insufficient compared to political and market declarations. In conventional electrolysis, more energy is consumed to produce hydrogen than can later be recovered from it. The main barriers to the widespread adoption of this technology are the costs of electrolyzers and the electricity required for the electrolysis process. On average, about 3 kWh of electricity is needed to produce 1 m<sup>3</sup> of hydrogen. Producing 1 kg of hydrogen at 25 °C and atmospheric pressure requires approximately 39 kWh of electricity and around 9–12 L of water (ultrapure water). Operating costs can be reduced by integrating electrolyzers with renewable energy sources. A separate challenge lies in ensuring adequate infrastructure for hydrogen transport and storage.

Several electrolysis technologies have been described in the literature, differing in technical parameters, process efficiency, material requirements, and integration potential with renewable energy sources [22]. The most technologically mature types of electrolyzers include:

- Alkaline electrolyzers (AES),
- Proton exchange membrane electrolyzers (PEM),
- Anion exchange membrane electrolyzers (AEM),
- High-temperature solid oxide electrolyzers (SOEC).

Alkaline electrolysis is currently considered the most mature technology in terms of industrial application. Alkaline electrolyzers use potassium or sodium hydroxide solutions as the electrolyte. Typical operating parameters for AES electrolyzers include a current density of 0.2–0.4 A/cm<sup>2</sup>, an operating temperature range of 60–90 °C, and an energy efficiency of 60–70%. The use of readily available and inexpensive materials in their construction translates into lower investment and operational costs. The average capital cost is estimated at between 400 and 800 €/kW of electrolyzer capacity. These devices are also characterized by high durability, with a service life of up to 90,000 operating hours. The disadvantages of alkaline electrolyzers include relatively slow load dynamics (particularly important when powered by renewable energy sources such as photovoltaic panels and wind turbines), the risk of corrosion and the need for countermeasures, operational limitations at high pressures, and relatively large device dimensions in relation to power output [23,24].

PEM electrolyzers use a solid polymer membrane that exchanges protons as the electrolyte. These devices operate at temperatures between 50 and 80 °C and feature a compact design due to high current densities ranging from 1 to 2 A/cm<sup>2</sup>. PEM electrolyzers are more flexible to load variations (capable of rapid power changes within a short time), making them well suited for integration with renewable energy sources. Another significant advantage is their ability to operate at high pressures (30–70 bar), which reduces the energy required for subsequent hydrogen compression for delivery or storage. However, PEM technology is costly due to the use of expensive materials such as iridium and platinum as electrode catalysts. The production of durable polymer membranes also adds to the cost. Additional operational expenses arise from the need for high-purity water and advanced cooling systems. The estimated service life of PEM electrolyzers ranges from 20,000 to 40,000 operating hours, with a maximum efficiency of up to 75% [25–27].

A key advantage of proton exchange membrane electrolyzers is their ability to achieve electrochemical hydrogen compression directly within the stack, which is not feasible in conventional alkaline electrolyzers. Due to the dense and gas-tight nature of the polymer electrolyte membrane, PEM electrolyzers can operate with high differential pressures between the anode and cathode, enabling hydrogen to be produced at pressures of up to 70 bar without the need for mechanical compressors. This so-called electrochemical compression significantly

reduces balance-of-plant complexity and parasitic energy consumption. In contrast, alkaline electrolyzers employ a porous diaphragm and a liquid electrolyte, which limit the allowable pressure difference across the cell because of increased gas crossover and safety risks. As a result, hydrogen from AEM systems is typically produced at low pressure and requires downstream mechanical compression, leading to additional capital cost and efficiency losses.

AEM technology combines some advantages of alkaline (lower costs due to the use of cheaper catalyst materials) and PEM electrolyzers (compact size, solid polymer membrane electrolyte, capability for high-pressure operation). This technology is still under development. AEM electrolyzers exhibit efficiencies comparable to PEM devices, operating temperatures between 50 and 70 °C, and current densities from 0.5 to 1 A/cm<sup>2</sup>. The clear advantages of anion exchange membrane electrolyzers include less stringent water purity requirements and the absence of the need for noble metals. However, development challenges include achieving sufficient membrane stability and addressing polymer degradation in alkaline, oxygen-rich environments. The expected service life of AEM electrolyzers currently ranges from 2000 to 8000 operating hours [24,28].

High-temperature solid oxide electrolyzers (SOEC) operate at temperatures between 700 and 900 °C, requiring solid ceramic electrolytes. SOEC electrolyzers can reach efficiencies of up to 90% by reducing electrical energy demand through simultaneous hydrogen production and the utilization of residual heat from other industrial processes. An important advantage of operating at such high temperatures is the ability to directly electrolyze steam. However, these high operating temperatures also pose challenges, such as the need for expensive ceramic materials capable of withstanding thermal stress. Additional drawbacks include material durability issues after multiple thermal cycles and the necessity of a stable heat source [27,29,30].

A comparison of the parameters of the discussed water electrolysis technologies is presented in Table 1. It summarizes the information presented in the publications cited above.

**Table 1.** Comparison of parameters of the discussed water electrolysis technologies.

| Technology                              | AES                                   | PEM                              | AEM                             | SOEC                                  |
|-----------------------------------------|---------------------------------------|----------------------------------|---------------------------------|---------------------------------------|
| Electrolyte                             | Liquid solution KOH or NaOH           | Polymer proton exchange membrane | Polymer anion exchange membrane | Ceramic                               |
| Operating temperature [°C]              | 60                                    | 50                               | 50                              | 700–900                               |
| Operating pressure [bar]                | <=30                                  | 30–70                            | <=30                            | <=10                                  |
| Efficiency [%]                          | 60                                    | 70                               | 65                              | 80                                    |
| Current density [A/cm <sup>2</sup> ]    | 0.2–0.4                               | 1                                | 0.5–1                           | 0.3–1                                 |
| Hydrogen production [m <sup>3</sup> /h] | <760                                  | <30                              | ---                             | <760                                  |
| Load response dynamics                  | Slow (s–min)                          | Fast (ms–s)                      | Medium                          | Medium                                |
| Start-up time [min]                     | ~15                                   | <15                              | ---                             | >60                                   |
| CAPEX [€/kW]                            | 400–800                               | 900–1500                         | <700                            | >2000                                 |
| Lifetime [h]                            | 60,000–90,000                         | 20,000–40,000                    | 2000–8000                       | 10,000–20,000                         |
| Noble metals                            | None                                  | Iridium, platinum                | None                            | None                                  |
| TRL                                     | 9                                     | 8–9                              | 6                               | 5–7                                   |
| Applications                            | Industry, hydrogen refueling stations | RES integration, mobility        | RES integration                 | High-temperature industrial processes |

The integration of electrolyzers with renewable energy sources is essential for producing green hydrogen, but it brings a range of challenges and opportunities. Electrolyzers can be designed either for continuous operation at a constant load or for flexible operation, with frequent start-up and shut-down cycles and varying power levels, to match the fluctuating

generation from wind turbines and photovoltaic panels, as such generally depending on defined use case, consumer-side scenarios as well as those based on generation. Suitable technologies for frequent power changes include PEM-type devices and some modern AEM units. Electrolyzers based on AES technology perform better in continuous operation mode, although modified designs have been developed to improve their flexibility.

#### 2.4. Hydrogen Storage

In large industrial plants, the hydrogen produced by the electrolyzer is immediately consumed in on-site technological processes. However, in smaller-scale industry and transport applications, the generated gas must be stored for later use. Moreover, efficient hydrogen storage is essential for balancing the variable output of renewable energy sources (RES) and ensuring the energy security of hydrogen-based systems. Current hydrogen storage technologies can be divided into three main categories: physical, chemical, and geological.

The simplest physical hydrogen storage technology involves compressing the gas and storing it in tanks at pressures ranging from 200 to 700 bar. This solution is suitable for both stationary and mobile applications. Compressed hydrogen storage systems feature a volumetric energy density of about 5 MJ/dm<sup>3</sup> and a gravimetric energy density of approximately 120 MJ/kg. Another physical hydrogen storage method is the storage of hydrogen in liquid form. Such storage offers higher volumetric energy density, reaching approximately 9 MJ/dm<sup>3</sup>. However, the liquefaction process requires energy-intensive cryogenic installations capable of cooling hydrogen to temperatures below −253 °C. For this reason, the technology is economically justified primarily for long-distance hydrogen transport and rocket propulsion. The main disadvantages of physical hydrogen storage technologies include additional costs associated with building and operating compression and liquefaction systems. It is also worth noting that hydrogen stored in liquid or compressed form has a lower energy density than fossil fuels [31–33].

Among chemical hydrogen storage technologies, LOHC (Liquid Organic Hydrogen Carriers) technology involves using liquid compounds, such as toluene, that chemically bind hydrogen through a catalytic process, enabling safe transport and storage in a manner similar to liquid fossil fuels. LOHC technology has great potential for large-scale hydrogen storage; however, hydrogen recovery requires a dehydrogenation process conducted at temperatures of 200–300 °C in the presence of catalysts. This is considered a drawback, as it generates additional costs and reduces overall energy efficiency. Another chemical hydrogen storage method involves hydrogen absorption by metals to form metal hydrides (e.g., MgH<sub>2</sub>). This process is regarded as safe, but the resulting materials are heavy and require temperatures of about 300–400 °C to release the stored hydrogen [34].

The group of geological hydrogen storage methods (including caverns) appears to offer the most promising solutions for the seasonal, large-scale storage of hydrogen. These methods include injecting hydrogen into porous rock formations, depleted natural gas and oil fields, and salt caverns. The latter are considered the safest and most leak-tight option, with available storage capacities reaching up to 5000 tons of hydrogen and losses below 5% per year. Geological storage methods are viewed as a viable approach for the long-term balancing of energy systems; however, their feasibility and economic viability strongly depend on local geological conditions [35,36]. Table 2 summarizes the information presented in the publications cited above.

**Table 2.** Comparison of hydrogen storage methods.

| Technology                           | H <sub>2</sub> compression             | H <sub>2</sub> Liquefaction  | Metal hydride absorption | LOHC                        | Geological storage         |
|--------------------------------------|----------------------------------------|------------------------------|--------------------------|-----------------------------|----------------------------|
| Physical state                       | Gas                                    | Liquid                       | Solid                    | Liquid                      | Gas                        |
| Operating temperature [°C]           | 15                                     | <−253                        | 300–400                  | 200–300                     | Rock temperature           |
| Operating pressure [bar]             | 200–700                                | ~1                           | ~1                       | ~1                          | 10–200                     |
| Energy density [MJ/dm <sup>3</sup> ] | 4                                      | 8                            | 6                        | 7–8                         | ---                        |
| Energy losses [%]                    | 10                                     | 30                           | 10                       | 20                          | <5                         |
| TRL                                  | 9                                      | 8–9                          | 6–8                      | 6–8                         | 8–9                        |
| Applications                         | Transport, hydrogen refueling stations | Transport, rocket propulsion | Stationary storage       | Transport, seasonal storage | Industry, seasonal storage |

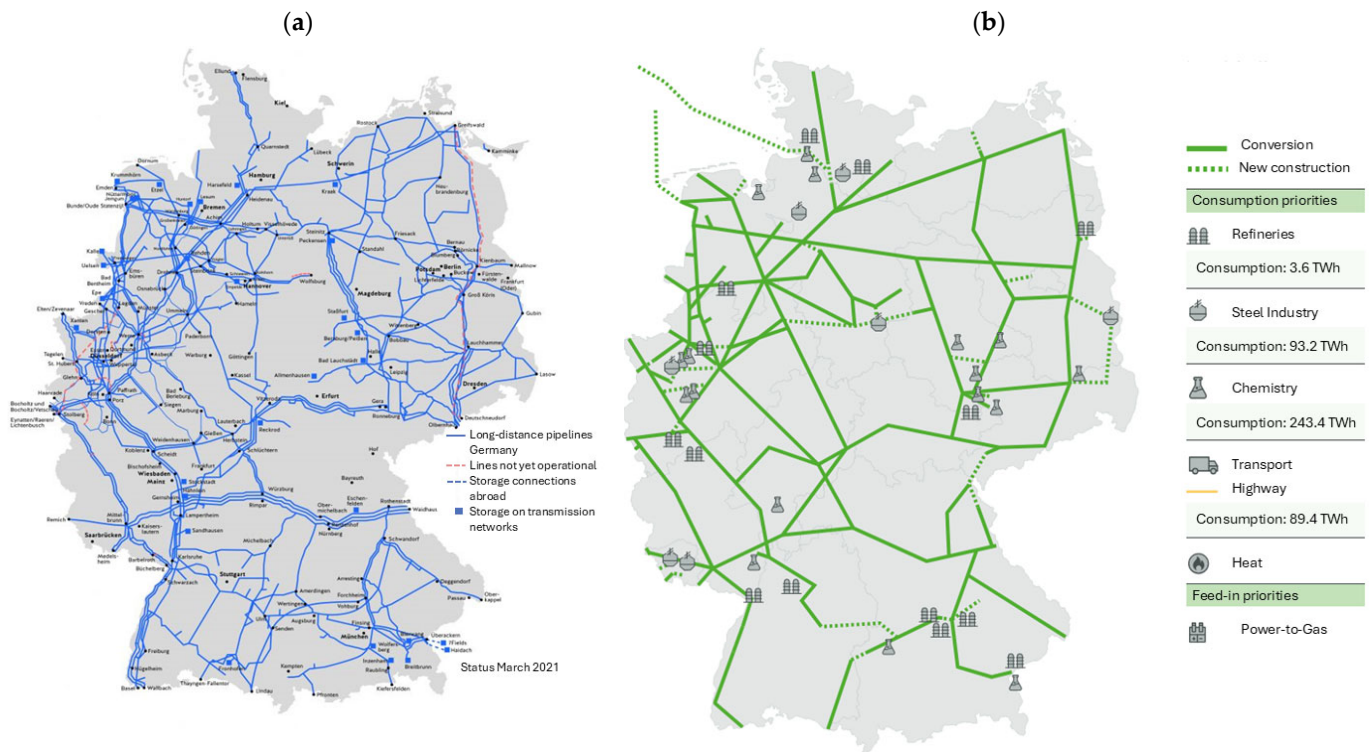
### 2.5. Hydrogen Transport

In future, the hydrogen produced will generally be used at a different location than where it is generated, as electricity-based production from renewable energy sources will be the main source. Either mobile transport systems (low capacity) or hydrogen networks will be used to transport the hydrogen. The existing gas networks can already be used today (adding H<sub>2</sub> to existing networks), converted/adapted (a procedure for converting natural gas networks to hydrogen networks in accordance with the Energy Industry Act EnWG in Germany), or new, dedicated hydrogen networks can be built, which involves considerable costs. Hydrogen transport can be realized through dedicated pipelines, pressurized or liquefied storage containers, or by repurposing existing natural gas infrastructure. The building of new hydrogen pipelines allows for significant reductions in capital expenditure, while requiring targeted investments in retrofitting, material compatibility, safety measures, and regulatory compliance. Figure 4 shows the scale of potential investments based on the current gas network in Germany and planned upgrades to the hydrogen network, taking into account new hydrogen investments.

The example of Germany (transport length 13,300 km, high pressure 124,000 km, total 517,000 km) clearly shows that existing gas network structures are very well developed and suitable for meeting the new challenges of long-distance hydrogen transport at minimal cost (conversion or adaptation) in the future. According to [37], 80% of the gas networks in Germany are fundamentally suitable for hydrogen operation, as 11,000 km of the transport network has already been converted, and the final configuration is expected to have an energy capacity of 504 TWh p.a. and a possible peak consumption of 110 GWh/h. Whether the existing capacities will have to be fully utilized or fully loaded in the future, and whether further expansion/additional construction will be necessary, depends on the expansion scenarios for the overall energy system, as domestic supply for heat provision is becoming less important (e.g., heat pumps instead of gas heating), so that gas connections and, in some cases, gas distribution networks will no longer be needed to the same extent (see Figure 4).

Another alternative for the direct use of hydrogen and feeding hydrogen back into the power grid (e.g., during power peaks or as a blueprint for renewable power generation) is direct combustion using gas engines. There are already many gas engines on the market that can operate efficiently and reliably with different mixtures of natural gas and hydrogen and can serve as a complete replacement for gas engines in the future. Conversion options for existing natural gas CHP plants are also likely to come onto the market as a further

alternative, offering broad and long-term opportunities for a complete switch to green hydrogen operation [38] and thus increasing the sustainability of the overall energy system.



**Figure 4.** (a) Overview of the German gas transmission network and (b) the future hydrogen network in 2050 [1]. Reproduced with permission from Przemyslaw Komarnicki, Zbigniew Antoni Styczynski, Michael Kranhold, General Energy System (GES) of the Future, Sector Coupling through Electricity and Hydrogen; published by Springer Fachmedien Wiesbaden, 2024.

## 2.6. $H_2$ Use and Consumption

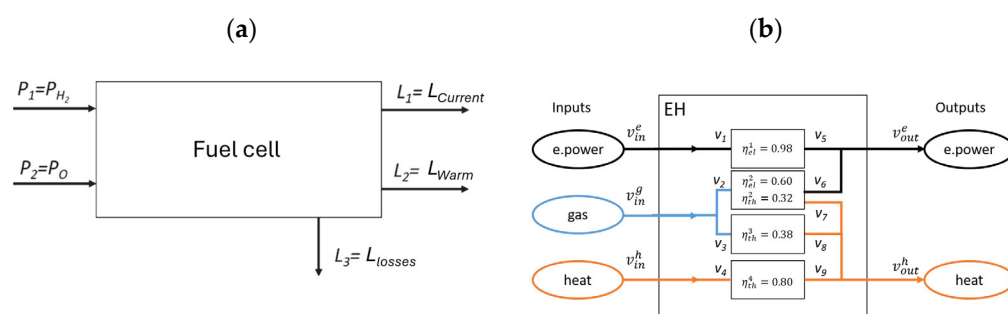
Green hydrogen has a wide range of applications, but, due to its properties (e.g., energy density), its use is concentrated in the power system in industry, as an energy source or substrate for various production processes (material use of hydrogen).

In the power system, hydrogen will be used in the leveling and backup gas turbine for support, balance, and by the deficit of renewable generation [38]. The main industrial sectors are steel, chemicals, and refineries, where green hydrogen is a unique alternative on the path to sustainability and will increasingly serve as a substitute for natural gas (including  $CO_2$  reduction). Other areas of application for  $H_2$  include transportation (fuel cell-powered vehicles), heating (direct firing, reduction of energy conversion stages), and energy (feedback into the power grid). It is expected that there will be an increasing demand for green hydrogen worldwide in the future. In Germany alone, 71 TWh will be needed in 2030 and 504 TWh in 2050 to reliably meet demand, with approximately 42 GW of secured generation having to be imported into Germany [39]. According to [37], the greatest demand in 2050 is expected to be in basic chemicals (approx. 30%) and chemical sites (approx. 18%), closely followed by transportation (approx. 18%) and the steel industry (approx. 16%—replacement of blast furnaces with direct reduction plants (DRI)). The heating sector's demand for green hydrogen in 2050 is estimated at approx. 11% of total demand. Refineries using green hydrogen will play a minor role in 2050, accounting for approx. 0.7% [39].

### 3. System Modeling and Practical Project Development—Technical and Economic Requirements and Potential

This article employs black box modeling, which describes the investigated object solely on the basis of observed input and output data, without analyzing its internal structure, physical mechanisms, or the cause–effect relationships occurring within the system. In this approach, hydrogen production is treated as a “black box” to which input signals (e.g., control variables, external conditions) are applied, and the corresponding output signals (e.g., system responses, measurable quantities) are then considered for steady state situations. Based on the collected input–output data pairs, a mathematical model was developed that represents the relationship between them. An important characteristic of the described black box model is that it does not include any dynamic elements. This means that the model’s output depends exclusively on the current values of the input data, and not on their history, internal states, or time delays. The model therefore has a static nature and does not describe transient phenomena or the time dynamics of the system.

The advantage of this approach lies in the possibility of rapidly obtaining a model even for complex systems, provided that a sufficient amount of data is available. Its limitation, however, is the lack of physical interpretability and the inability to represent the dynamic behavior of the investigated object. The models and associated simulations are used to investigate and verify the properties of the system and its components and interrelationships, and to map their physical and technical characteristics. A fundamental distinction is made between static and dynamic simulations, whereby the aim of dynamic simulations is to verify the control behavior of the system under investigation, i.e., its operation. During the planning phase, static models are used to describe the physical properties of the individual operating resources, the so-called design values, and are then expanded to include economic and financial aspects. Individual models, see Figure 5, are connected as so-called black boxes (simplified/usable or complete models) in overall system structures, even across sectors, as energy hub models, whereby the interfaces, i.e., energy or coupling parameters, play a binding role.



**Figure 5.** Simulation models (a) fuel cell black box and (b) energy hub model examples [8]. Reproduced with permission from Przemyslaw Komarnicki, Zbigniew Antoni Styczynski, Michael Kranhold, Sector Coupling—Energy-Sustainable Economy of the Future, Fundamentals, Model and Planning Example of a General Energy System (GES); published by Springer Fachmedien Wiesbaden, 2023.

The application of the energy hub (EH) modeling method allows the highly complex structures of a multimedia energy conversion system to be represented in the form of a graph. The nodes of the graph represent the conversion processes, while media flows are represented by edges. Graph theory allows the relationships between input and output values (vectors) to be formulated mathematically. The input and output nodes enable the energy hub to be connected to other external structures and/or other energy nodes [8].

The relationship between the external nodes and the internal edges of the energy hub is defined by a node–edge incidence matrix,  $A_i$ . Consequently, the specific rules detailed in Equation (1) govern each individual entry  $A_i(k,l)$  within the matrix:

$$A_i(k,l) = \begin{cases} 1, & \text{Edge is connected to the input of node I} \\ -1, & \text{Edge is connected to the output of node II} \\ 0, & \text{in other cases} \end{cases} \quad (1)$$

The transfer matrix  $H_i$  for a converter at node is determined by its conversion efficiency. In the case of a single-input, single-output converter, the entries of the  $H_i$  matrix are defined according to Equation (2):

$$H_i = |\eta_i^1| \quad (2)$$

Once the incidence matrix and the transmission matrix are defined, the conversion matrix—which characterizes the energy flow relationships among the edges linked to node—can be derived using Equation (3):

$$Z_i = H_i A_i \quad (3)$$

The comprehensive conversion matrix.  $Z$  for an energy hub, consisting of nodes, is formulated as shown in Equation (4):

$$Z = [Z_1^T \dots Z_i^T \dots Z_N^T]^T \quad (4)$$

Additionally, it is necessary to define the input and output incidence matrices  $X$  and  $Y$ , which characterize the energy flows within the EH edges. The specific elements of these matrices are determined by Equations (5) and (6):

$$X(i,j) = \begin{cases} 1, & \text{Edge } j \text{ is connected to the I input port} \\ 0, & \text{in other cases} \end{cases} \quad (5)$$

$$Y(i,j) = \begin{cases} 1, & \text{Edge } j \text{ is connected to the I output port} \\ 0, & \text{in other cases} \end{cases} \quad (6)$$

Thus, the equations for the input and output incidences can be given by Equations (7) and (8):

$$V_{in} = X \cdot V \quad (7)$$

$$V_{out} = Y \cdot V \quad (8)$$

Ultimately, based on the parameters defined above, the comprehensive energy flow equation is formulated as shown in Equation (9):

$$[X^T Y^T Z^T]^T V = [V_{in}^T V_{out}^T 0^T]^T \quad (9)$$

The equations (balances) for the model, shown in Figure 5, are as follows:

- for inputs:

$$v_1 = v_{in}^E \quad (10)$$

$$v_2 + v_3 = v_{in}^G \quad (11)$$

$$v_4 = v_{in}^W \quad (12)$$

- for outputs:

$$v_5 + v_6 = v_{out}^E \quad (13)$$

$$v_7 + v_8 + v_9 = v_{out}^W \quad (14)$$

- for processes of change:

$$v_2 \cdot \eta_{el}^1 - v_5 = 0 \quad (15)$$

$$v_2 \cdot \eta_{el}^2 - v_6 = 0 \quad (16)$$

$$v_2 \cdot \eta_{th}^2 - v_7 = 0 \quad (17)$$

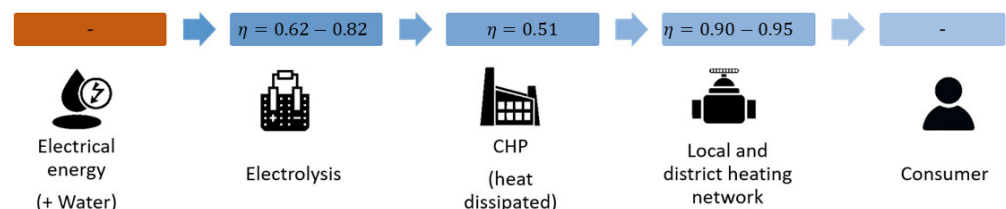
$$v_3 \cdot \eta_{th}^3 - v_8 = 0 \quad (18)$$

$$v_4 \cdot \eta_{th}^4 - v_9 = 0 \quad (19)$$

Consequently, the energy flow relationship established in Equation (9) can be reformulated into the final model representation shown in Equation (20):

$$\begin{bmatrix} 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 1 \\ \eta_{el}^1 & 0 & 0 & 0 & -1 & 0 & 0 & 0 & 0 \\ 0 & \eta_{el}^2 & 0 & 0 & 0 & -1 & 0 & 0 & 0 \\ 0 & \eta_{th}^2 & 0 & 0 & 0 & 0 & -1 & 0 & 0 \\ 0 & 0 & \eta_{th}^3 & 0 & 0 & 0 & 0 & -1 & 0 \\ 0 & 0 & 0 & \eta_{th}^4 & 0 & 0 & 0 & 0 & -1 \end{bmatrix} \begin{bmatrix} v_1 \\ v_2 \\ v_3 \\ v_4 \\ v_5 \\ v_6 \\ v_7 \\ v_8 \\ v_9 \end{bmatrix} = \begin{bmatrix} v_{in}^E \\ v_{in}^G \\ v_{in}^W \\ v_{out}^E \\ v_{out}^W \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \quad (20)$$

Depending on the application, the models can be highly complex, e.g., including replication via differential equations, which also contain Laplace transforms to enable the dynamic behavior of the plants or subsystems. For the planning of plants or, in this case, hydrogen infrastructures, it is sufficient to use static models that represent the individual plants and thus represent the overall system via the coupling point with the aid of, for example, efficiency factors (see Figure 6).



**Figure 6.** Electrolyzer–CHP system representation using efficiency chain [8]. Reproduced with permission from Przemyslaw Komarnicki, Zbigniew Antoni Styczynski, Michael Kranhold, Sector Coupling—Energy-Sustainable Economy of the Future, Fundamentals, Model and Planning Example of a General Energy System (GES); published by Springer Fachmedien Wiesbaden, 2023.

In addition to the technical models that represent the physical properties of the individual plants and the overall infrastructure, their economic properties (in this case, CAPEX and OPEX in particular) are also taken into account in order to derive an overall model of the infrastructure and thus are able to drive project development forward. CAPEX stands for

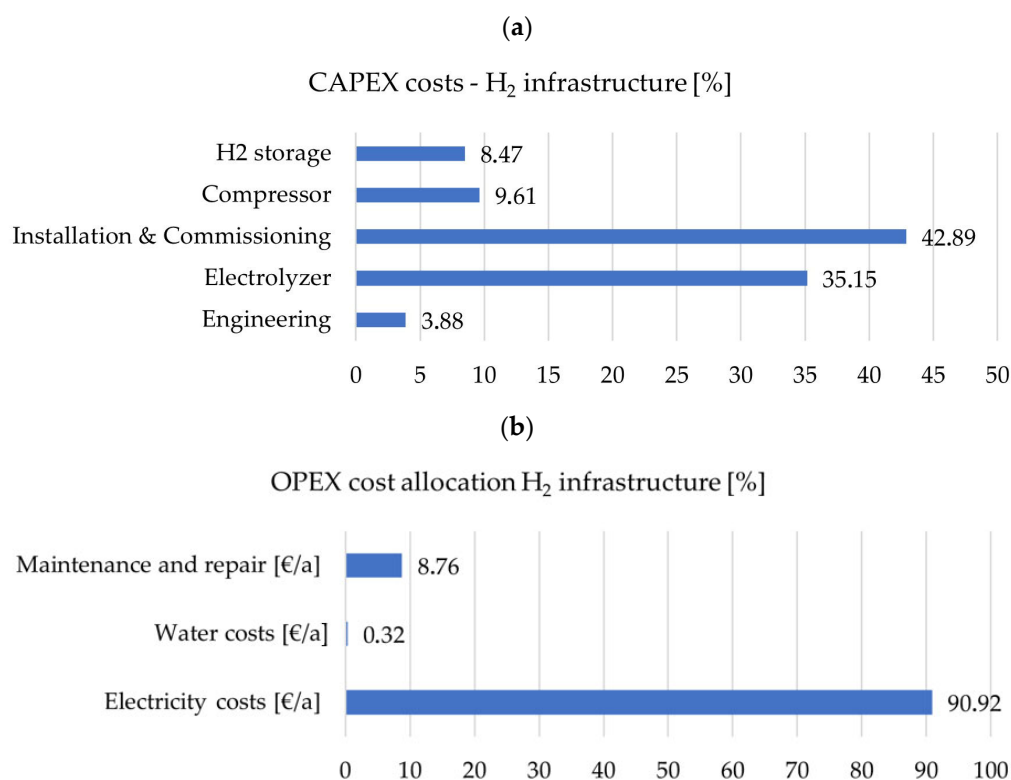
“capital expenditures” and refers to the investments a company makes to acquire, improve, or maintain long-term assets such as buildings, land, machinery, or equipment. CAPEX includes expenditures for physical assets that are necessary for the company’s business activities and are expected to provide benefits over a longer period of time. Investments in assets are usually significant and can affect the company’s financial position, future growth, and profitability. Therefore, they are often carefully planned and evaluated before decisions are made [40]. OPEX, on the other hand, refers to the general operating expenses associated with the day-to-day operations of the company. These include expenses such as rent, salaries, utilities, marketing and sales, office supplies, and other similar costs. These expenses are typically recorded in the company’s income statement and have a direct impact on the company’s profit in a given fiscal year [41].

When developing a hydrogen infrastructure project, all phases of the plant’s life cycle are generally considered, starting with idea development, design and planning, installation and commissioning, as well as operation and management, including maintenance and servicing, where cross-sector characteristics (electricity, water, gas) with a higher degree of complexity are to be expected. Not only technical requirements such as reliability and safety must be considered, but also economic factors, in particular CAPEX and OPEX, i.e., for example, investment, H<sub>2</sub> production, and operating costs for the entire infrastructure.

Technical requirements already play a major role when considering electricity and water sources, i.e., it makes a technical and economic difference whether the electricity comes directly from renewable sources (required area, volatility, energy storage requirements to ensure continuous supply, electrical distance to the electrolyzer, fixed or variable electricity price PPA or direct sales) or the energy supply grid (note electricity mix, significantly higher stability of supply vs. renewable energy sources, possibly higher electricity transmission costs, grid effects, fixed or variable electricity price). These technical requirements regarding the electrical energy supply are reflected in the direct but also indirect costs (direct consumers or a hydrogen storage facility required, what volumes of hydrogen can be purchased when, and what quantities of hydrogen are required). In addition, there are direct technical requirements that may arise from the construction and operation of the electrolyzer on the part of the investor, such as technology (typically AEM or PEM), production efficiency (hydrogen and oxygen production capacity, nominal pressure, operating temperature, e.g., 80 kgH<sub>2</sub>/h, operating temperature 90 +/− 5 degrees Celsius), plant availability (e.g., 97% of the time), hydrogen purity (before and after purification, e.g., 99,995% and depending on further use, e.g., directly in the chemical industry or for mobility, which must first be transported further), electrolyzer power (e.g., 5 MW or 10 MW modules), electrolyzer supply voltage (depending on power and grid, but typically medium voltage 10, 20 kV), cooling system (closed and self-sufficient or open), electrolyzer design (redundant, modular, or singular, pressure stages, e.g., 30 bar/g, and compressors), and operating options (standby, island, load-controlled, emergency operation).

The costs (CAPEX) defined in the idea development, design, and planning phase must be supplemented by initially estimated operating costs (OPEX), take technical and specific requirements into account, and estimate uncertain risks (costs). For a practical hydrogen infrastructure with an electrolyzer (including power –10 MW, production capacities of 800 Nm<sup>3</sup>/h, efficiency of 0.85, plant availability of 8200 h/a and a compressor with a mass flow of 90 kg/h coupled with an H<sub>2</sub> storage tank (capacity 2000 kg)), a cost model was developed taking into account all relevant parameters (including water consumption and costs, electricity consumption and price). Construction, installation, and commissioning play a decisive role in the investment costs (more than 40% of total investment costs), followed by the electrolyzer as the system delivered to the installation site (more than 35% of total investment costs). This cost structure for construction and commissioning is mainly

due to the costs of the engineers and material costs (foundations), which have not yet been optimized, especially for new technologies, but this is expected to happen in the future. The costs of the technology are, on the one hand, the plant costs, which are also not yet widely used systems with long experience in planning and operation, as well as transport and insurance (see Figure 7a). The costs for hydrogen storage and any compressors that may be necessary to achieve higher pressure levels are elements that can vary depending on the application (power supply to the electrolysis plant directly from renewable sources or from the grid, direct H<sub>2</sub> use, e.g., in the chemical industry as a substrate or as an energy source for mobility). Engineering costs of approximately 4% must always be taken into account and should be optimized as experience with the planning, construction, and operation of such infrastructure increases.



**Figure 7.** Cost allocation (CAPEX (a), OPEX (b)) for typical hydrogen infrastructure.

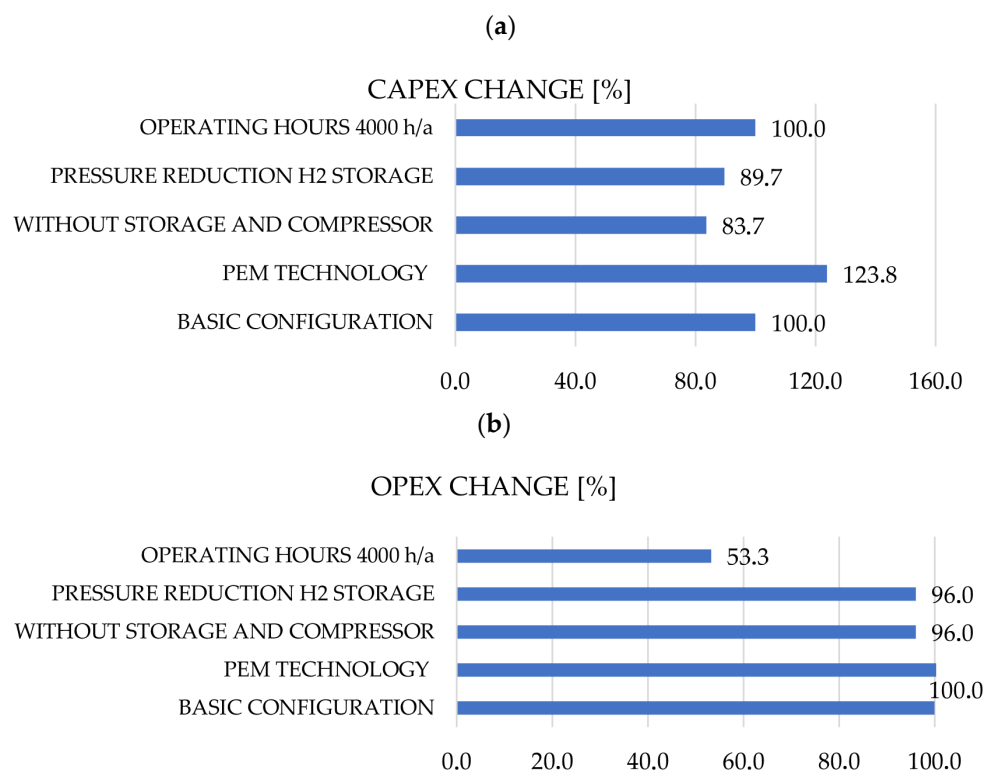
Electricity costs for supplying the electrolyzer play a decisive role (more than 90%) in the operating costs of a hydrogen infrastructure and can vary greatly depending on the supply concept (grid connection, length of the line) and the price of electricity (renewable, grid electricity mix, PPA contracts, exchange purchase). Maintenance and repair costs include, among other things, maintenance of the systems and necessary repair costs (e.g., age-related replacement of membranes) and the hedging of possible risks in connection with guaranteed system availability (guaranteed parameters according to contract), and amount to approximately 9% in the example shown. On the other hand, the costs for water procurement play a minor role (0.3%), but may increase significantly in the future due to various scenarios (water scarcity, climate change) (see Figure 7b).

When planning the hydrogen infrastructure, and in particular the electrolyzer, a technically viable solution must be found that meets the requirements and offers the most economical configuration between CAPEX and OPEX costs. On the one hand, there is the technological possibility of reducing the electrolyzer's power consumption, which could clearly reduce OPEX, but on the other hand, this would increase the CAPEX of the plants due to reduced operating assets. On the other hand, increasing the hydrogen production

capacity (operating hours) of a plant also means rising electricity costs and accelerated plant aging, and thus also the so-called maintenance CAPEX costs.

In the developed model of the overall hydrogen infrastructure, which takes into account both technical plant parameters such as efficiency, pressure stages, temperatures, and others, as well as economic parameters such as investment and operating costs, various scenario changes are calculated in order to investigate the possible influence on the cost structure. Due to the simplified nature of the proposed model, which is intended to enable a rapid and computationally efficient assessment of hydrogen-related investments and planning, several secondary yet technically complex processes were not explicitly represented. These include, in particular, compression efficiency losses associated with hydrogen pressurization (typically ranging from 90% to 98% depending on compressor type and operating pressure), thermal energy recovery and utilization from electrolyzer waste heat, as well as the electricity demand of auxiliary subsystems. Based on the base scenario system configuration (electrolysis capacity 10 MW, production capacity 800 Nm<sup>3</sup>/h electrolyzers efficiency 0.85, plant availability of 8200 h/a and a compressor with a mass flow of 90 kg/h coupled with an H<sub>2</sub> storage tank (capacity 2000 kg, electrolyzer efficiency with respect to the lower heating value (LHV) of hydrogen, corresponding to 33.3 kWh/kg H<sub>2</sub>) see Figure 8, four further scenarios were developed and modeled:

1. Replacement of the AES with PEM technology for the electrolyzer,
2. System without H<sub>2</sub> storage and necessary compressor,
3. Reduction of the pressure stage at the outlet from 700 bar to 350 bar,
4. Reduction of the expected operating hours from 8200 h/a to 4000 h/a.

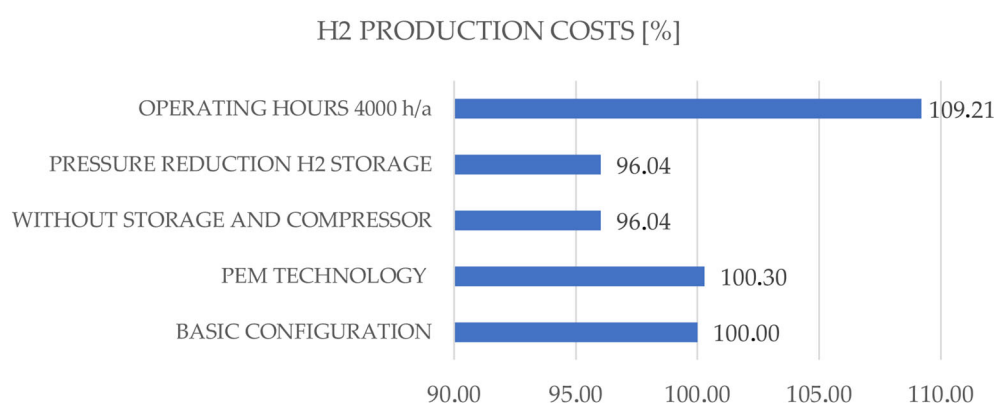


**Figure 8.** (CAPEX (a), OPEX (b)) changes in relation to different scenario configurations.

These scenario extensions correspond to real-world applications (e.g., direct H<sub>2</sub> feed, therefore no H<sub>2</sub> necessary because consumption is very high in relation to production, direct supply of the electrolyzer from renewable energy sources, therefore reduction of operating hours to 4000 h/a) and are evaluated in terms of possible CAPEX and OPEX impact.

It should be noted that the large CAPEX increase of approximately 23% of the total investment is caused by the change in technology from AES to PEM, which in practice is justified by, for example, increased requirements for dynamic operation of the electrolyzer, e.g., direct renewable feed. The largest reduction in total CAPEX investment, approx. 16%, can be achieved by dispensing with the installation of the hydrogen storage tank and associated compressor, which is understandable in terms of plant costs and feasible for certain applications see Figure 8a. Operating costs (OPEX) can be significantly reduced by approximately 47% by halving the operating hours, which is due in particular to lower electricity costs and optimal operation of the systems (fewer cycles and less maintenance) Figure 8b. It should be noted that the optimization of both CAPEX and OPEX costs are interrelated and must always be considered on a case-by-case basis. For example, in the case of PEM electrolyzers, CAPEX costs are generally reduced (e.g., by increasing the life cycle and durability of the plant, which reduces investment costs and, at the same time, operating costs), although there is a tipping point beyond which profits can decline. On the other hand, such complex and cross-sector hydrogen systems (power generation, water treatment, electrolyzer, storage, compressor, peripherals) are developed retrospectively, i.e., the system configuration is defined by end-use requirements (power, time and power gradients, limits, etc.).

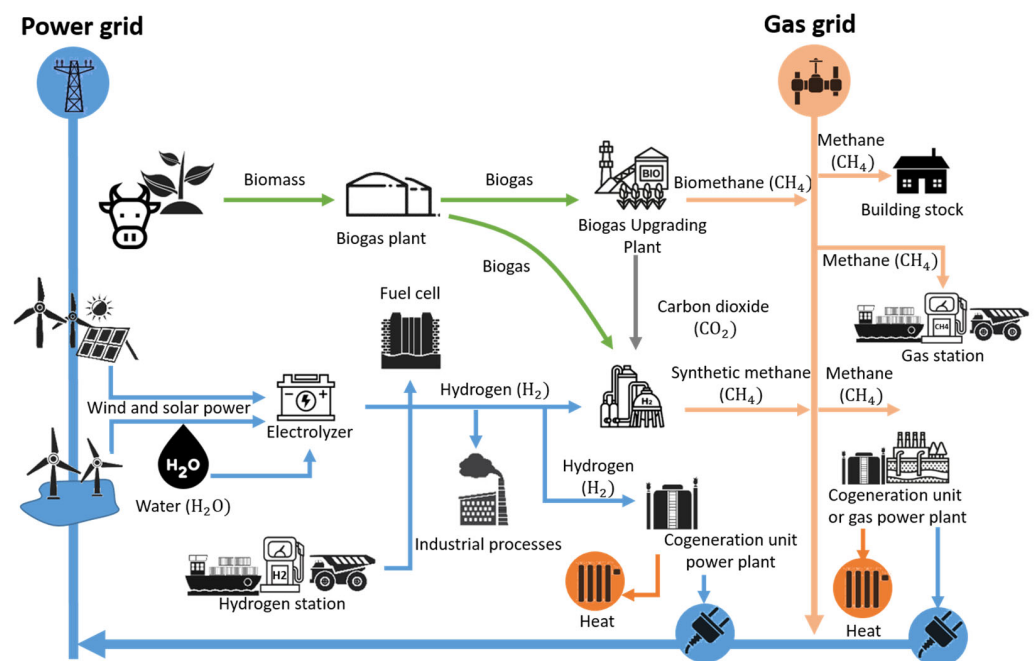
The final commercial and economic assessment of the overall system, including equipment and infrastructure, is reflected in the final price of the green hydrogen produced, so that competitive pricing can be achieved for customers, taking into account technical and environmental requirements (see Figure 9). As can be seen from the illustration, the price difference between different scenarios varies and can be influenced by CAPEX (e.g., without storage and compressor, the production price of 1 kgH<sub>2</sub> is reduced by approx. 4% compared to the base) or OPEX (reduction of operating hours leads to an increase in the price of the production price of 1 kgH<sub>2</sub> by approx. 9%), without taking into account possible transport costs, margins, and taxes. The future number for hydrogen costs to be achieved is 2 €/kg. Today, the cost of producing hydrogen from solar power plants is 6 €/kg and, from wind power, 4 €/kg. Regionally, green hydrogen can already be produced for 2.50 €/kg. For 2050, some scenarios simulated in various studies predict significantly lower costs for green hydrogen of up to 1.26 €/kg [1].



**Figure 9.** H<sub>2</sub> production costs in relation to different system and operating configurations.

The planning, construction, and operation of such complex and relatively new infrastructures, including technologies, involve various technical and subsequent economic direct and indirect risks that can only be considered to a limited extent when drawing up a financing concept. These include, among other things, technology ordering and its delivery and transport route (loading, unloading, mode of transport, and length), including insurance, adherence to deadlines for construction and commissioning, ensuring a neutral

cash flow for such long and cost-intensive investments, continuous optimization of detailed planning, and adaptation to conditions and situations encountered. As can be seen from the case study presented and described for implementation, various technical and economic factors play an important role in developing and implementing an optimal case. In addition, the cross-sector hydrogen infrastructure (electricity, water, gas) offers many potentials, such as electricity storage or supplying other structures with green heat, but also poses various risks (new technologies, complex risk assessment that must be considered across sectors). Furthermore, the future will involve planning, building, and operating individual H<sub>2</sub> infrastructures to create a continuous link beyond system boundaries and establish a hydrogen cycle, thereby exploiting various synergy effects (efficiency, flexibility, reliability) while ensuring technical feasibility and economic viability (see Figure 10). The multifaceted application possibilities of green hydrogen should be taken into account, considering its properties such as energy density and storage, thereby developing an energy cycle economy with a focus on green hydrogen as a hub for the energy transition, which, depending on necessity and thanks to the flexibility of H<sub>2</sub>, allows the reliability of supply to be ensured in all energy sectors (see Figure 10).



**Figure 10.** Hydrogen cycle in the future—overall energy system [8]. Reproduced with permission from Przemyslaw Komarnicki, Zbigniew Antoni Styczynski, Michael Kranhold, Sector Coupling—Energy-Sustainable Economy of the Future, Fundamentals, Model and Planning Example of a General Energy System (GES); published by Springer Fachmedien Wiesbaden, 2023.

## 4. Discussion

Green hydrogen is necessary as a next step for achieving a reliable and sustainable energy transformation, especially in the industrial sector. Furthermore, this new, broad flexibility connected with the use of hydrogen as an inside energy medium is necessary for the stable operation of power grid infrastructure, due to the increasing share of renewable energies. The development, implementation, and operation of complex and partially new infrastructures for green hydrogen, including specific additional facilities such as storage, compressors, and pipelines, depending on the application, is necessary from a technical, regulatory, and economic perspective. A sustainable energy transition for the energy sector and other sectors, such as energy-intensive industries (steel, chemicals), can only be achieved by switching to green hydrogen as the starting product. The universal properties

of hydrogen, such as high energy density, enable better storage than other storage media such as batteries. It is therefore suitable for many applications and sectors, as it can function both as a raw material and energy source and as an energy storage medium. However, it is also clear that the production process for green hydrogen depends on many resources (including electricity and water) and that the conversion chain is associated with losses. This, together with the use of volatile renewable energy sources, means that such hydrogen infrastructures represent a relatively complex and completely new challenge. They have not yet been implemented on a large scale, and the experience and optimization approaches are limited at this stage.

## 5. Conclusions

As shown in this paper, it is apparent that both the technologies (especially electrolyzers, but also storage facilities with a relatively manageable number of current producers) and the business models (CAPEX, OPEX, dynamic electricity prices, volatile energy sources, long-term projects with relatively long payback periods) currently still lead to a lack of planning security. Therefore, the regulatory framework (including hydrogen color and meaning) must be further developed to implement such systems in a scalable and economically viable manner. Nevertheless, a number of demonstration and production pilot plants are currently being built worldwide, especially in Europe, so it can be assumed that this technology, which is critical for sustainability, will become established in the near future.

Future trends include the development of local hydrogen infrastructure on the gigawatt scale. For example, Saxony-Anhalt in Germany is building such infrastructure [42], which will further be a part of the European hydrogen network/infrastructure [39,43].

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**Data Availability Statement:** The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

**Conflicts of Interest:** The author declares no conflicts of interest.

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