energies

MDPI

Review

Hydrogen Production Cost Forecasts since the 1970s and Implications for Technological Development

Tomonori Miyagawa and Mika Goto *

Department of Innovation Science, School of Environment and Society, Tokyo Institute of Technology, 3-3-6, Shibaura, Minato-ku, Tokyo 108-0023, Japan; miyagawa.t.ae@m.titech.ac.jp
* Correspondence: goto.m.af@m.titech.ac.jp

Abstract: This study reviews the extant literature on hydrogen production cost forecasts to identify and analyze the historical trend of such forecasts in order to explore the feasibility of wider adoption. Hydrogen is an important energy source that can be used to achieve a carbon-neutral society, but the widespread adoption of hydrogen production technologies is hampered by the high costs. The production costs vary depending on the technology employed: gray, renewable electrolysis, or biomass. The study identifies 174 production cost forecast data points from articles published between 1979 and 2020 and makes a comparative assessment using non-parametric statistical tests. The results show three different cost forecast trends across technologies. First, the production cost of gray hydrogen showed an increasing trend until 2015, but started declining after 2015. Second, the renewable electrolysis hydrogen cost was the highest of all, but has shown a gradual declining trend since 2015. Finally, the biomass hydrogen cost has been relatively cheaper up until 2015, after which it became the highest. Renewable electrolysis and biomass hydrogen will be potential candidates (as principal drivers) to reduce CO_2 emissions in the future, but renewable electrolysis hydrogen is more promising in this regard due to its declining production cost trend. Gray hydrogen can also be an alternative candidate to renewable electrolysis hydrogen because it can be equipped with carbon capture storage (CCS) to produce blue hydrogen, although we need to consider additional production costs incurred by the introduction of CCS. The study discusses the technological development and policy implications of the results on hydrogen production costs.

Keywords: production cost forecast; gray hydrogen; renewable electrolysis hydrogen; biomass hydrogen; historical trend

Citation: Miyagawa, T.; Goto, M. Hydrogen Production Cost Forecasts since the 1970s and Implications for Technological Development. *Energies* **2022**, *15*, 4375. https://doi.org/10.3390/en15124375

Academic Editor: Donato Morea

Received: 29 May 2022
Accepted: 14 June 2022
Published: 15 June 2022

1. Introduction

Since the Paris Agreement came into effect in November 2016 and entered its implementation phase in 2020, leaders, policymakers, and society have been concerned about meeting the Agreement's goal of carbon neutrality by 2050, reducing greenhouse gas emissions. Renewable energy generation has steadily increased in many countries, with its cost coming down progressively. However, the deployment of renewable energy has been a constraint for the transmission grid owing to the intermittency of solar photovoltaics (PV) and wind power generation. Alternative renewable energies, such as biomass, can avoid the intermittency problem, but the production costs of such alternatives are still higher than that of solar PV and wind power energy.

Hydrogen has the potential to solve both carbon emission and electricity intermittency problems. It can replace fossil fuels in economic activities, such as energy, transportation, building, and industries. Hydrogen can be produced by water electrolysis using abundant renewable electricity, adequately mitigating the problem of transmission grid constraints.

Academic researchers have debated the techno-economic aspects of hydrogen for decades. Maggio et al. (2019) [1] discussed the use of hydrogen to balance the mismatch between renewable energy production and demand; however, they only reviewed 12 articles to analyze hydrogen production cost forecasts from 2008 to 2017. Therefore, it was thought that if we looked into a larger number of papers covering a longer period, the trends and conclusions might be different. This was the motivation for this research. We reviewed approximately 300 articles on renewable energy system-based hydrogen (published between 2008 and 2017) that also analyzed the costs of hydrogen production from electrolysis, steam methane reforming (SMR), and other processes. The general conclusion from these studies was that, while there were progressive cost improvements over time, as expected, the actual reported costs did not change significantly.

We first focused on the articles analyzing hydrogen delivery costs, as the total costs delivered to the final consumers could then be compared with incumbent alternatives, such as petrol for automobiles. For the search process, we selected the keywords, "hydrogen", "economic*", and "supply chain", to identify articles containing techno- or socio-economic analyses of the hydrogen supply chain, as summarized in Table 1. The asterisk attached to a keyword indicates a wildcard that can be replaced with any word. The search identified 98 articles matching the keywords.

Table 1. Search process.

Field	Option Introduced
Keywords	"hydrogen" AND "economic *" [1] AND "supply chain"
Search in	Title, abstract, keywords
Period explored	Open
Type of documents	Articles
Language	English
Database	Scopus

[1] * indicates a wildcard.

The search found articles on various technologies in the supply chain. The range of technologies covered by the screening was wide, as shown in Table 1 and summarized in Table 2. The variety of potential combinations of technologies in the supply chain, however, made it difficult to find a trend in the cost forecast because the possible combinations were too broad to identify the practical trends from a limited number of datasets.

Table 2. Variety of supply chains.

Production Technology	Storage	Delivery Mode	Refilling
Coal gasification	Liquid	Tanker truck	Liquid refilling
Gas reformer (SMR)	Compressed gas	Tube trailer	Gas refilling
Biomass gasification	Ammonia	Pipeline	Onsite reforming
Electrolysis		Railway	
		Ship	

Therefore, we decided to narrow down the focus to hydrogen production costs with different technologies, along with the year of publication of the study. With increased awareness of carbon emission reductions, the number of published articles can only increase with time. Until recently, renewable electricity was more expensive than other generation technologies; therefore, renewable electrolysis technology has been ignored in the research on hydrogen mass production of hydrogen, while incumbent hydrocarbon or coal- and gas-based hydrogen have been intensively discussed. However, the cost of hydrogen production is likely to reduce over time, regardless of the technologies applied.

The subsequent sections describe the trends in hydrogen production forecasts from 1979 to 2020, organized as follows: Section 2 explains hydrogen production technologies and their production costs; Section 3 describes the analytical method used in this study; Section 4 summarizes the findings of this study; Section 5 concludes the paper.

2. Hydrogen Production Technologies and Cost Estimations

This section briefly explains hydrogen production costs from a technological perspective and discusses the cost forecast method.

2.1. Hydrogen Production Technologies

Hydrogen production methods can be classified into two categories: hydrocarbon-based and non-hydrocarbon-based (Sharma, Agarwal, and Jain (2021)) [2]. The methods using fossil fuels are SMR, coal gasification, and biomass gasification. Currently, hydrogen is produced almost exclusively from fossil fuels through SMR (Balat (2008)) [3], which is the most popular process for producing hydrogen from natural gas. It requires a high process temperature, and burning natural gas is the most common practice for providing the required heat. Steam reformation of natural gas produces hydrogen-rich gas.

SMR is a three-step hydrogen production process. The main steps adopted in this method are reforming, shift-conversion gas purification, and methanation. In the first step, the SMR method produces a mixture of carbon oxide (CO) and hydrogen; that is, methane is catalytically reformed at elevated temperatures and pressures to produce a syngas mixture of H_2 and CO. A catalytic shift reaction is then performed to combine CO and H_2O to arrive at the H_2 product. The hydrogen duct is purified via absorption, and the reforming step is described by [$CH_4 + H_2O \rightarrow CO + 3H_2$].

Hydrogen can be produced in various other ways: (a) gasification of coal and syngas or artificial water gas [$CO + H_2$] from coal can be reformed to hydrogen as [$CO + H_2O \rightarrow H_2 + CO_2$]; (b) biomass gasification, steam gasification, etc., described as [$\text{Biomass} \rightarrow H_2 + CO_2 + CO + N_2$]; and, (c) water and steam electrolysis are classified into two types of water electrolyzers, alkaline electrolyte and polymer electrolyte membrane (PEM), and the net reaction for producing hydrogen and oxygen by water electrolysis is described as [$H_2O \rightarrow H_2 + 1/2O_2$].

2.2. Cost Estimation Methods

The method of calculating hydrogen production cost varies with the production technology and process. However, it can be summarized, as applicable to most production technologies and processes, as follows (Lysenko, Sadaka, and Brown (2012)) [4].

(Hydrogen production cost = annual operating cost/annual hydrogen production), in which (Annual operating cost = annual capital charge + total direct expenses + total indirect costs), (Annual capital charge = annualized fixed capital + annualized working capital), (Total direct expenses = raw material + operating labor + supervisory labor + maintenance and repair cost + operating supplies + laboratory charges + patents and royalties), and (Total indirect costs = overhead + local taxes + insurance + general expenses).

The methods of sourcing input data vary but can be mostly grouped into two: the H2A method and reference-to-peer analysis. Although this study does not differentiate between these methods when comparing hydrogen production cost forecasts, we briefly address their characteristics.

The H2A method was defined by the US Department of Energy (DOE) [5]. The procedure is reliable and transparent because it is based on transparent reporting of process design assumptions and a consistent cost analysis methodology for the production of hydrogen. Data on capital and operating costs and financial parameters are provided by the DOE as default values. Users can enter their own values instead of the given default values, so they are stable, flexible, and useful for cost analysis users. The models use a standard discounted cash flow rate of return (ROR) analysis methodology to determine the hydrogen selling cost, depending on the desired internal ROR.

Another popular method, peer analysis, refers to peer articles that analyze and provide cost data in projects with similar production methods and regions. Both methods are viable for hydrogen cost analysis, but the H2A method is more transparent and reliable, while peer references are likely to suffer from ambiguity of the original data source, different estimation times, and currency conversions.

3. Methods

This study used Elsevier's Scopus search engine to review academic articles investigating hydrogen production costs published up to January 2021. First, we set keywords for "hydrogen production costs" and other fields, as listed in Table 3.

Table 3. Search strategy in Scopus site.

Field	Option Selected
Keywords	"hydrogen production cost"
Search in	Title, abstract, keywords
Period explored	Open
Type of documents	Articles
Language	English
Database	Scopus

The search identified 144 articles that matched the selected options. Figure 1 shows the historical trend in the publication of these 144 articles over the years. The number of articles significantly increased after 2000, perhaps due to the increasing interest in hydrogen. Interestingly, as the figure shows, the number of articles increased and decreased in waves, once around 2010 and then after 2015. We also investigated the reasons for this volatility.

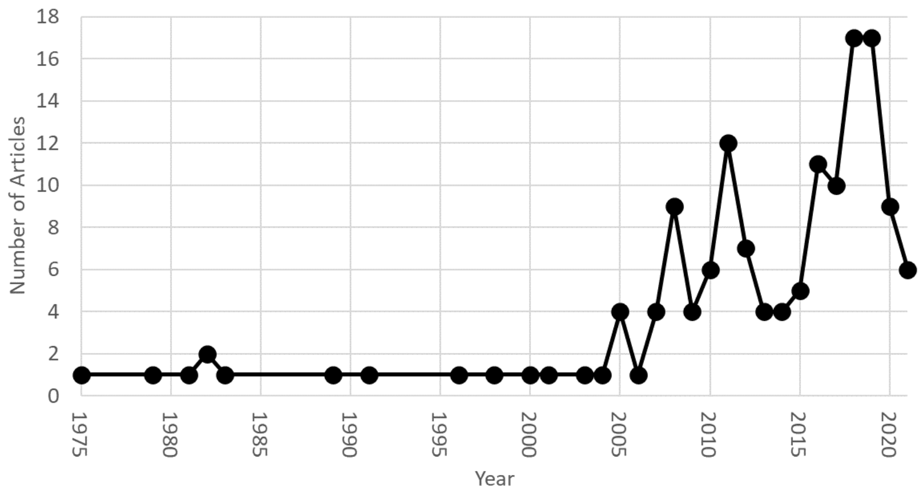

Figure 1. Trend of the number of articles published from 1975 to 2021. Note: The horizontal axis represents the publication year. The figure for 2021 is only for January.

Thereafter, we summarized the hydrogen costs estimated in these articles. Table A1 summarizes the forecasted hydrogen production costs, as identified from 174 cases of hydrogen production costs in 114 articles; 30 articles did not provide the estimated hydrogen production costs. Each hydrogen production cost was converted to US dollars per kilo of hydrogen, using the conversion rate described in Table 4.

Table 4. Conversion rate.

Hydrogen conversion	1 Gigajoule (GJ) = 8.333 kg
	1 Cubic meter (m^3) = 0.08988 kg
	1 Megawatt hour (MWh) = 30.0 kg
	1 kilo mol (kmol) = 2.02 kg
Exchange rates	Purchasing power parity (OECD)

Sources: created by the authors using data from Lemus and Martínez Duart (2010) [6] for the first three conversion rates, convertworld.com (https://www.convertworld.com/, accessed on 20 September 2020) for the kilo mol conversion rate, and OECD (https://data.oecd.org/conversion/purchasing-power-parities-ppp.htm, accessed on 20 September 2020) for the exchange rates.

The collected production cost data were classified by (1) the year of publication of the article, (2) the period of projection of the hydrogen production costs in the articles (i.e., the projected time), and (3) the hydrogen production method.

Based on the above classifications, this study analyzed the trend of historical hydrogen production cost forecasts using non-parametric tests. Specifically, we used the Kruskal–Wallis rank-sum test and Wilcoxon rank-sum test with respect to (a) the chronological order of the years of publication and (b) production methods. Production methods are classified as (i) gray hydrogen (coal gasification and SMR), (ii) renewable electrolysis hydrogen (solar electrolysis and wind electrolysis), (iii) biomass hydrogen (biomass gasification and biomass reforming), and (iv) others (biomass fermentation, chemical looping, electrolysis other than renewables, solar thermochemical, waste gasification, reforming, etc.). Non-parametric analyses were performed using STATA software version 16.1.

The collected data are summarized in Table 5. Figure 2 plots the data on the scatter chart, with a horizontal axis (*X*) of projected time (forecast years) and a vertical axis (*Y*) of the forecasted production costs.

Table 5. Summary of data.

(USD/kg)	Total	Gray (Coal and Gas)	Renewable Electrolysis	Biomass (Gasification and Reforming)	Others
Number of Samples	174	44	48	29	53
Average	4.81	2.08	6.05	3.18	6.85
Max.	65.35	7.59	16.31	8.38	65.35
Min.	0.21	0.53	1.08	0.21	0.84
Stdev.	6.70	1.41	3.82	2.03	10.81

Note: Max., Min., and Stdev. denote maximum, minimum, and standard deviation, respectively.

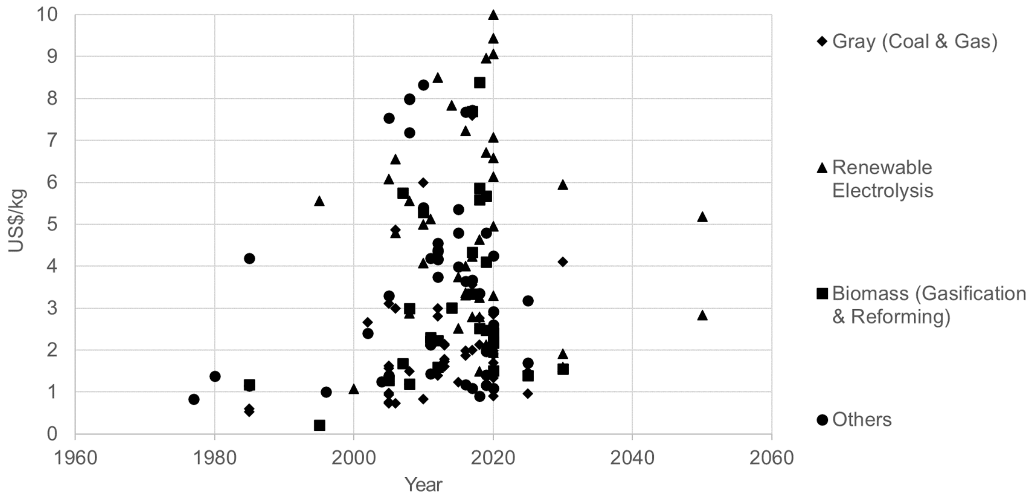

Figure 2. Scatter chart of forecast years and hydrogen production costs. Note: others include biomass fermentation, chemical looping, electrolysis other than renewables, solar thermochemical, waste gasification, reforming, etc.

We performed non-parametric tests (Kruskal–Wallis rank-sum test and Wilcoxon rank-sum test) in four steps. Note that these tests sort the cost forecasts from cheaper to higher (more expensive) ones and provide them with sequential ranks. Thus, for example, a cost ranked 10 is cheaper than that ranked 100. First, we applied the Wilcoxon rank-sum test to the production cost forecast of each production method (i.e., gray, renewable electrolysis, and biomass) by comparing them with all other categories over the full period to allow us to examine whether the production cost of each method was statistically different from the others (see Figure 3).

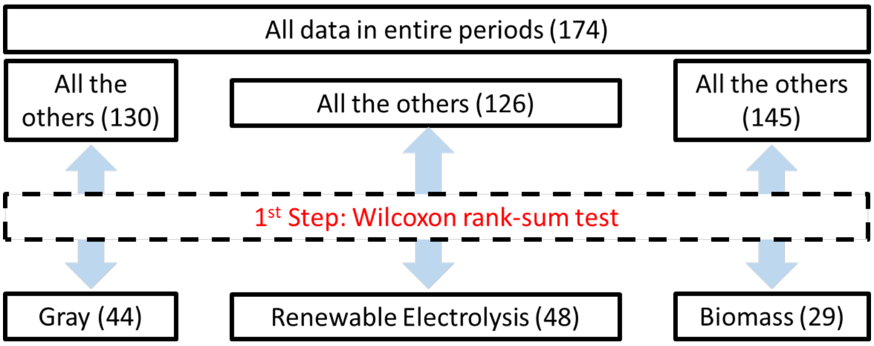

Figure 3. Wilcoxon rank-sum test between gray/renewable electrolysis/biomass hydrogen and all the others over time. Note: numbers in parentheses indicate the number of samples (cost forecasts) included in the category.

In the second step, we conducted the Wilcoxon rank-sum test, as in the first step, but for different groups of the years of publication (before 2000, 2001–2010, 2011–2015, and 2016–2020), to compare the changes in the costs over time. It is ideal to compare the cost data not only in publication years, but also in combination with the forecast years and regions in the second step, as the production costs of gray and renewable electrolysis hydrogen are highly dependent on forecast years and regions, and whether cheap gas, coal, or renewable electricity are available, which vary according to region. However, the 174 data samples are not sufficient to analyze fragmented categories with combinations of forecast years and regions. Therefore, as Figure 4 shows, this study focused on publication years, recognizing the limitation that there are no segregations of forecast years and regions in the same categories of the publication year ranges (before 2000, 2001–2010, 2011–2015, and 2016–2020).

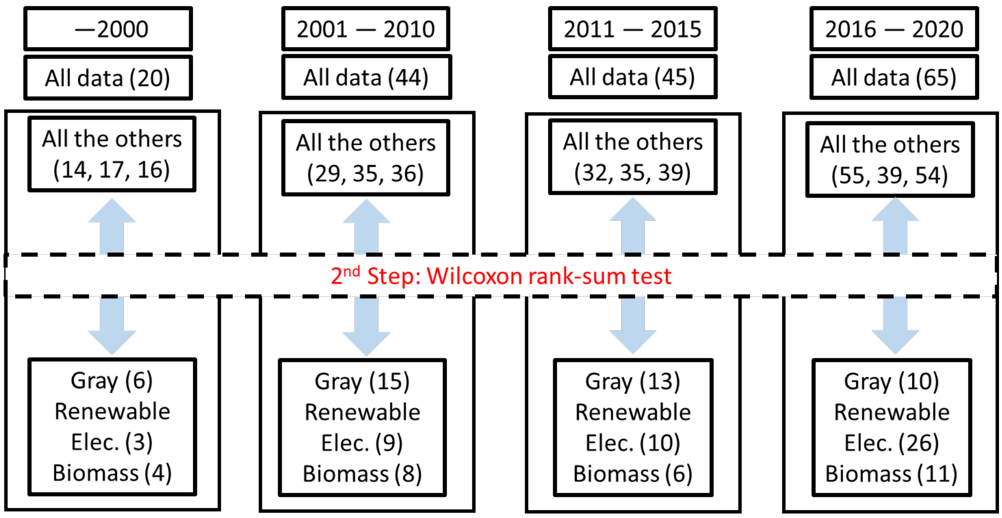

Figure 4. Wilcoxon rank-sum test between gray/renewable electrolysis/biomass hydrogen and all of the others in the different time categories. Note: numbers in parentheses indicate the number of samples (cost forecasts) included in the category.

The third step analyzed each production method using the Kruskal–Wallis test to identify whether there were significant differences among the time categories (see Figure 5).

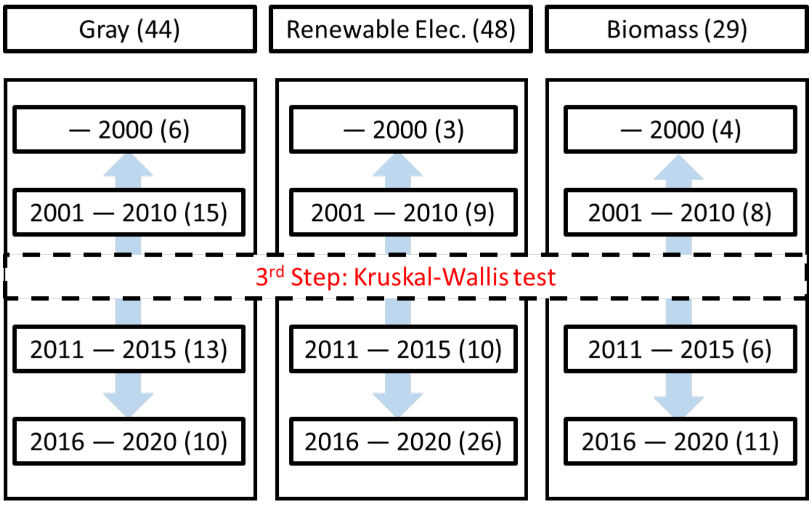

Figure 5. Kruskal–Wallis test in each gray/renewable electrolysis/biomass hydrogen. Note: numbers in parentheses indicate the number of samples (cost forecasts) included in the category.

Finally, in the fourth step, as Figure 6 shows, each production method was analyzed using the Wilcoxon rank-sum test between the adjacent time categories to identify which time category was different (or had changed) from the adjacent time categories.

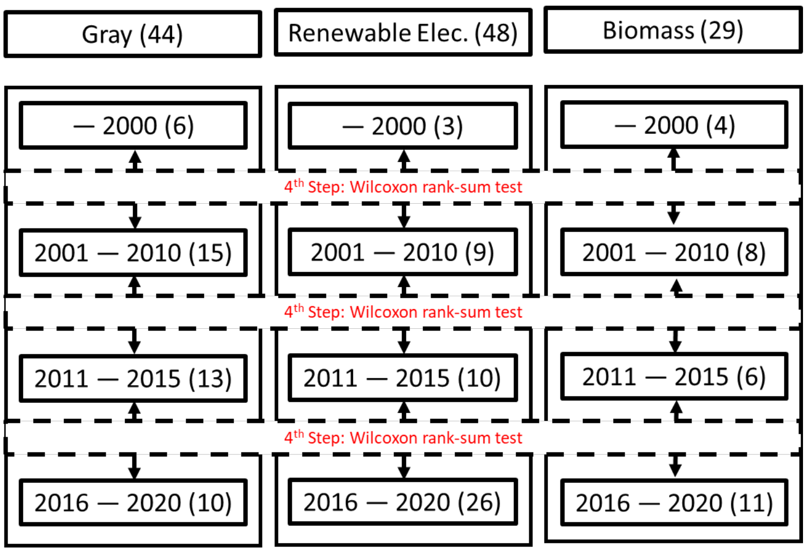

Figure 6. Wilcoxon rank-sum test in each gray/renewable electrolysis/biomass between different time categories. Note: numbers in parentheses indicate the number of samples (cost forecasts) included in the category.

4. Results

We present the results of the non-parametric tests in the four steps presented in Section 3 for each production method of gray, renewable electrolysis, and biomass, as follows.

4.1. Gray Hydrogen

4.1.1. Wilcoxon Rank-Sum (First and Second Step) Tests between Gray Hydrogen and Other Hydrogen Types over Time

Table 6 presents the results of the first and second step tests. The columns from left to right indicate the results for the entire period, i.e., before 2000, 2001–2010, 2011–2015, and 2016–2020. Over the entire period, the null hypothesis was rejected at the 1% significance level, which reveals that the gray hydrogen samples differed from those of the other types in the entire period at the 1% significance level. In particular, the result of the rank-sum of gray hydrogen (2225) was lower than the expected rank-sum (3850), which indicates that the cost of gray hydrogen tends to be lower than that of the other hydrogen types.

Similar to the entire period, the other columns show the results of the rank-sum tests for the four different time categories. The null hypothesis was rejected for all categories at either the 1% or 5% levels. In addition, each rank-sum (i.e., 38, 190.5, 160, and 183) was far lower than expected (i.e., 63, 337.5, 299, and 330). These test results, therefore, confirm that the costs of gray hydrogen are different from (and always lower than) those of the other hydrogens in any time category.

Table 6. Wilcoxon rank-sum test between gray hydrogen and all other hydrogen types over time.

	Obs.	**R. sum**	**Ex.**	**Obs.**	**R. sum**	**Ex.**	**Obs.**	**R. sum**	**Ex.**	**Obs.**	**R. sum**	**Ex.**	**Obs.**	**R. sum**	**Ex.**
		Entire Period			**–2000**			**2001–2010**			**2011–2015**			**2016–2020**	
Gray	44	2225	3850	6	38	63	15	190.5	337.5	13	160	299	10	183	330
Others	130	13,000	11,375	14	172	147	29	799.5	652.5	32	875	736	55	1962	1815
Total	174	15,225	15,225	20	210	210	44	990	990	45	1035	1035	65	2145	2145
z value		5.626 ***			2.063 **			3.640 ***			3.481 ***			2.673 ***	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected rank-sum value. *** and ** indicate significance at the 1% and 5% levels, respectively.

4.1.2. Kruskal–Wallis Test for Gray Hydrogen for Different Periods (Third Test)

In the third step, the different categories of gray hydrogen production costs were examined using the Kruskal–Wallis test. Table 7 shows that the null hypothesis (i.e., all samples across categories are identical) is rejected at the 1% significance level ($p = 0.0053$). Therefore, we consider that not all production costs are identical for all categories of the published years.

Table 7. Kruskal–Wallis test for gray hydrogen.

Published Years	**Number of Observations**	**Rank-Sum**
−2000	6	41
2001–2010	15	320
2011–2015	13	375
2016–2020	10	254
	Chi-squared value: 12.732 with 3 d.f. *p*-value: 0.0053	

Note: d.f. denotes the degree of freedom.

4.1.3. Wilcoxon Rank-Sum Test for Gray Hydrogen for Different Periods (Fourth Step)

The next is the fourth step, which is to identify the category that is not identical to the other adjacent categories of published years. In other words, this test can show how the gray hydrogen cost forecast has evolved. Table 8 shows that only the adjacent categories before 2000 and 2001–2010 were rejected at the 5% significance level, and those between 2001–2010 and 2011–2015, and between 2011–2015 and 2016–2020 were not rejected at effective significance levels. It is interesting to note that the significant difference between categories decreased over time. Further, when we look at the gap between the observed rank-sum and the expected sum before 2000 and 2001–2010, and between 2001–2010 and 2011–2015, the observed rank-sum was higher than that of the expected one in the later period (i.e., 197 > 165, 222 > 188.5), while for comparison, between 2011–2015 and 2016–2020, the rank-sum of the latter period was lower than that of the expected (i.e., 108 < 120). This indicates that the gray hydrogen production cost was forecasted to increase until 2015, but this trend of the forecasted cost was reversed (to decline after 2016).

Table 8. Wilcoxon rank-sum test for gray hydrogen in different time categories.

	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.
	–2000 vs. 2001–2010			2001–2010 vs. 2011–2015			2011–2015 vs. 2016–2020		
Earlier	6	34	66	15	184	217.5	13	168	156
Later	15	197	165	13	222	188.5	10	108	120
Total	21	231	231	28	406	406	23	276	276
z value		−2.492 **			−1.544			0.744	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected value. ** indicates significance at the 5% level.

4.2. Renewable Electrolysis Hydrogen

This section performs non-parametric tests for renewable electrolysis hydrogen using the same procedure as gray hydrogen.

4.2.1. Wilcoxon Rank-Sum (First and Second Step) Tests between Renewable Electrolysis Hydrogen and Other Hydrogens over Time

Table 9 presents the results of the first and the second step tests. The columns indicate the results for the entire period before 2000, 2001–2010, 2011–2015, and 2016–2020, from left to right.

For the entire period, the null hypothesis was rejected at the 1% significance level, which confirms that the samples of renewable electrolysis hydrogen were different from those of the other hydrogens in the entire period at the 1% significance level. In addition, the rank-sum of renewable electrolysis hydrogen (5628) is higher than the expected rank-sum (4200), which indicates that the costs of renewable electrolysis hydrogen tend to be higher than those of other hydrogens.

Similar to the entire period, the other columns show the rank-sum test results in the four different time categories (before 2000, 2001–2010, 2011–2015, and 2016–2020). The null hypothesis was rejected at the 1%, 5%, or 10% levels. Each rank-sum (48, 282, 338.5, and 1009.5) was far higher than the expected value (31.5, 202.5, 230, and 858). These test results, therefore, confirm that the costs of renewable electrolysis hydrogen are different from and constantly higher than those of the other hydrogens in any time category.

Table 9. Wilcoxon rank-sum test between renewable electrolysis hydrogen and the other hydrogen types over time.

	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.
	Entire Period			–2000			2001–2010			2011–2015			2016–2020		
R. Elec	48	5628	4200	3	48	31.5	9	282	202.5	10	338.5	230	26	1009.5	858
Others	126	9597	11,025	17	162	178.5	35	708	787.5	35	696.5	805	39	1135.5	1287
Total	174	15,225	15,225	20	210	210	44	990	990	45	1035	1035	65	2145	2145
z value		−4.808 ***			−1.747 *			−2.313 **			−2.962 ***			−2.029 **	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected value. ***, **, and * indicate the significance levels at 1%, 5%, and 10%, respectively.

4.2.2. Kruskal–Wallis Test for Renewable Electrolysis Hydrogen for Different Periods (Third Test)

In the third step, the different categories of renewable electrolysis hydrogen production costs were examined using the Kruskal–Wallis test. Table 10 shows that the null hypothesis (i.e., all samples across categories were identical) was not rejected at the 10% significance level (the p-value was 0.6573). This implies that the production cost of renewable electrolysis hydrogen did not evolve or it varied materially over time.

Table 10. Kruskal–Wallis equality of the production test for renewable electrolysis hydrogen.

R.Elec Issued	Obs	Rank-Sum
−2000	3	73.5
2001–2010	9	254.5
2011–2015	10	269
2016–2020	26	579
chi-squared value: 1.609 with 3 d.f. p-value: 0.6573		

Note: d.f. denotes the degree of freedom.

4.2.3. Wilcoxon Rank-Sum Test for Renewable Electrolysis Hydrogen for Different Periods (Fourth Step)

Thereafter, we conducted the fourth step test to identify which category was not identical to the other categories of publication years. Table 11 presents the results of the Wilcoxon rank-sum test. The table demonstrates that none of the null hypotheses were rejected, which indicates that the adjacent time categories did not reveal a significant difference in the forecasted production costs. However, the absolute z-values increased over time; in particular, the z-value during 2016–2020 (0.954) was higher than the previous periods (0.185, 0.245). Further, the rank-sum of 2016–2020 (454) was lower than its expected value (481), which indicates that the production cost forecasts for 2016–2020 were lower than those for 2011–2015. Therefore, these tests showed that the production costs of renewable electrolysis hydrogen gradually declined after 2015, although the changes were not statistically significant at the 10% level.

Table 11. Wilcoxon rank-sum test for renewable electrolysis hydrogen for different periods.

	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.
	–2000 vs. 2001–2010			2001–2010 vs. 2011–2015			2011–2015 vs. 2016–2020		
Earlier	3	18.5	19.5	9	93	90	10	212	185
Later	9	59.5	58.5	10	97	100	26	454	481
Total	12	78	78	19	190	190	36	666	666
z value		−0.185			0.245			0.954	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected value.

4.3. Biomass Hydrogen

4.3.1. Wilcoxon Rank-Sum (First and Second Step) Test between Biomass Hydrogen and Other Hydrogens over Time

Table 12 presents the results of the first and second step tests. The columns indicate the results for all periods before 2000, 2001–2010, 2011–2015, and 2016–2020, from left to right.

The null hypothesis—that there is no difference between the production costs of biomass and the other hydrogens—was not rejected for the entire period, even at the 10% significance level. This means that the samples of biomass hydrogen were not materially different from those of other hydrogens during this period. The result was also confirmed for biomass hydrogen by comparing the rank-sum (2257.5) with the expected rank-sum (2538), where they were not significantly different from each other. This indicates that the cost of biomass hydrogen is not significantly lower than those of other hydrogens.

Similarly, the other columns show the results of the rank-sum tests in different time categories (i.e., before 2000, 2001–2010, 2011–2015, and 2016–2020). Only the test for the period 2011–2015 was rejected at the 5% significance level, and the others were not rejected at the 10% significance level. Each observed rank-sum until 2015 (i.e., 38.5, 134.5, and 78) was lower than the expected value (i.e., 42, 180, and 138), whereas the rank-sum after 2016 (i.e., 427.5) was higher than the expected value (i.e., 363). This indicates that the cost of biomass hydrogen was lower than those of the other hydrogens until 2015 but increased after 2016.

Table 12. Wilcoxon rank-sum test between biomass hydrogen and other hydrogen types over time.

	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.
		Entire Period			**–2000**			**2001–2010**			**2011–2015**			**2016–2020**	
Biomass	29	2257.5	2538	4	38.5	42	8	134.5	180	6	78	138	11	427.5	363
Others	145	12,968	12,688	16	171.5	168	36	855.5	810	39	957	897	54	1717.5	1782
Total	174	15,225	15,225	20	210	210	44	990	990	45	1035	1035	65	2145	2145
z value		1.131			0.331			1.385			2.003 **			−1.128	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected value. ** indicates significance at the 5% level.

4.3.2. Kruskal–Wallis Test for Biomass Hydrogen for Different Periods (Third Step)

In the third step, the different categories of biomass hydrogen production costs were examined using the Kruskal–Wallis test. Table 13 shows that the null hypothesis (i.e., all samples across categories were identical) was rejected at the 1% significance level ($p = 0.0008$), indicating that the production cost of biomass hydrogen varied significantly over time.

Table 13. Kruskal–Wallis equality of production test for biomass hydrogen.

Biomass Issued	Obs	Rank-Sum
−2000	4	12
2001–2010	8	103
2011–2015	6	76
2016–2020	11	244
	chi-squared = 16.719 with 3 d.f. probability = 0.0008	

4.3.3. Wilcoxon Rank-Sum Test for Biomass Hydrogen for Different Periods (Fourth Step)

The Wilcoxon rank-sum tests in the adjacent time periods in Table 14 show that the rank-sum of the later period category (i.e., 66, 49, and 129) was always higher than expected (i.e., 52, 45, and 99), which indicates that the production cost of biomass hydrogen increased over time compared to the adjacent previous time periods. The absolute values of z fluctuated over time at 2.378, 0.516, and 3.015 for each comparison. Thus, at least two comparisons (before 2000 vs. 2001–2010 and 2011–2015 vs. 2016–2020) reveal statistically significant differences between the two adjacent time categories.

Table 14. Wilcoxon rank-sum test for biomass hydrogen between pre-2000 and 2001–2010.

	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.	Obs.	R. sum	Ex.
		–2000 vs. 2001–2010			**2001–2010 vs. 2011–2015**			**2011–2015 vs. 2016–2020**	
Earlier	4	12	26	8	56	60	6	24	54
Later	8	66	52	6	49	45	11	129	99
Total	12	78	78	14	105	105	17	153	153
z value		−2.378 **			-0.516			−3.015 ***	

Note: Obs. is the number of observations; R. sum is the rank-sum value; Ex. is the expected value. *** indicates significance at the 1% level, ** is at the 5% level, respectively.

5. Discussion

5.1. Gray Hydrogen

From the non-parametric test results, we confirm that the production cost of gray hydrogen was lower than that of other hydrogens during the study period. We surmise that this is due to the trend of the low cost of fuel (coal and gas). However, based on the articles' publication years, it can be concluded that the trend of the production cost of gray hydrogen increased until 2010, and started declining after 2015.

This change in trend can be linked to the fuel cost. Until 2010, the cost of resources, such as coal and gas, was expected to increase in the future, but after 2010, there was an expectation of price depression, which was reflected in the decline in fuel cost in the mid-2010s.

Figures 7 and 8 show the price trends of coal and gas between 1990 and 2020, averaging those in Europe, the US, and Japan. Fuel cost units in these figures were converted from the original data sources to make the values consistent with hydrogen production costs presented in Table 5 and Figure 2, using conversion rates in Table 4. Price trends became volatile after 2005 and were mostly subject to the global economic situation (of China's economic growth, in particular). However, the trend of the 4-year rolling average mostly corresponded to the estimation of gray hydrogen, as described in Section 4, where prices rose until 2010 and plateaued between 2011 and 2015, after which prices decreased gradually.

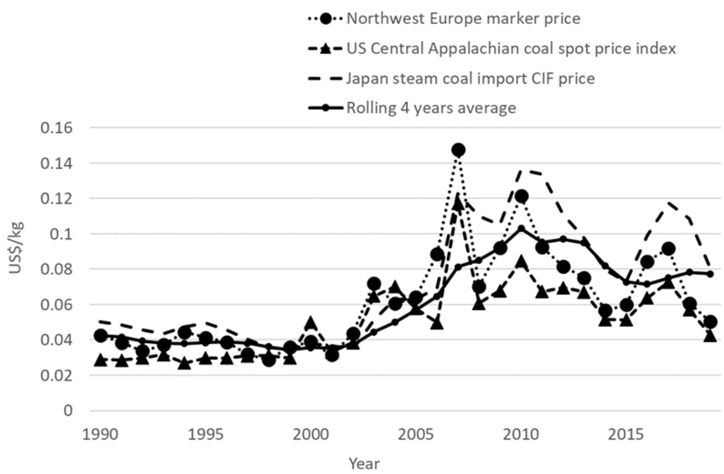

Figure 7. Trend of coal prices in Europe, US, Japan, and the 4-year rolling average. Source: created by the authors using data from BP Statistical Review of World Energy (July 2021) [7].

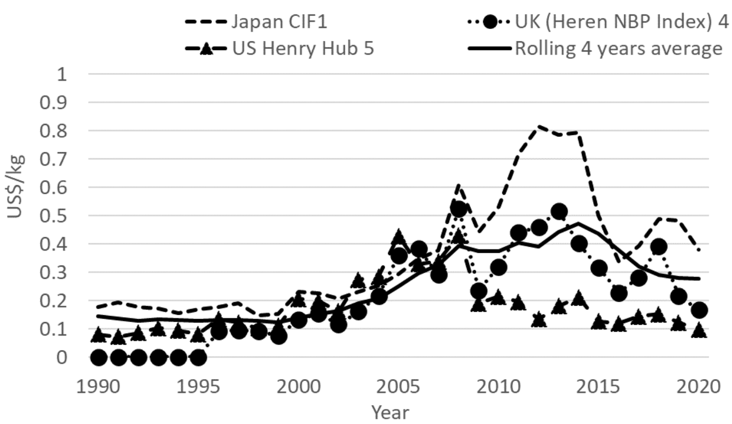

Figure 8. Trend of gas prices in the UK, US, Japan, and the 4-year rolling average. Source: created by the authors using data from the BP Statistical Review of World Energy (July 2021) [7].

In order to compare Figures 7 and 8, which plot the trends of actual coal and gas prices with those used for gray hydrogen cost forecasts in articles reviewed in this study, we extracted gas prices assumed in those articles and plotted them in Figure 9. The reason why we focused on gas prices is due to their higher levels compared to coal prices, thereby higher impacts were expected on gray hydrogen costs. Although the price levels are somewhat higher in Figure 9 than those in Figure 8, it is interesting to observe that the cost trend over time in Figure 9 (cost assumption) is roughly aligned with Figure 8 (actual cost), particularly with the UK trend, except for recent data in 2018 (higher cost case) and 2020. This implies that gray hydrogen cost forecasts in the articles properly assumed fuel prices in the calculations and we needed to consider future fuel cost developments when we assessed the gray hydrogen production costs.

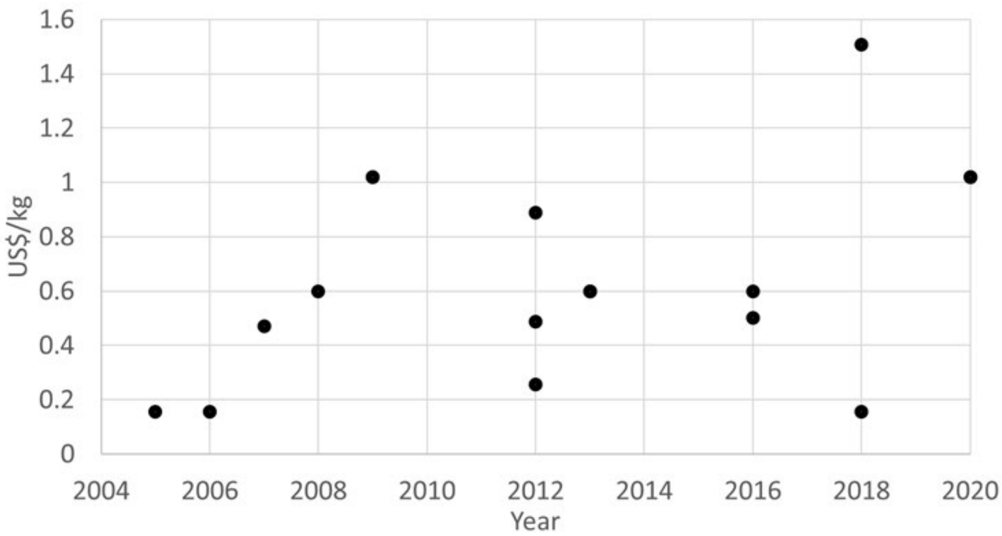

Figure 9. Scatter chart of gas costs assumed in SMR gray hydrogen.

5.2. Renewable Electrolysis Hydrogen

The non-parametric test results confirm that the production cost of renewable electrolysis hydrogen was higher than that of the other hydrogens over the study period. We estimate that this is due to the higher supply costs of renewable power, such as solar PV and wind, and capital expenditure in electrolyzers. When we compare the different time categories of the published articles, we could see that the production costs did not change significantly, which demonstrates that the renewable electrolysis hydrogen cost was not yet sufficiently low. However, articles published after 2015 tended to show a gradual decline in costs. We assume that these were influenced by declining renewable power costs (International Renewable Energy Agency (2020)) [8] and capital expenditures of electrolyzers (Christensen (2020)) [9].

Figure 10 shows the historical trend of the global, weighted-average utility scale, and the leveled cost of energy (LCOE) using various technologies. It provides evidence that the costs of solar and wind energy decreased over time. In particular, the LCOE of solar PV sharply declined, while those of offshore and onshore wind gradually declined.

Figure 11 shows the historical trend of the capital expenditures in electrolyzers in 2020 (US dollars). The expenditures are for two different technologies: alkaline electrolysis (AE) and proton exchange membranes (PEM). The data show that although there is a gradual declining trend in capital expenditures, the trend is not clear because of the low coefficient of determination (R^2), AE: R^2 = 0.0383, REM: R^2 = 0.2024.

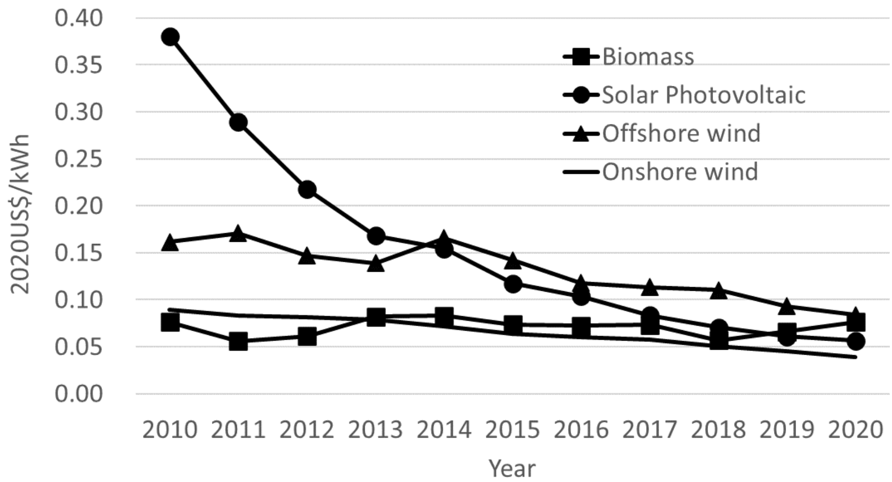

Figure 10. Trend of global, weighted-average, levelized renewable power generation costs in 2010–2020. Source: created by the authors using data from Renewable Power Generation Costs in 2020 (IRENA) [8].

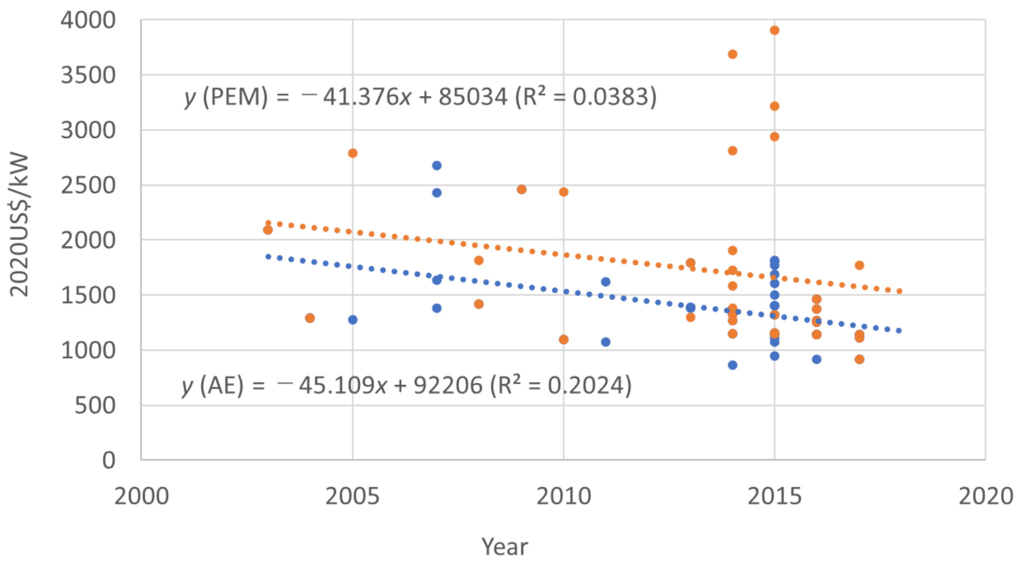

Figure 11. Trend of capital expenditures in electrolyzes (AE and PEM). Data source: created by the authors using data from Christensen (2020) [9].

Therefore, we assume that the cost reduction of renewable electrolysis hydrogen can be attributed to the reduction in the renewable power generation cost rather than in electrolyzer capital expenditures.

5.3. Biomass Hydrogen

Non-parametric tests confirm that the biomass hydrogen production cost was not significantly different from the other hydrogen types, but its cost was lower. Interestingly, its production cost increased over time and exceeded that of other hydrogens after 2015. This is because the main inputs of biomass hydrogen production are agricultural products, and the costs of agricultural products and labor increased, especially after 2015 (Food and Agriculture Organization of the United Nations (2020) [10], International Labour Organization (2020) [11]).

As shown in Figure 9, the historical trend of biomass power generation costs between 2010 and 2020 did not directly correspond to biomass hydrogen production costs. This relates to the technical aspect of hydrogen production because biomass hydrogen is mostly produced from biomass gasification rather than water electrolysis from biomass power generation.

6. Conclusions

This study investigated 174 hydrogen production cost data points from 114 articles published between 1979 and 2020. The non-parametric tests of these data present certain trends in the historical hydrogen cost forecasts. Gray hydrogen was the cheapest hydrogen production method, and its cost increased over time, while this trend reversed after 2015 due to weak fuel resource cost forecasts. The cost of renewable electrolysis hydrogen was always higher than that of the other hydrogens but started showing a gradual declining trend after 2015 because of the reduced renewable electricity cost and electrolyzer capital expenditure. The cost of biomass hydrogen increased similar to that of gray hydrogen and became higher than that of the others after 2015, due to increasing costs of agricultural products and labor. Renewable electrolysis hydrogen and biomass hydrogen will be potential candidates (as principal drivers) to reduce CO_2 emissions in the future, but renewable electrolysis hydrogen is more promising in this regard due to its declining production cost trend. Moreover, given that the production cost of gray hydrogen is showing a declining trend, it can be an alternative candidate to renewable electrolysis hydrogen because it can be equipped with carbon capture storage (CCS) to produce blue hydrogen, although we need to consider how much the cost of gray hydrogen will increase if the cost of CCS is added. The cost level of CCS depends on regions and local conditions, e.g., see International Energy Agency (2020) [12] on the cost trend of CCS that evidenced the case of a 35% cost reduction per CO_2 ton between 2014 and 2017 (Boundary Dam and Petra Nova in Canada). With the declining trend of the CCS cost, however, the total production cost of gray hydrogen with CCS will need to be competitive with renewable electrolysis hydrogen if we are to consider it as a future option.

There is a future task related to the data classification in this study. We conducted this study using 174 hydrogen production cost datasets but did not use the information on the cost forecast projection year and geographical regions (e.g., US, EU, or Asia). As pointed out in Section 3, these classifications with the projection year and regional segmentation can provide more detailed findings on the change in production costs, since those of gray and renewable electrolysis hydrogens are highly dependent on the availability of cheap gas, coal, or renewable electricity, which vary across subject regions. Moreover, the analysis of production cost forecasts in different projected years should be useful to investigate how production costs could change in the future. To conduct this extended study and achieve a more segmented analysis in a statistically significant manner, we need to expand the data source with an increased number of data points with detailed classifications by region and the forecasted year.

Funding: This research was funded by the Japan Society for the Promotion of Science (JSPS) through a Grant-in-Aid for Scientific Research (KAKENHI) 20KK0106.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Not applicable.

Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

Table A1. List of production cost forecasts in articles.

Authors	Issued Year	Projected Timing	Production Method	Country	Region	Production Cost Forecast
Beghi G.E. [13]	1979	1977	Electrolysis			USD 7–8/GJ
Broggi A. et al. [14]	1981	1996	Electrolysis			USD 8.40–9.21/GJ
Carleson G. [15]	1982	1985	Biomass (gasification)	Sweden	Europe	USD 9.80/GJ
Carleson G. [15]	1982	1985	Coal gasification	Sweden	Europe	USD 5.05/GJ
Carleson G. [15]	1982	1985	Electrolysis	Sweden	Europe	USD 9.65/GJ
Carleson G. [15]	1982	1985	SMR	Sweden	Europe	USD 4.45/GJ
Estève D. et al. [16]	1982	1986	Electrolysis (solar)			USD 1.4/m^3
Estève D. et al. [16]	1982	1995	Electrolysis (solar)			USD 0.5/m^3
Carleson G. [15]	1982	2005	Biomass (gasification)	Sweden	Europe	USD 10.70/GJ
Carleson G. [15]	1982	2005	Coal gasification	Sweden	Europe	USD 6.30/GJ
Carleson G. [15]	1982	2005	Electrolysis	Sweden	Europe	USD 11.60/GJ
Carleson G. [15]	1982	2005	SMR	Sweden	Europe	US7.80/GJ
Carleson G. [15]	1982	2025	Biomass (gasification)	Sweden	Europe	USD 11.6/GJ
Carleson G. [15]	1982	2025	Coal gasification	Sweden	Europe	USD 8.0/GJ
Carleson G. [15]	1982	2025	Electrolysis	Sweden	Europe	USD 14.1/GJ
Carleson G. [15]	1982	2025	SMR	Sweden	Europe	US12.4/GJ
Krikorian O.H. et al. [17]	1983	1980	Electrolysis	US	N America	USD 11.53–14.43/GJ
Aochi A. et al. [18]	1989	1985	Electrolysis	Japan	Asia	JPY 77.2/m^3
Ogden J.M. [19]	1991	2000	Electrolysis (solar)	US	N America	USD 9–14/GJ
Shiga H. et al. [20]	1998	1995	Biomass (gasification)	India	Asia	JPY 310/GJ
Ewan B.C.R. et al. [21]	2005	2005	Coal gasification	UK	Europe	USD 1.621/kg
Ewan B.C.R. et al. [21]	2005	2005	Coal gasification + CCS	UK	Europe	USD 3.114/kg
Da Silva E.P. et al. [22]	2005	2005	Electrolysis	Brazil	S America	USD 10.3/kg
Ewan B.C.R. et al. [21]	2005	2005	Electrolysis (solar)	UK	Europe	USD 14.95/kg
Ewan B.C.R. et al. [21]	2005	2005	Electrolysis (wind)	UK	Europe	USD 6.081/kg
Chen Z. et al. [23]	2005	2005	SMR	US	N America	USD 0.74–0.97/kg
Ewan B.C.R. et al. [21]	2005	2005	SMR	UK	Europe	USD 0.982/kg
Ewan B.C.R. et al. [21]	2005	2005	SMR + CCS	UK	Europe	USD 1.575/kg
Chen Z. et al. [24]	2006	2006	SMR	US	N America	USD 0.74–0.97/kg
Giaconia A. et al. [25]	2007	2005	Electrolysis	Italy	Europe	USD 7.531/kg
Dowaki K. et al. [26]	2007	2007	Biomass (gasification)	Japan	Asia	USD 5.75–7.86/kg
Forsberg P. et al. [27]	2007	2010	SMR (@ refueling station)	US	N America	USD 6.0/kg
Forsberg P. et al. [27]	2007	2030	SMR (@ refueling station)	US	N America	USD 4.1/kg
Lv P. et al. [28]	2008	2007	Biomass (gasification)	China	Asia	USD 1.69/kg
Balat M. [3]	2008	2008	Biomass	Turkey	Middle East	USD 10–14/GJ
Muradov N. et al. [29]	2008	2008	Biomass (reforming)	USA	N America	USD 3.00/kg
Balat M. [3]	2008	2008	Coal gasification	Turkey	Middle East	USD 10–12/GJ
Graf D. et al. [30]	2008	2008	Electrolysis	Germany	Europe	EUR 5.8/kg
Charvin P. et al. [31]	2008	2008	Electrolysis	France	Europe	USD 7.98/kg
Balat M. [3]	2008	2008	Electrolysis	Turkey	Middle East	USD 8/kg
Rivera-Tinoco R. et al. [32]	2008	2008	Electrolysis (biomass)	France	Europe	EUR 2.32/kg
Rodrigues Halmeman M.C. et al. [33]	2008	2008	Electrolysis (biomass)	Brazil	S America	USD 0.50 m^3
Balat M. [3]	2008	2008	SMR	Turkey	Middle East	USD 1.5/kg
Pilavachi P.A. et al. [34]	2009	2004	Electrolysis (hydraulic)	Greece	Europe	USD 1.25/kg
Pilavachi P.A. et al. [34]	2009	2004	Electrolysis (solar)	Greece	Europe	USD 16.00/kg
Lewis M.A. et al. [35]	2009	2005	Electrolysis	US	N America	USD 3.30/kg
Pilavachi P.A. et al. [34]	2009	2007	Biomass (gasification)	Greece	Europe	USD 23.78/kg [1]
Pilavachi P.A. et al. [34]	2009	2007	Coal gasification	Greece	Europe	USD 22.37/kg [2]
Pilavachi P.A. et al. [34]	2009	2007	Electrolysis (wind)	Greece	Europe	USD 36.75/kg [3]
Pilavachi P.A. et al. [34]	2009	2007	Smr	Greece	Europe	USD 32.75/kg [4]
Pregger T. et al. [36]	2009	2020	Biomass (gasification)	Germany	Europe	EUR 3.2–13ct/kWh

Table A1. *Cont.*

Authors	Issued Year	Projected Timing	Production Method	Country	Region	Production Cost Forecast
Pregger T. et al. [36]	2009	2020	Coal gasification + CCS	Germany	Europe	EUR 4.2–8.6ct/kWh
Pregger T. et al. [36]	2009	2020	Electrolysis (solar)	Germany	Europe	EUR 20–22ct/kWh
Pregger T. et al. [36]	2009	2020	Electrolysis (wind)	Germany	Europe	EUR 7–8ct/kWh
Pregger T. et al. [36]	2009	2020	SMR	Germany	Europe	EUR 3.6–7.7ct/kWh
Pregger T. et al. [36]	2009	2020	SMR + CCS	Germany	Europe	EUR 4.0–9.1ct/kWh
Wang Z.L. et al. [37]	2010	2002	Electrolysis	Canada	N America	USD 2.41/kg
Wang Z.L. et al. [37]	2010	2002	SMR	Canada	N America	USD 2.67/kg
Ljunggren M. et al. [38]	2010	2010	Biomass (fermentation)	Sweden	Europe	EUR 19.93/kg
Lemus R.G. et al. [6]	2010	2010	Biomass (gasification)	Spain	Europe	USD 44–82/GJ
Lemus R.G. et al. [6]	2010	2010	Electrolysis (hydraulic)	Spain	Europe	USD 45–66/GJ
Lemus R.G. et al. [6]	2010	2010	Electrolysis (solar)	Spain	Europe	USD 41.7–166/GJ
Lemus R.G. et al. [6]	2010	2010	Electrolysis (wind)	Spain	Europe	USD 34.0–75.2/GJ
Leybros J. et al. [39]	2010	2010	Hybrid-sulfur cycle	France	Europe	EUR 6.6/kg
Lemus R.G. et al. [6]	2010	2010	SMR	Spain	Europe	USD 6.9/GJ
Leybros J. et al. [40]	2010	2010	Sulfur–Iodine	France	Europe	EUR 12/kg
Lemus R.G. et al. [6]	2010	2020	Biomass (gasification)	Spain	Europe	USD 18.3/GJ
Lemus R.G. et al. [6]	2010	2030	Biomass (gasification)	Spain	Europe	USD 13–17/GJ
Ljunggren M. et al. [41]	2011	2011	Biomass (fermentation)	Sweden	Europe	EUR 51.0/kg
Müller S. et al. [42]	2011	2011	Biomass (gasification)	Austria	Europe	EUR 54/MWh
Huisman G.H. et al. [43]	2011	2011	Biomass (gasification)	Sweden	Europe	EUR 14.4/GJ
Mansilla C. et al. [44]	2011	2011	Electrolysis	France	Europe	EUR 3.27/kg
Balta M.T. et al. [45]	2011	2011	Electrolysis (geothermal)	Turkey	Middle East	USD 1.446–2.706/kg
Lu Y. et al. [46]	2011	2011	Electrolysis (solar)	China	Asia	RMB38.46/kg
Menanteau P. et al. [47]	2011	2011	Electrolysis (wind)	France	Europe	EUR 4–12/kg
Holtermann T. et al. [48]	2011	2011	Photobioreactor	Germany	Europe	EUR 50/MWh
Corgnale C. et al. [49]	2011	2015	Solar thermochemical	US	N America	USD 4.80/kg
Huisman G.H. et al. [43]	2011	2020	Biomass (gasification)	Sweden	Europe	EUR 12.8/GJ
Corgnale C. et al. [49]	2011	2025	Solar thermochemical	US	N America	USD 3.19/kg
Gim B. et al. [50]	2012	2006	Electrolysis (wind)	Korea	Asia	USD 6.55/kg
Gim B. et al. [50]	2012	2006	Electrolysis (wind)	US	N America	USD 4.80/kg
Gim B. et al. [50]	2012	2006	SMR	Korea	Asia	USD 4.87/kg
Gim B. et al. [50]	2012	2006	SMR	US	N America	USD 3.00/kg
Lysenko S. et al. [4]	2012	2012	Biomass (gasification)	US	N America	USD 2.23–3.01/kg
Becker W.L. et al. [51]	2012	2012	Biomass (gasification)	US	N America	USD 1.6/kg
Becker W.L. et al. [51]	2012	2012	CHHP	US	N America	USD 4.4/kg
Chiuta S. et al. [52]	2012	2012	Coal gasification	South Africa	Africa	USD 3/kg
Mansilla C. et al. [53]	2012	2012	Electrolysis	France	Europe	EUR 2.90/kg
Becker W.L. et al. [51]	2012	2012	Electrolysis	US	N America	USD 4.17/kg
Genç G. et al. [54]	2012	2012	Electrolysis (wind)	Turkey	Middle East	USD 8.5/kg
Becker W.L. et al. [51]	2012	2012	SMR	US	N America	USD 1.4/kg
Liberatore R. et al. [55]	2012	2012	Solar sulfur–iodine thermochemical	Italy	Europe	EUR 8.3/kg
Gim B. et al. [50]	2012	2017	Electrolysis (wind)	Korea	Asia	USD 4.23/kg
Gim B. et al. [50]	2012	2017	Electrolysis (wind)	US	N America	USD 2.80/kg
Gim B. et al. [50]	2012	2017	SMR	Korea	Asia	USD 3.56/kg
Gim B. et al. [50]	2012	2017	SMR	US	N America	USD 2.00/kg
Mansilla C. et al. [56]	2013	2012	Electrolysis	France	Europe	EUR 3.37/kg
Mansilla C. et al. [56]	2013	2012	Electrolysis	Germany	Europe	EUR 3.23/kg
Mansilla C. et al. [56]	2013	2012	Electrolysis	Spain	Europe	EUR 3.52/kg
Wu W. et al. [57]	2013	2012	SMR	Taiwan	Asia	USD 5.67/kmol
Olateju B. et al. [58]	2013	2013	Coal gasification	Canada	N America	USD 1.78/kg
Olateju B. et al. [58]	2013	2013	Coal gasification + CCS	Canada	N America	USD 2.11/kg
Olateju B. et al. [58]	2013	2013	Coal gasification + EOR	Canada	N America	USD 1.61/kg
Olateju B. et al. [58]	2013	2013	SMR	Canada	N America	USD 1.73/kg
Olateju B. et al. [58]	2013	2013	SMR + CCS	Canada	N America	USD 2.14/kg

Table A1. *Cont.*

Authors	Issued Year	Projected Timing	Production Method	Country	Region	Production Cost Forecast
Urbaniec K. et al. [59]	2014	2014	Biomass (fermentation)	Poland	Europe	EUR 9.30/kg
Brown D. et al. [60]	2014	2014	Biomass (gasification)	Canada	N America	USD 3.01/kg
Olateju B. et al. [61]	2014	2014	Electrolysis (wind)	Canada	N America	USD 7.84/kg
Guo L.J. et al. [62]	2015	2015	Coal gasification	China	Asia	USD 0.111m^3
Bennoua S. et al. [63]	2015	2015	Electrolysis	France	Europe	EUR 3.0–4.5/kg
Matzen M. et al. [64]	2015	2015	Electrolysis (wind)	US	N America	USD 3.74–5.86/kg
Galera S. et al. [65]	2015	2015	Water reforming	Spain	Europe	USD 5.36/kg
Loisel R. et al. [66]	2015	2030	Electrolysis (wind)	France	Europe	EUR 4.2–13.0/kg
Han W. et al. [67]	2016	2016	Biomass (fermentation)	China	Asia	USD 14.89/kg
Abuşoğlu A. et al. [68]	2016	2016	Electrolysis (biomass)	Turkey	Middle East	USD 3.31–15.63/kg
Olateju B. et al. [69]	2016	2016	Electrolysis (hydraulic)	Canada	N America	USD 1.18–2.43/kg
Southall G.D. et al. [70]	2016	2016	Electrolysis (renewable)	UK	Europe	GBP 4.98/kg
Olateju B. et al. [71]	2016	2016	Electrolysis (wind)	Canada	N America	USD 3.37–9.0/kg
AlRafea K. et al. [72]	2016	2016	Electrolysis (wind)	Canada	N America	USD 4.0–5.0/kg
Oh T.H. [73]	2016	2016	Formic acid	Korea	Asia	USD 380/kg [5]
Olateju B. et al. [71]	2016	2016	SMR	Canada	N America	USD 1.87–2.60/kg
Shafiee A. et al. [74]	2016	2016	SMR	Saudi Arabia	Middle East	USD 1.98/kg
Couto N.D. et al. [75]	2016	2016	Waste gasification	Portugal	Europe	EUR 2.66/kg
Chang W.-C. et al. [76]	2016	2016	Waste hydrogen from coked coal	Taiwan	Asia	USD 0.69–0.78/m^3
Gillessen B. et al. [77]	2017	2015	Electrolysis (solar)	Germany	Europe	EUR 0.057/kWh
Wang G.-R. et al. [78]	2017	2017	Biomass (gasification)	China	Asia	EUR 2.4–3.85/kg
Lei Y. et al. [79]	2017	2017	Biomass (reforming)	China	Asia	USD 0.231–0.465/kWh
Madeira J.G.F. et al. [80]	2017	2017	Biomass (reforming)	Brazil	S America	USD 0.13–0.24/kWh
Lee B. et al. [81]	2017	2017	Electrolysis	Korea	Asia	USD 7.72/kg
Yuksel Y.E. et al. [82]	2017	2017	Electrolysis (geothermal)	Turkey	Middle East	USD 1.1/kg
Lee B. et al. [81]	2017	2017	SMR	Korea	Asia	USD 7.59/kg
Ozcan H. et al. [83]	2017	2017	Water thermochemical	Canada	N America	USD 3.67/kg
Gillessen B. et al. [77]	2017	2030	Electrolysis (solar)	Germany	Europe	EUR 0.034/kWh
Schweitzer D. et al. [84]	2018	2018	Biomass (gasification)	Germany	Europe	EUR 6–10/kg
Di Marcoberardino G. et al. [85]	2018	2018	Biomass (reforming)	Italy	Europe	EUR 4–4.1/kg
Lin K.-W. et al. [86]	2018	2018	Biomass (reforming)	Taiwan	Asia	USD 5.1–5.66/kmol
Di Marcoberardino G. et al. [87]	2018	2018	Biomass (reforming)	Italy	Europe	EUR 4.2–5.0/kg
Ajanovic A. et al. [88]	2018	2018	Electrolysis (renewable)	Austria	Europe	EUR 0.07–0.12/kWh
Andresen L. et al. [89]	2018	2018	Electrolysis (renewable)	Germany	Europe	EUR 2.00–4.55/kg
Robinius M. et al. [90]	2018	2018	Electrolysis (renewable)	Germany	Europe	EUR 4–7.5/kg
Boudries R. [91]	2018	2018	Electrolysis (solar)	Algeria	Africa	USD 1.5–2.0/kg
Touili S. et al. [92]	2018	2018	Electrolysis (solar)	Morocco	Africa	USD 4.64–5.79/kg
Arora A. et al. [93]	2018	2018	SMR	US	N America	USD 2.13–3.12/kg
Riva L. et al. [94]	2018	2018	SMR		Europe	EUR 0.178/m^3
Lee D.-Y. et al. [95]	2018	2018	Steam cracking	US	N America	USD 0.9–1.1/kg
Keipi T. et al. [96]	2018	2018	Thermal decomposition of methane	Finland	Europe	EUR 72/MWh
Ajanovic A.et al. [88]	2018	2050	Electrolysis (renewable)	Austria	Europe	EUR 0.06–0.09/kWh
Grabarczyk R. et al. [97]	2019	2019	Biomass (fermentation)	Poland	Europe	EUR 32.68/kg
Becker W.L. et al. [98]	2019	2019	Biomass (gasification)	US	N America	USD 2.48/kg

Table A1. *Cont.*

Authors	Issued Year	Projected Timing	Production Method	Country	Region	Production Cost Forecast
Rau F. et al. [99]	2019	2019	Biomass (reforming)	Germany	Europe	EUR 2.90–5.32/kg
Di Marcoberardino G. et al. [100]	2019	2019	Biomass (reforming)	Italy	Europe	EUR 4.01–4.11/kg
Chisalita D.-A. et al. [101]	2019	2019	Chemical looping	Romania	Europe	EUR 41.84/MWH
Bahzad H. et al. [102]	2019	2019	Chemical looping	UK	Europe	USD 1.16–2.10/kg
Bahzad H. et al. [103]	2019	2019	Chemical looping	UK	Europe	USD 1.41–1.62/kg
González Rodríguez D. et al. [104]	2019	2019	Electrolysis (nuclear)	Brazil	S America	USD 4.8–5.96/kg
Timmerberg S. et al. [105]	2019	2019	Electrolysis (renewable)	Algeria, Morocco, Libya	Africa	EUR 45–99/MWh
Grüger F. et al. [106]	2019	2019	Electrolysis (renewable)	Germany	Europe	EUR 11.52–13.42/kg
Arellano-Garcia H. et al. [107]	2019	2019	Electrolysis (solar)		Europe	USD 10.9–11.0/kg
Micena R.P. et al. [108]	2019	2019	Electrolysis (solar)	Brazil	S America	USD 8.96–13.55/kg
Becker W.L. et al. [98]	2019	2019	Electrolysis (wind)	US	N America	USD 6.71/kg
Guerra O.J. et al. [109]	2019	2020	Electrolysis	UA	N America	USD 2.6–12.3/kg
Kikuchi Y. et al. [110]	2019	2030	Electrolysis (solar)	Japan	Asia	JPY 17.42–26.39/m^3
Khzouz M. et al. [111]	2020	2020	SMR	UK	Europe	USD 0.9/kg
Khzouz M. et al. [111]	2020	2020	Electrolysis	UK	Europe	USD 2.92/kg
Tolley T.E. et al. [112]	2020	2020	SMR	US	N America	USD 1.10/gge
He Y. et al. [113]	2020	2020	Chemical looping	China	Asia	USD 32.87/MWh
Armijo J. et al. [114]	2020	2020	Electrolysis (renewable)	Chile, Argentine	S America	USD 1.94–2.33/kg
Coleman D. et al. [115]	2020	2020	Electrolysis (wind)	Germany	Europe	EUR 3.50/kg
Schnuelle C. et al. [116]	2020	2020	Electrolysis (solar)	Germany	Europe	EUR 5.00/kg
Schnuelle C. et al. [116]	2020	2020	Electrolysis (wind)	Germany	Europe	EUR 4.33/kg
Roussanaly S. et al. [117]	2020	2020	SMR	Norway	Europe	EUR 12.2/m^3
Roussanaly S. et al. [117]	2020	2020	SMR + CCS	Norway	Europe	EUR 18.1ct/m^3
Lux B. et al. [118]	2020	2050	Electrolysis (renewable)		Europe	EUR 110/MWh
Matute G. et al. [119]	2021	2020	Electrolysis	Spain	Europe	EUR 3.0/kg
Kazi M.-K. et al. [120]	2021	2020	Electrolysis (renewable)	Qatar	Middle East	USD 10.0/kg
Herwarts S. et al. [121]	2021	2020	Electrolysis (wind)	Germany	Europe	EUR 6.4/kg
Koleva M. et al. [122]	2021	2020	Electrolysis (solar)	US	N America	USD 6.59/kg
Koleva M. et al. [122]	2021	2020	SMR	US	N America	USD 1.34/kg
de Souza T.A.Z. et al. [123]	2021	2020	Biomass (reforming)	Brazil	S America	USD 2.42–5.26/kg

Note: The numbers after author names refer to the reference numbers. [1] This case was excluded from the analysis as an outlier. [2] Ditto. [3] Ditto. [4] Ditto. [5] This case was excluded from the analysis as an outlier.

References

1. Maggio, G.; Nicita, A.; Squadrito, G. How the hydrogen production from RES could change energy and fuel markets: A review of recent literature. *Int. J. Hydrogen Energy* **2019**, *44*, 11371–11384. [CrossRef]
2. Sharma, S.; Agarwal, S.; Jain, A. Significance of hydrogen as economic and environmentally friendly fuel. *Energies* **2021**, *14*, 7389. [CrossRef]
3. Balat, M. Potential importance of hydrogen as a future solution to environmental and transportation problems. *Int. J. Hydrogen Energy* **2008**, *33*, 4013–4029. [CrossRef]
4. Lysenko, S.; Sadaka, S.; Brown, R.C. Comparison of the cost of hydrogen from air-blown and thermally ballasted gasifiers. *Biofuels Bioprod. Biorefining* **2012**, *6*, 673–685. [CrossRef]
5. US Department of Energy. DOE H2A Production Analysis. Available online: https://www.hydrogen.energy.gov/h2a_production.html (accessed on 15 May 2022).
6. Lemus, R.G.; Martínez Duart, J.M. Updated hydrogen production costs and parities for conventional and renewable technologies. *Int. J. Hydrogen Energy* **2010**, *35*, 3929–3936. [CrossRef]

7. BP. Statistical Review of World Energy. 2021. Available online: https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html (accessed on 15 May 2022).
8. International Renewable Energy Agency. Renewable Power Generation Costs in 2020. 2021. Available online: https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020 (accessed on 15 May 2022).
9. Christensen, A. *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe*; International Council on Clean Transportation: Washington, DC, USA, 2020.
10. Food and Agriculture Organization of the United Nations. Food Outlook—Biannual Report on Global Food Markets. 2020. Available online: https://www.fao.org/documents/card/en/c/ca9509en/ (accessed on 15 May 2022).
11. International Labour Organization. Global Wage Report 2020–2021. 2020. Available online: https://www.ilo.org/global/research/global-reports/global-wage-report/2020/lang--en/index.htm (accessed on 15 May 2022).
12. International Energy Agency. Energy Technology Perspectives 2020, Special Report on Carbon Capture Utilisation and Storage. 2020. Available online: https://www.iea.org/reports/energy-technology-perspectives-2020 (accessed on 12 June 2022).
13. Beghi, G.E. Present state and future prospects of thermochemical hydrogen production. *Int. J. Hydrogen Energy* **1979**, *4*, 499–512. [CrossRef]
14. Broggi, A.; Joels, R.; Mertel, G.; Morbello, M. A method for the techno-economic evaluation of chemical processes-improvements to the "OPTIMO" code. *Int. J. Hydrogen Energy* **1981**, *6*, 25–44. [CrossRef]
15. Carleson, G. Assessment of the potential future market in Sweden for hydrogen as an energy carrier. *Int. J. Hydrogen Energy* **1982**, *7*, 821–829. [CrossRef]
16. Estève, D.; Ganibal, C.; Steinmetz, D.; Vialaron, A. Performance of a photovoltaic electrolysis system. *Int. J. Hydrogen Energy* **1982**, *7*, 711–716. [CrossRef]
17. Krikorian, O.H.; Brown, L.C. Thermochemical hydrogen production based on magnetic fusion. *Int. J. Hydrogen Energy* **1983**, *8*, 515–528. [CrossRef]
18. Aochi, A.; Tadokoro, T.; Yoshida, K.; Kameyama, H.; Nobue, M.; Yamaguchi, T. Economical and technical evaluation of UT-3 thermochemical hydrogen production process for an industrial scale plant. *Int. J. Hydrogen Energy* **1989**, *14*, 421–429. [CrossRef]
19. Ogden, J.M. Cost and performance sensitivity studies for solar photovoltaic/electrolytic hydrogen systems. *Sol. Cells* **1991**, *30*, 515–523. [CrossRef]
20. Shiga, H.; Shinda, K.; Hagiwara, K.; Tsutsumi, A.; Sakurai, M.; Yoshida, K.; Bilgen, E. Large-scale hydrogen production from biogas. *Int. J. Hydrogen Energy* **1998**, *23*, 631–640. [CrossRef]
21. Ewan, B.C.R.; Allen, R.W.K. A figure of merit assessment of the routes to hydrogen. *Int. J. Hydrogen Energy* **2005**, *30*, 809–819. [CrossRef]
22. Da Silva, E.P.; Marin Neto, A.J.; Ferreira, P.F.P.; Camargo, J.C.; Apolinário, F.R.; Pinto, C.S. Analysis of hydrogen production from combined photovoltaics, wind energy and secondary hydroelectricity supply in Brazil. *Sol. Energy* **2005**, *78*, 670–677. [CrossRef]
23. Chen, Z.; Elnashaie, S.S.E.H. Economics of the clean fuel hydrogen in a novel autothermal reforming process. *Ind. Eng. Chem. Res.* **2005**, *44*, 4834–4840. [CrossRef]
24. Chen, Z.; Elnashaie, S.S.E.H. Development of a novel autothermal reforming process and its economics for clean hydrogen production. *Asia-Pac. J. Chem. Eng.* **2006**, *1*, 5–12. [CrossRef]
25. Giaconia, A.; Grena, R.; Lanchi, M.; Liberatore, R.; Tarquini, P. Hydrogen/methanol production by sulfur-iodine thermochemical cycle powered by combined solar/fossil energy. *Int. J. Hydrogen Energy* **2007**, *32*, 469–481. [CrossRef]
26. Dowaki, K.; Ohta, T.; Kasahara, Y.; Kameyama, M.; Sakawaki, K.; Mori, S. An economic and energy analysis on bio-hydrogen fuel using a gasification process. *Renew. Energy* **2007**, *32*, 80–94. [CrossRef]
27. Forsberg, P.; Karlström, M. On optimal investment strategies for a hydrogen refueling station. *Int. J. Hydrogen Energy* **2007**, *32*, 647–660. [CrossRef]
28. Lv, P.; Wu, C.; Ma, L.; Yuan, Z. A study on the economic efficiency of hydrogen production from biomass residues in China. *Renew. Energy* **2008**, *33*, 1874–1879. [CrossRef]
29. Muradov, N.; Smith, F.; T-Raissi, A. Hydrogen production by catalytic processing of renewable methane-rich gases. *Int. J. Hydrogen Energy* **2008**, *33*, 2023–2035. [CrossRef]
30. Graf, D.; Monnerie, N.; Roeb, M.; Schmitz, M.; Sattler, C. Economic comparison of solar hydrogen generation by means of thermochemical cycles and electrolysis. *Int. J. Hydrogen Energy* **2008**, *33*, 4511–4519. [CrossRef]
31. Charvin, P.; Stéphane, A.; Florent, L.; Gilles, F. Analysis of solar chemical processes for hydrogen production from water splitting thermochemical cycles. *Energy Convers. Manag.* **2008**, *49*, 1547–1556. [CrossRef]
32. Rivera-Tinoco, R.; Mansilla, C.; Bouallou, C.; Werkoff, F. On the possibilities of producing hydrogen by high temperature electrolysis of water steam supplied from biomass or waste incineration units. *Int. J. Green Energy* **2008**, *5*, 388–404. [CrossRef]
33. Rodrigues Halmeman, M.C.; Melegari de Souza, S.N.; Oyama, P.T. Potential and costs for the production of electrolytic hydrogen in alcohol and sugar cane plants in the central and south regions of Brazil. *Int. J. Hydrogen Energy* **2008**, *33*, 6858–6864. [CrossRef]
34. Pilavachi, P.A.; Chatzipanagi, A.I.; Spyropoulou, A.I. Evaluation of hydrogen production methods using the Analytic Hierarchy Process. *Int. J. Hydrogen Energy* **2009**, *34*, 5294–5303. [CrossRef]
35. Lewis, M.A.; Ferrandon, M.S.; Tatterson, D.F.; Mathias, P. Evaluation of alternative thermochemical cycles—Part III further development of the Cu-Cl cycle. *Int. J. Hydrogen Energy* **2009**, *34*, 4136–4145. [CrossRef]

36. Pregger, T.; Graf, D.; Krewitt, W.; Sattler, C.; Roeb, M.; Möller, S. Prospects of solar thermal hydrogen production processes. *Int. J. Hydrogen Energy* **2009**, *34*, 4256–4267. [CrossRef]
37. Wang, Z.L.; Naterer, G.F.; Gabriel, K.S.; Gravelsins, R.; Daggupati, V.N. Comparison of sulfur-iodine and copper-chlorine thermochemical hydrogen production cycles. *Int. J. Hydrogen Energy* **2010**, *35*, 4820–4830. [CrossRef]
38. Ljunggren, M.; Zacchi, G. Techno-economic evaluation of a two-step biological process for hydrogen production. *Biotechnol. Prog.* **2010**, *26*, 496–504. [CrossRef] [PubMed]
39. Leybros, J.; Saturnin, A.; Mansilla, C.; Gilardi, T.; Carles, P. Plant sizing and evaluation of hydrogen production costs from advanced processes coupled to a nuclear heat source: Part II: Hybrid-sulphur cycle. *Int. J. Hydrogen Energy* **2010**, *35*, 1019–1028. [CrossRef]
40. Leybros, J.; Gilardi, T.; Saturnin, A.; Mansilla, C.; Carles, P. Plant sizing and evaluation of hydrogen production costs from advanced processes coupled to a nuclear heat source. Part I: Sulphur-iodine cycle. *Int. J. Hydrogen Energy* **2010**, *35*, 1008–1018. [CrossRef]
41. Ljunggren, M.; Wallberg, O.; Zacchi, G. Techno-economic comparison of a biological hydrogen process and a 2nd generation ethanol process using barley straw as feedstock. *Bioresour. Technol.* **2011**, *102*, 9524–9531. [CrossRef] [PubMed]
42. Müller, S.; Stidl, M.; Pröll, T.; Rauch, R.; Hofbauer, H. Hydrogen from biomass: Large-scale hydrogen production based on a dual fluidized bed steam gasification system. *Biomass Convers. Biorefinery* **2011**, *1*, 55–61. [CrossRef]
43. Huisman, G.H.; Van Rens, G.L.M.A.; De Lathouder, H.; Cornelissen, R.L. Cost estimation of biomass-to-fuel plants producing methanol, dimethylether or hydrogen. *Biomass Bioenergy* **2011**, *35* (Suppl. S1), S155–S166. [CrossRef]
44. Mansilla, C.; Dautremont, S.; Shoai Tehrani, B.; Cotin, G.; Avril, S.; Burkhalter, E. Reducing the hydrogen production cost by operating alkaline electrolysis as a discontinuous process in the French market context. *Int. J. Hydrogen Energy* **2011**, *36*, 6407–6413. [CrossRef]
45. Balta, M.T.; Dincer, I.; Hepbasli, A. Exergoeconomic analysis of a hybrid copper-chlorine cycle driven by geothermal energy for hydrogen production. *Int. J. Hydrogen Energy* **2011**, *36*, 11300–11308. [CrossRef]
46. Lu, Y.; Zhao, L.; Guo, L. Technical and economic evaluation of solar hydrogen production by supercritical water gasification of biomass in China. *Int. J. Hydrogen Energy* **2011**, *36*, 14349–14359. [CrossRef]
47. Menanteau, P.; Quéméré, M.M.; Le Duigou, A.; Le Bastard, S. An economic analysis of the production of hydrogen from wind-generated electricity for use in transport applications. *Energy Policy* **2011**, *39*, 2957–2965. [CrossRef]
48. Holtermann, T.; Madlener, R. Assessment of the technological development and economic potential of photobioreactors. *Appl. Energy* **2011**, *88*, 1906–1919. [CrossRef]
49. Corgnale, C.; Summers, W.A. Solar hydrogen production by the Hybrid Sulfur process. *Int. J. Hydrogen Energy* **2011**, *36*, 11604–11619. [CrossRef]
50. Gim, B.; Yoon, W.L. Analysis of the economy of scale and estimation of the future hydrogen production costs at on-site hydrogen refueling stations in Korea. *Int. J. Hydrogen Energy* **2012**, *37*, 19138–19145. [CrossRef]
51. Becker, W.L.; Braun, R.J.; Penev, M.; Melaina, M. Design and technoeconomic performance analysis of a 1 MW solid oxide fuel cell polygeneration system for combined production of heat. *J. Power Source* **2012**, *200*, 34–44. [CrossRef]
52. Chiuta, S.; Blom, E. Techno-economic evaluation of a nuclear-assisted coal-to-liquid facility. *Prog. Nucl. Energy* **2012**, *54*, 68–74. [CrossRef]
53. Mansilla, C.; Louyrette, J.; Albou, S.; Barbieri, G.; Collignon, N.; Bourasseau, C.; Salasc, B.; Valentin, S.; Dautremont, S.; Martin, J.; et al. Electric system management through hydrogen production-A market driven approach in the French context. *Int. J. Hydrogen Energy* **2012**, *37*, 10986–10991. [CrossRef]
54. Genç, G.; Çelik, M.; Serdar Genç, M. Cost analysis of wind-electrolyzer-fuel cell system for energy demand in Pnarbaş-Kayseri. *Int. J. Hydrogen Energy* **2012**, *37*, 12158–12166. [CrossRef]
55. Liberatore, R.; Lanchi, M.; Giaconia, A.; Tarquini, P. Energy and economic assessment of an industrial plant for the hydrogen production by water-splitting through the sulfur-iodine thermochemical cycle powered by concentrated solar energy. *Int. J. Hydrogen Energy* **2012**, *37*, 9550–9565. [CrossRef]
56. Mansilla, C.; Louyrette, J.; Albou, S.; Bourasseau, C.; Dautremont, S. Economic competitiveness of off-peak hydrogen production today—A european comparison. *Energy* **2013**, *55*, 996–1001. [CrossRef]
57. Wu, W.; Wang, C.-Y. Design and control of stand-alone hydrogen production systems with maximum waste heat recovery. *Ind. Eng. Chem. Res.* **2013**, *52*, 14601–14612. [CrossRef]
58. Olateju, B.; Kumar, A. Techno-economic assessment of hydrogen production from underground coal gasification (UCG) in Western Canada with carbon capture and sequestration (CCS) for upgrading bitumen from oil sands. *Appl. Energy* **2013**, *111*, 428–440. [CrossRef]
59. Urbaniec, K.; Grabarczyk, R. Hydrogen production from sugar beet molasses—A techno-economic study. *J. Clean. Prod.* **2014**, *65*, 324–329. [CrossRef]
60. Brown, D.; Rowe, A.; Wild, P. Techno-economic comparisons of hydrogen and synthetic fuel production using forest residue feedstock. *Int. J. Hydrogen Energy* **2014**, *39*, 12551–12562. [CrossRef]
61. Olateju, B.; Monds, J.; Kumar, A. Large scale hydrogen production from wind energy for the upgrading of bitumen from oil sands. *Appl. Energy* **2014**, *118*, 48–56. [CrossRef]

62. Guo, L.J.; Jin, H.; Ge, Z.W.; Lu, Y.J.; Cao, C.Q. Industrialization prospects for hydrogen production by coal gasification in supercritical water and novel thermodynamic cycle power generation system with no pollution emission. *Sci. China Technol. Sci.* **2015**, *58*, 1989–2002. [CrossRef]
63. Bennoua, S.; Le Duigou, A.; Quéméré, M.-M.; Dautremont, S. Role of hydrogen in resolving electricity grid issues. *Int. J. Hydrogen Energy* **2015**, *40*, 7231–7245. [CrossRef]
64. Matzen, M.; Alhajji, M.; Demirel, Y. Chemical storage of wind energy by renewable methanol production: Feasibility analysis using a multi-criteria decision matrix. *Energy* **2015**, *93*, 343–353. [CrossRef]
65. Galera, S.; Gutiérrez Ortiz, F.J. Techno-economic assessment of hydrogen and power production from supercritical water reforming of glycerol. *Fuel* **2015**, *144*, 307–316. [CrossRef]
66. Loisel, R.; Baranger, L.; Chemouri, N.; Spinu, S.; Pardo, S. Economic evaluation of hybrid off-shore wind power and hydrogen storage system. *Int. J. Hydrogen Energy* **2015**, *40*, 6727–6739. [CrossRef]
67. Han, W.; Hu, Y.Y.; Li, S.Y.; Li, F.F.; Tang, J.H. Biohydrogen production from waste bread in a continuous stirred tank reactor: A techno-economic analysis. *Bioresour. Technol.* **2016**, *221*, 318–323. [CrossRef]
68. Abuşoğlu, A.; Demir, S.; Özahi, E. Energy and economic analyses of models developed for sustainable hydrogen production from biogas-based electricity and sewage sludge. *Int. J. Hydrogen Energy* **2016**, *41*, 13426–13435. [CrossRef]
69. Olateju, B.; Kumar, A. A techno-economic assessment of hydrogen production from hydropower in Western Canada for the upgrading of bitumen from oil sands. *Energy* **2016**, *115*, 604–614. [CrossRef]
70. Southall, G.D.; Khare, A. The feasibility of distributed hydrogen production from renewable energy sources and the financial contribution from UK motorists on environmental grounds. *Sustain. Cities Soc.* **2016**, *26*, 134–149. [CrossRef]
71. Olateju, B.; Kumar, A.; Secanell, M. A techno-economic assessment of large scale wind-hydrogen production with energy storage in Western Canada. *Int. J. Hydrogen Energy* **2016**, *41*, 8755–8776. [CrossRef]
72. AlRafea, K.; Fowler, M.; Elkamel, A.; Hajimiragha, A. Integration of renewable energy sources into combined cycle power plants through electrolysis generated hydrogen in a new designed energy hub. *Int. J. Hydrogen Energy* **2016**, *41*, 16718–16728. [CrossRef]
73. Oh, T.H. A formic acid hydrogen generator using Pd/C3N4 catalyst for mobile proton exchange membrane fuel cell systems. *Energy* **2016**, *112*, 679–685. [CrossRef]
74. Shafiee, A.; Arab, M.; Lai, Z.; Liu, Z.; Abbas, A. Modelling and sequential simulation of multi-tubular metallic membrane and techno-economics of a hydrogen production process employing thin-layer membrane reactor. *Int. J. Hydrogen Energy* **2016**, *41*, 19081–19097. [CrossRef]
75. Couto, N.D.; Silva, V.B.; Rouboa, A. Assessment on steam gasification of municipal solid waste against biomass substrates. *Energy Convers. Manag.* **2016**, *124*, 92–103. [CrossRef]
76. Chang, W.-C.; Huang, A.Y.-J.; Huang, D.-R.; Chen, T.-Y. An economic evaluation on the purification and storage of waste hydrogen for the use of fuel cell scooters. *Int. J. Green Energy* **2016**, *13*, 1608–1614. [CrossRef]
77. Gillessen, B.; Heinrichs, H.U.; Stenzel, P.; Linssen, J. Hybridization strategies of power-to-gas systems and battery storage using renewable energy. *Int. J. Hydrogen Energy* **2017**, *42*, 13554–13567. [CrossRef]
78. Wang, G.-R.; Li, D.-X.; Ruan, W.-B.; Jin, C.-L. Simulation and economic study of hydrogen production from biomass and RDF gasification. *Energy Sources Part B Econ. Plan. Policy* **2017**, *12*, 1061–1065. [CrossRef]
79. Lei, Y.; Bin, Y.; Peng, J. Economic analysis of hydrogen production from steam reforming process. *Energy Sources Part B Econ. Plan. Policy* **2017**, *12*, 1074–1079. [CrossRef]
80. Madeira, J.G.F.; Delgado, A.R.S.; Boloy, R.A.M.; Coutinho, E.R.; Loures, C.C.A. Exergetic and economic evaluation of incorporation of hydrogen production in a cassava wastewater plant. *Appl. Therm. Eng.* **2017**, *123*, 1072–1078. [CrossRef]
81. Lee, B.; Chae, H.; Choi, N.H.; Moon, C.; Moon, S.; Lim, H. Economic evaluation with sensitivity and profitability analysis for hydrogen production from water electrolysis in Korea. *Int. J. Hydrogen Energy* **2017**, *42*, 6462–6471. [CrossRef]
82. Yuksel, Y.E.; Ozturk, M. Thermodynamic and thermoeconomic analyses of a geothermal energy based integrated system for hydrogen production. *Int. J. Hydrogen Energy* **2017**, *42*, 2530–2546. [CrossRef]
83. Ozcan, H.; Dincer, I. Exergoeconomic optimization of a new four-step magnesium–chlorine cycle. *Int. J. Hydrogen Energy* **2017**, *42*, 2435–2445. [CrossRef]
84. Schweitzer, D.; Albrecht, F.G.; Schmid, M.; Beirow, M.; Spörl, R.; Dietrich, R.-U.; Seitz, A. Process simulation and techno-economic assessment of SER steam gasification for hydrogen production. *Int. J. Hydrogen Energy* **2018**, *43*, 569–579. [CrossRef]
85. Di Marcoberardino, G.; Foresti, S.; Binotti, M.; Manzolini, G. Potentiality of a biogas membrane reformer for decentralized hydrogen production. *Chem. Eng. Process.-Process Intensif.* **2018**, *129*, 131–141. [CrossRef]
86. Lin, K.-W.; Wu, H.-W. Hydrogen-rich syngas production of urea blended with biobutanol by a thermodynamic analysis. *Int. J. Hydrogen Energy* **2018**, *43*, 17562–17573. [CrossRef]
87. Di Marcoberardino, G.; Vitali, D.; Spinelli, F.; Binotti, M.; Manzolini, G. Green hydrogen production from raw biogas: A techno-economic investigation of conventional processes using pressure swing adsorption unit. *Processes* **2018**, *6*, 19. [CrossRef]
88. Ajanovic, A.; Haas, R. Economic prospects and policy framework for hydrogen as fuel in the transport sector. *Energy Policy* **2018**, *123*, 280–288. [CrossRef]
89. Andresen, L.; Bode, C.; Schmitz, G. Dynamic simulation of different transport options of renewable hydrogen to a refinery in a coupled energy system approach. *Int. J. Hydrogen Energy* **2018**, *43*, 19600–19614. [CrossRef]

90. Robinius, M.; Raje, T.; Nykamp, S.; Rott, T.; Müller, M.; Grube, T.; Katzenbach, B.; Küppers, S.; Stolten, D. Power-to-Gas: Electrolyzers as an alternative to network expansion—An example from a distribution system operator. *Appl. Energy* **2018**, *210*, 182–197. [CrossRef]
91. Boudries, R. Techno-economic study of hydrogen production using CSP technology. *Int. J. Hydrogen Energy* **2018**, *43*, 3406–3417. [CrossRef]
92. Touili, S.; Alami Merrouni, A.; Azouzoute, A.; El Hassouani, Y.; Amrani, A.-I. A technical and economical assessment of hydrogen production potential from solar energy in Morocco. *Int. J. Hydrogen Energy* **2018**, *43*, 22777–22796. [CrossRef]
93. Arora, A.; Bajaj, I.; Iyer, S.S.; Hasan, M.M.F. Optimal synthesis of periodic sorption enhanced reaction processes with application to hydrogen production. *Comput. Chem. Eng.* **2018**, *115*, 89–111. [CrossRef]
94. Riva, L.; Martínez, I.; Martini, M.; Gallucci, F.; van Sint Annaland, M.; Romano, M.C. Techno-economic analysis of the Ca-Cu process integrated in hydrogen plants with CO2 capture. *Int. J. Hydrogen Energy* **2018**, *43*, 15720–15738. [CrossRef]
95. Lee, D.-Y.; Elgowainy, A. By-product hydrogen from steam cracking of natural gas liquids (NGLs): Potential for large-scale hydrogen fuel production, life-cycle air emissions reduction, and economic benefit. *Int. J. Hydrogen Energy* **2018**, *43*, 20143–20160. [CrossRef]
96. Keipi, T.; Tolvanen, H.; Konttinen, J. Economic analysis of hydrogen production by methane thermal decomposition: Comparison to competing technologies. *Energy Convers. Manag.* **2018**, *159*, 264–273. [CrossRef]
97. Grabarczyk, R.; Urbaniec, K.; Wernik, J.; Trafczynski, M. Evaluation of the two-stage fermentative hydrogen production from sugar beet molasses. *Energies* **2019**, *12*, 4090. [CrossRef]
98. Becker, W.L.; Penev, M.; Braun, R.J. Production of synthetic natural gas from carbon dioxide and renewably generated hydrogen: A techno-economic analysis of a power-to-gas strategy. *J. Energy Resour. Technol. Trans. ASME* **2019**, *141*, 21901. [CrossRef]
99. Rau, F.; Herrmann, A.; Krause, H.; Fino, D.; Trimis, D. Efficiency of a pilot-plant for the autothermal reforming of biogas. *Int. J. Hydrogen Energy* **2019**, *44*, 19135–19140. [CrossRef]
100. Di Marcoberardino, G.; Liao, X.; Dauriat, A.; Binotti, M.; Manzolini, G. Life cycle assessment and economic analysis of an innovative biogas membrane reformer for hydrogen production. *Processes* **2019**, *7*, 86. [CrossRef]
101. Chisalita, D.-A.; Cormos, C.-C. Techno-economic assessment of hydrogen production processes based on various natural gas chemical looping systems with carbon capture. *Energy* **2019**, *181*, 331–344. [CrossRef]
102. Bahzad, H.; Katayama, K.; Boot-Handford, M.E.; Mac Dowell, N.; Shah, N.; Fennell, P.S. Iron-based chemical-looping technology for decarbonising iron and steel production. *Int. J. Greenh. Gas Control* **2019**, *91*, 102766. [CrossRef]
103. Bahzad, H.; Shah, N.; Dowell, N.M.; Boot-Handford, M.; Soltani, S.M.; Ho, M.; Fennell, P.S. Development and techno-economic analyses of a novel hydrogen production process via chemical looping. *Int. J. Hydrogen Energy* **2019**, *44*, 21251–21263. [CrossRef]
104. González Rodríguez, D.; Brayner de Oliveira Lira, C.A.; García Hernández, C.R.; Roberto de Andrade Lima, F. Hydrogen production methods efficiency coupled to an advanced high-temperature accelerator driven system. *Int. J. Hydrogen Energy* **2019**, *44*, 1392–1408. [CrossRef]
105. Timmerberg, S.; Kaltschmitt, M. Hydrogen from renewables: Supply from North Africa to Central Europe as blend in existing pipelines—Potentials and costs. *Appl. Energy* **2019**, *237*, 795–809. [CrossRef]
106. Grüger, F.; Hoch, O.; Hartmann, J.; Robinius, M.; Stolten, D. Optimized electrolyzer operation: Employing forecasts of wind energy availability, hydrogen demand, and electricity prices. *Int. J. Hydrogen Energy* **2019**, *44*, 4387–4397. [CrossRef]
107. Arellano-Garcia, H.; Ife, M.R.; Sanduk, M.; Sebastia-Saez, D. Hydrogen Production via Load-Matched Coupled Solar-Proton Exchange Membrane Electrolysis Using Aqueous Methanol. *Chem. Eng. Technol.* **2019**, *42*, 2340–2347. [CrossRef]
108. Micena, R.P.; Llerena-Pizarro, O.R.; de Souza, T.M.; Silveira, J.L. Solar-powered Hydrogen Refueling Stations: A techno-economic analysis. *Int. J. Hydrogen Energy* **2019**, *45*, 2308–2318. [CrossRef]
109. Guerra, O.J.; Eichman, J.; Kurtz, J.; Hodge, B.-M. Cost Competitiveness of Electrolytic Hydrogen. *Joule* **2019**, *3*, 2425–2443. [CrossRef]
110. Kikuchi, Y.; Ichikawa, T.; Sugiyama, M.; Koyama, M. Battery-assisted low-cost hydrogen production from solar energy: Rational target setting for future technology systems. *Int. J. Hydrogen Energy* **2019**, *44*, 1451–1465. [CrossRef]
111. Khzouz, M.; Gkanas, E.I.; Shao, J.; Sher, F.; Beherskyi, D.; El-Kharouf, A.; Qubeissi, M.A. Life Cycle Costing Analysis: Tools and Applications for Determining Hydrogen Production Cost for Fuel Cell Vehicle Technology. *Energies* **2020**, *13*, 3783. [CrossRef]
112. Tolley, T.E.; Fronk, B.M. Investigation of the benefits of diabatic microreactors for process intensification of the water-gas shift reaction within the steam reforming process. *Int. J. Hydrogen Energy* **2020**, *45*, 31507–31522. [CrossRef]
113. He, Y.; Zhu, L.; Li, L.; Liu, G. Hydrogen and Power Cogeneration Based on Chemical Looping Combustion: Is It Capable of Reducing Carbon Emissions and the Cost of Production? *Energy Fuels* **2020**, *34*, 3501–3512. [CrossRef]
114. Armijo, J.; Philibert, C. Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina. *Int. J. Hydrogen Energy* **2020**, *45*, 1541–1558. [CrossRef]
115. Coleman, D.; Kopp, M.; Wagner, T.; Scheppat, B. The value chain of green hydrogen for fuel cell buses—A case study for the Rhine-Main area in Germany. *Int. J. Hydrogen Energy* **2020**, *45*, 5122–5133. [CrossRef]
116. Schnuelle, C.; Wassermann, T.; Fuhrlaender, D.; Zondervan, E. Dynamic hydrogen production from PV & wind direct electricity supply—Modeling and techno-economic assessment. *Int. J. Hydrogen Energy* **2020**, *45*, 29938–29952.
117. Roussanaly, S.; Anantharaman, R.; Fu, C. Low-carbon footprint hydrogen production from natural gas: A techno-economic analysis of carbon capture and storage from steam-methane reforming. *Chem. Eng. Trans.* **2020**, *81*, 1015–1020.

118. Lux, B.; Pfluger, B. A supply curve of electricity-based hydrogen in a decarbonized European energy system in 2050. *Appl. Energy* **2020**, *269*, 115011. [CrossRef]
119. Matute, G.; Yusta, J.M.; Beyza, J.; Correas, L.C. Multi-state techno-economic model for optimal dispatch of grid connected hydrogen electrolysis systems operating under dynamic conditions. *Int. J. Hydrogen Energy* **2021**, *46*, 1449–1460. [CrossRef]
120. Kazi, M.-K.; Eljack, F.; El-Halwagi, M.M.; Haouari, M. Green hydrogen for industrial sector decarbonization: Costs and impacts on hydrogen economy in Qatar. *Comput. Chem. Eng.* **2021**, *145*, 107144. [CrossRef]
121. Herwartz, S.; Pagenkopf, J.; Streuling, C. Sector coupling potential of wind-based hydrogen production and fuel cell train operation in regional rail transport in berlin and Brandenburg. *Int. J. Hydrogen Energy* **2021**, *46*, 29597–29615. [CrossRef]
122. Koleva, M.; Guerra, O.J.; Eichman, J.; Hodge, B.-M.; Kurtz, J. Optimal design of solar-driven electrolytic hydrogen production systems within electricity markets. *J. Power Source* **2021**, *483*, 229183. [CrossRef]
123. De Souza, T.A.Z.; Coronado, C.J.R.; Silveira, J.L.; Pinto, G.M. Economic assessment of hydrogen and electricity cogeneration through steam reforming-SOFC system in the Brazilian biodiesel industry. *J. Clean. Prod.* **2021**, *279*, 123814. [CrossRef]