Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe

Author:

ADAM CHRISTENSEN
adam@threeseas.co

This research was funded by the International Council on Clean Transportation. A previous version of this report was made public on June 4, 2020. This version of the report updates parameters around compressor costs and the accompanying electricity consumption.

Final release, June 18, 2020

Contents

List of Figures

List of Tables

List of Abbreviations

AE	**A**lkaline **E**lectrolyzer
BNEF	**B**loomberg **N**ew **E**nergy **F**inance
EU	**E**uropean **U**nion
IEA	**I**nternational **E**nergy **A**gency
IRENA	**I**nternational **RE**newable **E**nergy **A**gency
kW	**k**ilo**w**att
LCOE	**L**evelized **C**ost **o**f **E**lectricity
LCOH	**L**evelized **C**ost **o**f **H**ydrogen
MW	**M**ega**w**att
NPV	**N**et **P**resent **V**alue
NREL	**N**ational **R**enewable **E**nergy Laboratory
PEM	**P**roton **E**xchange **M**embrane
SOE	**S**olid **O**xide **E**lectrolyzer Cell
TRB	**T**echnical **R**esource **B**in
US	**U**nited **S**tates
WACC	**W**eighted **A**verage **C**ost of **C**apital

Acknowledgements

This project was generously funded by the the International Council on Clean Transportation.

Chapter 1

Executive Summary

This work examines the price of H_2 production from renewable electricity generators in both the United States and the European Union. Many other reports exist on this topic, but with varying degrees of transparency to cost assumptions. These methodological differences make it difficult to compare H_2 prices from different studies without first examining all the details. We note that many high profile studies report H_2 prices that ignore other system costs beyond those associated with the electrolyzer CAPEX and the purchase of electricity to operate the electrolyzer. There are, of course, other system costs that must be considered in order to build out a fully operational H_2 electrolysis plant. Data on these other system costs are still not well understood and should be documented more fully, but to zero them out completely could be misleading. We also note that many of the projections of electricity price would be considered optimistic even when compared to the optimistic electricity price scenarios included in this work. In some cases these “best” case scenarios might represent a “global best” while other projections of electricity price are more opaque.

In this study we assume plant costs originate from the electrolyzer CAPEX, electrolyzer replacement (if necessary), electricity, water, piping, compressor CAPEX, on-site (short-term) storage, and other fixed OPEX costs – ultimately we assume that this plant would be connected to a distribution pipeline. With these data, we attempt to build the most transparent accounting of H_2 prices when produced from a variety of renewable electricity generators. Our data is drawn only from public sources and includes a large database of CAPEX prices and capacity factors for wind and solar generators for the United States and Europe. This geographically explicit data is leveraged to calculate the distribution of H_2 price for both the US and EU under three different connection configurations. Scenario #1 assumes that the electrolyzer is connected to the larger electric grid and can benefit from high capacity factors (but must pay associated grid fees). Scenario #2 assumes that the electrolyzer is directly connected to a renewable electricity generator (and thus does not need to pay grid fees, but the electrolyzer can only be operated at the capacity factor of the renewable electricity generator). Scenario #3 assumes that the electrolyzer is only operated on electricity that would otherwise be curtailed. Our primary results are summarized below; the minimum prices shown here correspond with the most favorable locations within the EU and US.

Grid Connected

- The median price of H_2 (in the US, 2020-2050) will decrease from \$8.81/kg to \$5.77/kg; the minimum price decreases from \$6.06/kg to \$4.15/kg.
- The median price of H_2 (in the EU, 2020-2050) will decrease from \$13.11/kg to \$7.69/kg; the minimum price decreases from \$4.83/kg to \$3.21/kg.

Direct Connection

- The median price of H_2 (in the US, 2020-2050) will decrease from \$10.61/kg to \$5.97/kg; the minimum price decreases from \$4.56/kg to \$2.44/kg.
- The median price of H_2 (in the EU, 2020-2050) will decrease from \$19.23/kg to \$10.02/kg; the minimum price decreases from \$4.06/kg to \$2.23/kg.

Curtailed Electricity

- The median price of H_2 (in the US, 2020-2050) will decrease from \$11.02/kg to \$5.92/kg; the minimum price decreases from \$6.10/kg to \$4.75/kg.
- The median price of H_2 (in the EU, 2020-2050) will decrease from \$10.85/kg to \$6.08/kg; the minimum price decreases from \$5.97/kg to \$4.67/kg.

The hydrogen price (when produced from renewable electricity generators) calculated here is highly dependent on geographic location with significantly cheaper production prices in some favorable localities.

Chapter 2

Renewable Hydrogen: *Study Outline*

The primary objective of this report is to develop an understanding of the costs associated with the production of hydrogen from water electrolysis using various forms of intermittent renewable electricity in the United States (US) and European Union (EU). Throughout this analysis we do not make any assumptions regarding policy incentives or other financial benefits. These modeling assumptions, which are often found in the literature, can obscure the results making it difficult for policy-makers/analysts to compile data and make recommendations. This analysis covers both the United States (excluding Alaska and Hawaii) and Europe from the years 2020-2050. A basic block diagram model of a power-to-gas system is shown in Figure 2.1.

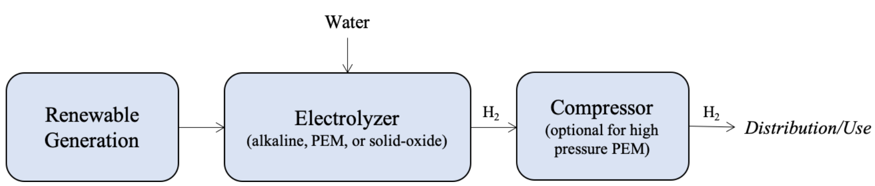


FIGURE 2.1: Model plant for the production of renewable hydrogen.

For this study we focus on three renewable electricity technologies: (1) *solar photovoltaic (utility scale)*, (2) *onshore wind*, and (3) *offshore wind*. We assume that there are three primary electrolyzer technologies that could be interconnected with these renewable electricity generators. The electrolyzer technologies that are considered in this study are: *alkaline electrolyzer* (AE), *proton exchange membrane (PEM)*, and *solid-oxide electrolyzers* (SOE). The output from each of these electrolyzers will be a concentrated stream of hydrogen gas as well as oxygen. In the case of the PEM electrolyzer, we assume that the PEM is a "high pressure" PEM, which negates the need for an external hydrogen compressor – only the AE and SOE will require a final compression stage.

The hydrogen produced from these reactions must then be captured and transported to demand centers either though pipelines (that must be built) or tanker truck/train. These post-production steps add additional costs that are not captured in this work. For purposes of this study, we focus only the costs associated with capital expenditures and all fixed/variable costs associated with production of hydrogen and compression.

For purposes of modeling these systems it is assumed that any renewable technology could be paired with any other electrolyzer technology – full enumeration yields nine unique power-to-gas *configurations*.

2.1 Model Scenarios

In addition to assuming the nine system configurations we consider three *scenarios* that attempt to capture the various ways an electrolyzer could be physically connected to a renewable electricity generator. These *scenarios* reflect proposals that have been considered at various levels of government – making them policy relevant. The three bounding scenarios are:

- *Scenario 1 – Grid Connect*: We assume that the electrolyzer is grid connected and therefore can produce hydrogen gas at a 100% capacity factor – the ratio of an actual electrical energy output over a given period of time to the maximum possible electrical energy output. If the electrolyzer is grid connected it is assumed that the business would contract either with a utility or directly to electricity generators through long-term power purchase agreements to procure only renewable electricity. We estimate the electricity price the business would pay as the price of electricity generation plus transmission and distribution charges.

- *Scenario 2 – Direct Connect*: We assume that the electrolyzer is independent of the larger transmission grid and instead is connected directly to a renewable electricity generator. Under this scenario the price of electricity is lower that in Scenario 1 because transmission and distribution charges are not considered. However, the intermittency of the renewable electricity generator means that the electrolyzer's capacity factor is equal to the generator's capacity factor. We make no assumptions about co-location, just that all the energy from the renewable electricity generator flows to the electrolyzer and nowhere else. For simplicity, we do not model any sort of hybrid solar/wind systems in order to increase the effective capacity factor.

- *Scenario 3 – Curtailed Electricity*: In this scenario we assume that the electrolyzer is grid connected, but serves only as a load balancing/storage entity. We assume that in times of high renewable generation some energy would need to be curtailed at zero $/kWh. We recognize that the number of hours per day that curtailed energy would be available would vary enormously by location and across time. Absent a model that can capture the market-based behavior of the transmission grid, we simply assume a flat 4 hours per day.

The following chapters present a literature review, discussion of the modeling methodology, and presentation of economic parameters used to project renewable hydrogen prices.

Chapter 3

Renewable Generation

This chapter will review primary sources of data that, ultimately, will instantiate a cash flow economic model of a renewable electricity generator.

3.1 Literature Review

Uncertainty exists regarding many of the techno-economic parameters that are necessary to construct an economic model of a renewable electricity generator. Not only must the data for renewable electricity generators be projected out to 2050, but it must also be free of inconsistencies that might hamper comparisons between different technology categories being modeled. To that end, the only public data source that is available for these technology descriptions is the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) [1]. NREL's ATB dataset projects various techno-economic parameters out to 2050 along three paths – a pessimistic *constant* path, a optimistic *low* and a middle path (*mid*). Data exists for a number of technology categories beyond those considered in this work. This database only includes United States data, however, it is assumed that these data for utility scale solar/wind investments fluctuate on a global scale, as such, European rates will not differ significantly.

The technical and financial operation of a renewable generation plant can be approximated with a suite of parameters, which are detailed in Table 3.1 – installed capacity (kW), generator droop (%/yr), inverter costs ($/kW), inverter lifetime (yr), CAPEX rate ($/kW), wind turbine blade replacement rates, fixed operation/maintenance costs ($/kW), and variable operation/maintenance costs ($/kWh). Capacity factor (%) is another extremely important modeling parameter that is often used to describe the intermittency of a renewable electricity generator. While NREL's ATB does provide capacity factor projections out to 2050, the geographical extent of the data is limited to only a couple discrete cities in the US. We supplement the ATB dataset with capacity factor data from NREL's Renewable Energy Deployment System (ReEDS) modeling system [2]. Specifically, we use capacity factor data from the ReEDS modeling system because of the geographic resolution, but capacity factor improvement over time is not captured natively in this dataset. To represent this dimension of technological improvement we apply the year-by-year improvement rate from the ATB dataset to the ReEDS data. These improvement rates are also detailed in Table 3.1. Figures 3.1, 3.2, and 3.3 show the capacity factor used in this analysis.

The raw NREL ReEDS capacity factor data is reported for 356 regions in the US at an hourly timescale for a number of technical resource bins (TRBs). Technical resource bins help describe the resource potential (i.e., wind speed, solar insolation, etc.) that is available at a location. We aggregate the ReEDS data to

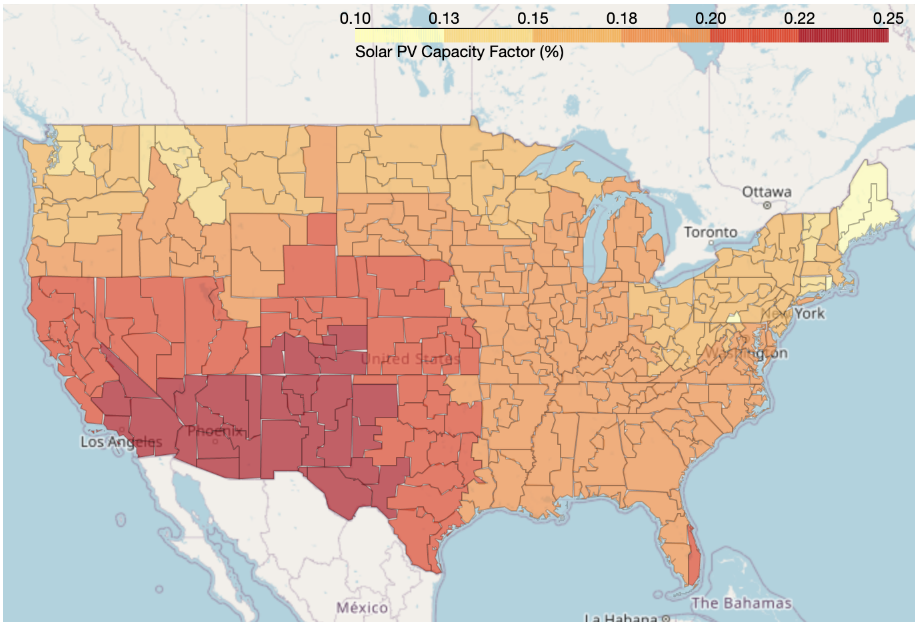


FIGURE 3.1: Capacity factor for solar PV systems in the US.

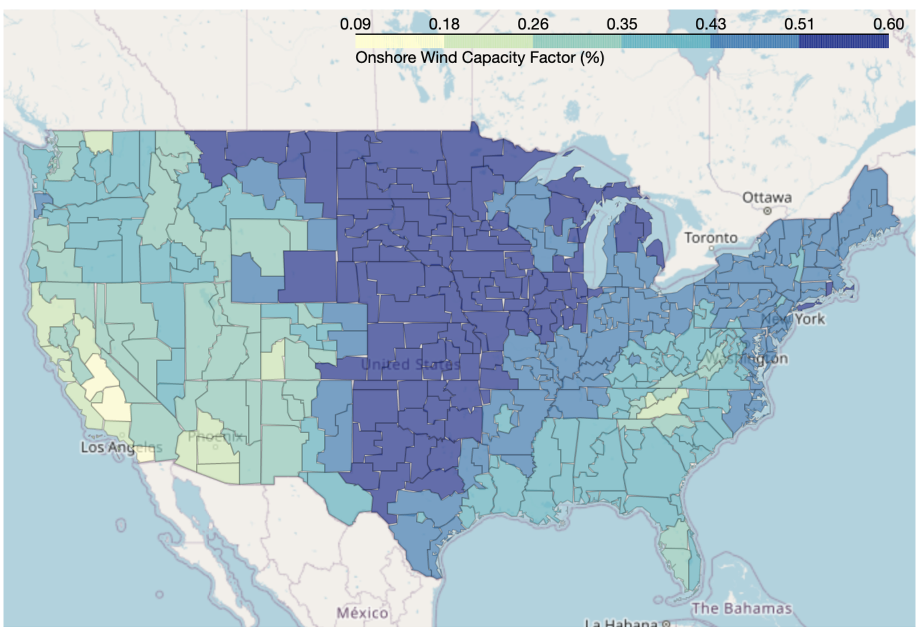


FIGURE 3.2: Capacity factor for onshore wind systems in the US.

annual, TRB weighted, capacity factors. This way we have 356 capacity factors for each of our three renewable electricity generators.

Data of this resolution was not available for Europe, instead we use data generated at the country level

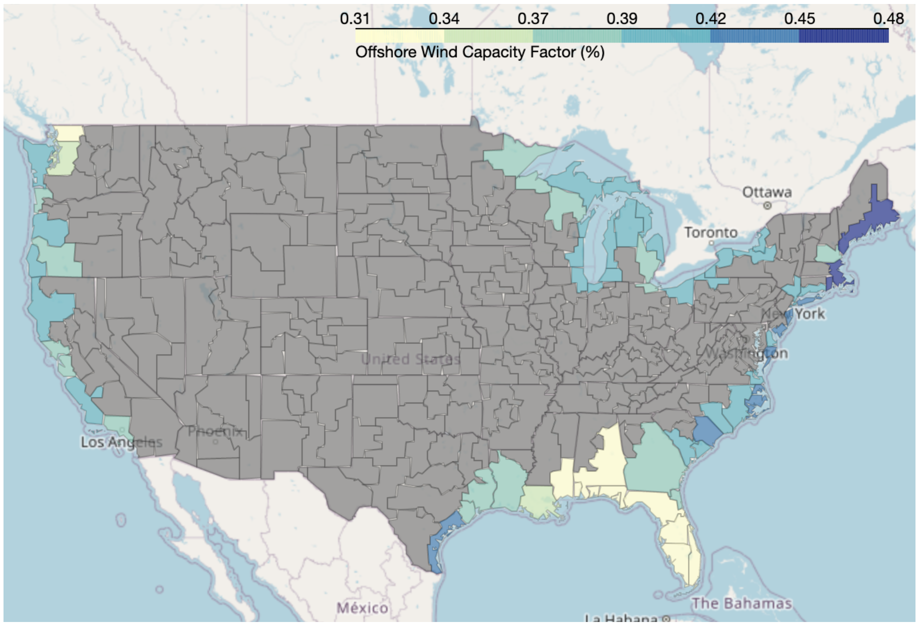


FIGURE 3.3: Capacity factor for offshore wind systems in the US. Grey regions indicate that offshore systems are not feasible.

from [3, 4], shown in Figures 3.4 and 3.5. Furthermore, this data was not differentiated by wind technology type; we assume that both onshore and offshore wind systems have the same capacity factor.

3.2 Overall Economic Modeling Methodology

Electricity price projections were estimated as the time series of Levelized Cost of Energy (LCOE) for wind and solar systems in Europe from 2020-2050 for the three projection pathways (*low*, *mid*, and *constant*) that were specified in NREL's ATB dataset. The LCOE is a measure of the average total cost to build and operate a generator over its lifetime divided by the total energy output over the lifetime of the plant. In other words, this measure allows one to calculate the minimum price necessary to sell energy in order to meet a certain hurdle rate – the hurdle rate is the minimum rate of return on a project or investment. In this study a hurdle rate of 7% was assumed for both new solar/wind projects; this is consistent with a technology that has been proven commercial at global scales. The aggregated parameters needed to describe both wind and solar cash flows are described in Table 3.1. It was assumed that the generator system had zero salvage value at the end-of-life and that accelerated depreciation (5-year) was calculated with a straight-line method.

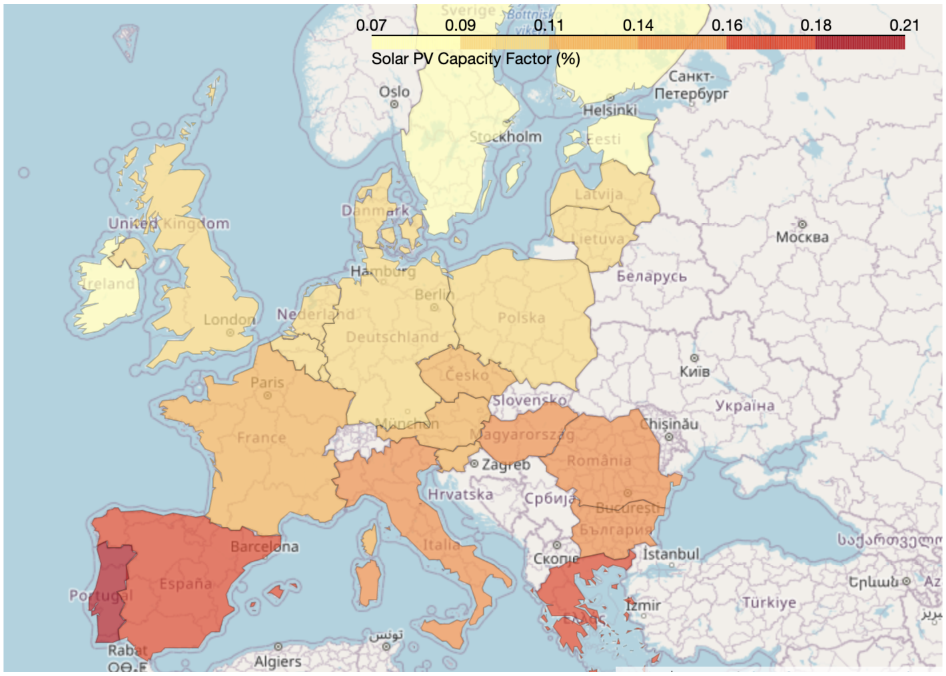


FIGURE 3.4: Capacity factor for solar PV systems in Europe.

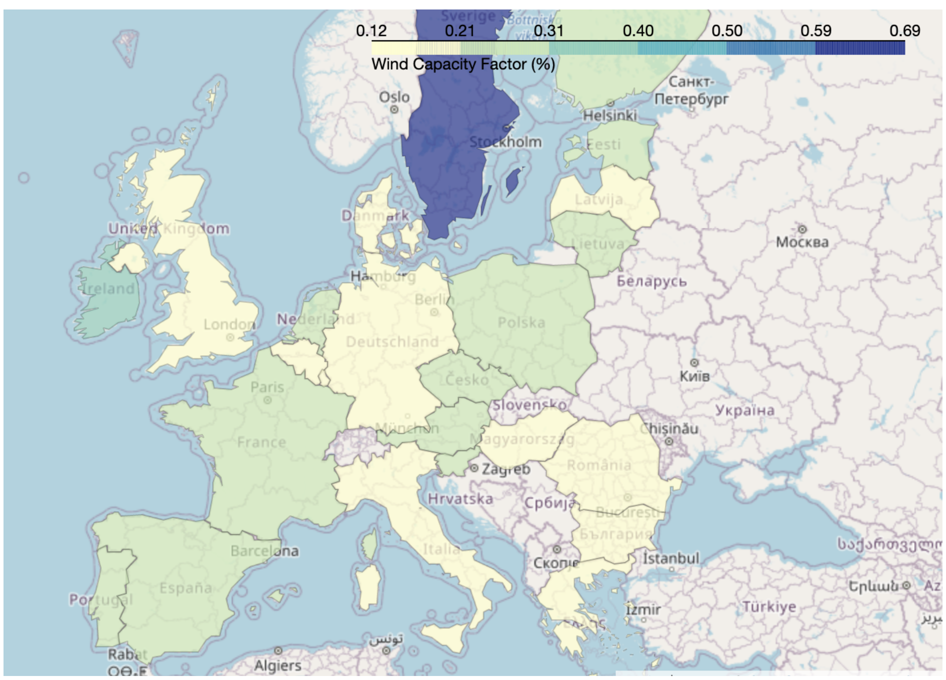


FIGURE 3.5: Capacity factor for both on and offshore wind systems in Europe.

TABLE 3.1: Parameters used in the levelized cost of energy calculations

Data Description	Solar	Wind
System Life	30 years	30 years
Rate of Capital Expenditure ($kW/DC)	[1]	[1]
Generator Capacity Factor (%)	See 3.1, 3.2, 3.3	See 3.4, 3.5
Fixed Operations and Maintenance Costs	[1]	[1]
Variable Operations and Maintenance Costs	[1]	[1]
Solar Capacity Factor Improvement	0.14 %/yr	—
Onshore Wind Capacity Factor Improvement	—	2.25 %/yr (2020-2030), 0.15 %/yr (2030-2050)
Offshore Wind Capacity Factor Improvement	—	0.53 %/yr
Generator Performance Degradation	-1 %/year	-0.5 %/year
Inverter Replacement Cost	100 $/kW DC	—
Inverter Lifetime	10 years	—
Gearbox Replacement Cost	—	15 % of CAPEX rate
Gearbox Lifetime	—	7 years
Blade Replacement Cost	—	20 % of CAPEX rate
Blade Lifetime	—	15 years
Number of Replacement Blades	—	1

Using the LCOE metric as a proxy for the actual generation price represents a balance between completeness and transparency. Using the LCOE metric assumes that the renewable hydrogen plant is able to obtain electricity from a new plant installed in that year. In reality, the generation-only electricity price would be a more complicated function of transmission grid dynamics. However, a transparent model that considers the details of grid effects is not available. We do not assume any incentives for renewable electricity generation. Tax rates for each country were taken from the Tax Foundation dataset (`https://taxfoundation.org/publications/corporate-tax-rates-around-the-world/`).

3.3 Results – Electricity Prices

This section presents the final US electricity prices for the three price projection pathways (*low*, *mid*, and *constant*) that were mapped out in NREL's ATB dataset. Data for Scenario #1 (*generation & transmission/distribution*) prices for the three renewable electricity generators are shown in Figures 3.6, 3.7, and 3.8. Data for Scenario #2 (*generation only*) prices for the three renewable electricity generators are shown in Figures 3.9, 3.10, and 3.11. Projections of the LCOE are similar to those electricity prices reported elsewhere, although, as will be pointed out in Chapter 6 there are varying degrees of optimism associated with each individual report [1, 5, 6, 7].

Electricity prices for the EU are not explicitly printed here because they are duplicative except for their differing transmission and distribution costs; again, it has been assumed that prices for utility scale renewable electricity generators fluctuate on a global scale. As such, European results follow similar price trends for Scenario #1.

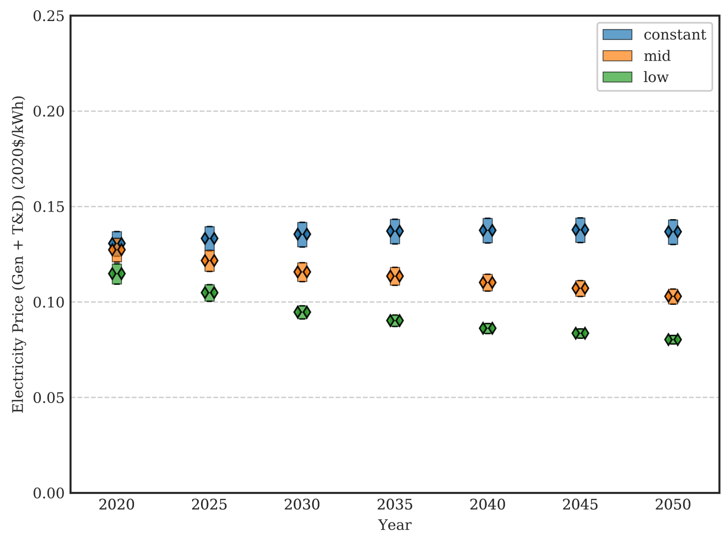


FIGURE 3.6: Electricity prices for solar for Scenario #1. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

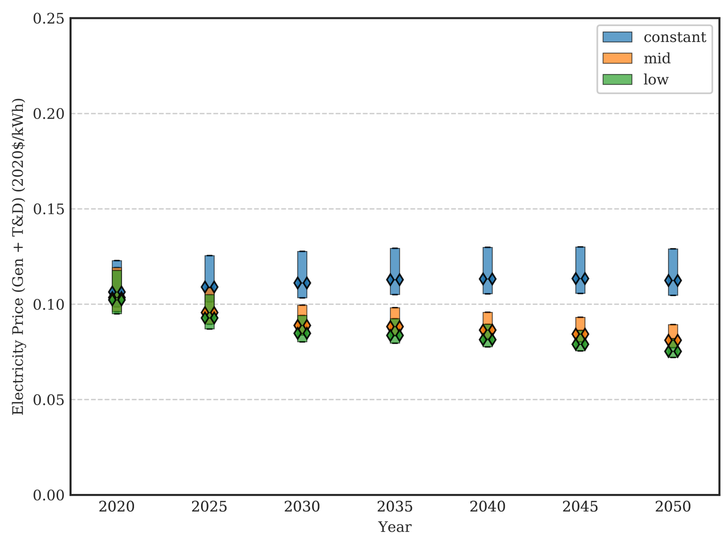


FIGURE 3.7: Electricity prices for onshore wind for Scenario #1. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

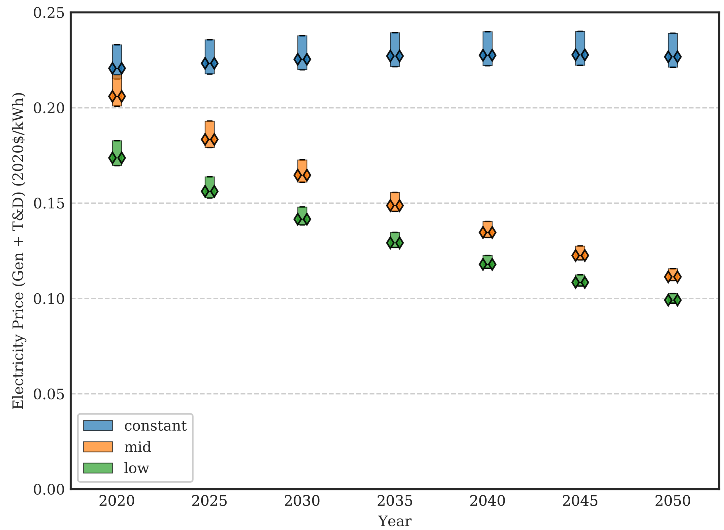


FIGURE 3.8: Electricity prices for offshore wind for Scenario #1. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

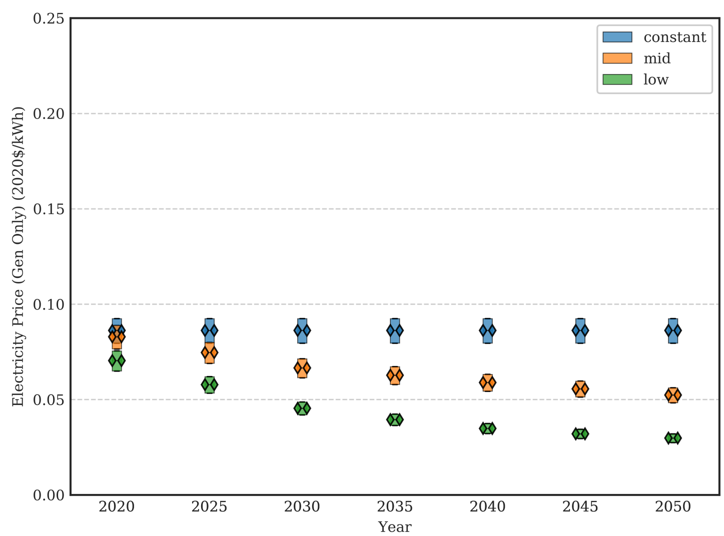


FIGURE 3.9: Electricity prices for solar for Scenario #2. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

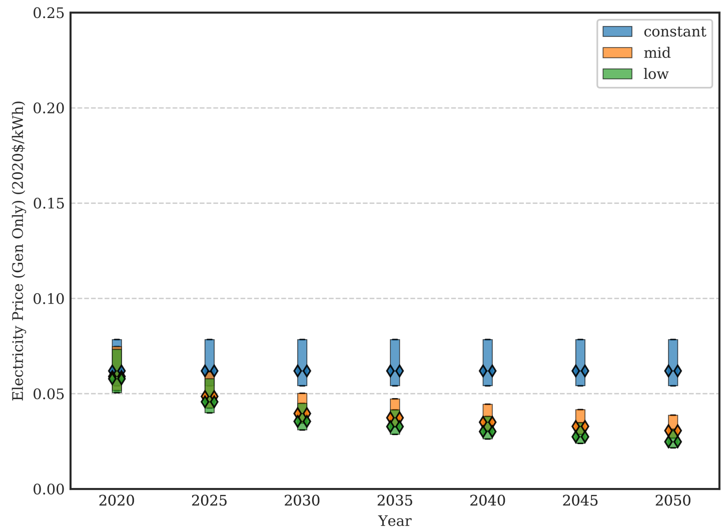


FIGURE 3.10: Electricity prices for onshore wind for Scenario #2. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

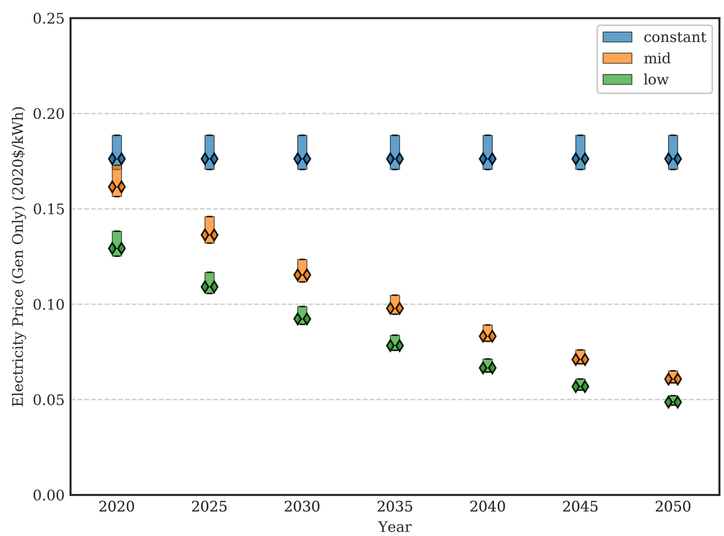


FIGURE 3.11: Electricity prices for offshore wind for Scenario #2. The boxplot shows the range in electricity price that could be expected in the US based on resource availability.

Chapter 4

Hydrogen Production

This chapter is dedicated to the economic evaluation of renewable hydrogen pathways and begins with a literature review. The methodology used to perform this evaluation is then described. The following subsections will also detail the data that was reviewed and used to instantiate our modeling framework. Results of the analysis are detailed in Chapter 5 for each of the scenarios described in Chapter 2.

4.1 Literature Review

Academic research for producing hydrogen from electrolysis fuels stretches back to 1977 when Steinberg et al. discussed synthetic methanol production from CO_2, water and nuclear fusion energy [8, 9, 10]. Since 1977 the state of research has morphed in important ways from materials science research to systems analysis. While the evolution of the research is important context, the main purpose of this literature review is focused on the state of knowledge on the costs associated with each of the system components. This analysis focuses on understanding the following parameters:

- Electrolyzer CAPEX costs (for AE, PEM and SOE systems)
- Electrolyzer OPEX costs
- Compressor CAPEX costs (for supplemental compression of H_2 gas)
- Compressor OPEX costs (for supplemental compression of H_2 gas)
- Balance of System costs (piping, water, etc.)
- Electrolyzer lifetime (dictates when electrolyzer will need to be replaced)
- Conversion efficiency (how efficiently can water be converted to H_2 gas)

Generally speaking, there is wide agreement around the conversion efficiency values for the three electrolyzer types (AE, PEM, and SOE). However, there is huge range of variability for all cost parameters. This is not surprising for a technology that has not reached full maturity. The following sections will detail these important parameters.

4.2 Electrolyzer CAPEX Costs

Until very recently CAPEX costs associated with the electrolyzer that could be found in the literature were a grab bag of values representing a range of currencies and constant year $ values – occasionally these values included other system components as well. This unharmonized data made it nearly impossible to understand larger industry trends for predicting the cost improvements as the industry matured. Efforts by Brynolf et al. (2017) and more recently by Glenk et al. (2019) were made to harmonize these important CAPEX parameters [11, 12]. We follow the literature review by Glenk et al. for its completeness and transparent methodology. Their review included only original sources of data and excluded literature that did not provide clear costs estimates or methodologies for producing cost estimates. The cost data from the sources that remained was then harmonized into 2016 € costs to aid technology comparisons. Glenk et al. caution that only a few points for SOE systems exist; it was not included in their analysis as a result. We include SOE systems in this analysis simply for completeness, it should only be taken as illustrative. Table 4.1 is from Glenk et al. but includes original sources for completeness.

TABLE 4.1: Referenced Electrolyzer CAPEX Costs from Glenk et al.

Electrolyzer Type	Year of Estimate	(2016 €/kW)	(2020 $/kW)	Original Source
AE	2003	1830	2091	[13]
AE	2004	1131	1293	Report – N/A (See [12])
AE	2004	1131	1293	Report – N/A (See [12])
AE	2005	1120	1280	[14]
AE	2007	2129	2433	[15]
AE	2007	1431	1635	[16]
AE	2007	2345	2680	[17]
AE	2007	1210	1383	[18]
AE	2008	1241	1418	[19]
AE	2009	2154	2462	[20]
AE	2010	960	1097	[21]
AE	2011	941	1075	[22]
AE	2011	1417	1619	Report – N/A (See [12])
AE	2013	1215	1389	[23]
AE	2013	1210	1383	[24]
AE	2013	1215	1389	[25]
AE	2013	1569	1793	[26]
AE	2014	1110	1269	[27]
AE	2014	757	865	[28]
AE	2014	1160	1326	[29]
AE	2014	1009	1153	[30]
AE	2014	1160	1326	[31]
AE	2015	1589	1816	Interview (See [12])
AE	2015	976	1115	Interview (See [12])

Continued on next page

Table 4.1 – *Continued from previous page*

Electrolyzer Type	**Year of Estimate**	**(2016 €/kW)**	**(2020 $/kW)**	**Original Source**
AE	2015	1551	1773	Interview (See [12])
AE	2015	1475	1686	Interview (See [12])
AE	2015	1232	1408	Interview (See [12])
AE	2015	1584	1810	Interview (See [12])
AE	2015	1313	1501	Interview (See [12])
AE	2015	1229	1405	Interview (See [12])
AE	2015	940	1074	Interview (See [12])
AE	2015	831	950	Interview (See [12])
AE	2015	1157	1322	Report – N/A (See [12])
AE	2015	1006	1150	Report – N/A (See [12])
AE	2015	1006	1150	Report – N/A (See [12])
AE	2015	1012	1157	[32]
AE	2015	1408	1609	[33]
AE	2016	800	914	Report – N/A (See [12])
AE	2016	1000	1143	Report – N/A (See [12])
AE	2016	1283	1466	Presentation (See [12])
AE	2016	1200	1371	[34]
AE	2016	1000	1143	[35]
AE	2016	1100	1257	[36]
AE	2016	1112	1271	[37]
AE	2017	800	914	Report – N/A (See [12])
AE	2017	1000	1143	Report – N/A (See [12])
AE	2017	1000	1143	Report – N/A (See [12])
AE	2017	975	1114	Report – N/A (See [12])
AE	2020	948	1083	[38]
AE	2025	932	1065	Report – N/A (See [12])
AE	2030	757	865	[39]
AE	2030	645	737	[40]
PEM	2003	1830	2091	[13]
PEM	2004	1131	1293	Report – N/A (See [12])
PEM	2005	2440	2789	[41]
PEM	2008	1587	1814	[42]
PEM	2008	1241	1418	[19]
PEM	2009	2154	2462	[20]
PEM	2010	2133	2438	[43]
PEM	2010	960	1097	[21]
PEM	2013	1569	1793	[26]
PEM	2013	1135	1297	Report – N/A (See [12])
PEM	2014	3227	3688	[44]
PEM	2014	1110	1269	[27]

Continued on next page

Table 4.1 – *Continued from previous page*

Electrolyzer Type	Year of Estimate	(2016 €/kW)	(2020 $/kW)	Original Source
PEM	2014	1160	1326	[29]
PEM	2014	2463	2815	[45]
PEM	2014	1009	1153	[30]
PEM	2014	1160	1326	[31]
PEM	2014	1513	1729	[46]
PEM	2014	1670	1909	Interview (See [12])
PEM	2014	1387	1585	Report – N/A (See [12])
PEM	2014	1210	1383	Report – N/A (See [12])
PEM	2015	3420	3909	[47]
PEM	2015	2816	3218	[48]
PEM	2015	1012	1157	[32]
PEM	2015	1157	1322	Report – N/A (See [12])
PEM	2015	1006	1150	Report – N/A (See [12])
PEM	2015	2575	2943	Report – N/A (See [12])
PEM	2015	1006	1150	Report – N/A (See [12])
PEM	2016	1200	1371	[34]
PEM	2016	1000	1143	[35]
PEM	2016	1100	1257	[36]
PEM	2016	1112	1271	[37]
PEM	2016	1283	1466	Presentation (See [12])
PEM	2016	1000	1143	Report – N/A (See [12])
PEM	2017	800	914	Report – N/A (See [12])
PEM	2017	1550	1771	Report – N/A (See [12])
PEM	2017	1000	1143	Report – N/A (See [12])
PEM	2017	975	1114	Report – N/A (See [12])
PEM	2025	932	1065	Report – N/A (See [12])
PEM	2030	645	737	[40]
PEM	2030	1177	1345	[49]
SOE	2012	2172	2482	[50]
SOE	2012	12000	13714	Report – N/A (See [12])
SOE	2015	7500	8571	Report – N/A (See [12])
SOE	2017	4500	5143	Report – N/A (See [12])
SOE	2018	2017	2305	Report – N/A (See [12])
SOE	2020	941	1075	[51]
SOE	2020	593	678	[33]
SOE	2020	2000	2286	Report – N/A (See [12])
SOE	2025	1006	1150	[46]
SOE	2025	925	1057	Report – N/A (See [12])
SOE	2030	1000	1143	[35]
SOE	2030	645	737	[40]

Continued on next page

Table 4.1 – *Continued from previous page*

Electrolyzer Type	Year of Estimate	(2016 €/kW)	(2020 $/kW)	Original Source
SOE	2030	354	405	[51]
SOE	2030	1177	1345	[49]
SOE	2030	725	829	Report – N/A (See [12])
SOE	2030	656	750	Report – N/A (See [12])

The result of all this data is that Glenk et al. were able to analyze the trends in electrolyzer annual cost reductions, although the estimates for cost improvements still reflect the wide range of possible electrolyzer prices. For PEM systems Glenk et al. suggest that a 4.77 +/- 1.88% per year cost reduction would be possible, while 2.96 +/- 1.23% per year decline would be possible for AE systems [12]. For this work we did not attempt to formulate the best measure of central tendency, but instead we adopted a monte carlo-style approach to analyzing these renewable hydrogen systems. We formulate a *low*, *mid*, and *high* price projection for AE, PEM and SOE systems that corresponds to the min, mean and max of the cost parameters (year 2020) from table 4.1. The rate of cost improvements shown in Table 4.2 were chosen to fall within the range of values for PEM and AE systems from Glenk et al.

TABLE 4.2: Electrolyzer CAPEX price parameters.

System Type	*Scenario*	(2020 $/kW)	Rate of Improvement (%/yr)
AE	low	571	0.5
AE	mid	988	2.0
AE	high	1268	2.5
PEM	low	385	0.5
PEM	mid	1182	2.0
PEM	high	2068	2.5
SOE	low	677	0.5
SOE	mid	1346	2.0
SOE	high	2285	2.5

4.2.1 Comparison of CAPEX Costs to other Studies

We view the references in Table 4.1 as primary cost references, but there are other policy oriented reports that have also investigated various aspects of renewable hydrogen production, and thus, rely on their own estimates of electrolyzer CAPEX costs. Table 4.3 details electrolyzer CAPEX assumptions in various reports for comparison with ours.

TABLE 4.3: Comparison of electrolyzer CAPEX costs to other studies.

Report	Electrolyzer Type	Year of Estimate	(2020 $/kW)	This Work (2020 $/kW)	Reference
IEA	AE	2020	500	571-1268	[5]
IEA	AE	2030	400	541-1208	[5]
IEA	AE	*Long Term*	200	487-1090	[5]
IRENA	AE	2020	840	571-1268	[7]
IRENA	AE	2050	200	487-1090	[7]
Bloomberg	AE	2019	1200	571-1268	[6]
Bloomberg	AE	2022	600-1100	565-1256	[6]
Bloomberg	AE	2025	400-1000	556-1238	[6]
Bloomberg	AE	2030	115-135	541-1208	[6]
Bloomberg	AE	2050	80-98	487-1090	[6]
IEA	PEM	2020	1100	385-2068	[5]
IEA	PEM	2030	650	365-1968	[5]
IEA	PEM	*Long Term*	200	325-1781	[5]
Bloomberg	PEM	2019	1400	385-2068	[6]
Bloomberg	PEM	2030	425-1000	365-1968	[6]
Bloomberg	PEM	2050	150-200	325-1781	[6]
IEA	SOE	2020	2800	677-2285	[5]
IEA	SOE	2030	800	647-2175	[5]
IEA	SOE	*Long Term*	500	587-1968	[5]

4.3 Electrolyzer OPEX Costs

Electrolyzer OPEX costs are most commonly modeled as a fraction of the original CAPEX and have been previously modeled as independent of the electrolyzer type [11]. Most studies put this value between 1-3% of the electrolyzer CAPEX [11]. We follow the modeling methodology in Glenk et al. and adopt a fixed OPEX cost of $40/kW for the US and $50/kW in the EU [12]. Variable OPEX costs associated with the electrolyzer include the costs of electricity (as modeled), and water (0.08 $/kg of H_2) [12].

4.4 Hydrogen Compression with Short Term (On-Site) Storage

In addition to the electrolyzer a renewable hydrogen system will require a compressor and piping in order to get it ready to be injected into a pipeline or to be put into tanker trucks and shipped. For this analysis we focus on a compressor system that can inject hydrogen into a pipeline – specifically we include the CAPEX for the compressor, on-site storage, as well as the on-going cost of electricity to power the compressor. We assume that the compressor would also run on the same renewable electricity that powers the electrolyzer (at the same price). We do not model the cost of distributing hydrogen to end users. These costs are real costs that will add to the delivered price of hydrogen, but are left for future modeling exercises because there are many unresolved market-based forces that will dictate how large or small these costs will be.

Data for compressor CAPEX is sparse, and often presented in an aggregate metric with other system components. This complicates the analysis since we are only interested in the on-site capital investments associated with distributing H_2 via pipeline; many studies entangle these costs with other refueling station costs (as opposed to production site-only costs). Since we are modeling a compression system that will be used to inject hydrogen into a pipeline, we look at systems that will have an outlet pressure of between 30-150 bar (3–15 MPa or 435-2175 psi) for injection into a transmission line. These compressors must also be capable of supplying high flowrates of compressed hydrogen. These requirements narrow the data available even further. For this work, we focus on capital costs reported in Penev et al. as they present data regarding the capital costs, production capacity, and specific energy required to operated such a compressor. Penev et al. also present their findings for several system sizes. Their data are from the US Department of Energy's Hydrogen Analysis (H2A) production model and the Hydrogen Delivery Scenario Analysis Model (HDSAM) and are reported in Table 4.4. Penev was also a primary contributor to the DOE H2A Hydrogen Production Model (`https://www.hydrogen.energy.gov/h2a_analysis.html`)

TABLE 4.4: Comparison of Compressor CAPEX

Capacity (kg/yr)	**CAPEX (2020$)**	**CAPEX Rate (2020$/kg)**	**Energy Req. (kWh/kg)**	**Reference**
1,168,000	3,888,840	3.32	0.399	[52]
16,940,240	16,989,074	3.05	0.399	[52]
38,663,759	38,775,217	2.94	0.399	[52]

Following Penev et al. we assume a CAPEX rate of $3/kg of production capacity and a specific energy consumption rate of 0.399 kWh/kg. These values are in rough agreement with Nexant for a similar system configuration [53]. We make no assumptions about oversizing the compressor system to handle dynamic situations when the electrolyzer is directly connected to a variable resource, such as in Scenario #2. It is inferred from the sensitivity analysis in Penev et al. that the on-site storage solution would be able to hold $\approx$ 1 day worth of hydrogen. It might be necessary to have seasonal storage to handle summer peak demand and winter planned outages; these seasonal storage solutions are not considered in this work.

While we consider the Penev et al. system configuration as the primary configuration for this work, we also wanted to investigate a production site that would only consider a compressor-only (no short term storage) configuration. Investigating this system configuration allows us to assess the impact of on-site storage to the overall cost of H_2. In the compressor-only scenario it is likely that the pipeline would need to be "packed", as can be done with natural gas systems, in order to smooth short-term supply/demand dynamics. In this way, the owner/operator of the hydrogen produciton plant could avoid the cost of storage facilities, which contribute significantly to the overall CAPEX rate presented in Penev et al. To calcultate the compressor-only CAPEX we first must calculate the shaft power that is needed to compress hydrogen from an electrolyzer outlet pressure of 18 bar (260 psi) to pipline pressures that are 40 bar (580 psi). An idealized gas relationship is used in order to calcuate the power requirement (Equation 4.1) [53, 54]

$$P = Q\left(\frac{1}{24 * 3600}\right)\frac{ZTR}{M_{H_2}\eta}\frac{N\gamma}{\gamma - 1}\left(\left(\frac{P_{out}}{P_{in}}\right)^{\frac{\gamma-1}{N\gamma}} - 1\right) \tag{4.1}$$

Where, Q is the flow rate (kg/day), P_{in} is the inlet pressure of the compressor, P_{out} is the outlet pressure of the compressor, Z the hydrogen compressibility factor equal to 1.03198, N is the number of compressor stages (assumed to be 2 for this work), T is the inlet temperature of the compressor (310.95) K), γ is the ratio of specific heats (1.4), M_{H_2} is the molecular mass of hydrogen (2.15 g/mol), η is the compressor efficiency ratio (taken as 75%), the universal constant of ideal gas $R = 8.314\frac{J}{molK}$. The $\left(\frac{1}{24}\frac{1}{3600}\right)$ is a necessary factor that converts day units into seconds. We find that at flow rate of 36,000 kg/day the shaft power from the compressor would need to be 583 kW. The overall motor efficiency is assumed to be 95% bringing the electrical load up to 613 kW. Following Nexant, we also oversize the compressor motor by 10% [53]. Both Nexant (Equation 4.2) and the National Research Council (Equation 4.3) have developed relationships that allow the conversion between the rated compressor power and the CAPEX; both equations give CAPEX in 2020$ [53, 54].

$$CAPEX = 19207\left(P^{0.6089}\right)(1.19) \tag{4.2}$$

$$CAPEX = 2545\,(P) \tag{4.3}$$

Where P is the power in kW from Equation 4.1. In this case, the NRC relationship yields a CAPEX rate of 0.13 $/kg of production capacity and the Nexant relationship yields 0.18 $/kg of production capacity. For this exercise we settle on a mean value of 0.15 $/kg as our compressor-only CAPEX rate; it is assumed that electricity is consumed at the same 0.399 kWh/kg as with Penev et al.

Ultimately, we find that the additional costs of on-site storage contributes approximately 0.50-0.60 $/kg to the final price of produced H_2, while a compressor-only system configuration would add approximately 0.05-0.10 $/kg. This cost breakdown between compression and storage is similar to that referenced by Amos [55].

4.5 Other System Costs – Balance of Plant

We follow the costs provided in Glenk et al., which were gathered from manufacturer interviews, and apply an additional 50 $/kW for CAPEX costs associated with the balance of system (piping, electrical, etc.).

4.6 Electrolyzer Lifetime

While there is some variability in the reported electolyzer lifetime, there is general agreement that current AE and PEM systems would have lifetimes of 75,000 and 60,000 hours respectively [5]. We project these lifetimes out to 2050 with a simple linear relationship up to 125,000 hours [5]. We also follow the International Energy Agency's estimates of SOE lifetimes: 20,000 hours for current systems out to 87,5000 hours in 2050 [5]. Following Brynolf et al., once a electrolyzer requires replacement, those replacement costs are estimated to be 50% of the initial capital costs [11].

4.7 Conversion Efficiency

If a electrolyzer could be built that was 100% efficient it would be able to produce 0.03 kg H_2/kWh. This ideal is scaled down by a conversion efficiency parameter, which varies by electrolyzer type. Modest improvements over time are assumed to follow a linear path out to 2050; Table 4.5 details these parameters.

TABLE 4.5: Electrolyzer efficiencies (η_{E2H}) used in this study.

Parameter	2020 Value	2050 Value	Reference
AE	70%	80%	[5]
PEM	60%	74%	[5]
SOE	81%	90%	[5]

4.8 Overall Economic Modeling Methodology

In order to calculate the price of hydrogen we develop an economic model that is analogous to that developed in Section 3.2 – the Levelized Cost of Hydrogen is assumed to be a proxy measure for future market prices of hydrogen. In this study a hurdle rate of 7% was assumed for the hydrogen project, a value that might be viewed as more consistent with mature technologies that have already been proven at commercial scales. While this is not strictly true, AE and PEM systems have been in the marketplace for a long time and are not necessarily considered a new technology. SOE systems are only now entering the market, and might command a higher hurdle rate in order to incentivize investments [56]. All this considered, we decided to choose a bounding value for the hurdle rate rather than over-specify data that cannot be directly supported from literature.

This work considers a range of cash flows that would impact the overall viability of a renewable hydrogen plant. These cash flows include: capital expenses, operations and maintenance, electrolyzer replacements, corporate taxes (rates are country specific), depreciation, and feedstock costs (i.e., electricity, water).

This study performs the economic analysis from the perspective of a project developer (i.e., a company or companies that wish to build a renewable hydrogen plant in EU or the US). The plant being considered is assumed to have a 30 year lifetime and is built over a period of 2 years. Table 4.6 details the necessary economic parameters used in the calculation of the price of hydrogen.

TABLE 4.6: Fundamental economic parameters for NPV calculations.

Parameter	Value
Plant Lifetime	30 years (no salvage value)
Construction Time	2 years (75% initial capital in year 1, 25% in year 2)
Depreciation Method	Straight Line
Depreciation Rate	5%

Chapter 5

Results

The economic model that was described in Section 4.8 is now used to generate data for the price of hydrogen in a Monte Carlo style analysis. This way we can assess the distribution of prices for both the United States and Europe. Unlike a true Monte Carlo analysis, we do not draw parameters randomly, we simply enumerate a large number of plausible system configurations. For the United States we have (356 regions) x (3 electrical generators) x (3 electrical generation scenarios) x (3 electrolyzer technologies) x (3 electrolyzer scenarios) x (7 scenario years) = 201,852 system configurations; for Europe we have 14,175 possible system configurations.

The histograms in the following figures show the distribution of plausible H_2 price across all possible regions, renewable electricity generators, and electrolyzer types. The y-axis in this graph is simply the number of system configurations that fall within the H_2 price bins that are shown on the x-axis. The coloring scheme is meant to draw the eye to the median H_2 price, which is an important measure of central tendency. It is also important to highlight the minimum H_2 price; both values are explicitly stated in the text insets.

The maps show the geographical distribution of the *minimum* hydrogen price that can be found for each time period over all electrolyzer system configurations; however we restricit the calculation of the minimum price to the "mid" electricity price scenario.

5.1 Scenario #1: *Results*

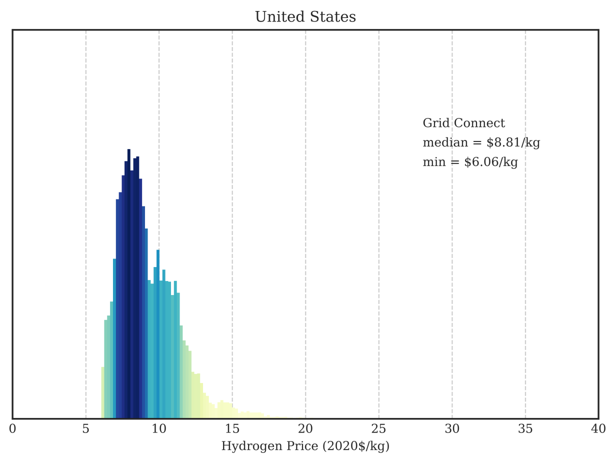
Recall that Scenario #1 assumes that the power-to-gas plant is directly connected to the electric grid and therefore can run at 100% capacity but must pay additional electricity costs associated with transmission and distribution. The results can be summarized as:

- The median price of H_2 in the US will decrease from \$8.81/kg in 2020 to \$5.77/kg in 2050; during that same timeframe the minimum price decreases from \$6.06/kg to \$4.15/kg.
- The median price of H_2 in the EU will decrease from \$13.11/kg in 2020 to \$7.69/kg in 2050; during that same timeframe the minimum price decreases from \$4.83/kg to \$3.21/kg.

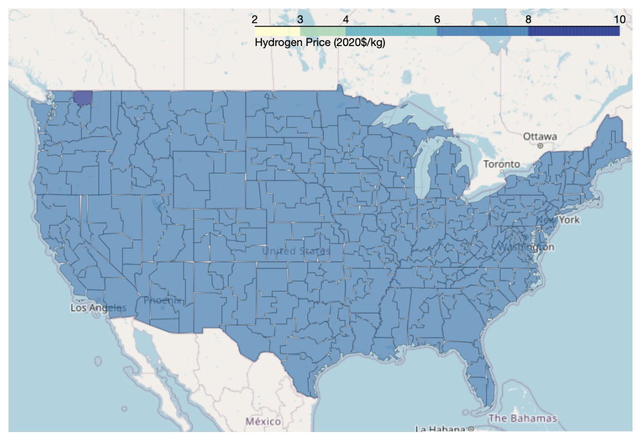
The following figures show the H_2 price distribution and the geographical distribution of the resulting H_2 prices. To clarify futher, the left histogram shows the H_2 price distribution across all 201,852 possible configuration for the US and 14,175 possible configurations for the EU. The H_2 price distributions are non-normal, thus only the median and min values are reported. The data mapped in the right hand side shows only the minimum price (from any system configuration) for hydrogen that would be available in a specific region with mid-range renewable electricity prices. The minimum price reported in histograms and in the bullet points above reflects the lowest-cost system configuration and the "low" renewable electricity scenarios shown in Section 3.3. Regional differences are driven primarily by variation in the potential for renewable electricity generation (capacity factor), but corporate tax rates also vary by countries in the EU (it is assumed that all US regions are subject to a constant composite rate that approximates both state and federal taxes).

Figures 5.1-5.7 summarize the results for the United States between 2020-2050. Figures 5.8-5.14 summarize the results for the European Union between 2020-2050.

5.1.1 United States - Hydrogen Prices

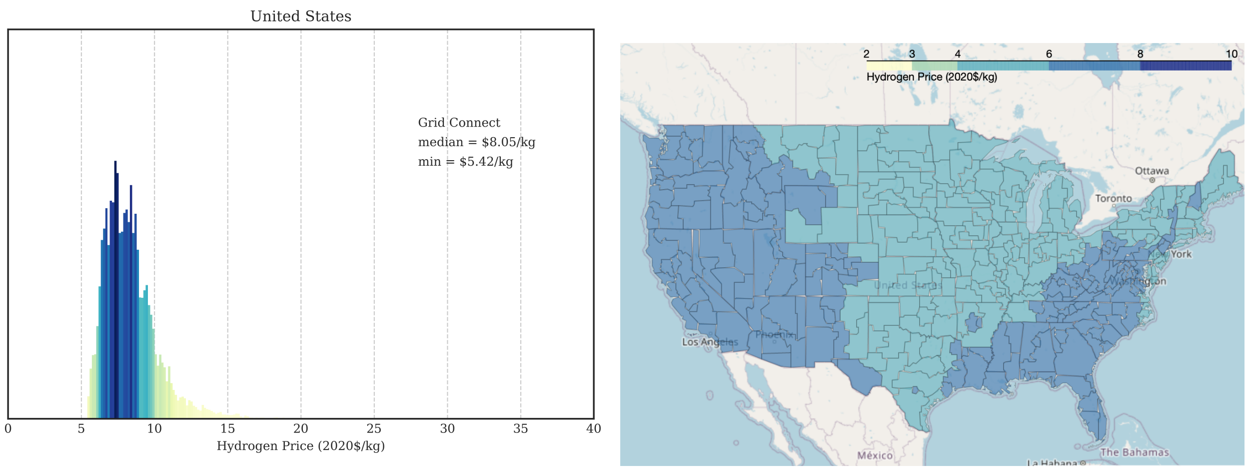


(A) Distribution of H_2 prices over all systems



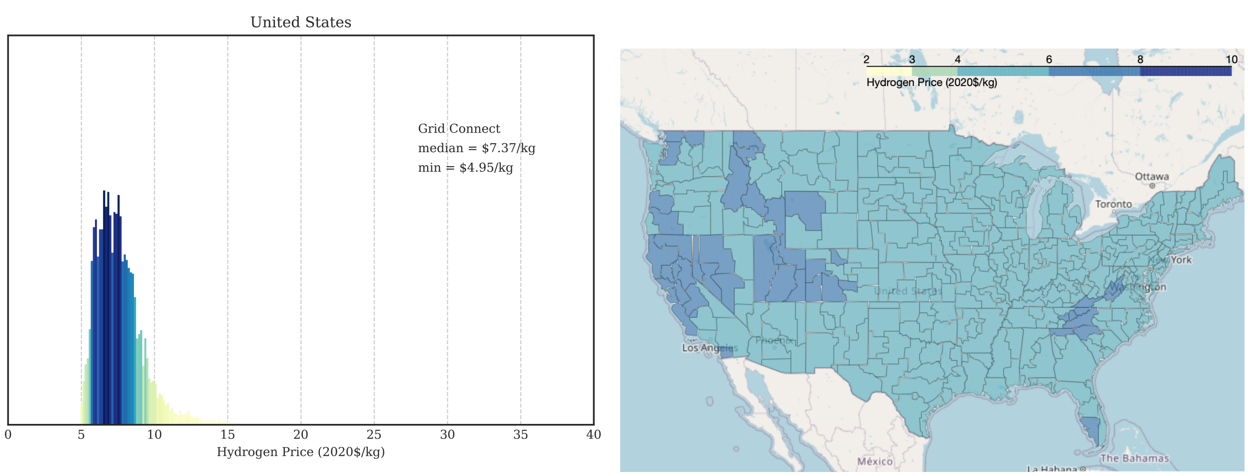
(B) Min H_2 price found over all system configurations

FIGURE 5.1: H_2 prices in 2020 – United States – Scenario #1 (grid connected)



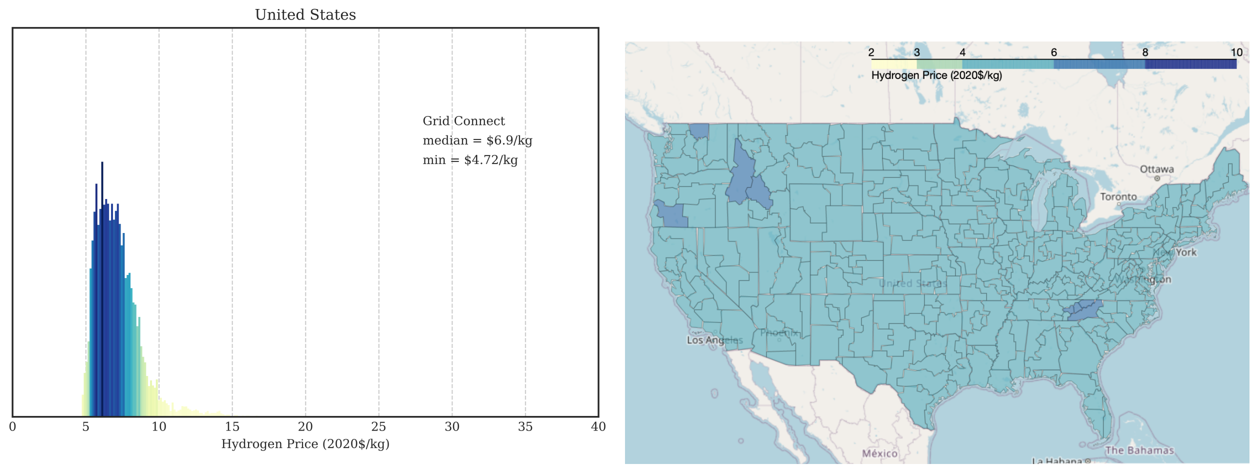
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.2: H_2 prices in 2025 – United States – Scenario #1 (grid connected)



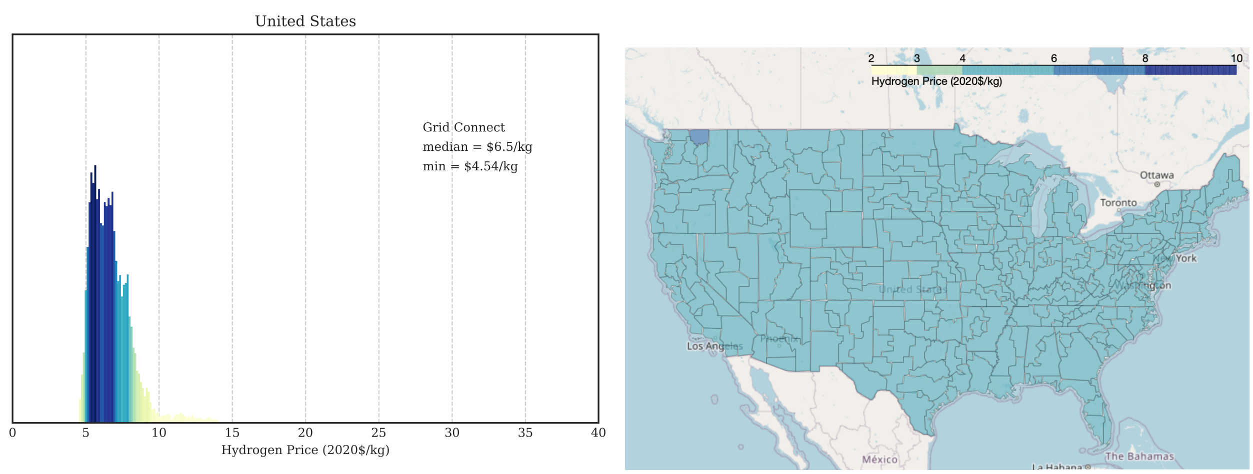
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.3: H_2 prices in 2030 – United States – Scenario #1 (grid connected)



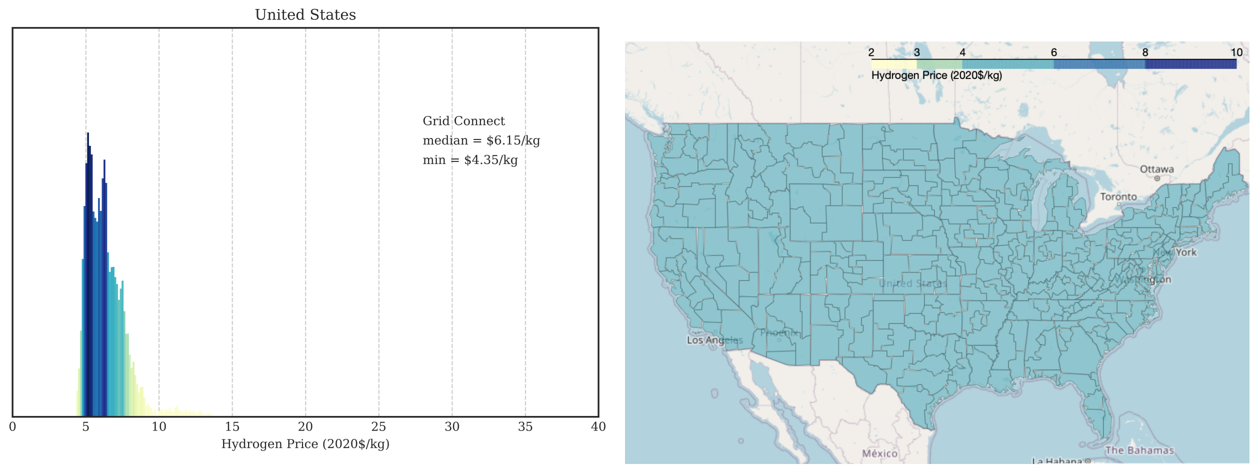
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.4: H_2 prices in 2035 – United States – Scenario #1 (grid connected)



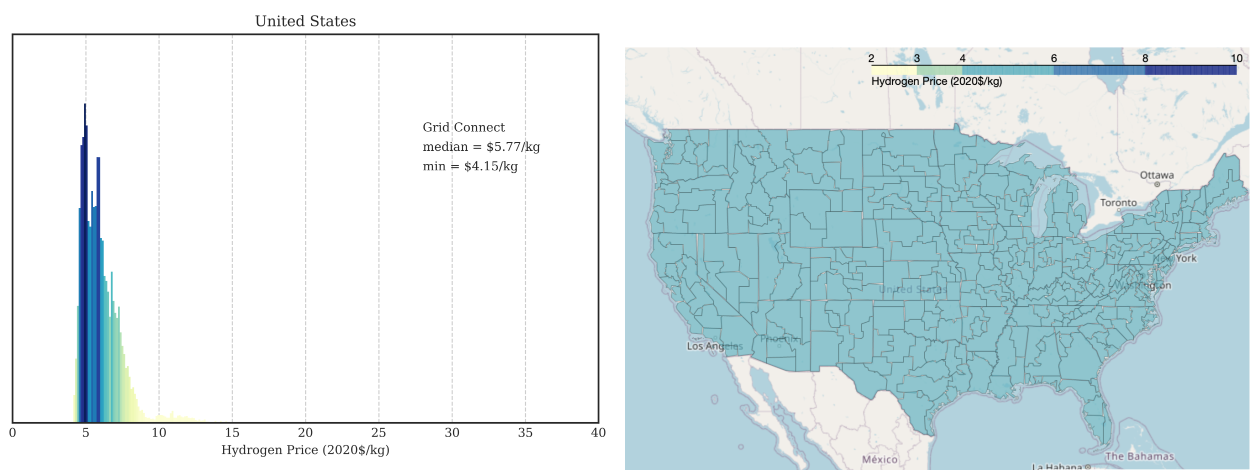
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.5: H_2 prices in 2040 – United States – Scenario #1 (grid connected)



(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

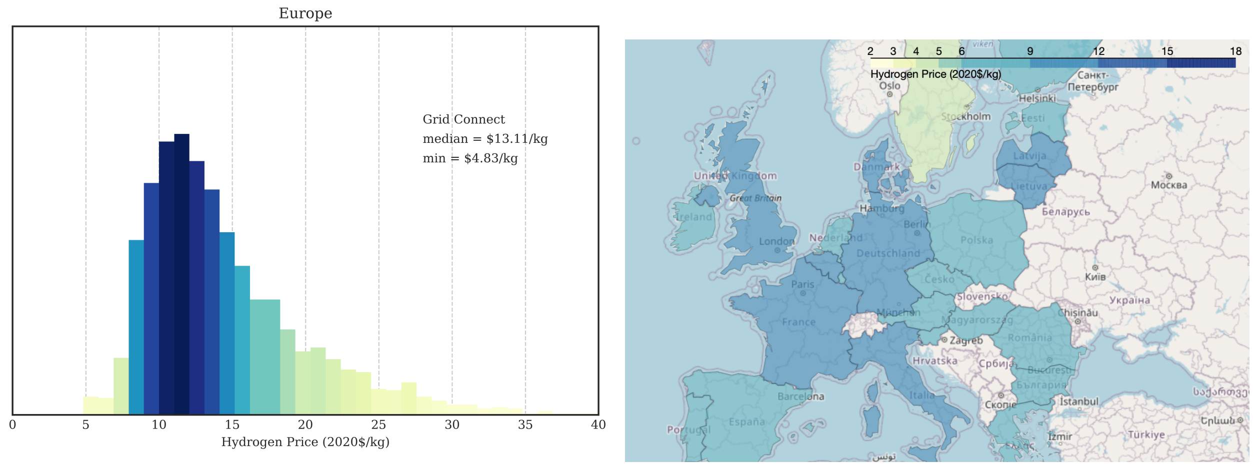
FIGURE 5.6: H_2 prices in 2045 – United States – Scenario #1 (grid connected)



(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

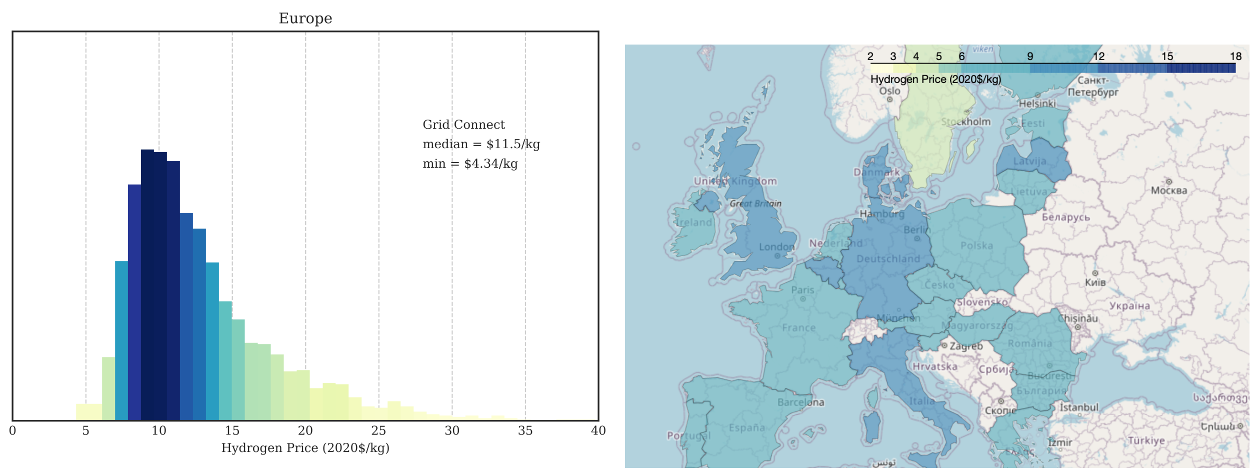
FIGURE 5.7: H_2 prices in 2050 – United States – Scenario #1 (grid connected)

5.1.2 Europe - Hydrogen Prices



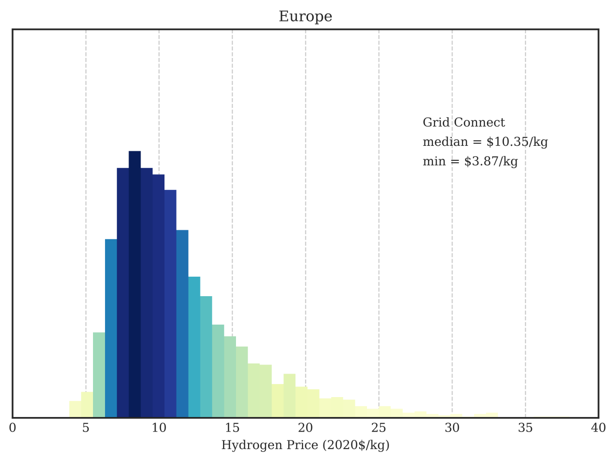
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.8: H_2 prices in 2020 – Europe – Scenario #1 (grid connected)

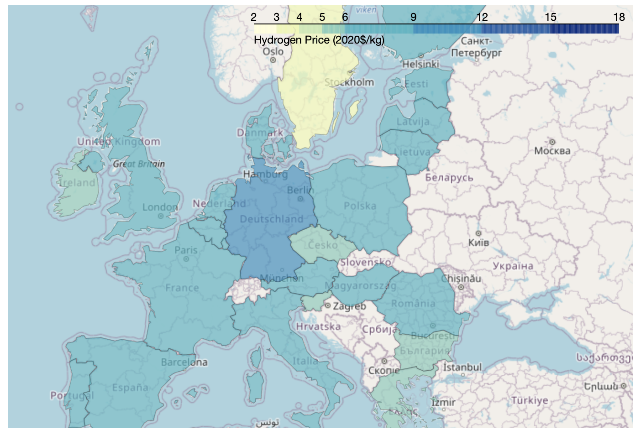


(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.9: H_2 prices in 2025 – Europe – Scenario #1 (grid connected)

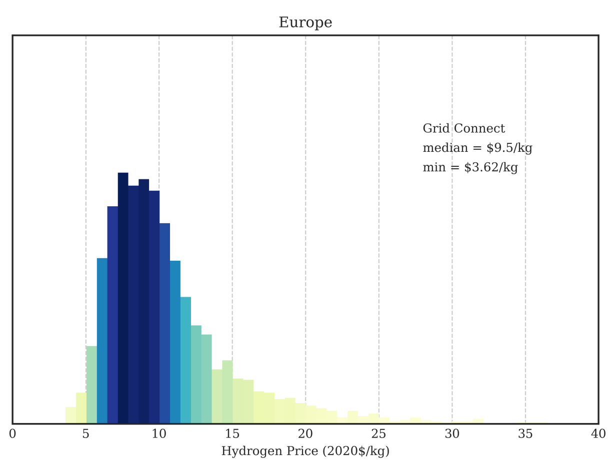


(A) Distribution of H_2 prices over all systems

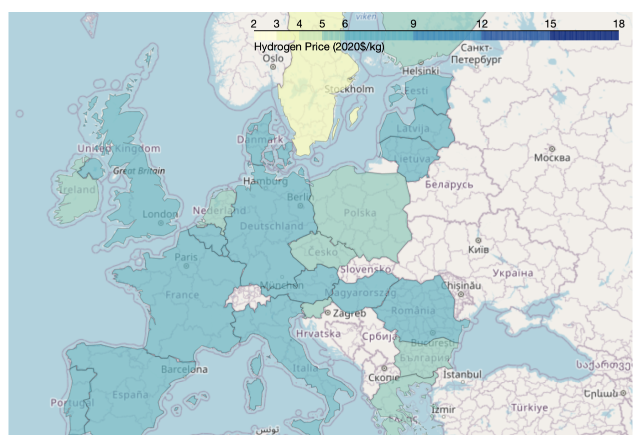


(B) Min H_2 price found over all system configurations

FIGURE 5.10: H_2 prices in 2030 – Europe – Scenario #1 (grid connected)

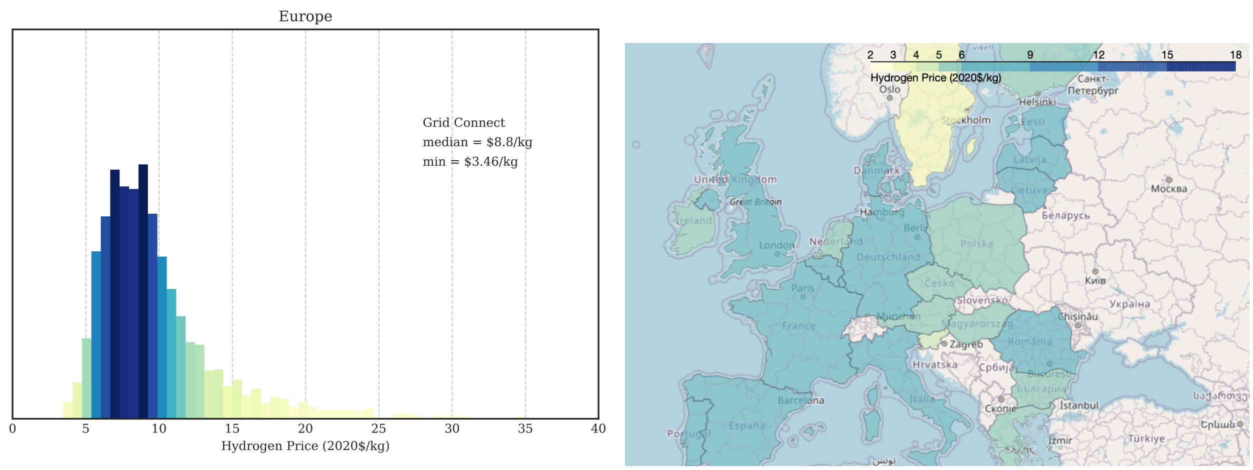


(A) Distribution of H_2 prices over all systems



(B) Min H_2 price found over all system configurations

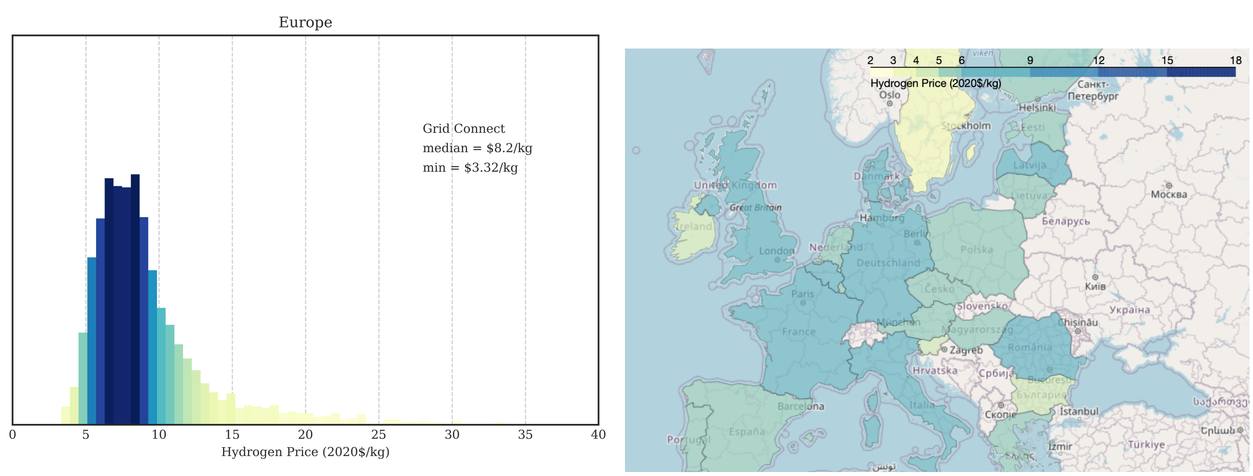
FIGURE 5.11: H_2 prices in 2035 – Europe – Scenario #1 (grid connected)



(A) Distribution of H_2 prices over all systems

(B) Min H_2 price found over all system configurations

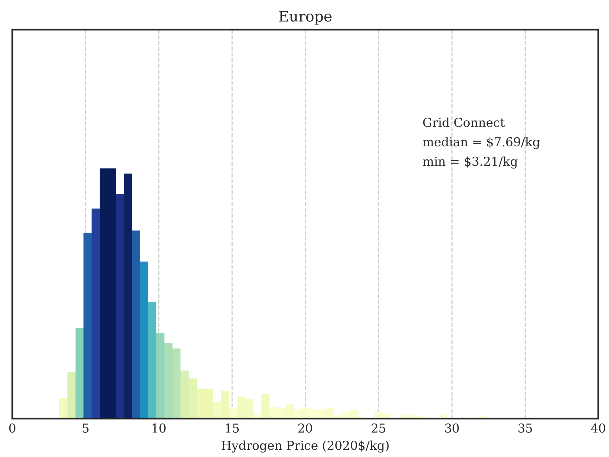
FIGURE 5.12: H_2 prices in 2040 – Europe – Scenario #1 (grid connected)



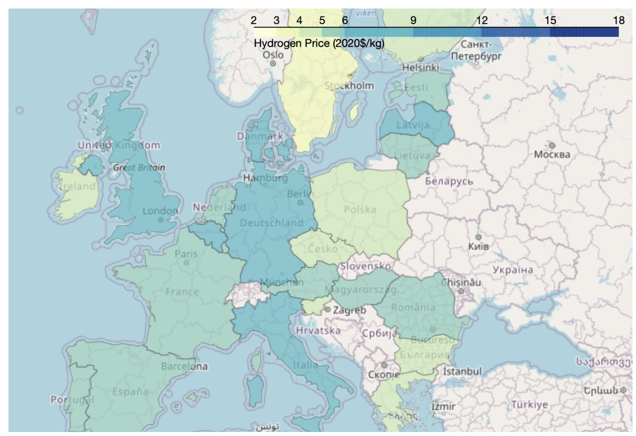
(A) Distribution of H_2 prices over all systems

(B) Min H_2 price found over all system configurations

FIGURE 5.13: H_2 prices in 2045 – Europe – Scenario #1 (grid connected)



(A) Distribution of H_2 prices over all systems



(B) Min H_2 price found over all system configurations

FIGURE 5.14: H_2 prices in 2050 – Europe – Scenario #1 (grid connected)

5.2 Scenario #2: *Results*

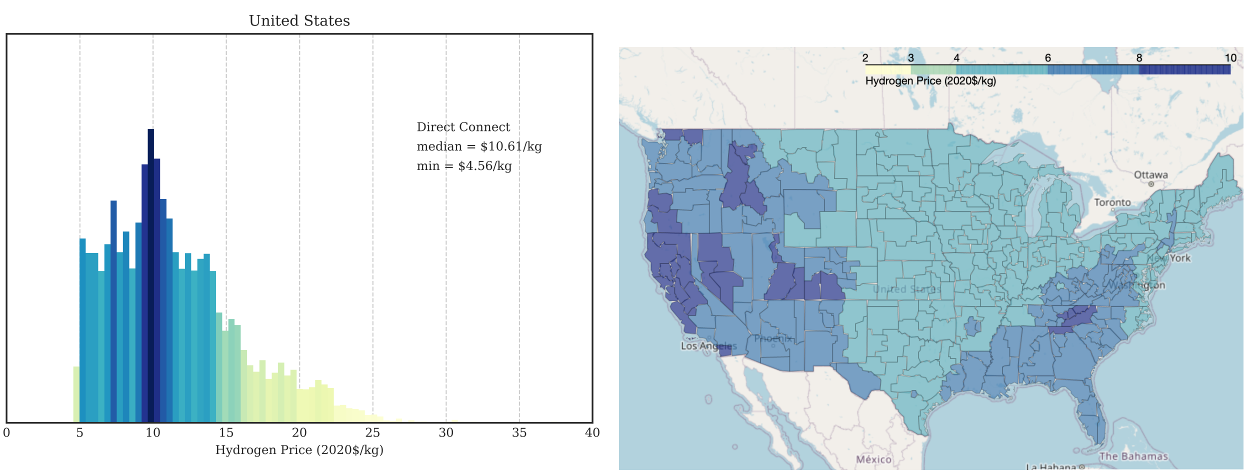
Recall that Scenario #2 assumes that the power-to-gas plant is connected to the renewable electricity generator and therefore will run at the capacity factor of the generator but does not pay electricity costs associated with transmission and distribution. The results can be summarized as:

- The median price of H_2 in the US will decrease from \$10.61/kg in 2020 to \$5.97/kg in 2050; during that same timeframe the minimum price decreases from \$4.56/kg to \$2.44/kg.
- The median price of H_2 in the EU will decrease from \$19.23/kg in 2020 to \$10.02/kg in 2050; during that same timeframe the minimum price decreases from \$4.06/kg to \$2.23/kg.

The following figures show the H_2 price distribution and the geographical distribution of these H_2 prices (and follow the same analytical logic discussed in section 5.1).

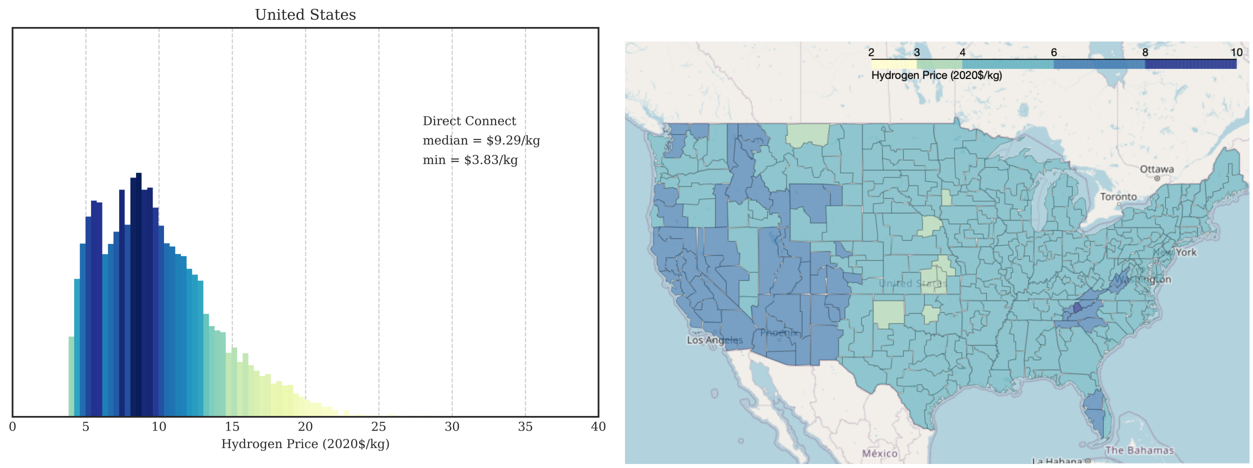
Figures 5.15-5.21 summarize the results for the United States between 2020-2050. Figures 5.22-5.28 summarize the results for the European Union between 2020-2050.

5.2.1 United States - Hydrogen Prices



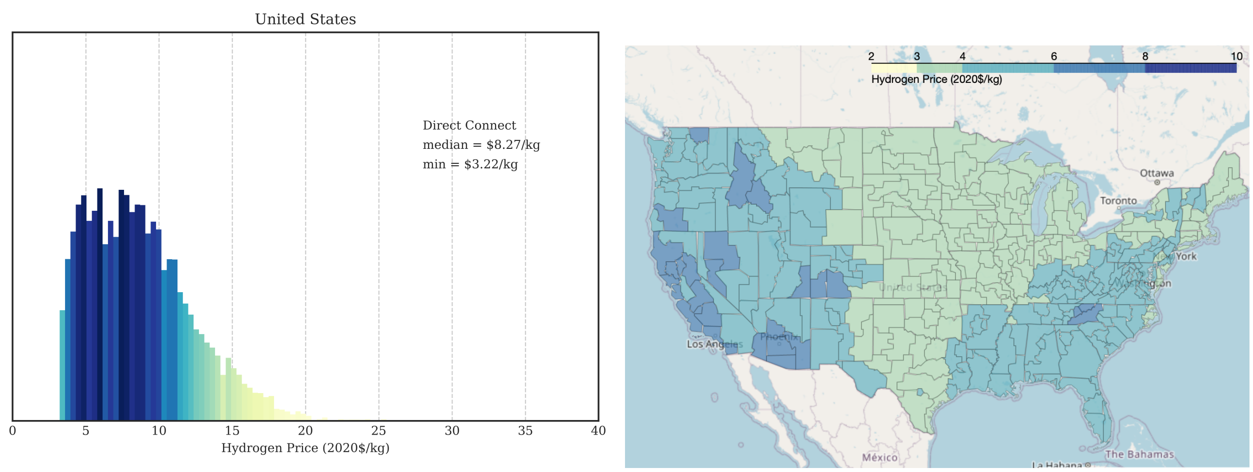
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.15: H_2 prices in 2020 – United States – Scenario #2 (direct connection)



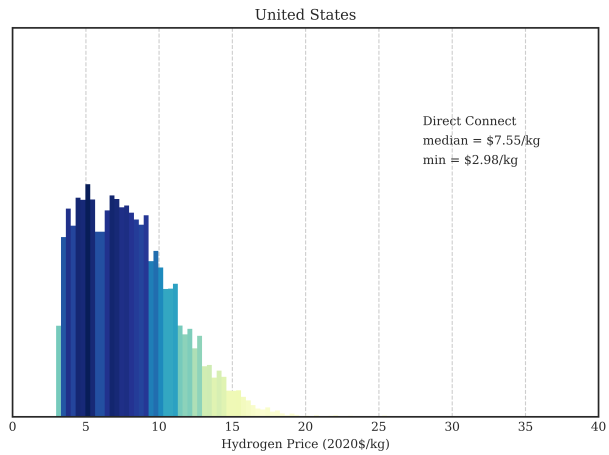
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.16: H_2 prices in 2025 – United States – Scenario #2 (direct connection)

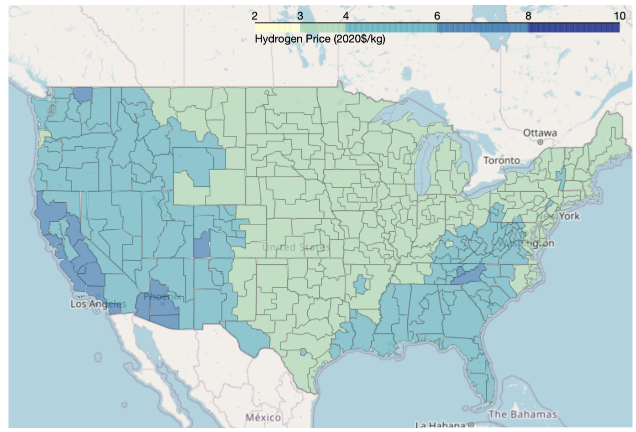


(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.17: H_2 prices in 2030 – United States – Scenario #2 (direct connection)

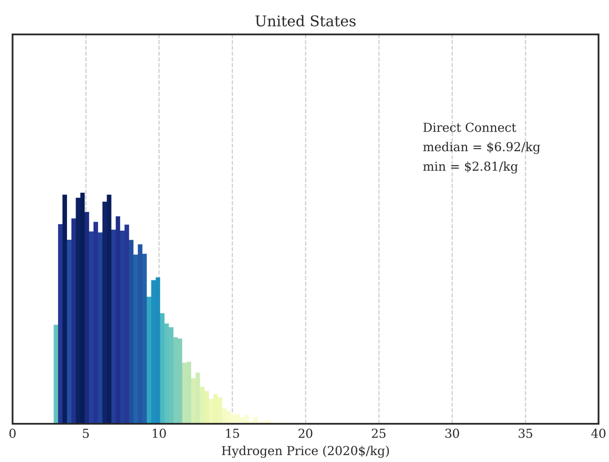


(A) Distribution of H_2 prices over all systems

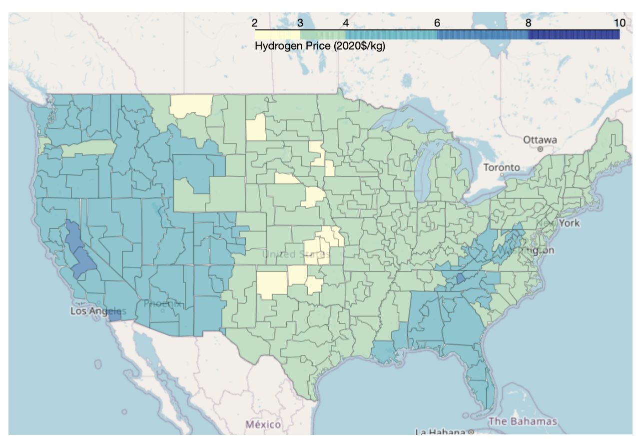


(B) Min H_2 price found over all system configurations

FIGURE 5.18: H_2 prices in 2035 – United States – Scenario #2 (direct connection)

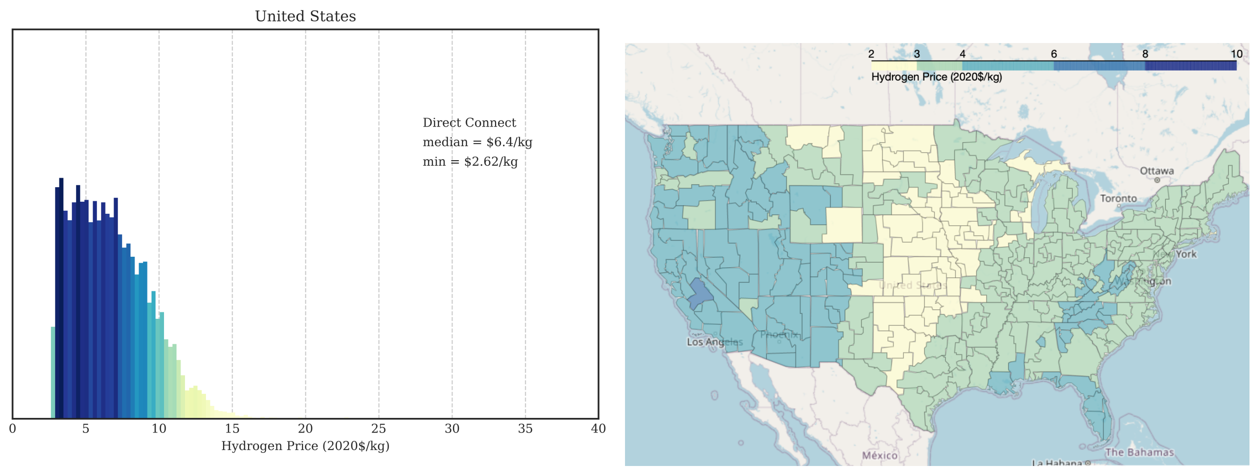


(A) Distribution of H_2 prices over all systems



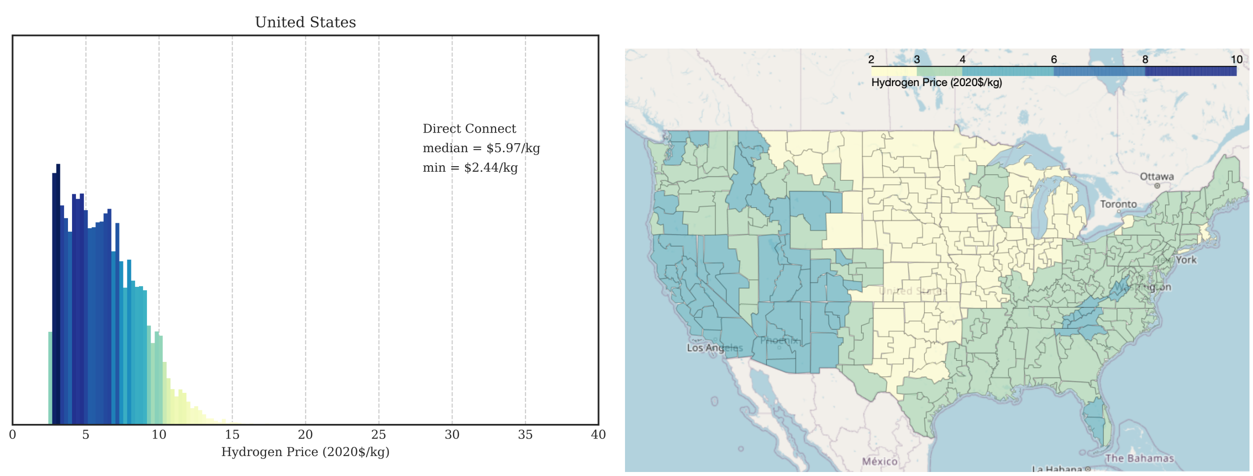
(B) Min H_2 price found over all system configurations

FIGURE 5.19: H_2 prices in 2040 – United States – Scenario #2 (direct connection)



(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

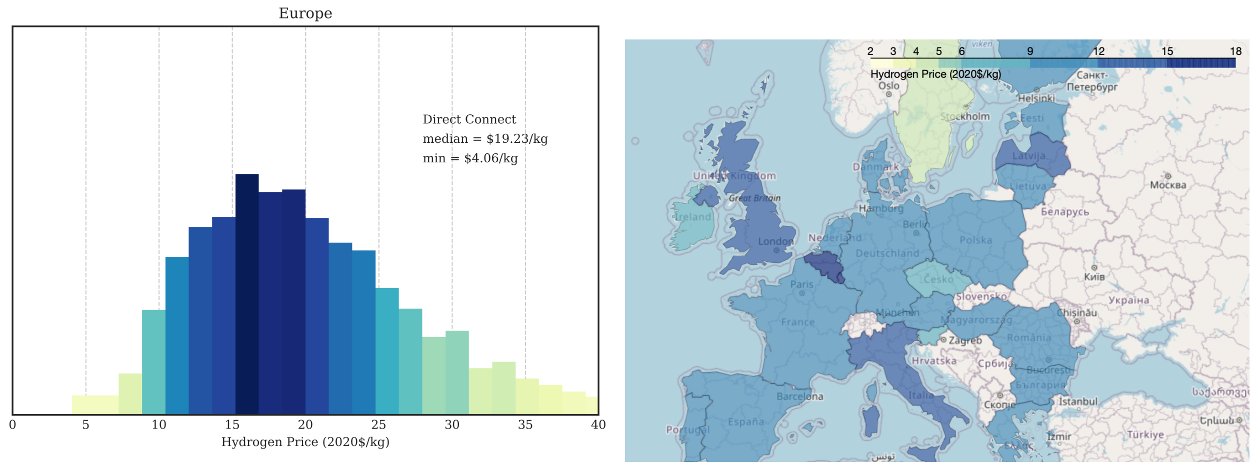
FIGURE 5.20: H_2 prices in 2045 – United States – Scenario #2 (direct connection)



(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

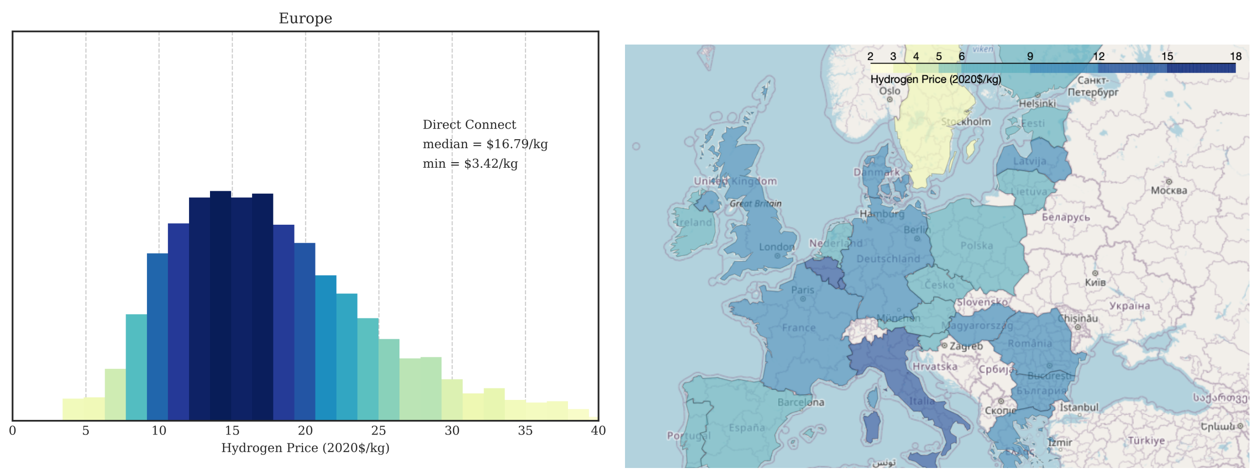
FIGURE 5.21: H_2 prices in 2050 – United States – Scenario #2 (direct connection)

5.2.2 Europe - Hydrogen Prices



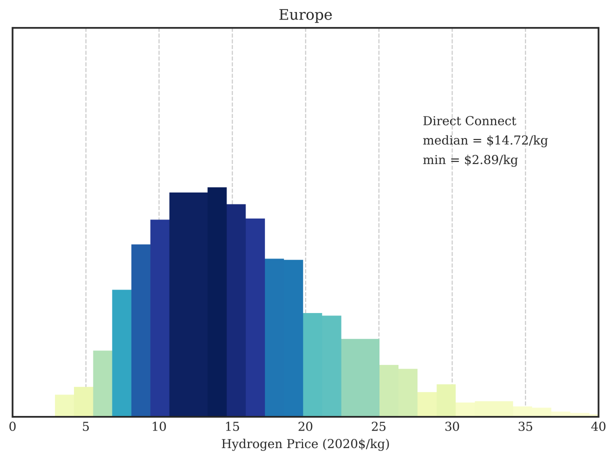
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.22: H_2 prices in 2020 – Europe – Scenario #2 (direct connection)

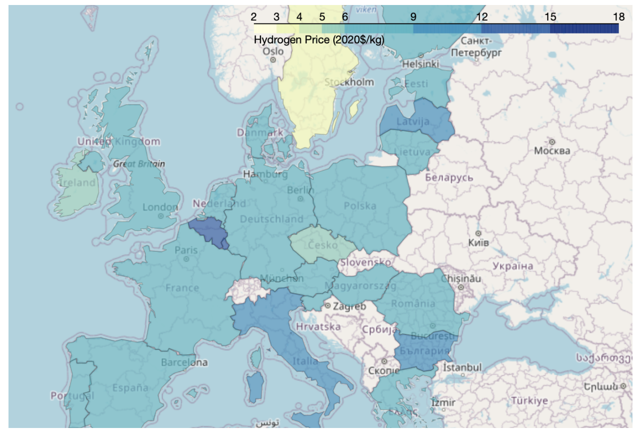


(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.23: H_2 prices in 2025 – Europe – Scenario #2 (direct connection)

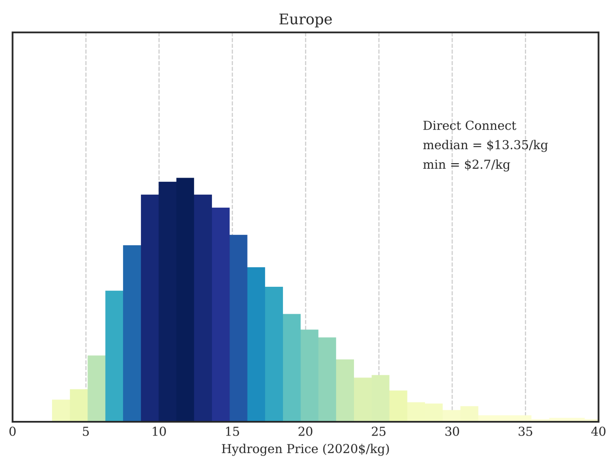


(A) Distribution of H_2 prices over all systems

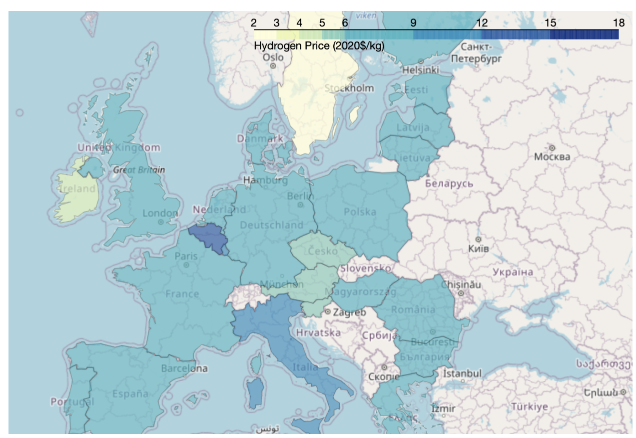


(B) Min H_2 price found over all system configurations

FIGURE 5.24: H_2 prices in 2030 – Europe – Scenario #2 (direct connection)

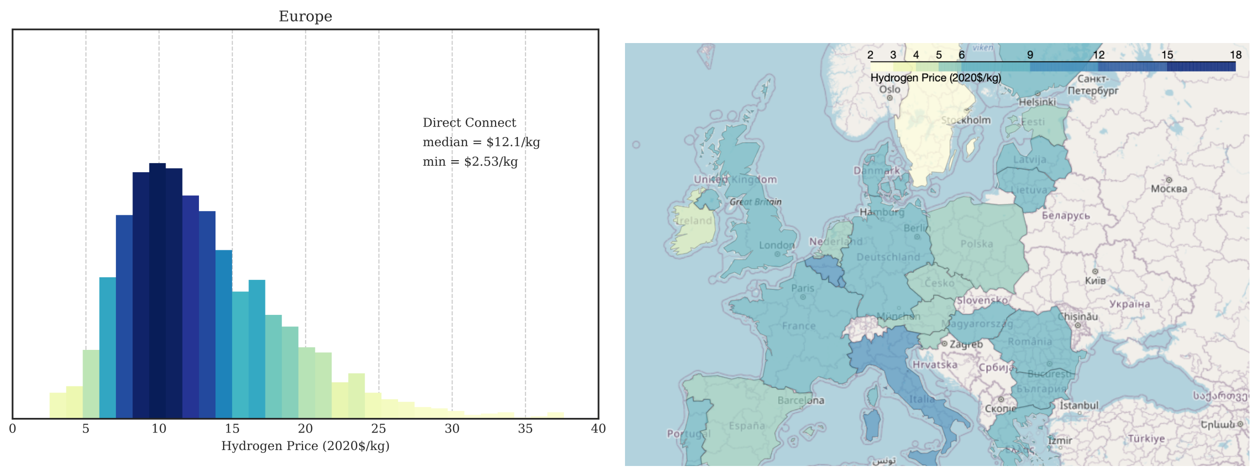


(A) Distribution of H_2 prices over all systems



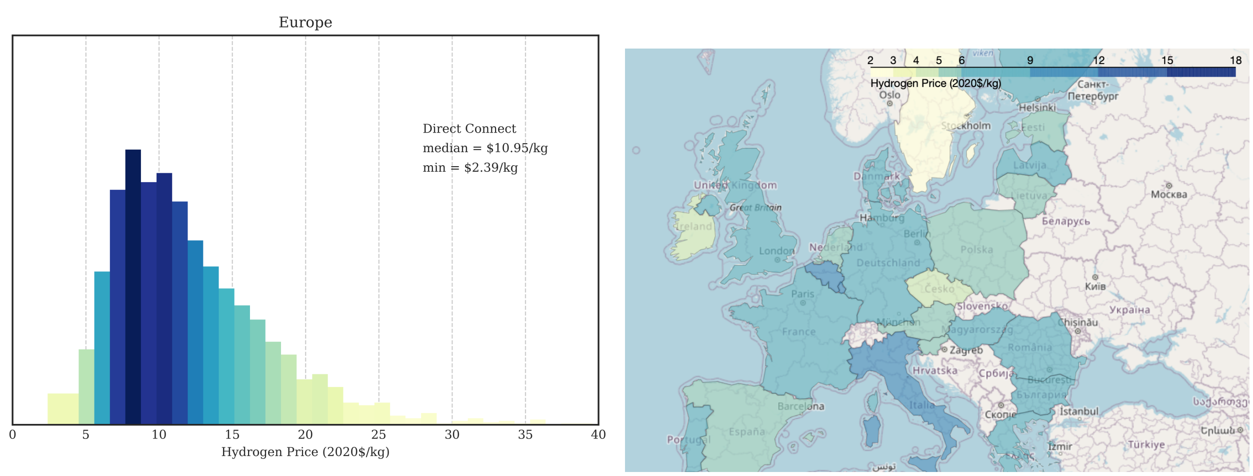
(B) Min H_2 price found over all system configurations

FIGURE 5.25: H_2 prices in 2035 – Europe – Scenario #2 (direct connection)



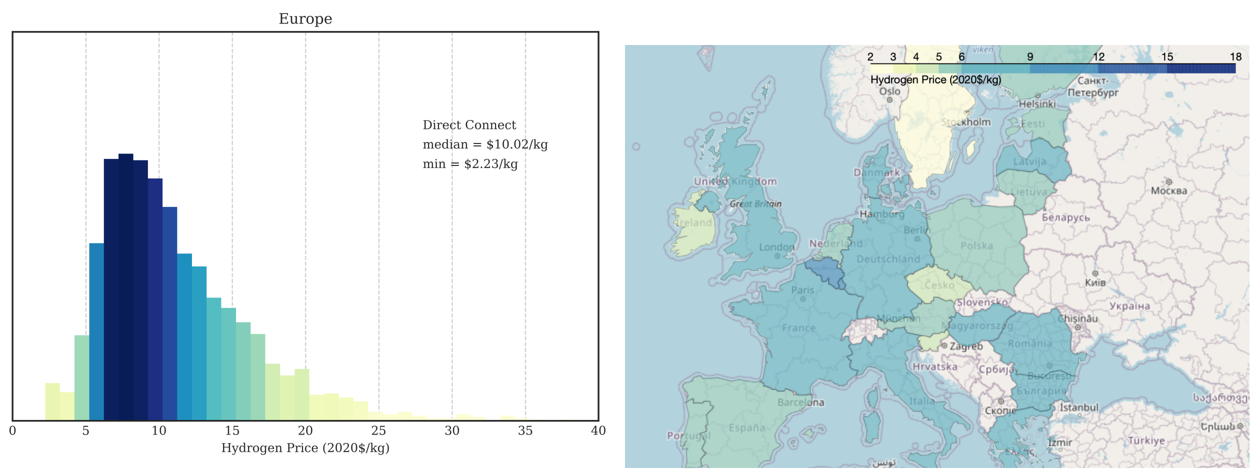
(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.26: H_2 prices in 2040 – Europe – Scenario #2 (direct connection)



(A) Distribution of H_2 prices over all systems (B) Min H_2 price found over all system configurations

FIGURE 5.27: H_2 prices in 2045 – Europe – Scenario #2 (direct connection)



(A) Distribution of H_2 prices over all systems

(B) Min H_2 price found over all system configurations

FIGURE 5.28: H_2 prices in 2050 – Europe – Scenario #2 (direct connection)

5.3 Scenario #3: *Results*

Recall that Scenario #3 assumes that the power-to-gas plant is connected to the transmission grid, but only draws energy when renewable energy must be curtailed (assumed to be 4 hours per day = 16% capacity factor). The curtailed electricity is considered to be free ($0/kWh). The histograms do not show as wide a distribution as a result of the capacity factor being equalized across all regions – variation is only due to differences in technology configurations and tax rates. The results can be summarized as:

- The median price of H_2 in the US will decrease from $11.02/kg in 2020 to $5.92/kg in 2050; during that same timeframe the minimum price decreases from $6.10/kg to $4.75/kg.
- The median price of H_2 in the EU will decrease from $10.85/kg in 2020 to $6.08/kg in 2050; during that same timeframe the minimum price decreases from $5.97/kg to $4.67/kg.

5.3.1 United States - Hydrogen Prices

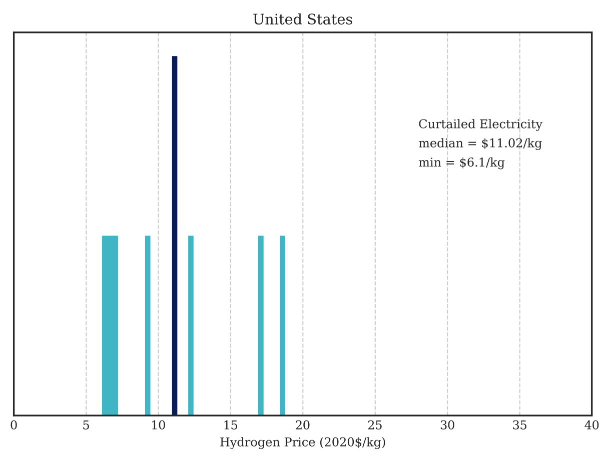


FIGURE 5.29: H_2 prices in 2020 – United States – Scenario #3 (curtailed electricity)

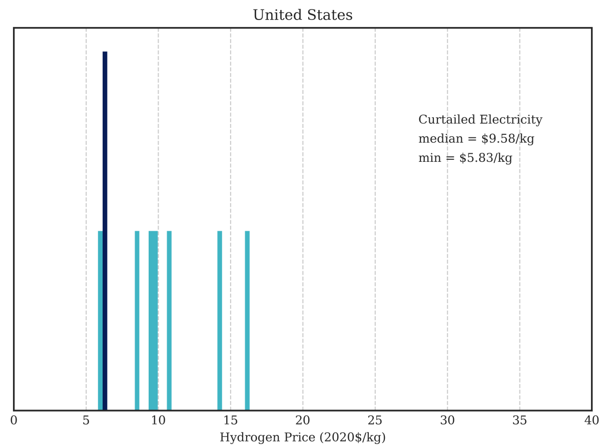


FIGURE 5.30: H_2 prices in 2025 – United States – Scenario #3 (curtailed electricity)

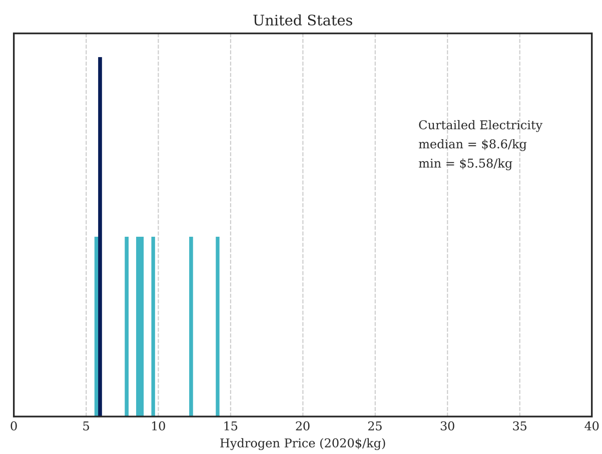


FIGURE 5.31: H_2 prices in 2030 – United States – Scenario #3 (curtailed electricity)

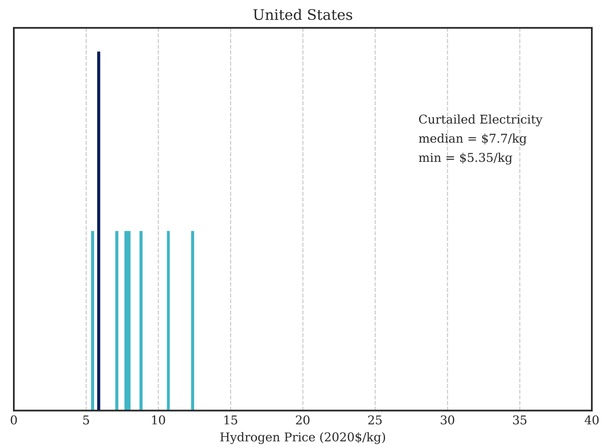


FIGURE 5.32: H_2 prices in 2035 – United States – Scenario #3 (curtailed electricity)

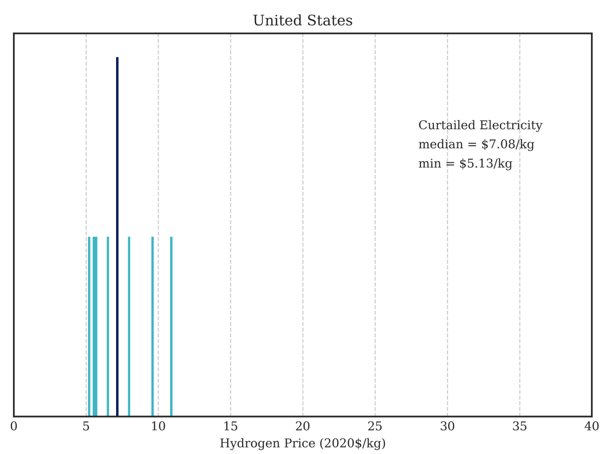


FIGURE 5.33: H_2 prices in 2040 – United States – Scenario #3 (curtailed electricity)

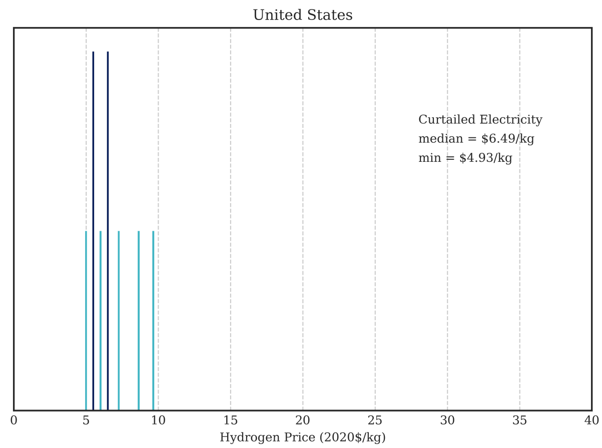


FIGURE 5.34: H_2 prices in 2045 – United States – Scenario #3 (curtailed electricity)

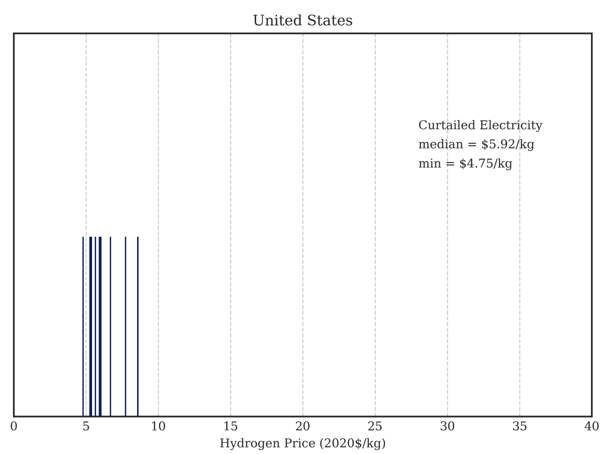


FIGURE 5.35: H_2 prices in 2050 – United States – Scenario #3 (curtailed electricity)

5.3.2 Europe - Hydrogen Prices

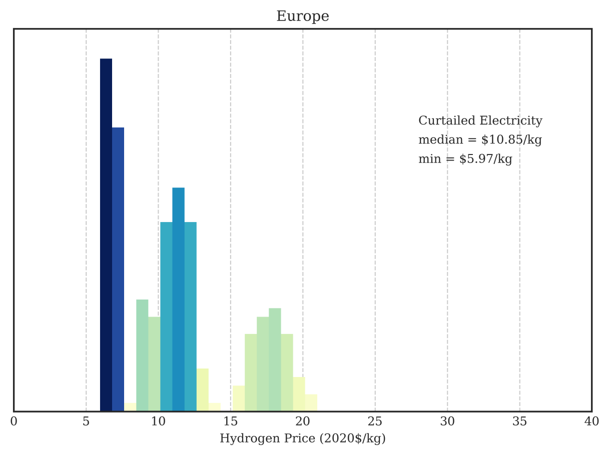


FIGURE 5.36: H_2 prices in 2020 – Europe – Scenario #3 (curtailed electricity)

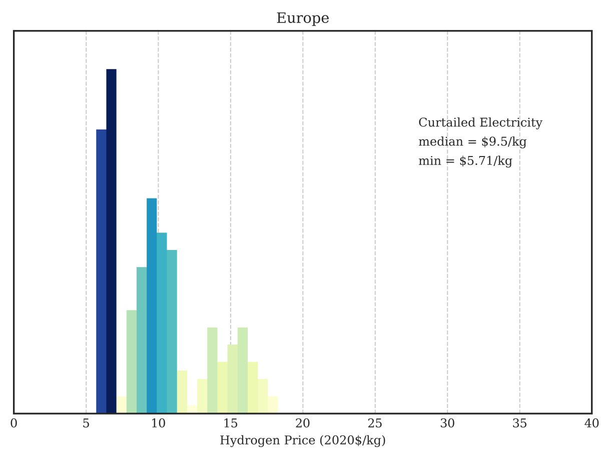


FIGURE 5.37: H_2 prices in 2025 – Europe – Scenario #3 (curtailed electricity)

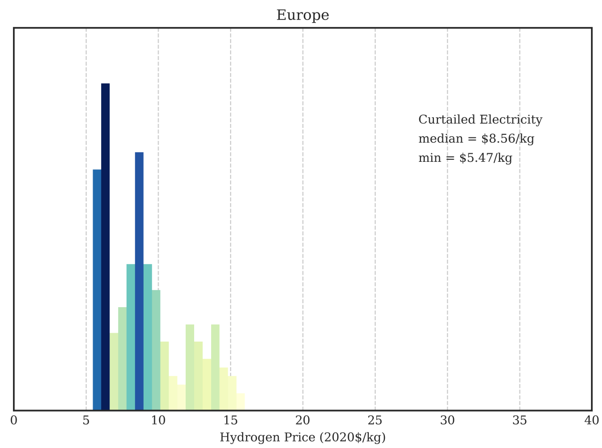


FIGURE 5.38: H_2 prices in 2030 – Europe – Scenario #3 (curtailed electricity)

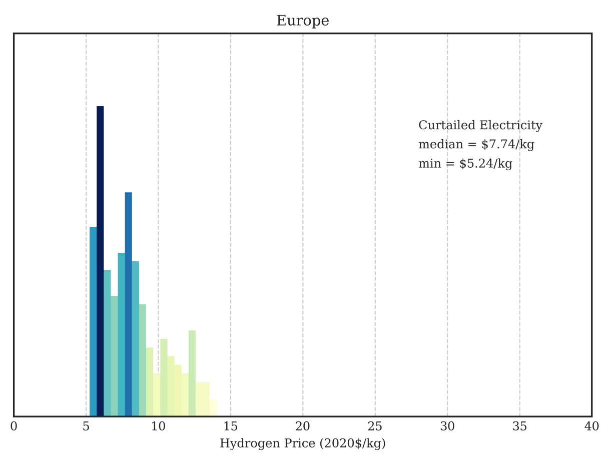


FIGURE 5.39: H_2 prices in 2035 – Europe – Scenario #3 (curtailed electricity)

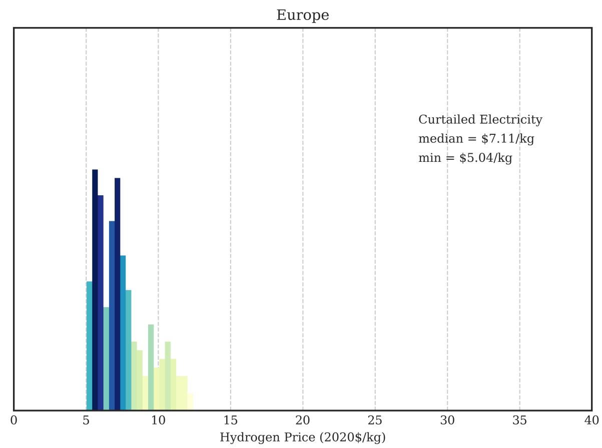


FIGURE 5.40: H_2 prices in 2040 – Europe – Scenario #3 (curtailed electricity)

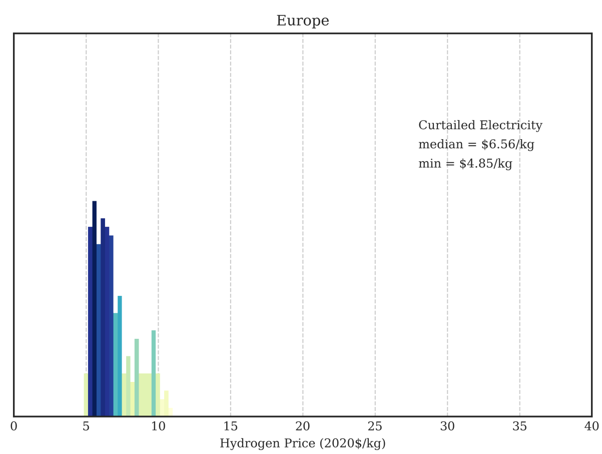


FIGURE 5.41: H_2 prices in 2045 – Europe – Scenario #3 (curtailed electricity)

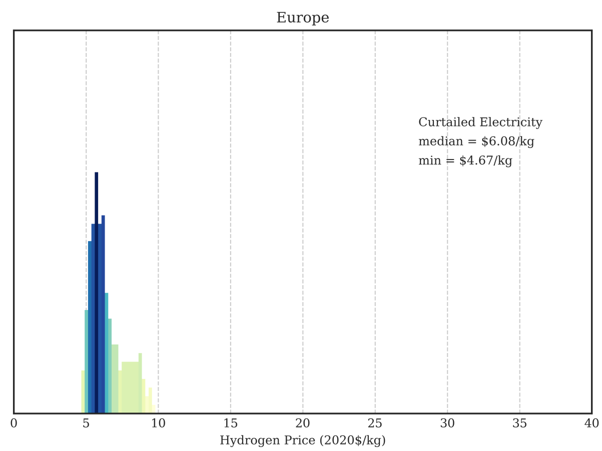


FIGURE 5.42: H_2 prices in 2050 – Europe – Scenario #3 (curtailed electricity)

Chapter 6

Study Comparison

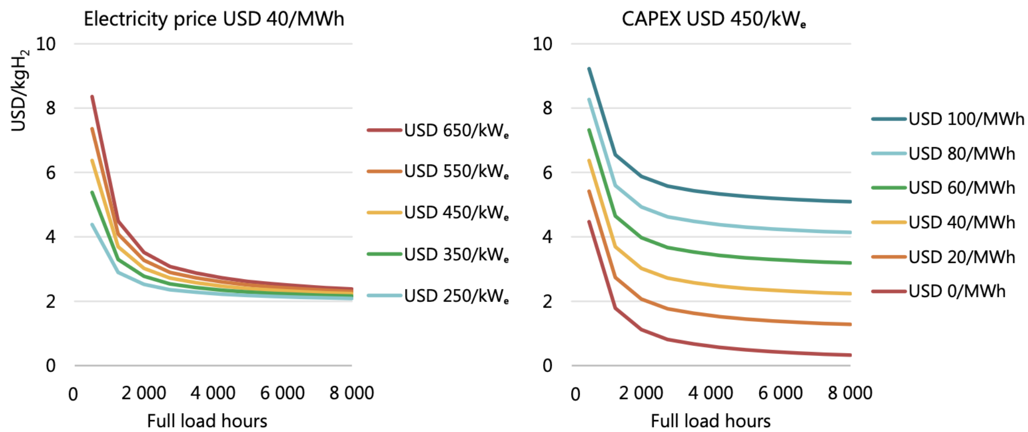
There are a number of economic parameters that are needed in order to fully define the technical and economic performance of a power-to-gas system; these parameters are detailed in Chapter 5. Parameter value differences will result in discrepancies when directly comparing studies, however, it is also important to document the underlying set of assumptions that each study uses in order to more fairly compare results. This chapter is dedicated to documenting the set of assumptions used by three prominent studies by the International Energy Agency (IEA), Bloomberg New Energy Finance (BNEF), and the International Renewable Energy Agency (IRENA) [5, 6, 7].

6.1 Summary of Results from IEA Report

The main results from the IEA that are of concern to this work are summarized in four Figures: 12, 13, 14, and 16. We will take each of these figures in turn and describe their results and compare them to assumptions made in this work.

In sum, the IEA report ignores important system costs that are associated with building out a fully operational H_2 electrolysis plant, at the same time their electricity price projections are more optimistic than even the most optimistic scenario produced by NREL in the Annual Technology Baseline.

6.1.1 IEA Future of Hydrogen – Figure 12



Notes: MWh = megawatt hour. Based on an electrolyser efficiency of 69% (LHV) and a discount rate of 8%.

Source: IEA 2019.

FIGURE 6.1: IEA – Figure 12, reproduced from [5]

Figure 12 is captioned "Future levelised cost of hydrogen (LCOH) production by operating hour for different electrolyser investment costs (left) and electricity costs (right)" and shows the H_2 (\$/kg) sensitivity to different capacity factors (0.0-0.91), electrolyzer CAPEX costs (\$250-650/kW), and electricity prices (0-100 MWh). These graphs were produced under an 8% hurdle rate assumption and an electrolyzer efficiency of 69%. It is unclear what year these H_2 production prices are supposed to represent. It is up to the reader to infer from the Assumption Annex and Table 3 (page 44-45) that the sensitivity values probably represent a "Long Term" view of H_2 production costs under an optimistic cost reduction scenario.

There is also no discussion of the assumed source of electricity that could provide the range of prices that IEA includes in this sensitivity test. In this work, we do project electricity prices to be as low as $\approx$ \$0.03/kWh from onshore wind generators, but the capacity factor would be limited to 0.69 (6044 hours) – this example correspondes to Swedish wind resources. Capacity factors shown in Figure 12 above this range would require grid connections and therefore would likely need to pay transmission and distribution charges. These charges, without considering the cost of actually producing the renewable electricity, would be enough to push the electricity price toward the maximum values that were considered by IEA.

There is little discussion of the methodologies used to project the CAPEX costs, although IEA does state that "Parameters for the cost and performance of technologies have been based on extensive literature analysis, conversations with experts and peer review." The present study uses historical cost trend to project CAPEX costs out to 2050 (with uncertainty). IEA uses CAPEX values for AE systems that range between 500 \$/kW (in 2020) to 200 \$/kW in 2050; the present study builds scenarios that use CAPEX values between 571-1268 \$/kW in 2020 and 487-1090 \$/kW in 2050. More details on other systems can be found in Table 4.3.

While these graphs present the "production" costs, it is up to the reader to interpret exactly what is meant by "production". We were able to reproduce the IEA data shown in Figure 12 with our financial model framework and incorporating the IEA assumptions, but only if we neglected all system costs beyond the electricity and electrolyzer CAPEX costs. This is in contrast to this work, which only presents H_2

prices as produced, compressed (w/short-term on-site storage) and injected into a pipeline distribution system. Production of H_2, as described in Chapter 4, includes costs from – electrolyzer CAPEX, electrolyzer replacement (if necessary), electricity, water, piping, compressor CAPEX, storage, and other fixed OPEX costs.

A casual reader or policy maker could easily overlook the missing costs, unclear timeframe, and optimistic electricity prices and draw some incomplete conclusions as to the economic viability of H_2 production.

6.1.2 IEA Future of Hydrogen – Figure 13

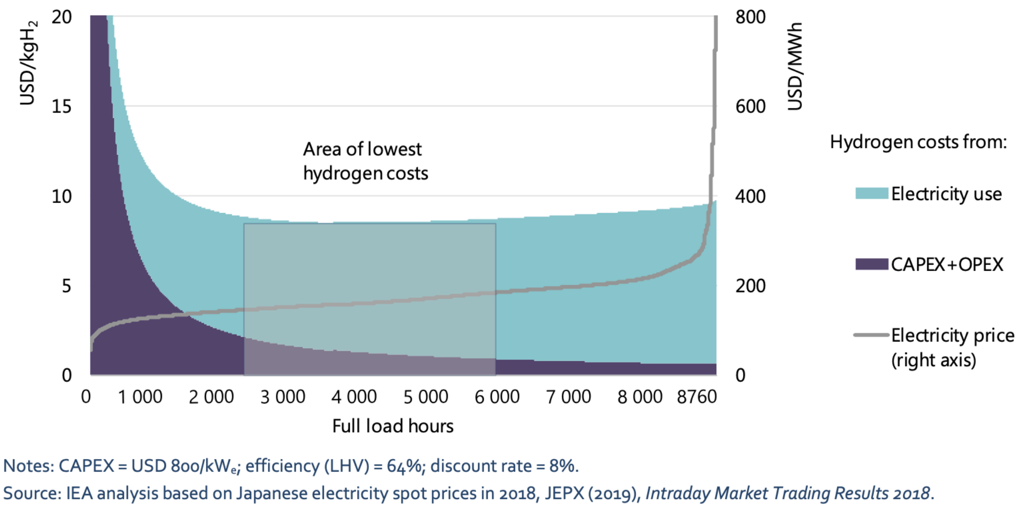
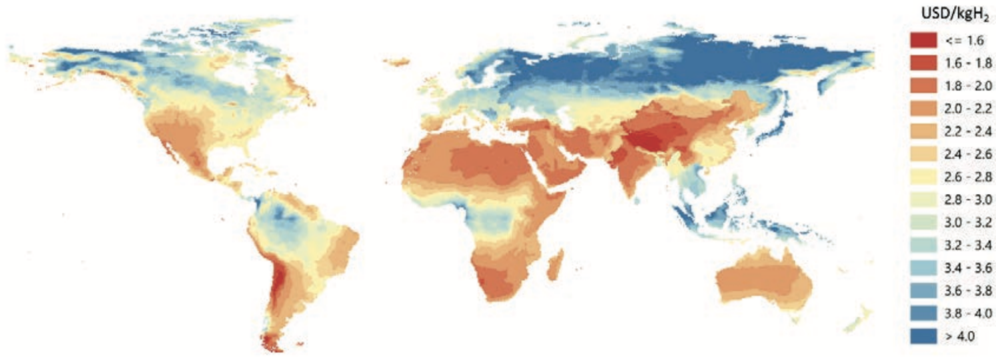


FIGURE 6.2: IEA – Figure 13, reproduced from [5]

Figure 13 is captioned "Hydrogen costs from electrolysis using grid electricity" and shows the H_2 production costs for an electrolyzer that was \$800/kW and 64% efficient. Figure 13 does clarify that the electricity is provided from the grid (electricity prices from Japan) and therefore the electricity prices are in a range that would be expected even in the US or Europe (as was the focus of this work). As such, the hydrogen production prices are much closer to those calculated in this work. Their hydrogen prices range from a minimum of $\approx$ \$8/kg to above \$20/kg of H_2. These values align with the values produced in this work, although it is unclear if their methodologies capture all the cost details that are presented here. The primary conclusion of this graph is that electricity use is the primary driver of H_2 price, a conclusion that this work also agrees with.

6.1.3 IEA Future of Hydrogen – Figure 14



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Electrolyser CAPEX = USD 450/kW$_e$, efficiency (LHV) = 74%; solar PV CAPEX and onshore wind CAPEX = between USD 400–1 000/kW and USD 900–2 500/kW depending on the region; discount rate = 8%.

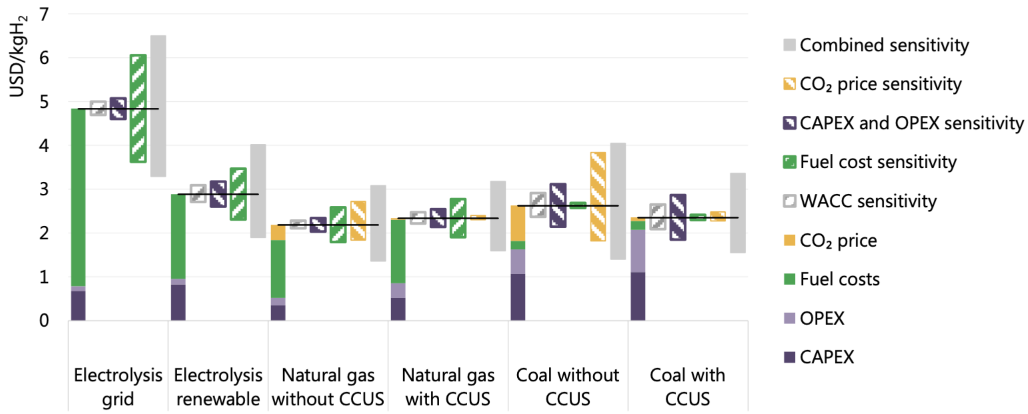
Source: IEA analysis based on wind data from Rife et al. (2014), *NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40 km Reanalysis* and solar data from renewables.ninja (2019).

FIGURE 6.3: IEA – Figure 14, reproduced from [5]

Figure 14 is captioned "Hydrogen costs from hybrid solar PV and onshore wind systems in the long term" and shows the geographical distribution of H_2 prices from a simple power-to-gas system. IEA states that the model used to generate these prices assume the electrolyser CAPEX to be \$450/kW (74% efficient, an optimistic assumption). Solar PV CAPEX and onshore wind CAPEX vary by region and range between \$400–1000/kW and \$900–2500/kW, respectively. The hurdle rate is assumed to be 8%.

While it is important to understand the geographical distribution of these resources, the description of the assumptions used to generate this figure are insufficient. Specifically, it is unclear what capacity factor a "hybrid" system would be able to achieve. It is also unclear what, if any, other costs are included in this analysis and for what year this data is supposed to represent (other than "in the long term"). From the range of prices in the legend it is left to the reader to infer that, again, this is an optimistic scenario in terms of both capacity factor and electrolyzer CAPEX cost. As with Figure 12, a time-strapped analyst or policy maker could easily overlook the missing costs, unclear timeframe, and optimistic electricity prices and draw some incomplete conclusions as to the economic viability of H_2 production.

6.1.4 IEA Future of Hydrogen – Figure 16



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019.

FIGURE 6.4: IEA – Figure 16, reproduced from [5]

Figure 16 is captioned “Hydrogen production costs for different technology options, 2030” and shows the hydrogen price for several different pathways; we are interested in the “Electrolysis grid” and “Electrolysis renewable” scenarios. IEA states that this figure assumed an electricity price of $40/MWh and 4000 full load hours (capacity factor = 0.45); uncertainty is assumed to be a fixed $\pm 30\%$. While not explicitly stated, IEA does make reference to the Assumptions Annex for further information. When the reader arrives at the Annex, it is still unclear what values are used to produce Figure 16. It is left to the reader to infer that the capacity factor used for the “electrolysis grid” scenario is 0.57 (5000 hours) and 0.23/0.27 (2054 hours for the EU and 2425 hours for the US) for the “electrolysis renewable” scenario. The prices for electricity range from $100-114/MWh for grid based electricity and $31-47/MWh for renewable electricity generators. We calculate electricity prices that are within these ranges, however, they occur later than 2030 as assumed here in Figure 16. Only the most optimistic scenario from NREL’s ATB result in renewable electricity prices that are par with those used in “electrolysis renewable” scenario (see Figure 3.6-3.11).

The electrolyzer CAPEX cost is similarly unclear, but the Assumption Annex make reference to a 2030 CAPEX cost of $700/kW for a “water electrolysis” system; it is unclear what type of electrolyzer this price is supposed to represent. In this work we generally assume a CAPEX range between $365-2175/kW across all electrolyzer types in 2030.

The IEA results for “electrolysis grid” show that the price of H_2 to be between $3.50-6.75/kg; the “electrolysis renewable” scenario shows a price of $2.00-4.00/kg. This work shows median in 2030 that are $7.37/kg ($4.95/kg minimum) for a grid connected system; our direct connected results (for 2030) show a median value of $8.27/kg and a minimum price of $3.22/kg. Our price premium is primarily due to the addition of other system costs that we include (compressor CAPEX, piping, water, etc.).

6.2 Summary of Results from Bloomberg New Energy Finance Report

The main results from the BNEF state that “with a scale-up in production of electrolyzers and optimized power supply for large-scale production, we forecast that the cost of producing renewable hydrogen could fall to $1.4- 2.9/kg by 2030 and just $0.8-1.0/kg by 2050”. These figures ignore important system costs that are associated with building out a fully operational H_2 electrolysis plant and only focus on the electrolyzer CAPEX costs and costs associated with the purchase of electricity and water. While electricity price projections are in general agreement with this current work the CAPEX price projections used by BNEF deviate from this current study and are much more optimistic. Additionally, these prices might only be achieveable in areas with idealized resource conditions (which may or may not be achieveable), something that would hinder widespread adoption.

6.2.1 Capital Costs for Chinese Electrolyzers

The BNEF report makes many mentions to the price differences between electrolyzers that were manufactured in China vs. those made in wester countries. Chinese electrolyzers are approximately 50% the cost of those electrolyzers built in western countries. This huge difference is explained by BNEF as:

- “Cheaper raw materials and labor. Labor is particularly important, as electrolyzers are still largely handmade.”
- “Higher factory utilization rates: The electrolyzer manufacturing industry in China is highly concentrated, and the top three suppliers together have a 90% share of the domestic market. Demand for their products (in traditional industries that require small-scale on-site pure hydrogen generation) is stable as it is linked with general manufacturing industry growth, which is much stronger in China than in developed countries. Chinese electrolyzer companies also have secure and predictable sales volumes and have a strong understanding about demand. As a consequence, their manufacturing capacity is well-matched with the demand, resulting in high utilization rates, particularly for lines producing large electrolyzers.”

It is difficult to verify these claims since many of BNEF sources are references to their own work. The literature on electrolyzer costs that was reviewed in Chapter 4 makes no mention of this huge discrepancy in western vs. Chinese prices. Prices for large western-made AE and PEM electrolyzers generally agree with those used in this work.

6.2.2 Modeling Assumptions and Technical Parameters

The BNEF report contains a summary table of all the benchmark costs and technical parameters that were used in describing MW-scale electrolyzer systems. Most of these values present in this table are in general agreement with the values that were used in this work to calculate the price of H_2. Of note is that there are no costs associated with compression, piping, water, etc., the BNEF price calculations only include those costs associated with the electrolyzer itself.

The metric that is used by BNEF to describe the electricity consumption (kWh/kg of H_2) is related to the electrolyzer efficiency parameter that is more commonly used in other reports. The conversion between the two numbers can be calculated as Electricity Consumption (kWh/kg H_2) $= [\eta(\text{ideal yield rate})]^{-1}$. The ideal yield rate is simply 0.03 kg of H_2/kWh and is calculated by converting the energy density of H_2 (120 MJ/kg) to units of kWh/kg and taking the reciprocal. The BNEF report assumes that the electricity consumption rate is 53 kWh/kg of H_2, which is equivalent to a 63% efficient electrolyzer. This conversion efficiency also agrees with values in this work.

Of note is the electrolyzer capacity factor (91%); this high number suggests that BNEF assumes that these systems will be grid connected, however BNEF does go on to produce other scenarios that are not necessarily drawing electricity from the grid for 91% of the time. Care must be taken to inspect when disucssing results so as to not to conflate two different subanalyses.

6.2.3 H_2 Cost – Grid Connected/Continuous Operation

BNEF includes a subanalysis that aims to calculate the LCOH from grid-connected systems in continuous operation in 2019. This subanalysis and details the price of H_2 for different AE and PEM electrolyzer systems for 2019. BNEF calculates that the price of H_2 should be in the range of $5.52-6.82 (2019$/kg) when electricity is priced at $0.10/kWh and the same 91% capacity factor (as mentioned previously) is assumed. We were able to reproduce these values with the set of BNEF assumptions.

While these prices are likely low because they omit other important costs, the price of electricity is a reasonable value to assume given current grid prices and the potential for prices to be behave in the future. This subanalysis makes it clear that CAPEX costs are not the primary driver of H_2 price, instead the cost of electricity accounts for more than 80% (or more) of the total cost of H_2.

To provide further context, we specify a hypothetical system with $0 costs except for costs associated with the purchase of electricity. This system is illustrative in that we can get a sense of the lower bound on a kg of H_2 based on only the price of electricity. If we generously assume that the conversion efficiency is 80%, the system can achieve a 100% capacity factor, and electricity was $0.01/kWh the levelized cost of hydrogen would be $0.83/kg. There are no scenarios in this work that would suggest that a price of electricity could ever (2020-2050) be purchased at $0.01/kWh for 100% of the time. Governments would need to provide subsidies in order to ensure that power-to-gas plants could purchase electricity at rates this low.

6.2.4 H_2 Cost – Grid Connected/Off-Peak Electricity Prices

This subanalysis suggests that the LCOH operating with off-peak (grid-based) electricity would be between $2.75-5.02/kg. BNEF assumes that the power-to-gas plant uses electricity purchased during off-peak hours. This electricity is purchased at $0.045/kWh and comes with a capacity factor of 50%. We were able to verify the result presented here with our modeling framework.

6.2.5 H_2 Cost – Grid Connected/Curtailed Electricity

This subanalysis looks at the LCOH as if it were produced from curtailed (zero-cost) electricity in 2019 (similar to our Scenario #3). It is difficult to quantify the level of curtailed electricity, thus BNEF calculates the price of H_2 for three different systems along a range of capacity factors (0-100%). We assume a 16% capacity factor for our curtailed electricity scenario. BNEF reported that the LCOH for a PEM (western origin) would be $8.62, $5.46 for an AE system (western origin), and $1.13 for an AE system of Chinese origin); these values were calculated using a 15% capacity factor assumption.

6.2.6 H_2 Cost – Direct Connection to a Renewable Electricity Generator

This subanalysis looks at the levelized cost of H_2 as if it were directly connected to a wind generator (similar to our Scenarion #2). BNEF optimizes the geneator configuration in order to increase the effective capacity factor. To achieve a higher utilization rate of the electrolyzer BNEF identifies three options:

- Oversize the renewable generator, which causes curtailment during times of max output, but results in more energy delivery in periods below max output, increasing the overall utilization.
- Couple wind and PV generators to take advantage of the typical negative correlation between PV and wind generation profiles (the wind often blows when the sun does not shine).
- Add batteries to enable supply at times when generators are not producing. This action can only boost the electrolyzer's utilization rate when power generators are oversized.

BNEF concludes that the most cost-effective approach is to couple wind and PV generation, but they go on to recognize that this may not be an option in all locations. For this subanalysis it is unclear exactly which system configuration is used to achieve the capacity factors and electricity prices that are summarized in Table 6.1. BNEF does mention that *"The LCOH values shown in [Figure 21 in the BNEF report] are based on separate system optimizations for the three equipment options, which result in different wind farm capacities (assuming the same capacity for the three electrolyzers) and therefore different power prices and utilization rates for the electrolyzers. Oversizing the wind farm leads to curtailment and a higher LCOE; meanwhile, the electrolyzer can operate with a higher utilization rate and achieve a lower levelized cost of equipment per unit of hydrogen produced. The system is optimized between electricity cost and equipment cost, which depends on electrolyzer capex, fixed opex, the levelized cost of the wind plant without curtailment, and the output profile of the wind farm. For the example analysis here, we assumed a $40/MWh LCOE (no curtailment) from a wind farm in California, with an annual capacity factor of 38% (hourly generation profile extracted from California Independent System Operator's 2018 wind output). A high utilization rate is more valuable (or economically worthy) in an expensive system, despite a high coupled LCOE. In this example, the optimal utilization rate for the Western-made PEM system is 62%, while that for the Chinese-made alkaline is 51%."* [6].

TABLE 6.1: LCOH Summary from the BNEF Report

Scenario	Electrolyzer	CF	Electricity ($/kWh)	LCOH ($/kg)
Grid Connected	AE (Chinese)	91%	$0.10/kWh	$5.52/kg
Grid Connected	AE (Western)	91%	$0.10/kWh	$6.20/kg
Grid Connected	PEM (Western)	91%	$0.10/kWh	$6.82/kg
Grid Connected/Off-Peak	AE (Chinese)	50%	$0.045/kWh	$2.75/kg
Grid Connected/Off-Peak	AE (Western)	50%	$0.045/kWh	$4.03/kg
Grid Connected/Off-Peak	PEM (Western)	50%	$0.045/kWh	$5.02/kg
Curtailed Electricity	AE (Chinese)	15%	$0.00/kWh	$1.13/kg
Curtailed Electricity	AE (Western)	15%	$0.00/kWh	$5.46/kg
Curtailed Electricity	PEM (Western)	15%	$0.00/kWh	$8.62/kg
Direct Connection	AE (Chinese)	51%	$0.0409/kWh	$2.53/kg
Direct Connection	AE (Western)	58%	$0.0437/kWh	$3.72/kg
Direct Connection	PEM (Western)	62%	$0.0459/kWh	$4.57/kg

6.2.7 Electricity Price Projections

BNEF states "we project that PV and/or wind could provide electricity to a large-scale electrolyzer for just $24-28/MWh [$0.024-0.028/kWh] by 2030 and $15-17/MWh [$0.015-0.017/kWh] by 2050." Based on price paths shown in the report, it appears that the first price range of $24-28/MWh is based on solar generators in India, while the $15-17/MWh price range appears to be based on onshore wind in India.

The electricity price paths (2019-2050) do detail other country-specific electricity price paths, but exact numerical comparisons are difficult due to the resolution of the graphs. The present study calculates that the lowest solar PV electricity price would be $34/MWh (US) and $42/MWh (EU) in 2030 and $22/MWh (US) and $27/MWh (EU) in 2050. The present study also calculates that the lowest onshore wind electricity price would be $27/MWh (US) and $23/MWh (EU) in 2030 and $19/MWh (US) and $16/MWh (EU) in 2050.

Caution should be taken when referencing these prices because they are the minimum prices calculated for a region, the median price of electricity could be much higher. These price paths are also not directly used in the creation of the LCOH in any of the subanalyses introduced in Sections 6.2.3, 6.2.4, 6.2.5, 6.2.6.

6.2.8 CAPEX Forecasting

BNEF, like others, including our work, attempt to forecast the system CAPEX for large-scale electrolysis projects. There are several sections of this report that are dedicated to this single economic parameter. While there are main details that could be covered, we state here that the CAPEX reduction pathways from 2019-2050 and again highlight the fact that BNEF assumes that Chinese electrolyzers are dramatically less expensive than other western-made systems. Some of the CAPEX price points that were detailed by BNEF are included in Table 4.3 alongside the values used in this current work. Of note is that BNEF assumes that there will be a cost convergence between the western and Chinese systems in 2030, where their prices will equalize out at the lower Chinese price. There is no justification provided for this assumption. These trajectories also are much more aggressive than historical cost reduction patterns examined by Glenk et al [12]; this work relies on CAPEX projections that mimic historical behavior

6.3 Summary of Results from IRENA Report

The main results from the IRENA report that are of concern to this work are summarized in four figures (9, 10, 11, 14). As we did with the other report summaries, we will take each of these references in turn and describe their results and compare them to assumptions made in this work.

In sum, the IRENA report ignores important system costs that are associated with building out a fully operational H_2 electrolysis plant, at the same time their electricity price projections are more optimistic than even the most optimistic scenario produced by NREL in the Annual Technology Baseline. Many of their price scenarios and capacity factors represent a "global best", which highlights the importance of being explicit about the geographic extent of the analysis.

6.3.1 IRENA – Figure 9

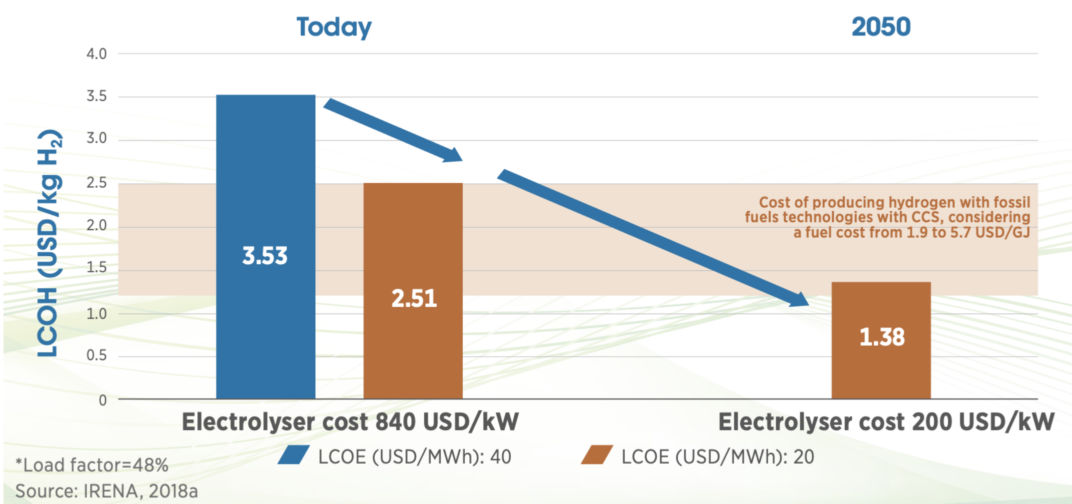


FIGURE 6.5: IRENA – Figure 9, reproduced from [7]

Figure 9 is captioned "Hydrogen costs at different electricity prices and electrolyser Capex" and shows, at a high level, what the H_2 price would be under different electrolyzer costs and electricity prices. For these calculations they assume a capacity factor of 40%. IRENA uses different combinations of electrolyzer/electricity prices to forecast H_2 prices out to 2050. They assume an electrolyzer price of \$840/kW and electricity costs at \$0.04/kWh for current day calculations. These prices are scaled down to \$200/kW and electricity costs at \$0.20/kWh for 2050 projections.

The electricity prices used in this graph are overly optimistic in that they follow a path below the most optimistic price projection pathway from NREL's ATB dataset. The capacity factor that is used for these simulations also reflects a "best case" scenario for the renewable electricity generator (while not explicitly stated in this figure, it is likely that they assume electricity is delivered through a direct connection to a wind generator). It should not be assumed that this capacity factor is available at all geographical locations.

We have verified that the values reported here are correctly calculated, but like other reports, the low price of H_2 could be considered misleading through the combination of overly optimistic electricity prices and ignoring other system costs; the IRENA report only assumes costs associated with the actual electrolyzer and the purchase of electricity.

6.3.2 IRENA – Figure 10

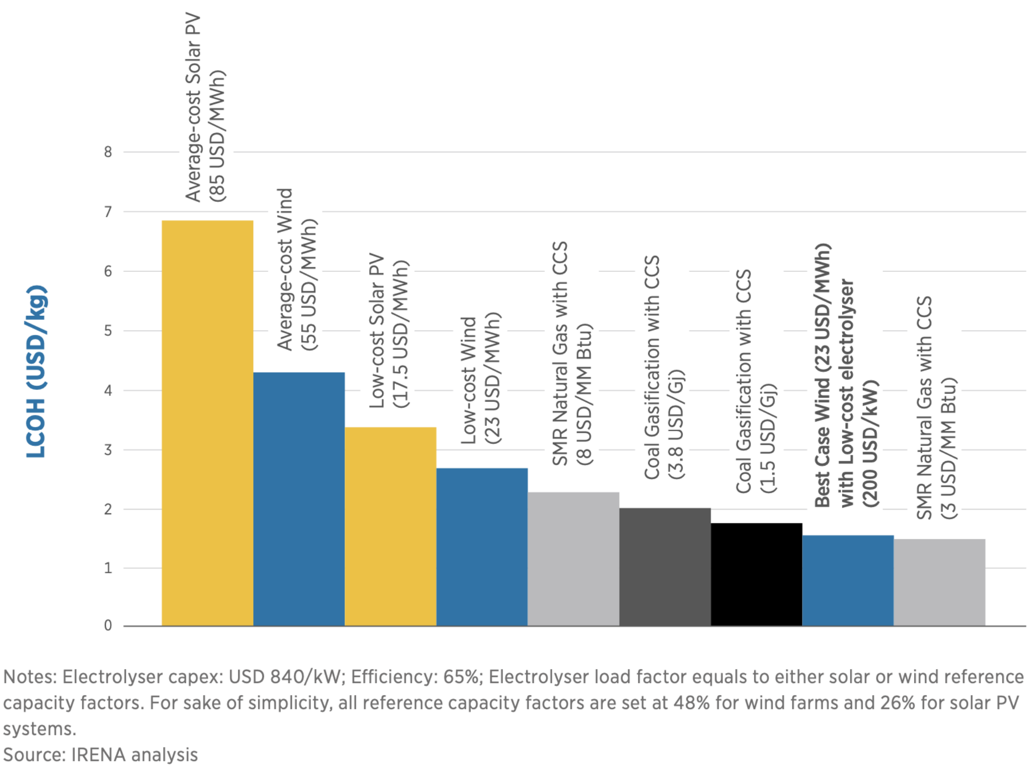


FIGURE 6.6: IRENA – Figure 10, reproduced from [7]

Figure 10 is captioned "Costs of producing hydrogen from renewables and fossil fuels today" and compares the costs associated with many different types of H_2 pathways. We are primarily interested in their estimates of H_2 prices from their "Average" and "Low Cost" scenarios for wind and solar generators. For this figure IRENA assumes an electrolyzer price of \$840/kW (65% efficient) and electricity costs range between \$0.0175-0.085/kWh. Wind generation is assumed to have a 48% capacity factor and solar is assumed to have a 26% capacity factor.

Again, IRENA assumes a combination of capacity factors for both wind and solar that should be considered a global "best case" scenario. We agree with the electricity prices used for both of IRENA's "Average" scenarios, but again, these prices are more closely aligned with a "best case" US/EU scenario not an "average". The "low cost" scenarios produced by IRENA incorporate prices that are $\approx 1/4$ of the most optimistic produced by NREL for the US. They do recognize that "low-cost renewable power of USD 23/MWh is seen today in wind projects in countries such as Brazil and Saudi Arabia".

6.3.3 IRENA – Figure 11

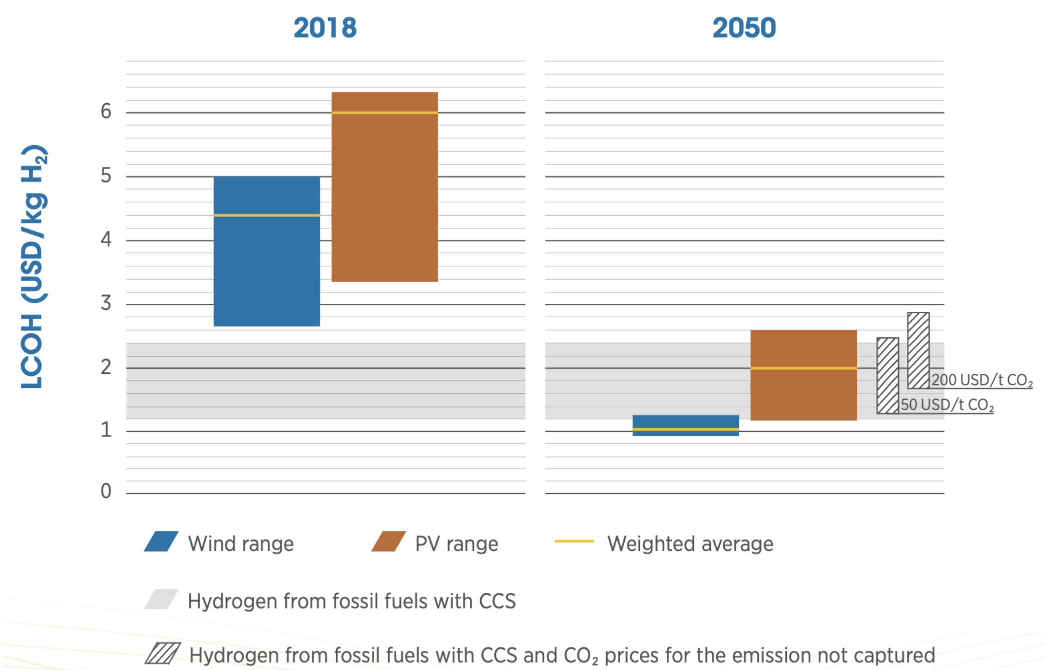


FIGURE 6.7: IRENA – Figure 11, reproduced from [7]

Figure 11 is captioned "Cost of producing hydrogen from renewables and fossil fuels, 2018 and 2050" and shows the H_2 price falling so that it is competitive with H_2 production from fossil fuels. IRENA also assumes that there will be a price to pay for any emitted carbon ($50/ton and $200/ton) when producing H_2, these added prices make H_2 production from renewable electricity generators more economically viable.

There are a lot of assumptions detailed in this graph they are detailed in Table 6.2. Note that it is unclear why Figure 11 presents 2018 values, but the notes in the caption list 2030 data, we make no assumptions as to the true meaning of the data and only reproduce IRENA's table for comparison at face value. While there is agreement between this work and IRENA's "average" assumptions (Table 6.2) we still believe that the costs of H_2 production are being under estimated as other systems costs have been ignored.

TABLE 6.2: Comparison of assumptions used in IRENA Figure 11.

Year	Scenario	Capacity Factor	Electricity Price ($/kWh)	Comparison to this work
2030	Wind (best)	47%	0.023	*more optimistic*
2030	Wind (average)	34%	0.055	*agreement*
2030	PV (best)	27%	0.018	*much more optimistic*
2030	PV (average)	18%	0.085	*agreement*
2050	Wind (best)	63%	0.011	*more optimistic*
2050	Wind (average)	45%	0.023	*more optimistic*
2050	PV (best)	27%	0.0045	*much more optimistic*
2050	PV (average)	18%	0.022	*agreement*

6.3.4 IRENA – Figure 14

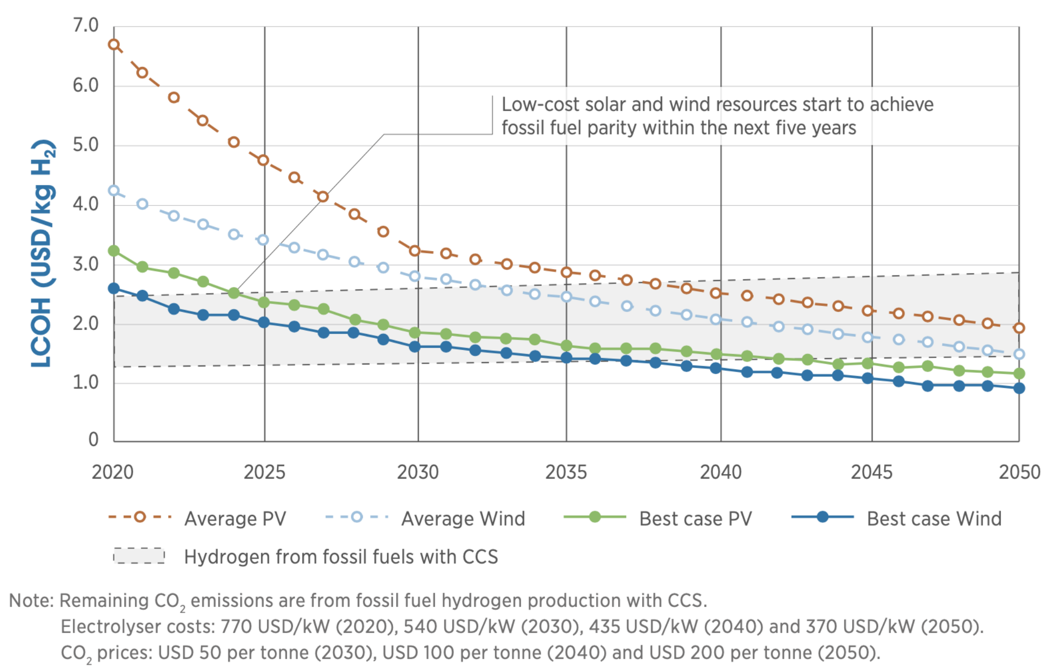


FIGURE 6.8: IRENA – Figure 14, reproduced from [7]

Figure 14 is captioned "Hydrogen production costs from solar and wind vs. fossil fuels" and shows the price trajectories for various H_2 production pathways from now until 2050. This graph explicitly states that "Low-cost solar and wind resources start to achieve fossil fuel parity within the next five years". This bold claim relies on assumptions that there are zero other system costs. It appears that this data was also calculated using the assumptions in Table 6.2, which have already been documented as being overly optimistic when compared to the US and EU cases – IRENA considers the “best case” scenario to truly be the “global best”. This graph also assumes that carbon prices will impact the price of traditional H_2 production from fossil fuels; IRENA assumes carbon prices of $50/ton (2030), $100/ton (2040), and $200/ton (2050). These carbon prices increase the cost of traditional H_2 production and help make H_2 production from renewable electricity generators more economically viable.

Bibliography

[1] National Renewable Energy Laboratory. *Annual Technology Baseline Dataset*. URL: https://atb.nrel.gov/electricity/data.html.

[2] National Renewable Energy Laboratory. *Renewable Energy Deployment System Model (ReEDS)*. URL: https://www.nrel.gov/analysis/reeds/.

[3] Iratxe Gonzalez Aparicio et al. “EMHIRES dataset Part II: Solar power generation”. In: *European Meteorological derived High resolution RES generation time series for present and future scenarios. Part II: PV generation using the PVGIS model. EUR* 28629 (2017).

[4] Iratxe Gonzalez Aparicio et al. *EMHIRES dataset Part I: Wind power generation*. Tech. rep. European Commission, 2016.

[5] IEA. *The Future of Hydrogen*. Tech. rep. Paris, 2019. URL: https://www.iea.org/reports/the-future-of-hydrogen.

[6] Bloomberg New Energy Finance. *Hydrogen: The Economics of Production From Renewables*. Tech. rep. 2019.

[7] IRENA. *Hydrogen: A renewable energy perspective*. Tech. rep. Paris, Sept. 2019. URL: https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective.

[8] Vi Duong Dang and Meyer Steinberg. “Production of synthetic methanol from air and water using controlled thermonuclear reactor power—II. Capital investment and production costs”. In: *Energy Conversion* 17.4 (1977), pp. 133–140.

[9] Meyer Steinberg. “Synthetic carbonaceous fuels and feedstocks from oxides of carbon and nuclear power”. In: *Fuel* 57.8 (1978), pp. 460–468.

[10] Meyer Steinberg and Vi-Duong Dang. “Production of synthetic methanol from air and water using controlled thermonuclear reactor power—I. Technology and energy requirement”. In: *Energy Conversion* 17.2-3 (1977), pp. 97–112.

[11] Selma Brynolf et al. “Electrofuels for the transport sector: a review of production costs”. In: *Renewable and Sustainable Energy Reviews* (2017).

[12] Gunther Glenk and Stefan Reichelstein. “Economics of converting renewable power to hydrogen”. In: *Nature Energy* 4.3 (2019), pp. 216–222.

[13] N Lymberopoulos. “Hydrogen production from renewables”. In: *Center for Renewable Energy Sources (CRES), Pikermi Attiki, Project Technical Assistant Framework Contract EESD Contract No: NNE5-PTA-2002-003/1* (2005).

[14] J I Levene. “Economic Analysis of Hydrogen Production from Wind: Preprint”. en. In: (), p. 20.

[15] C Brunetto and G Tina. "Optimal hydrogen storage sizing for wind power plants in day ahead electricity market". In: *IET Renewable Power Generation* 1.4 (2007). Publisher: IET, pp. 220–226.

[16] Christopher J Greiner, Magnus KorpÅs, and Arne T Holen. "A Norwegian case study on the production of hydrogen from wind power". In: *International Journal of Hydrogen Energy* 32.10-11 (2007). Publisher: Elsevier, pp. 1500–1507.

[17] J Linnemann and R Steinberger-Wilckens. "Realistic costs of wind-hydrogen vehicle fuel production". In: *International Journal of Hydrogen Energy* 32.10-11 (2007). Publisher: Elsevier, pp. 1492–1499.

[18] F Mueller-Langer et al. "Techno-economic assessment of hydrogen production processes for the hydrogen economy for the short and medium term". In: *International Journal of Hydrogen Energy* 32.16 (2007). Publisher: Elsevier, pp. 3797–3810.

[19] Michael Wenske. "Wasserstoff–Herstellung per Elektrolyse". In: *17th energie symposium*. Citeseer, 2008.

[20] Michael Sterner. *Bioenergy and renewable power methane in integrated 100% renewable energy systems: Limiting global warming by transforming energy systems*. Vol. 14. kassel university press GmbH, 2009.

[21] Tom Smolinka, Martin Günther, and Jürgen Garche. *Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien: NOW-Studie: Kurzfassung des Abschlussberichts*. Fraunhofer ISE, 2011.

[22] C Mansilla et al. "Reducing the hydrogen production cost by operating alkaline electrolysis as a discontinuous process in the French market context". In: *International journal of hydrogen energy* 36.11 (2011). Publisher: Elsevier, pp. 6407–6413.

[23] Uwe Albrecht et al. "Analyse der Kosten Erneuerbarer Gase". In: *Eine Studie der Ludwig-Bölkow-Systemtechnik GmbH. Im Auftrag des Bundesverbandes Erneuerbare Energie eV* (2013).

[24] F Graf et al. "Technoökonomische Studie von Power-to-Gas-Konzepten". In: *Deutschen Vereins des Gas-und Wasserfaches (DVGW), Tech. Rep.* (2014).

[25] C. Mansilla et al. "Economic competitiveness of off-peak hydrogen production today – A European comparison". en. In: *Energy* 55 (June 2013), pp. 996–1001. ISSN: 03605442. DOI: 10.1016/j.energy.2013.03.022. URL: https://linkinghub.elsevier.com/retrieve/pii/S0360544213002107 (visited on 04/16/2020).

[26] Gert Müller-Syring et al. "Entwicklung von modularen Konzepten zur Erzeugung, Speicherung und Einspeisung von Wasserstoff und Methan ins Erdgasnetz". de. In: (), p. 350.

[27] Luca Bertuccioli et al. "Study on development of water electrolysis in the EU". In: *Fuel cells and hydrogen joint undertaking* (2014).

[28] Mareike Jentsch, Tobias Trost, and Michael Sterner. "Optimal use of power-to-gas energy storage systems in an 85% renewable energy scenario". In: *Energy Procedia* 46.0 (2014). Publisher: Elsevier, pp. 254–261.

[29] Markus Lehner et al. *Power-to-gas: technology and business models*. Springer, 2014.

[30] H Steinmüller et al. "Power-to-Gas–eine Systemanalyse". In: *Markt-und Technologiescouting und–analyse. Energieinstitut an der Johannes Kepler Universität Linz, TU Wien, MU Leoben, JKU Linz* (2014).

[31] Michael Sterner and Ingo Stadler. *Energiespeicher-Bedarf, Technologien, Integration*. Springer-Verlag, 2014.

[32] Raphael Winkler-Goldstein and Aline Rastetter. "Power to gas: the final breakthrough for the hydrogen economy?" In: *Green* 3.1 (2013). Publisher: De Gruyter, pp. 69–78.

[33] Behnam Zakeri and Sanna Syri. "Electrical energy storage systems: A comparative life cycle cost analysis". In: *Renewable and sustainable energy reviews* 42 (2015). Publisher: Elsevier, pp. 569–596.

[34] Jecques De Bucy, O Lacroix, and L Jammes. "The potential of Power-to-Gas". In: *ENEA Consulting, Paris, France* (2016).

[35] Manuel Götz et al. "Renewable Power-to-Gas: A technological and economic review". In: *Renewable energy* 85 (2016). Publisher: Elsevier, pp. 1371–1390.

[36] Wouter Vanhoudt et al. "Power-to-gas. Short term and long term opportunities to leverage synergies between the electricity and transport sectors through power-to-hydrogen". In: *Hinicio SA and LBST-Ludwig-Bölkow-Systemtechnik GmbH* (2016).

[37] Sean B Walker et al. "Benchmarking and selection of Power-to-Gas utilizing electrolytic hydrogen as an energy storage alternative". In: *International Journal of Hydrogen Energy* 41.19 (2016). Publisher: Elsevier, pp. 7717–7731.

[38] Guido Pleßmann et al. "Global energy storage demand for a 100% renewable electricity supply". In: *Energy Procedia* 46.0 (2014). Publisher: Elsevier, pp. 22–31.

[39] Mareike Jentsch. "Potenziale von Power-to-Gas Energiespeichern". In: *Fraunhofer-Institut für Windenergie und Energiesystemtechnik IWES, Stuttgart* (2015).

[40] Verena Jülch. "Comparison of electricity storage options using levelized cost of storage (LCOS) method". en. In: *Applied Energy* 183 (Dec. 2016), pp. 1594–1606. ISSN: 03062619. DOI: 10.1016/j.apenergy.2016.08.165. URL: https://linkinghub.elsevier.com/retrieve/pii/S0306261916312740 (visited on 04/16/2020).

[41] D Steward et al. *Lifecycle cost analysis of hydrogen versus other technologies for electrical energy storage*. Tech. rep. National Renewable Energy Lab.(NREL), Golden, CO (United States), 2009.

[42] Stanko Hočevar and William Summers. "Hydrogen production". In: *Hydrogen technology*. Springer, 2008, pp. 15–79.

[43] Philippe Menanteau et al. "Une analyse économique de la production d'hydrogène à partir d'électricité éolienne pour des usages transport". In: (2010).

[44] Chris Ainscough, David Peterson, and Eric Miller. "Hydrogen production cost from PEM electrolysis". In: *DOE Hydrogen and Fuel Cells Program Record, United States Department of Energy, Washington, DC* (2014).

[45] Timothy E Lipman, Jennifer L Edwards, and Daniel M Kammen. "Fuel cell system economics: comparing the costs of generating power with stationary and motor vehicle PEM fuel cell systems". In: *Energy Policy* 32.1 (2004). Publisher: Elsevier, pp. 101–125.

[46] Alberto Varone and Michele Ferrari. “Power to liquid and power to gas: An option for the German Energiewende”. In: *Renewable and Sustainable Energy Reviews* 45 (2015). Publisher: Elsevier, pp. 207–218.

[47] Benjamin Guinot et al. “Profitability of an electrolysis based hydrogen production plant providing grid balancing services”. In: *International Journal of Hydrogen Energy* 40.29 (2015). Publisher: Elsevier, pp. 8778–8787.

[48] Max Wei et al. *A total cost of ownership model for low temperature PEM fuel cells in combined heat and power and backup power applications*. Tech. rep. Lawrence Berkeley National Lab.(LBNL), Berkeley, CA (United States), 2014.

[49] Bent Sørensen et al. “Hydrogen as an energy carrier: scenarios for future use of hydrogen in the Danish energy system”. In: *International Journal of Hydrogen Energy* 29.1 (2004). Publisher: Elsevier, pp. 23–32.

[50] Annabelle Brisse and Josef Schefold. “High temperature electrolysis at EIFER, main achievements at cell and stack level”. In: *Energy Procedia* 29 (2012). Publisher: Elsevier, pp. 53–63.

[51] Brian vad Mathiesen et al. “Technology data for high temperature solid oxide electrolyser cells, alkali and PEM electrolysers”. In: (2013). Publisher: Department of development and planning, Aalborg University.

[52] Michael Penev, Jarett Zuboy, and Chad Hunter. “Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling stations”. In: *Transportation Research Part D: Transport and Environment* 77 (2019). Publisher: Elsevier, pp. 92–105.

[53] Inc Nexant. “H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results”. In: (2008). Publisher: US Department of Energy Washington DC.

[54] Jean André et al. “Time development of new hydrogen transmission pipeline networks for France”. In: *International journal of hydrogen energy* 39.20 (2014). Publisher: Elsevier, pp. 10323–10337.

[55] Wade A Amos. *Costs of storing and transporting hydrogen*. Tech. rep. National Renewable Energy Lab., Golden, CO (US), 1999.

[56] Energy Information Administration. *Assumptions to the Annual Energy Outlook: 2017*. Tech. rep. 2017. URL: https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2017).pdf.