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Is Greece Ready for a Hydrogen Energy Transition?—Quantifying Relative Costs in Hard to Abate Industries

Evanthia A. Nanaki [1,2,*], Spyros Kiartzis [1] and George Xydis [2,3]

[1] Department of New Technologies & Alternative Energy Sources, HelleniQ Energy, 8A Chimarras Street, 15125 Maroussi, Greece; skiartzis@helleniq.gr
[2] Department of Business Development and Technology, Aarhus University, Birk Centerpark 15, Innovatorium, 7400 Herning, Denmark; gxydis@gmail.com
[3] Fluid Mechanics and Turbomachinery Laboratory, Department of Mechanical Engineering, University of the Peloponnese, 1 Megalou Alexandrou Str., Koukouli, 26334 Patras, Greece
* Correspondence: enanaki@helleniq.gr

Abstract: During the past few years, hydrogen use has come to be considered as an alternative energy carrier in a future decarbonized world. Many developed nations are undergoing a shift towards low-carbon energy sources, driven by the excessive reliance on fossil fuels and the detrimental effects of climate change. This study aims to investigate the potential for hydrogen deployment in the Greek energy market during the next few decades. In this context, green hydrogen's potential application in the Greek market is being assessed, employing an integrated techno-economic model grounded in worldwide trends and localized expenses. The forthcoming years will see an analysis of both the challenges and opportunities surrounding the integration and implementation of hydrogen in new and existing processes within Greece. Many alternative ways to produce hydrogen in Greece are investigated, contemplating different production paths. We evaluate how fluctuations in hydrogen, oil, and carbon prices affect the economics of green hydrogen adoption in oil refining, as is detailed in the draft of the European Union delegated act published in May 2022. The Levelized Cost of Hydrogen (LCOH) for different scenarios is calculated for the time frame up until 2050. A sensitivity analysis reveals that investment costs, electricity prices, electrolyzer efficiency, and carbon taxes significantly influence the LCOH, ultimately impacting the economic competitiveness of hydrogen production. These findings underscore the importance of aligning public–private partnership agendas in hydrogen production to create optimal conditions for investment attraction and development.

Keywords: green hydrogen; Greece; energy transition; LCOH

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1. Introduction

The adverse effects of climate change, mainly caused by large-scale fossil fuel utilization and consumption [1–3], have forced investigations into clean energy solutions aiming at a sustainable energy transition. Since the Paris Agreement in 2015 [4], many governments have focused their efforts on offsetting greenhouse gas emissions and achieving their decarbonization targets. In this context, the role of renewable fuels in a decarbonized world is of great significance.

Clean stock-based energy carriers such as hydrogen offer a synergistic solution that works with a wide range of applications while lowering costs and emissions throughout the system [5]. The predominant method for producing hydrogen involves steam methane reforming in natural gas (referred to as "grey hydrogen")—representing 80% of hydrogen produced (almost 90 Mt/a)—with significant emissions of carbon dioxide. Reducing these emissions via Carbon Capture Utilization and Storage (CCUS) (so-called "blue hydrogen") is considered as a viable solution [6]. In this direction, the International Energy Agency (IEA) estimates that by 2030, the global hydrogen production is projected to reach 200 million tons per annum (Mt/a), with approximately 70% of it expected to originate from low-carbon

sources [7]. The Hydrogen Strategy Communication places a high priority on advancing renewable hydrogen and establishes incremental targets for capacity installation from 2020 to 2050: at least 6 gigawatts (GW) installed and 1 million tons of production by 2024, 40 GW and 10 million tons of production by 2030, and full commercial scale expected by 2050 [8].

Renewable hydrogen originates from sustainable sources (excluding biomass fuels), and can reduce greenhouse gas (GHG) emissions by 70% in relation to conventional fuels [9]. The Renewable Energy Directive (RED II) provides the same definition of renewable hydrogen; however, RED II projects that by 2030, renewable hydrogen is expected to account for 50% of total hydrogen consumption across both the energy sector and industries utilizing hydrogen as feedstock. In this context, the EU's public consultation on the Delegated Act outlined criteria for defining renewable electricity and established reporting requirements to prevent the utilization of previously subsidized renewable electricity [10–13]. Similarly, on other continents, the trends are the same [14–19].

Greece—following the EU's climate goals—aims to achieve carbon neutrality by 2050 by adopting ambitious climate and energy goals. According to the Greek National Energy and Climate Plan [20], the Renewable Energy Sources (RES) share for 2030 should reach at least 35% of the final gross energy demand; 60% of the final gross electricity demand; 40% of the heating and cooling sector; and 14% of the transport sector. In this context, new applications and technologies for the generation of power from RES, such as the production of hydrogen, will likely be assessed through pilot projects. The NECP considers hydrogen a future solution, although it is currently at a nascent development stage. To be more specific, it is estimated that by 2030, the domestic production of hydrogen from electrolysis will reach 3500 GWh, with a capacity of 750 MW [21]. This will be fueled by RES Renewable Energy projects, generating 3 GW (80% photovoltaic and 20% wind power). It is assumed that the produced green hydrogen will primarily substitute natural gas and partially petroleum in refineries, industry, and transportation sectors.

The oil refinery industry is among the industries that consumes hydrogen as a feedstock. Oil refineries use hydrogen to eliminate impurities, particularly sulfur, and to enhance heavy oil fractions into lighter products. Hydrogen consumption in the oil refining industry is of crucial importance, with almost 40 million tons (Mt) of hydrogen out of the global demand of 90 Mt in 2020 [9]. Almost all hydrogen used in refineries is produced from unabated fossil fuels, resulting in more than 200 Mt CO_2 emitted in 2021. The oil refining industry in Greece is aiming at a holistic transformation, and is fully aligned with the targets set by the European Union regarding the new and cleaner energy forms and the reduction in greenhouse gas emissions.

However, before now, very few studies have addressed hydrogen production in Greece; the present study aims to cover the limited research work in the literature. The majority of studies do not focus on Greece and do not take into consideration specific cost for Greece. In this context, this paper seeks to address this gap by estimating the cost of producing green hydrogen in the oil refinery sector, and to investigate the role of green hydrogen based on Greece's current policy framework. Thus, this paper provides a techno-economic assessment of green hydrogen generation in the oil refinery sector of Greece, under different technology trajectories. The price of green hydrogen produced using different types of electrolyzers and employing different electricity production pathways is estimated for the current year (indicated as 2020), 2030 and 2050. The paper includes five sections. After the Introduction (Section 1), the overview of green hydrogen (Section 2) provides a range of pertinent studies examining green hydrogen production from various perspectives, as well as relative costs and current implementations in the oil refinery industry. The scenario design, the system description, the analysis and the methodologies are outlined in Sections 3 and 4, while the findings are presented and discussed in Section 5.

2. Green Hydrogen Production: Current Trends and Costs

Green hydrogen is regarded as a carbon-neutral solution as it can be produced using sustainable resources such as renewable energy or biogas. When it is generated from

renewable electricity (solar, wind, etc.), in cases when the power production exceeds the demand, it can be employed to enhance grid flexibility and stability. Additionally, it can offer seasonal energy storage capabilities. To be more specific, the Power-to-Gas (PtG) arrangement uses the renewable-based surplus in order to produce hydrogen via water electrolysis. Electricity is utilized to separate water into hydrogen and oxygen; meanwhile, hydrogen can be stored and converted back into electricity or utilized for various energy applications. In this way, renewable hydrogen production or so-called green hydrogen increases grid stability and flexibility [22].

Currently, as per the European Hydrogen Observatory's estimations, hydrogen production costs in Europe for 2022, utilizing grid electricity, averaged 9.85 EUR/kg H_2, whereas hydrogen production costs through electrolysis with a direct connection to a renewable energy source had an average estimated cost of 6.86 EUR/kg [23]. However, the cost of hydrogen production technologies, within the next decade, is estimated to decrease by 50%. To be more specific, by 2030, the costs of renewable hydrogen production could decrease to a range of USD 1.4/kg to 2.3/kg, accelerating in this way green hydrogen investments in certain regions by 2028–2034 [24]. Based on the abovementioned, and given that numerous countries worldwide have formulated national strategies to expedite the development of the green hydrogen value chain, various studies have been carried out, aiming to point out its importance and assess relative production costs. These include the studies of Chu et al. [25], who suggested a plan outlining feasible measures to ensure a strategic supply of hydrogen to the Korean economy; Liu et al. [15], who investigated key factors for hydrogen systems from the Chinese perspective for "green hydrogen standard" initiatives; and AbouSeada and Hatem [16], who threw light on the prospects of green hydrogen production in Africa. Park et al. also studied the Korean green hydrogen sector in depth [26]. Benalcazar and Komorowska [12] examined the possibility of generating green hydrogen across diverse regions in Poland. Zhou et al. [17] indicated that green hydrogen is of fundamental importance for the development of a carbon-free society in China. Aziz et al. [27] explored the prospects and the current state of green hydrogen production in Saudi Arabia. Karavel et al. [28] assessed the potential of green hydrogen production in Turkey using solar energy, and evaluated multiple technologies to demonstrate that investments in hydrogen generation assets should guide future investments in this economic sector. Søgaard-Deakin and Xydis [29] focused on lessons learnt from the Danish production of green hydrogen from clean drinking water via proton membrane electrolysis, while Sorrenti et al. [30] studied the viability of green hydrogen generation and energy islands.

A detailed analysis regarding the recent and future costs of clean hydrogen production is discussed by El-Emam and Ozcan [31]. Janssen et al. [32] summarized the European conditions for hydrogen economy development, providing detailed country-specific cost projections for renewable hydrogen generation with perspectives extending up to 2050 (claiming that relative costs can be below 2 EUR/kg in 2050). Touili et al. [19] suggested that the solar hydrogen potential and the corresponding production costs within the Moroccan territory vary between 6.489 and 8.308 ton/km^2, with costs between 5.79 and 4.64 USD/kg, respectively. The costs of green hydrogen are affected also by the electricity price and the type of power source that supplies the electrolyzers. In 2020, the Levelized Cost of Hydrogen (LCOH) provided by solar photovoltaics (PV) in Europe stood at approximately 7.5 USD/kg H_2. Meanwhile, the LCOH for offshore wind and onshore wind was notably lower, at 4.4 USD/kg H_2 and 4.2 USD/kg H_2, respectively [7]. The evaluation of electrolytic hydrogen production and utilization in Ecuador suggests that hydrogen can be produced at a low cost of USD 3 per kilogram of hydrogen (kgH_2), provided that electrolysis plants operate continuously and utilize low-cost electricity [33]. Apart from the electricity price cost barrier, it has been suggested that CAPEX is of paramount importance to investigate in the production of green hydrogen [34]. The mention of the electricity price cost barrier highlights the potential economic hurdles associated with high electricity prices, which are a vital component in green hydrogen production through methods like electrolysis [35].

On the other hand, the assertion that CAPEX is of paramount importance underscores the crucial role that upfront capital expenditures play in establishing or upgrading the necessary infrastructure for green hydrogen production. Successfully navigating and managing both the electricity cost barrier and CAPEX are pivotal for making green hydrogen economically viable and attractive to potential investors, ensuring its competitiveness in the evolving energy landscape [36].

Another factor influencing the cost of green hydrogen generation is the electrolyzer technology. Electrolyzers represent an electrochemical apparatus employed to split water molecules into hydrogen and oxygen through electrical means. Within an electrolyzer, the conversion of electrical energy into chemical energy occurs, resulting in the production of hydrogen. Comprising two electrodes and an electrolyte, an electrolyzer cell forms the fundamental unit. Multiple cells can be interconnected in series to create a stack, thereby facilitating hydrogen generation. Ancillary components of the electrolyzer encompass the cooling apparatus, systems for hydrogen purification, rectifiers, and provisions for demineralized water supply, among others. The available technologies include Alkaline Electrolyzers (AEs), Proton Exchange Membrane Electrolyzers (PEMEs), and Solid Oxyde Electrolyzers (SOEs). AEs, compared to the other two types of electrolyzers, are advantageous due to market availability, non-reliance on noble metals as constituent materials, extended lifespan, and reduced investment costs [37]. However, they face certain technical constraints, including low operating pressure thresholds and restricted operational current densities (below 400 mA/cm^2), which are linked to the formation of potentially combustible hydrogen and oxygen mixtures diffusing through membranes [38]. SOE is still in the development phase, whereas AE and PEME are considered more matured technologies. It has been estimated that reductions of 33%, 34% and 50% in hydrogen price in Denmark can be achieved by the large-scale utilization of AEs, PEMEs and SOEs, respectively [39]. Despite the fact that the AE is a mature technology, it has the potential to achieve a CAPEX reduction of 27% by 2030 [40]. It needs to be pointed out that there are also membraneless electrolyzers that can be used for low-cost hydrogen production, which the industry has started to embrace and incorporate [41].

2.1. Hydrogen Energy Transition within the Greek Energy Sector

Greece has set an ambitious goal for 2030 and beyond as part of its new National Energy and Climate Plan [20], which targets the installation of 1.7 GW of electrolyzers by 2030 (135,000 tons of green hydrogen production) and 30.6 GW of electrolyzers by 2050, producing 2.3 million tons of green hydrogen. The total consumption of green hydrogen in Greece is expected to reach 63.6 TWh a year by 2050, with 70% of the fuel used in transportation. Natural gas in the Greek system will be mixed with green hydrogen to 5.6% by 2030 and to 15.4% by 2050. Biomethane is also expected to contribute 15.4% and 20.4%, respectively, in order to make gas consumption cleaner. In order to do this, the authorities are planning to enforce a mandatory annual minimum for gas suppliers that will gradually increase. This strategy aims to encourage gas suppliers to adopt cleaner practices and technologies in their operations, thereby reducing the overall environmental impact of gas consumption. By implementing a mandatory minimum standard, authorities not only set clear expectations for suppliers, but also pave the way for a progressive shift towards cleaner energy solutions, contributing to a more sustainable and eco-friendly gas industry [42].

Greece's approach to the development of hydrogen energy comprises: hydrogen production from renewable electricity; hydrogen use for the decarbonization of the transport sector (mainly shipping); long-term hydrogen storage for power generation; the use of existing gas infrastructure for hydrogen transport, and the stimulation of hydrogen-related R&D. The Greek industry sector has a significant potential for hydrogen use in industry, given that the ammonia industry and refineries both use fossil-derived hydrogen [43].

To be more specific, oil refineries undertake numerous industrial processes to convert crude oils into various products. Among these, hydro-processing covers a range of

catalytic processes, including hydrotreating and hydrocracking for the removal of sulfur (hydro-desulfurisation (HDS)), oxygen, nitrogen and metals. During the hydrocracking process, heavy gas oils undergo simultaneous cracking and hydrogenation, resulting in the production of refined fuels with reduced molecular sizes and higher hydrogen-to-carbon ratios. This process yields significant quantities of diesel and kerosene. In hydro-treating, hydrogen is employed to hydrogenate sulfur and nitrogen compounds, ultimately removing them as hydrogen sulfide (H_2S) and ammonia (NH_3). Taking into consideration the fact that refinery product specifications have become stricter in order to meet environmental requirements, the demand for hydrogen to supply hydroprocessing units continuously increases [44]. Regarding hydrogen supply within the refinery, it is facilitated through the hydrogen generation unit (HGU), where hydrogen is generated through the steam reforming of natural gas (NG), naphtha, liquefied petroleum gas (LPG), or through the partial oxidation (POx) process. Alternatively, hydrogen can be sourced from merchant gas producers and transported to the refinery via pipelines. The quantity required for the aforementioned processes in refineries typically varies based on the crude oil quality and the extent of impurities that need to be eliminated.

2.2. Green Hydrogen and Applications in Refineries

Recently, there has been a surge of interest in the planning and implementation of electrolytic hydrogen and carbon capture projects in refineries across Europe. For instance, in Germany, BP [45] plans to supply 20% of the Lingen refinery's hydrogen demand with electrolytic hydrogen. The renewable electricity required for electrolysis will be generated by an offshore wind farm in the North Sea, with operations scheduled to commence by 2024. In Germany, the REFHYNE project involves a partnership between Shell and four other companies. Together, they are constructing a 10 MW Polymer Electrolyte Membrane (PEM) electrolyzer to produce hydrogen for a refinery and offer ancillary services to the German Transmission System Operators. The project will also monitor the conditions under which the electrolyzer business models become viable, in order to establish a base for the justification of changes in existing policies [46]. Shell also established, in 2020, the NortH2 project (located in the north side of the Netherlands), aimed at constructing large-scale wind farms in the North Sea (aiming to reach 10 GW by 2040). The initial turbines are expected to be operational by 2027 and will be dedicated to producing renewable hydrogen primarily aimed at meeting the demands of the industrial sector [47]. HySynergy is another interesting project, where Everfuel and Shell established a partnership in Frederica, Denmark, in order to build a GW-rated P2X plant with a 10-metric-tonhydrogen storage facility [48]. Another showcase is the MultiPLHY project, set at Neste's renewable products refinery in Rotterdam, which also relies on SOEC technology [49]. The objective of this project was to install, integrate, and operate a high-temperature electrolyzer (HTE) system on a multi-megawatt scale (approximately 2.4 MW) at a biofuels refinery in Rotterdam, Netherlands. The purpose was to produce hydrogen ($\geq$60 kg/h) for the refinery's processes.

Despite the great interest in green hydrogen applications in refineries, few studies have previously assessed their use in oil refineries. More specifically, there is no previous study, to our knowledge, that assesses green hydrogen production in the Greek oil market. This study developed feasible hydrogen scenarios for the Greek oil industry to address this research gap. The current study takes into consideration the energy needs of Greece and the European Green Deal, and tries to shed light on the following question: "Can Greece meet the 2030–2050 European green deal targets?". In this direction, different hydrogen production scenarios in an energy-intensive industry sector in Greece (oil refinery) are being evaluated, in order to select the best technology that will accelerate the energy transition while safeguarding the economic and technical sustainability of relative investments.

3. Scenario Design and Methodology

As regards scenario designs, these were developed taking into consideration various techno-economic parameters such as CAPEX, OPEX, costs of PPA contracts, H_2 production,

commodities prices, types of electrolyzer etc. Scenario design is focused on the comparison of the integration of different systems in terms of efficiencies and investment costs, the use of PV energy surplus, as well as CO_2 emissions and CO_2 emissions avoided. Figure 1 illustrates the configuration of the system under study.

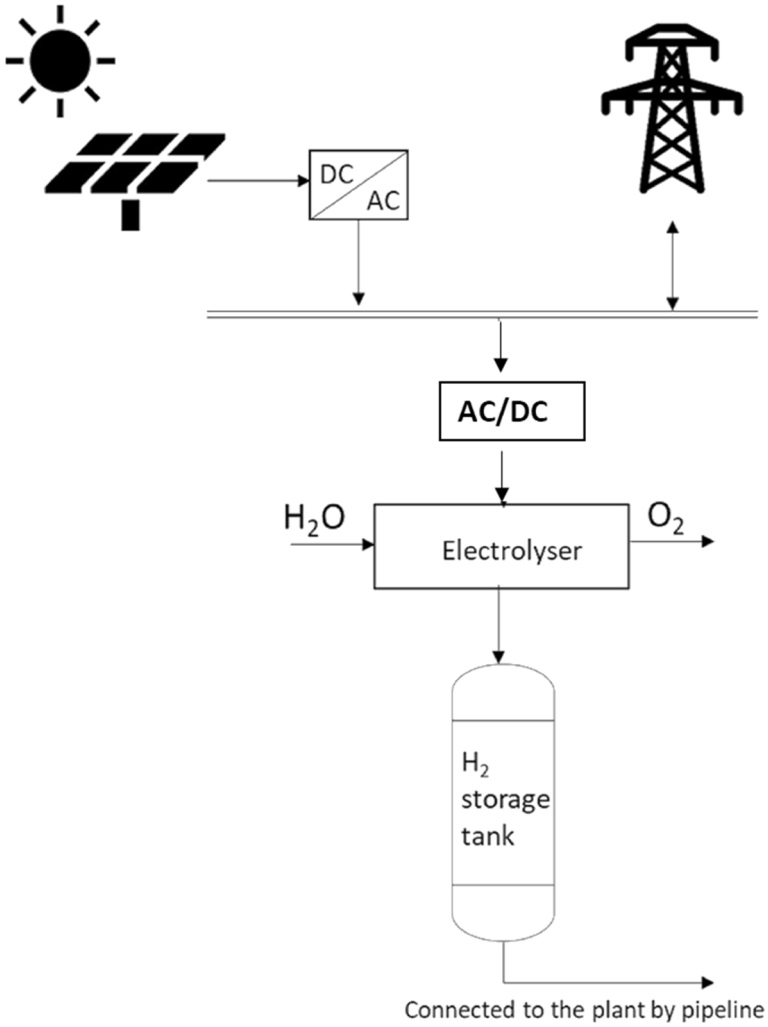


Figure 1. Configuration of the system under study.

Grey—Business as Usual Scenario (BAU)

This scenario is built on the conventional hydrogen production system (representing the current situation), using a steam methane reformer (SMR) with Pressure Swing Adsorption (PSA) purification to obtain 2000 Nm^3/day of 99.9% pure hydrogen in an oil refinery. The annual hydrogen production is 100,000 tn/year. This scenario is used as the base to compare to other scenarios.

Blue—Carbon Capture Storage (CCS) Scenario for Existing Steam Methane Reformer

In this scenario, the hydrogen generation unit operates with low CO_2 emissions. It is based on the Business-As-Usual (BAU) scenario; however, in this case, a carbon capture facility is integrated into the Steam Methane Reforming (SMR) unit. A CO_2 capture facility is installed at the exit of the reformer, capturing approximately 50% of the CO_2 produced during SMR. The primary CO_2 capture method employed for steam reforming is captured post-combustion through chemical absorption using an amine-based solvent [50]. The SMR unit runs on natural gas, and the share of captured CO_2 reaches 60%.

Green—PV Power Purchase Agreement (PPA) Scenario

In this scenario the refinery invests in a solar power plant in an area near the refinery's premises. The power requirements for the operation of the electrolyzer system are covered by a dedicated-grid connected solar PV plant. The individual module for the PV plant has a peak power of 50 W, utilizing a mono-crystalline unit (Model 1Soltech 1STH-240-WH, Anodized Aluminum Alloy, 1Soltech, Farmers Branch, TX, USA) with both azimuthal and tilt angles fixed at 158°.

During the daytime, the PV plant supplies a portion of the electricity generated by it to power the operation of the electrolyzer unit, while the excess electricity is fed back into the grid. During nighttime hours, when electricity is needed for the electrolyzer system, stored green electricity is drawn from the grid. The hydrogen produced is stored in a hydrogen storage tank connected to the refinery via a pipeline (Figure 1).

Power Purchase Agreements are long-term contracts between producers (or developers of electricity production projects) and buyers of energy (typically called off-takers). During the agreement period, the producer is liable for all costs that revolve around energy generation, and the buyers procure energy at a specified rate (fixed or indexed). PPA terms usually range between 5 and 20 years. Green PPAs are agreements where the energy is produced by an RES asset (dispatchable or not). The off-taker disengages almost completely from fluctuating prices for energy, which depend heavily on prices of CO_2 emission allowances and Natural Gas prices (the standard fuel for electricity generation in the post-lignite era) [51]. In this scenario, in order to power the electrolyzer system, PPAs on utility-scale PV are secured. The generated energy is transmitted through the electricity grid. Surplus electricity can be sold on the spot market (day-ahead auction). Since the hydrogen is going to decarbonize the refinery process, only green hydrogen (according to RED 2) will be produced. This can be secured through PPAs that fulfill the additionality, simultaneity and locality criteria, or through an electricity network with more than 90% renewable energies. The total solar radiation on the tilted PV surface is estimated as 1600 h, representing the system's electricity production over a year. The PPA cost based on the abovementioned and Greece's regulatory framework is considered as 200 EUR/MWh (Day Ahead/PPA).

A techno-economic analysis is performed, aiming to evaluate the Levelized Cost of Hydrogen (LCOH) for the abovementioned scenarios (grey, blue and green hydrogen production). The scenarios evaluated refer to the current decade (2020), the NECP target year (2030), as well as the long-term target year for carbon neutrality (2050).

The production costs include: CAPEX (capital expenditure) and OPEX (operating expenditure). The generation costs are assessed for three electrolyzer technologies: Alkaline Water Electrolysis (ALK), Polymer Electrolyte Membrane (PEM), and Solid Oxide Electrolyzer Cell (SOEC). The scenarios take into consideration: investment costs; efficiency; electricity generated both from the Greek national grid as well as from solar PV for the years 2020, 2030, and 2050. Finally, in order to identify the factors affecting the LCOH production, a sensitivity analysis is performed.

3.1. Levelized Cost of Hydrogen

Levelized Costs serve as indicators to evaluate the economic efficiency and competitiveness of a technology by quantifying its economic feasibility [52]. In this context, the Levelized Cost of Energy (LCOE) is utilized for the assessment and comparison of different energy storage systems. With this method, the cost of electricity generation over the life of the system is determined. The LCOE is determined by dividing the total capital cost of the storage by the expected energy output, while also considering the time-varying value of money [53]. In another approach, LCOE represents the minimum price the generated power should be sold at, in order to break even at the end of the expected lifetime (Equation (1)).

$$\mathrm{LCOE} = \frac{\sum_{n=1}^{N} (I_n + F_n + V_n) \times (1+i)^{-n}}{\sum_{n=1}^{N} E_n \times (1+i)^{-n}} \quad (1)$$

where:

- I_n = Cost of investment;
- F_n = Fixed operational expenditure (F-OPEX);
- V_n = Variable operational expenditure;
- E_n = Energy obtained in year n;
- N = Plant lifetime;
- i = Discount rate.

The investment costs are calculated as per Equation (2), where:

- C_x = CAPEX (costs associated with electrolyzers, dispensers, engineering, procurement, and construction (EPC));
- X = Quantity of spare parts related to CAPEX;
- CRF = Capital Recovery Factor (Equation (3)).

$$I_{a,n} = I_n \times \text{CRF} = \sum_{x=1}^{x} (C_x) \times \text{CRF} \quad (2)$$

$$\text{CRF} = \frac{i\,(1+i)^n}{(1+i)^n - 1} \quad (3)$$

Fixed operating expenditure (F-OPEX) ($F_{a,n}$) is calculated as a percentage of the annualized CAPEX (Table 2), whereas the variable operating expenditure (V-OPEX ($V_{a,n}$)) is calculated as follows:

$$V_a = C_e + C_w + C_n \quad (4)$$

C_e, C_w and C_n are the natural gas, water, and electricity costs. Total annual costs are calculated as per Equation (5):

$$C_a = I_{a,n} + F_{a,n} + V_{a,n} \quad (5)$$

where:

- C_a = Annualized total costs;
- $I_{a,n}$ = Annualized investment;
- $F_{a,n}$ = Fixed OPEX (EUR/year);
- $V_{a,n}$ = Variable OPEX (EUR/year)

The calculation of energy output is calculated on the basis of kWh/year or kg/year. The ratio of total costs to the energy obtained as hydrogen EH2a (kWh/year) yields the LCOH, as indicated in Equation (6) and expressed in kWh/year:

$$\text{LCOH} = \frac{C_a}{E_{H2a}} \quad (6)$$

3.2. Cost Assessment and Data

Production costs include both CAPEX and OPEX. CAPEX includes production equipment costs, compressors, dispensers, construction, and other EPC expenses. Meanwhile, OPEX encompasses fixed costs associated with operating the hydrogen production setup, as well as replacement and variable costs, such as those related to water, fuel, and feedstock.

Table 1 summarizes the investment cost—expressed in million EUR per MW—of hydrogen generation, the efficiency of conversion, and the lifespan of the technologies and production methods being studied [54].

Table 2 outlines the operational data and parameters (such as production capacity, CAPEX and OPEX, energy and material inputs, operational hours, carbon tax, etc.) used in calculating LCOH across various scenarios. The annual operational costs of hydrogen production through water electrolysis encompass operation and maintenance expenses, raw material costs, etc. OPEX is estimated as 1.5% of the total capital investment. This estimation is aligned with estimations of previous studies regarding the decarbonization of natural gas systems [55]. Production costs mainly consist of several raw material

inputs, including efficiency, water consumption, and electrolyte consumption in water electrolysis for hydrogen production. Furthermore, to analyze the variation in hydrogen production costs resulting from different energy generation technologies, the electricity prices of purchased electricity are based on the power generation costs of various energy generation technologies.

Table 1. Investment costs, efficiency, and stack lifetime for electrolyzers and Steam Methane Reformers for the years 2020, 2030, and 2050 [54].

Factor	Year	PEM	ALK	SOEC	SMR + CCU	PV
Investment cost (Mil EUR/MW)	2020	1.26–2.82	0.44–2.83	1.07–6.66	0.79–1.65	0.43–0.83
	2030	0.84–2.82	0.36–1.53	0.58–3.33	0.91–1.29	0.27–0.27
	2050	0.77–2.74	0.22–0.88	0.39–1.14	0.86–1.21	0.16–0.16
Efficiency (LHV %)	2020	56–63	63–70	74–81	69	-
	2030	61–69	63–72	74–84	69	-
	2050	67–74	70–80	77–84	69	-
Lifetime (Hours)	2020	30,000–90,000	50,000–90,000	10,000–30,000	-	1343
	2030	60,000–90,000	72,500–100,000	40,000–60,000	-	1484
	2050	100,000–150,000	100,000–150,000	75,000–100,000	-	1499

Table 2. Parameters taken into consideration for the calculation of LCOH.

Parameter	Technology	Value	Units	Source
Hydrogen production	PEM	3	MW H_2	[56]
	ALK	13	MW H_2	[56]
	SOEC	2.5	MW H_2	[57]
	CCU	300	MW H_2	[58]
Lifetime	Electrolyzers	20	Years	[54]
	CCU	25	years	[58]
	PV	20	years	[57]
F-OPEX	Electrolyzers	1.5% of CAPEX	EUR	[53]
	CCU	3% of CAPEX	EUR	[58]
Replacement and chemical costs: annualized (REPEX)	Electrolyzers	20% of CAPEX per replacement	EUR	[59]
	CCU	3% of CAPEX	EUR	[58]
Emission factors	Grid electricity	344	$gCO_2/kWh\ e^-$	[60]
	H_2 production (via CCU)	890	$gCO_2/Nm_3\ H_2$	[61]
Electrolyzers' efficiency (LHV of H_2)	PEM, ALK, and SOEC	61	%	[57]
Full load hour factor (capacity)	Grid electricity	80	%	[53]
	Solar electricity	20	%	[58]
	Natural gas	95	%	[58]
ETS CO_2 emissions: (carbon) tax		82	EUR/tCO_2	[62]
Density		0.0889	kg/Nm^3	
Lower heating value		33.3333	kWh/kg H_2	

Table 2. *Cont.*

Parameter Technology		Value	Units	Source
Discount rate		6	%	[53]
Capacity recovery factor (CRF)	Electrolyzers	0.0872		
	Grey	0.0782		
	Blue—CCU	0.0782		
Water consumption	PEM	10.12	kg/kg H_2	[54]
	ALK	10.12	kg/kg H_2	[54]
	SOEC	13.00	kg/kg H_2	[57]
	CCU	6.70	kg/kg H_2	[58]
Energy costs	Grid electricity (without taxes in Greece)	0.1845	EUR/kWh	[63]
	Lowest cost of solar electricity (European average)	0.02	EUR/kWh	[64]
	Natural gas	0.1171	EUR/kWh	[64]
Water costs	Electrolyzers	1.8188	EUR/m^3	[63]
	CCU	0.2	EUR/m^3	[58]

4. Results and Discussion

4.1. Hydrogen Production Costs

Table 3 summarizes the calculation of LCOH for the various hydrogen generation technologies (in EUR/kgH_2) for the scenarios for 2020, 2030, and 2050, respectively. The results suggest that in 2023, the cost of green hydrogen production is not as competitive as the costs of grey and blue hydrogen. The costs of hydrogen generation via steam methane reforming without carbon capture (grey scenario) span across 1.925–2.078 EUR/kgH_2.

Table 3. Calculation of LCOH in 2020, 2030, and 2050 (EUR/kWh H_2) in Greece.

Technology			Year					
			2020		2030		2050	
			Min	Max	Min	Max	Min	Max
Electrolyzer	PEM	GRID	6.65	9.70	6.03	8.55	3.88	5.34
		PV	5.54	11.49	4.49	8.63	2.88	3.34
Electrolyzer	ALK	GRID	6.20	11.11	6.04	8.67	5.34	6.48
		PV	4.89	15.48	4.52	9.83	3.79	6.72
Electrolyzer	SOEC	GRID	6.36	16.43	5.57	7.96	5.13	6.10
		PV	6.06	24.00	4.27	10.54	3.88	6.50
SMR		GREY—BAU	1.92	2.08	-	-	-	-
		BLUE—CCS	2.36	2.48	2.20	2.45	1.82	2.00

It is noted that, even though all LCOHs of methane reforming with carbon capture (blue scenario) are more expensive (compared to the grey scenario a with cost of NG at 0.1171 EUR/kWh), remaining the cheapest LCOH for low-carbon alternatives in hard-to-abate industries, such as refineries (Figure 2).

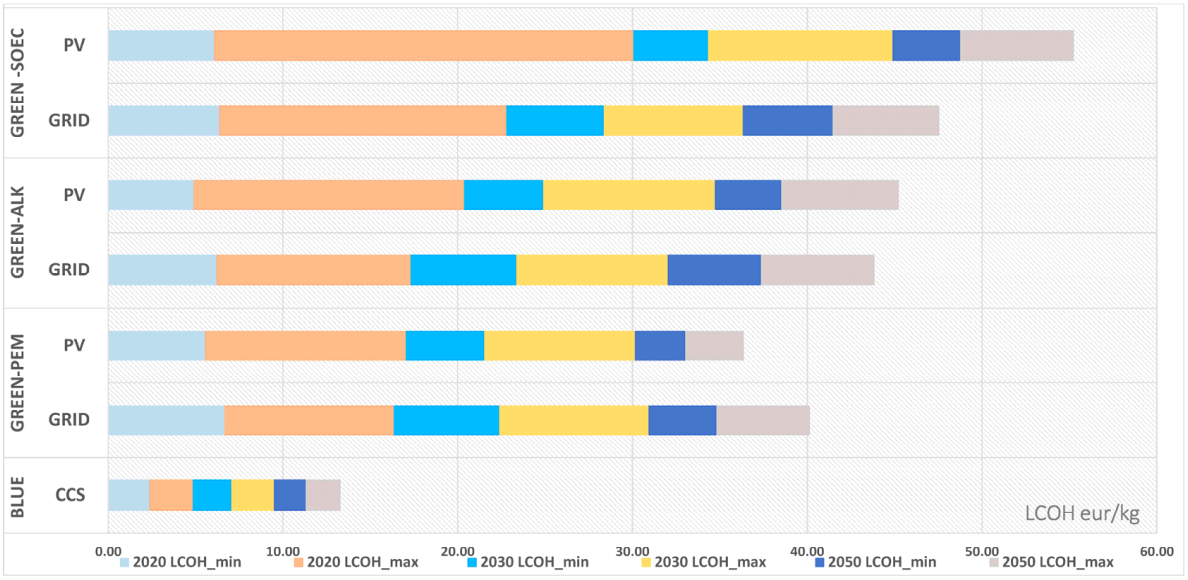


Figure 2. Minimum and maximum LCOH (EUR/kg) of the technologies under study.

On the other hand, the production of green hydrogen is affected by the type of electrolyte as well as the type of energy. In the year 2023 (2020 column), the minimum LCOH cost is 5.54 EUR/kgH_2 (PEM connected to solar PV), whereas the maximum LCOH is 24.00 EUR/kgH_2 (SOEC connected to solar PV). On the other hand, in 2050, SOEC hydrogen production via solar energy may be as competitive as PEM hydrogen production via solar energy, reaching 3.88 EUR/kgH_2.

The grey scenario (BAU) is the cheapest, at 1.92 EUR/kgH_2. It is noteworthy that the evaluation of relative costs in 2030 and 2050 is essential, particularly when assessing the impacts of the carbon tax on energy coming from conventional pathways. Currently (i.e., calculations for 2020), the most economical pathway for hydrogen production is the one described in the grey scenario, while solar-powered electrolyzers exhibit the lowest levelized cost of hydrogen across various electricity production scenarios. Grey and blue hydrogen prove to be more cost-effective than green hydrogen; the latter can be attributed to factors such as the Technological Level of Readiness (TRL), carbon emissions, as well as fuel prices.

4.2. Sensitivity Analysis on LCOH

A sensitivity analysis has been carried out, aiming to evaluate the impacts of input parameters when calculating the LCOH under different scenarios. The analysis is performed by varying within a range of ±30% (%). The parameters taken into consideration include the investment costs, the discount rate, the capacity factor, the cost of electricity/natural gas, as well as the hydrogen production capacity. The production of hydrogen via the blue—CCS scenario is affected not only by the prices of natural gas, but also by the capacity factor and investment cost (Figure 3). As regards the prices of natural gas, it is noted that the LCOH is reduced to 2.25 EUR/kgH_2 at the lower sensitivity bound, and increased to around 5.00 EUR/kgH_2 at the upper sensitivity bound. This is attributed mainly to the large volume of natural gas utilized in the SMR-CCS plants, invariably causing large increases in their LCOH. Similarly, the LCOH values, when examining the impacts of the capacity factor, were 3.85 EUR/kgH_2 and 3.4 EUR/kgH_2 for the lower and upper sensitivity bounds, respectively. Moreover, an upward trend in the LCOH is noticed as the investment cost increases, with 3.9 EUR/kgH_2 at the upper sensitivity bound.

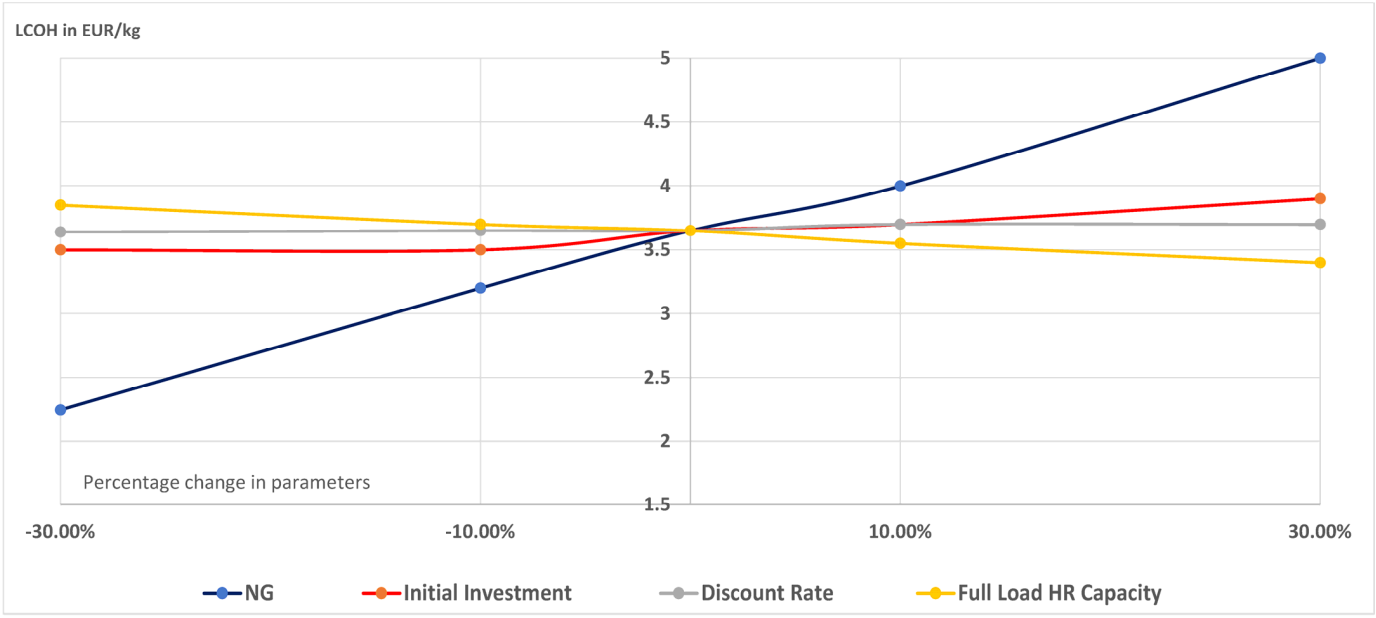


Figure 3. Sensitivity of LCOH (EUR/kg) at ±30% (%) of parameters for the blue—CCS scenario.

Figures 4 and 5 demonstrate that LCOH decreases when the capacity of the electrolyzer increases, both when the PEM is grid-powered and when it is solar-powered. The LCOH for green hydrogen decreases as technology and electrolyzer efficiency improve. In addition, the sensitivity analysis for the production of green hydrogen using the PEM electrolyzer indicates that 80% of the total costs for grid-connected electricity sources are attributed to electricity costs, whereas the solar power hydrogen production pathway is affected by investment costs (constituting more than 60% of the overall expenses). It is highlighted that the energy costs associated with grid and solar electricity are 0.1845 EUR/kWh and 0.02 EUR/kWh, respectively (Table 2).

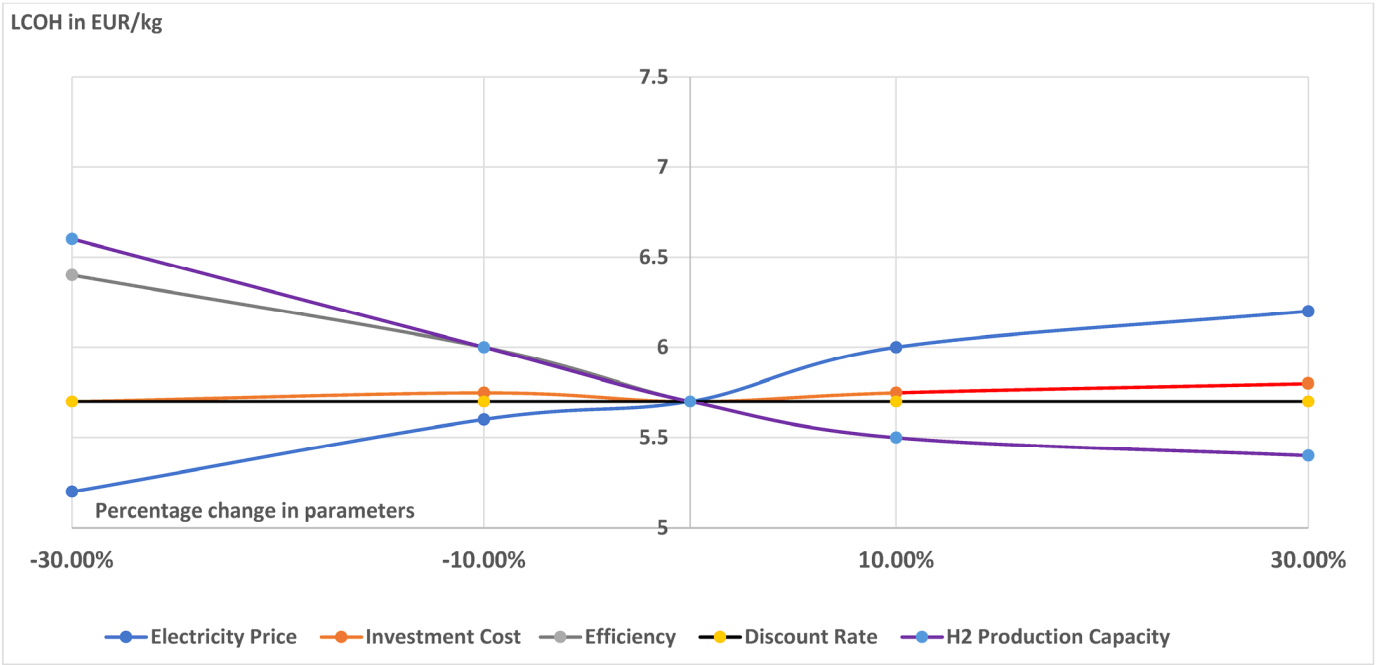


Figure 4. Sensitivity of LCOH (EUR/kg) at ±30% (%) of parameters for the green—PEM, grid electricity scenario.

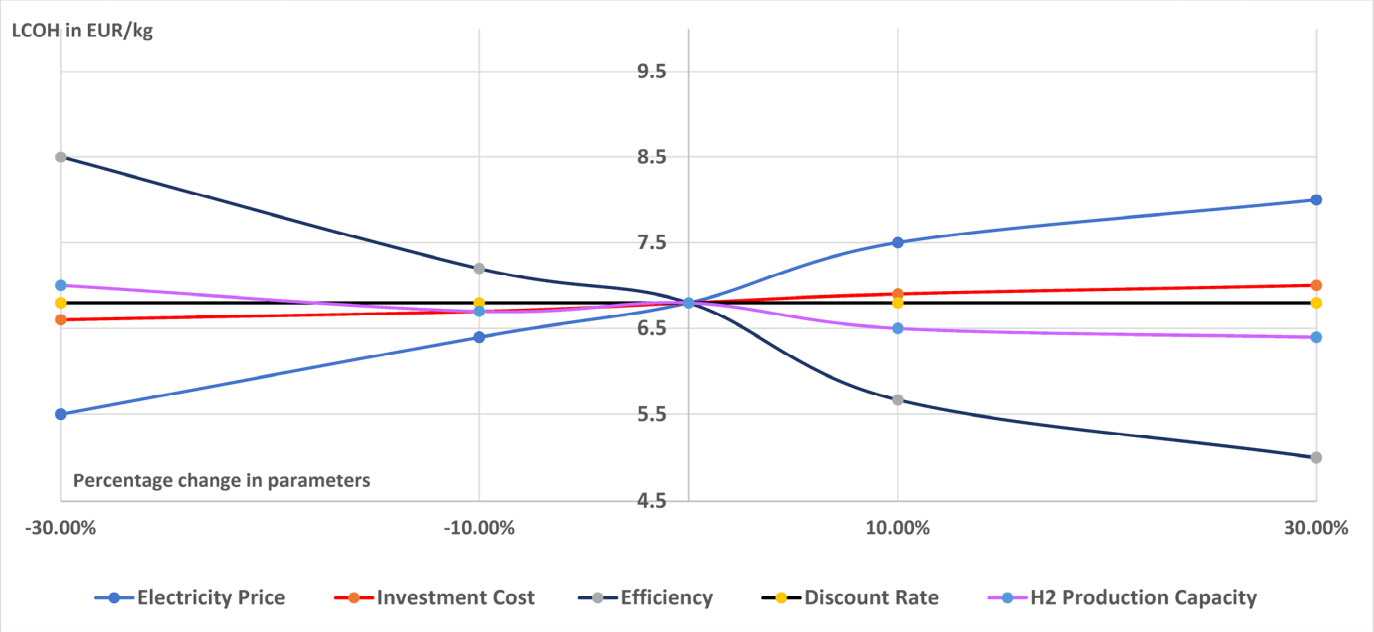


Figure 5. Sensitivity of LCOH (EUR/kg) at ±30% (%) of parameters for the green—PEM, solar electricity scenario.

Another factor of crucial importance is the electricity source used for hydrogen production. Solar power offers a more favorable price for hydrogen production compared to grid-connected electricity. Figure 5 illustrates the impacts of various parameters on the Levelized Cost of Hydrogen (LCOH) using electricity generated from solar power. The hydrogen production cost is predominantly influenced by the electricity cost, with capital costs being the most important factor.

It should be stated that the production of green hydrogen is directly tied to the availability and cost of renewable electricity sources, and so understanding and addressing these cost factors become pivotal. The ongoing efforts to reduce the cost of electricity through advancements in renewable technologies and increased efficiency will play a crucial role in enhancing the economic viability of hydrogen production. Simultaneously, managing and optimizing capital costs in the design and implementation of hydrogen production facilities will be essential for fostering a competitive and sustainable hydrogen market.

5. Conclusions and Future Outlook

This work has investigated the techno-economic performance of Greece's hydrogen production capacity, calculating relative LCOH in hard-to-abate industries, such as oil refining. It is here shown that Greece is not yet ready to support a total hydrogen energy transition, taking into consideration the important gap in the production cost between green hydrogen and blue/grey hydrogen. As a matter of fact, the current framework does not enable the realization of zero-carbon industries by 2050.

In performing a techno-economic analysis, based on the reliance on natural gas and other gaseous energy carriers such as hydrogen, this study concludes that immediate amendments and changes are necessary to achieve the 2050 carbon-neutral targets. Undoubtedly, the role of hydrogen in the decarbonization of hard-to-abate industries is of crucial importance. This, however, requires the creation of an ecosystem based on integrated planning and an innovative decision support system, which will mitigate the risks, strengthen the competitiveness, and create business opportunities in the whole value chain.

However, the findings of this study highlight the considerable challenge posed by the high cost of green hydrogen production in Greece, necessitating substantial investments in infrastructure, technology, and incentives to stimulate demand in hard-to-abate industries like refining. With ongoing development in the country's renewable energy sector and

efforts to encourage the adoption of green hydrogen, there is potential for a decrease in production costs over time. However, this is not enough, as a framework for the generation and distribution of green hydrogen should be developed, in order to limit uncertainty for investors. Furthermore, the lack of infrastructure in conjunction with the limited domestic market hinders the upscaling of hydrogen production in Greece. Moreover, the global green hydrogen market is still nascent, with limited international demand. This factor could constrain the opportunity for green hydrogen exports from Greece.

The regulatory and political constraints of green hydrogen generation constitute significant challenges that must be addressed for hard-to-abate industries, in order to reach their energy transition targets. Investments in the necessary infrastructure should be made in order to support the industry. Tackling these challenges will necessitate a sustained, long-term commitment to the development of the green hydrogen industry.

It is important to take into account stakeholder motivation, with the main emphasis being on decarbonization rather than favoring a specific approach. Various approaches must be undertaken to diminish reliance on fossil fuels and decrease greenhouse gas (GHG) emissions. The results of this work indicate that the current levelized cost of green hydrogen falls short compared to grey or blue hydrogen. Therefore, it is imperative to foster innovative action aiming to reduce costs, implement increased carbon taxation, encourage and incentivize hydrogen adoption, and secure enhanced funding from the European Union. Subsidies and cost allocation mechanisms are vital for increasing stakeholder participation and mitigating investment risks. To facilitate the transition towards green hydrogen, subsidies and cost allocation mechanisms become vital tools. These financial incentives will serve to increase stakeholder participation and help mitigate the risks associated with investments in cleaner technologies. By fostering a supportive and incentivized environment, policymakers can accelerate the shift towards greener and more sustainable hydrogen production methods, aligning with the broader objective of decarbonization and environmental responsibility.

It is suggested that the incorporation of a carbon tax has the potential to substantially lower the costs associated with hydrogen production from both steam methane reforming (SMR) and electrolyzers [65]. It is worth noting that in addition to a substantial rise in natural gas prices in the market, only a substantial fee per unit weight of CO_2 can achieve the desired outcome. Taking into account emissions and costs, the study concludes that methane reforming with carbon capture is a viable option (blue—CCS scenario), and it seems to be a viable solution for the decarbonization of hard-to-abate industries until such time as green hydrogen using RES can be cost-competitive. Furthermore, the employment of CCS is important for reaching the European decarbonization goals (by 2050, at least 10 Gt of CO_2) [63]. In addition, the significant uncertainty resulting from disrupted Russian gas supplies and geopolitical instabilities exacerbates energy scarcity in the European energy market, intensifying price pressures and volatility for both fossil and renewable energy sources. As a result, stakeholders in the energy sector must navigate these uncertainties and develop strategies to address the challenges posed by geopolitical factors, ensuring resilience and adaptability in the face of evolving market dynamics. In this context, phasing out Russian pipeline gas could increase the importance of CCS, as the minimum amount of CO_2 sequestered by 2050 could reach 15 Gt [66].

Finally, this work can be improved and expanded upon by taking into consideration: (i) other energy-intensive industrial sectors covered by ETS (i.e., steel, cement, ammonia, etc.), so as to provide a more comprehensive depiction of European industry; (ii) long-term uncertainties of the 2050 European energy system (especially in the areas of technology development and policy regulation). These uncertainties are of crucial importance to all stakeholders.

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