SCHOOL OF
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Economic Effects of Large-Scale Green Hydrogen Production

Gustav Nyrenstedt

Lund University, Department of Economics

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Supervisor: Gunes Gokmen

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Abstract

This thesis investigates potential macroeconomic effects of replacing a substantial part of the energy demand by green hydrogen in Brazil, Germany, Japan and the US. The objective is to calculate the levelized cost of hydrogen by assuming domestic production of green hydrogen, corresponding to 11% of the energy demand, in each respective country. Thus, this thesis provides insights into the economic feasibility of such large-scale green hydrogen production. The levelized cost of hydrogen is calculated based on an optimization tool taking the production costs, e.g. the cost of solar -or wind power, into account. Especially, the geographic location is of value since wind -and solar data are evaluated to minimize the production cost of green hydrogen. The levelized cost of hydrogen is then compared to current energy prices with a specific focus on oil to understand how the energy cost could change. This cost change is then compared to historic values to understand potential macroeconomic effects with a special focus on inflation and GDP. The energy costs increase by between 17.3%, for Brazil, and 104.4%, for Japan, in the evaluated scenarios. These cost changes are comparable to, or larger than, historic oil price changes during the period 1970-2007. This means that relying largely on green hydrogen likely induces similar macroeconomic effects as historic oil crises.

Keywords: Green Hydrogen; Energy Price Shocks; Energy Policy; Renewable Energy Economics; Levelized Cost of Hydrogen

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Contents

1. Introduction

Climate changes, as an effect of fossil fuel usage and following greenhouse gas emissions, have for decades been a topic for global concern. Studies have highlighted rising sea water levels (Shukla, 2017), animal species extinction (Cahill, 2014), human health concerns (Liu, 2024), extreme weather conditions (Stott, 2016), and agricultural stress (Aydinalp, 2008), all as an effect of global warming caused by emission of greenhouse gases. In response, several countries have set up and agreed to different protocols promising to reduce greenhouse gas emissions. EU, the US, Japan, and Brazil all set the goal of being climate-neutral by the year 2050 (EC, 2025; DOS, 2025; METI, 2025; STIP, 2025), to just mention a few. This calls for a re-structure of how energy is produced and utilized which could have large macroeconomic effects.

This thesis evaluates if green hydrogen is an economically feasible alternative to reach the climate goals. Specifically, green hydrogen produced by electrolysis of water with the help of solar or wind power will be evaluated by looking at the levelized cost of hydrogen (LCOH) in Brazil, Germany, Japan and the US. Further, the hydrogen production costs are compared with current energy costs to give macroeconomic insights on supplying 11%[1] of the energy demand from green hydrogen.

The main contribution of this thesis is to provide a cost estimate of green hydrogen production in each of the four countries by inputting renewable energy data in a new optimizer tool developed in a recent research study (Vazquez-Sanchez, 2025). The resulting minimized LCOH is compared to current energy costs with a specific focus on oil prices. The cost difference is then used to evaluate macroeconomic effects such as on GDP, unemployment and inflation.

The results suggest that under the 11%-assumptions, energy costs are increased by 17.3-104.4% when compared to current oil prices. These increases are of similar magnitude, or larger than historic oil price increases, indicating that macroeconomic effects are as large as the historic effects. Specifically, oil price increases have led to higher unemployment and lower real GDP growth (as described further in the “Energy-

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[1] Based on economic predictions of future hydrogen usage (DNV, 2025) as explained in the “Objectives, Motivation and Limitations”-section of this thesis

Economic Evaluations”-section). This comparison gives policy makers and decision-makers a stronger foundation to determine if green hydrogen is a viable path for a climate-neutral future and how the change from fossil fuels to hydrogen should take place.

2. Background, Literature Study and Problem Formulation

This chapter summarises the existing studies and known theory around the topics of climate change, green hydrogen and economic effects of energy price changes to build a foundation for this thesis. The chapter is divided into four parts: Energy in a Sustainable World (focused on tackling emissions of greenhouse gases); Energy-Economic Evaluations; Macroeconomic Theory; and Detailed Problem Formulation.

2.1. Energy in a Sustainable World

As noted in the Introduction, global greenhouse gas emissions have prompted countries and organizations to adopt climate goals. To meet these, high-emitting sectors are being targeted with regulations. In the EU, the largest contributors to greenhouse gas emissions are households (23.2%), manufacturing (19.4%), and electricity/gas supply (18.0%) (Eurostat, 2024). In the US, transportation leads at 28% (EPA, 2025). Regulatory approaches include emission caps (European Commission, 2024), environmental taxes (Government Offices of Sweden, 2025), and green subsidies (EPA, 2024).

To comply with these policies, sectors are shifting from fossil fuels to renewable energy. For instance, the EU plans to add 23 GW of wind power annually until 2050 (European Commission, 2025), while solar generation doubled from 2018 to 2022 (SolarPower Europe, 2025). Other strategies include green-fuel-transportation (Nyrenstedt, 2023), green-fuel heating (Longoria, 2021), and low-emission industrial processes (Lundmark, 2024).

Green fuels (such as hydrogen, ammonia, ethanol, and biodiesel) are characterized by low or no carbon content, minimizing CO_2 emissions (Buurman, 2023; Singh, 2019; Khamedov, 2021; Verhelst, 2014). Unlike fossil fuels, green fuels must be produced, which presents logistical and economic challenges. For example, hydrogen does not exist freely and must be extracted from other compounds.

To be sustainable, green fuel production must be clean, carbon-neutral, and economically viable. While hydrogen can be derived from fossil fuels like natural gas (Boretti, 2021), such methods emit CO_2 and conflict with its “green” label. Green hydrogen, by contrast, is produced through water electrolysis using renewable electricity (Harichandan, 2021).

Solar and wind power are widely considered the most viable sources for renewable electricity due to their cost-effectiveness and availability (Milligan, 2015; Khare, 2016), making them suitable for hydrogen electrolysis. As a fuel, hydrogen offers several advantages: zero direct CO_2 emissions, availability in many compounds, high energy density, and efficient one-step production (Chi, 2018). These benefits indicate that hydrogen has a large role to play in future energy scenarios (Oliveira, 2021; Hota, 2023).

In line with these advantages, many report -and policymakers also envision a major role for hydrogen in future energy systems (DNV, 2024). The EU targets 10 million tonnes of green hydrogen annually by 2050 (Enerdata, 2024); the US aims for 50 million tonnes (American Economic Association, 2025); and DNV forecasts hydrogen comprising 11% of Europe’s energy mix by 2050, and 7% in North America (DNV, 2025).

Currently, the EU produces about 11 million tonnes of hydrogen, primarily from natural gas (European Hydrogen Observatory, 2023). Thus, the main challenge is not volume but transitioning production to renewable sources. Water electrolysis, which splits water into hydrogen and oxygen without harmful byproducts (Zainal, 2024), is the leading method for green hydrogen, but it requires electricity and water, with renewable electricity being crucial.

Because renewable electricity has historically been expensive, green hydrogen remains costly (Agaton, 2022). Fossil-based hydrogen costs about 1–2.10 $/kg, while green hydrogen costs 3.60–5.80 $/kg (Kumar, 2022). These high costs (considering energy content compared to e.g. gasoline) makes cost-reduction efforts vital.

Production location significantly affects cost due to varying renewable energy potential. For example, solar power in sunnier areas can reduce electricity costs by up to 30% per kWh (DOE, 2025), lowering hydrogen costs. Other factors include water price, electrolysis equipment, storage, and investment opportunity costs. In water-scarce regions, costs rise further.

In summary, green hydrogen is viewed as critical to reducing fossil fuel reliance and greenhouse gas emissions. Its high production cost implies future energy prices may rise. Prior studies have assessed production costs locally, showing large variation (Abdelsalam, 2024; Pfennig, 2023). However, inconsistencies in cost calculation methods persist, prompting calls for standard frameworks (Irena, 2025). Furthermore, as existing studies mostly cover local production costs, a comprehensive study spanning many countries is needed.

A recent study developed an optimization model that also accounts for payback periods and water costs, often neglected in earlier models (Vazquez-Sanchez, 2025). This tool was used in the current thesis (see Methodology) to fill the literature gap of previous studies having cost inconsistencies. The results indicate that green hydrogen adoption may increase energy prices, potentially triggering macroeconomic effects as discussed in the next section.

2.2. Energy-Economic Evaluations

The effects of energy prices is a well-studied topic in history, not the least due to the importance of energy for human well fare and survival. A very short history lesson would probably emphasize how crucial the use of fire has been for human development and survival. Of course, without an energy source like wood, fires could have never been harnessed. In modern times, in the OPEC countries, many take an abundance of energy for granted where people might even struggle to survive without it. Imagine for example that it would only be possible to charge your phone on Fridays or that you can only drive your car once per month. Energy budgeting like this would heavily affect society and thus the national and global economy in different ways. It takes no scientific study to guess that this is true.

In general, changing energy prices have large effects on economic indicators. A study looking at energy price shocks in the US concluded that there is an inverse linear relationship between energy prices and consumer consumption (Edelstein, 2009). By looking at energy price shocks (in 1974, 1979, 1986, 1990, and 2003), the earlier idea that reduced energy prices have little to no effect on output and employment and that increased energy prices have large negative effects was deemed outdated.

Instead, Edelstein et al found that there is a more symmetric relationship to changing energy prices. When the price declines, an economic boost follows and when it increases, an economic contraction follows. In particular, the effect of consumers being more (or less) careful with spendings after a sudden real income change (which the changed energy price meant) was highlighted as the main explanation. It should be noted that the data used indicated that the real energy price changed from an index of around 80 to an index of around 140 during the period 1970-2007. As a benchmark, the oil crisis of 1973 made the index jump from around 80 to almost 100. This corresponds to an approximate change of 25% and was followed by a purchasing power loss of 0.4% (one of the largest losses of purchasing power during the period of 1970-2007). Thus, price changes of this size can have large economic effects.

Other studies have agreed with the conclusion that energy prices largely affect economic indicators, also in the long run. An earlier study (Berk, 2014) performed a statistical analysis of real GDP effects from changing energy prices over a period of 33 years, spanning 16 countries. The main conclusion was that there is a strong negative correlation between real GDP and energy prices. This was explained by reduced energy consumption with increased energy prices which in turn led to smaller economic output.

Traditionally, and largely today, oil has been a major source of energy globally. Therefore, economic research has been performed on economic effects of oil price changes, which can be used as a benchmark for other energy price changes. Several studies have highlighted the negative relationship between the global oil price and GDP (Darby, 1982; Burbridge, 1984; Jones, 1996). Another study (Brown, 2022) confirmed that both theory and empirical evidence shows the negative relationship above, although the magnitude of the effect of oil price changes has declined somewhat in modern times.

Specifically, Brown et al specifies that the oil price shocks induce a supply effect that then causes an adjustment cost for many economic actors. Hamilton’s findings largely agree with Brown's and show that several real-GDP-declines have been induced by oil price shocks (Hamilton, 2005). The real-GDP-decline then renders higher unemployment due to the higher energy costs (Kocaaslan, 2019).

That the oil-price-changes do not as largely affect economic indicators as they used to is confirmed in another study (Hooker, 1996) stating that that oil price shocks have not been a good indicator of future economic growth after 1973. In a later study, this was explained by the complexity of oil prices where several other economic indicators, e.g. interest rates, are also changed as an effect of changing oil prices (Hooker, 1999). Hooker also highlighted that after 1981, no real inflation effects are seen in US because of oil price changes (Hooker, 2002).

In contrast to this, modern studies suggest that higher energy prices directly cause higher inflation (Vlieghe, 2025). This contradiction is partly explained by Kilian et al showing that studies focusing only on the gasoline price underestimate the inflation effects of higher energy prices (Kilian, 2023). Kilian et al further highlights that there is a clear correlation between higher energy prices and inflation since many product prices are increasing as an effect of more expensive energy. Thus, the inflation is likely affected by energy prices, although the significance is still debated.

In summary, empirical evidence suggests that oil -and energy prices have significant effects on macroeconomic activity, typically leading to weaker economic outcomes when prices rise. However, the mechanisms driving this relationship, especially after 1981, remain an open question in the literature, with competing explanations involving changes in monetary policy and economic structure.

As discussed above, there is extensive literature on general energy price shocks, not the least for oil. This thesis instead provides a comprehensive evaluation of how future energy carriers can have macroeconomic effects by evaluating the LCOH and comparing it to existing energy prices (see section 2.4 for more information).

2.3. Macroeconomic Theory

The empirical evidence discussed in the previous section often stem from different macroeconomic theories. This section highlights some important macroeconomic theory used as a reference point of this study to draw conclusions around the energy price effect and is built on existing economic literature (Burda, 2022).

As a starting point, an energy price change is likely to induce a supply shock in some way since much economic activity is dependent on energy. Keynesian short-run theory states that prices are sticky meaning that a changed energy price does not immediately induce any other changes such as lower wages or raised prices. According to the Cambridge equation (Oxford Reference, 2025), money demand is proportional to the price level multiplied by the real income. Thus, if prices are sticky in the short run, a reduced income must mean reduced demand for money.

In the medium run, prices are not as sticky and can be changed. This means that higher energy prices likely lead to higher prices. If a supplier faces higher production costs, they will raise the prices for the consumers assuming constant margins. Thus, higher inflation follows. The Phillips curve suggests that this will in turn lead to lower unemployment in the medium run. The Phillips curve combined with Okun’s law gives the aggregate supply relationship suggesting that the higher inflation from increased energy prices would also lead to higher output. This contradicts the empirical data presented in section 2.2 which will be discussed further.

The long run aggregate supply curve explains this contradiction by being vertical in the sense that no matter the inflation, the equilibrium output is unchanged (Burda, 2022, p. 373). This is line with the scientific studies suggesting that there is no significant inflation effect of changed energy prices.

The AD-AS framework further describes the effects of a supply shock, such as one induced from higher energy prices. A supply shock is in this framework followed by lower output and higher inflation (Burda, 2022, p. 405) which aligns with the scientific studies highlighting how inflation is increased whenever an energy price shock occurs.

Several other effects may or may not add to the ones described in theory and might describe some of the inconsistencies found in empirical data. These effects include different monetary policies, currency changes, interest rates and other global effects (e.g. a pandemic).

In summary, long-term theory suggests that the effects of supply shocks such as increased energy prices will have negative effects on economic growth and unemployment unless there are countermeasures taken.

2.4. Detailed Problem Formulation

As described above, hydrogen has been labelled a promising fuel for reducing the carbon footprint of our society with several targets set up to increase its production in the future. It has also been noted that green hydrogen is needed to fully benefit from the lower carbon dioxide emissions associated with the fuel. Green hydrogen is in turn associated with higher production costs compared to traditional fossil fuel use.

While the macroeconomic effects of energy price changes have been extensively studied, particularly in the context of oil price shocks, there is still limited research examining how a future energy system dominated by green hydrogen might affect macroeconomic performance. Existing studies typically focus on a specific geographic location while comprehensive, cross-country macroeconomic analyses are lacking.

This thesis aims to address that gap by integrating a newly developed method for calculating the LCOH with a broader macroeconomic assessment. By computing hydrogen production costs in four countries and comparing them with current energy prices, the study estimates potential macroeconomic impacts such as implications for economic indicators like GDP and unemployment.

The thesis specifically answers the following research question:
What are the macroeconomic effects of replacing a large part of the energy mix with hydrogen?

3. Objectives, Motivation and Limitations

To answer the research question, this study aims to calculate the production cost of green hydrogen in the four countries Brazil, Germany, Japan and US. These countries were chosen based on available data and with the aim of covering different continents and types of economies. Note that no low-income countries will be considered since hydrogen production is assumed expensive (based on the earlier studies described in section 2.1) meaning that low-income countries may struggle to implement this in a near future. Also note that no evaluation of hydrogen end-use is made here meaning no distinction between potential applications (e.g. transportation or industry).

Only green hydrogen produced with the help of electricity from solar -and wind power is considered in this study due to its nature of overproducing electricity at certain times and underproducing at other, giving a need for energy storage such as via hydrogen. Thus, no other sources of electricity generation, such as hydropower or geothermal power, were considered in this study.

For each country, three locations were evaluated to ensure that good spots for solar - and wind power are included. These three locations contained one sunny location, one windy location and the capital as a reference location. Please see the Methodology section for more details on how these locations were chosen. All input data for hydrogen production cost calculations are based on current levels. These inputs include e.g. cost of solar energy, storage, and cost of wind energy. In a future scenario, these prices could vary heavily based on new technology and potential subsidies.

The hydrogen production cost calculation will further use an optimization methodology that targets minimum costs (see the Methodology section). The amount of hydrogen needed is set to 11% of the respective country's current energy demand, where different energy types are assumed perfect substitutes. This number was chosen from European targets of having 11% of the energy mix consisting of hydrogen by 2050 (DNV, 2025).

Thus, this study assumes that each country will follow this European prediction, creating a fictional scenario where only current energy consumption is evaluated. Note that future scenarios could vary significantly in terms of both production prices and country policies and targets. Also note that the studied scenario assumes no trade between the evaluated countries. Instead, the produced hydrogen is used in each respective country due not the least to that several countries deem self-sufficiency important in terms of energy (Lekavicius, 2019).

While many previous studies have evaluated hydrogen prices for particular locations, this study aims to take a more global approach (covering countries in four continents) combined with new simulation methods. This study further aims to connect hydrogen prices with macroeconomic effects to give recommendations to policy makers for possible future scenarios. The major objectives of this study are summarised as:

- Calculating green hydrogen production costs for four countries and in total twelve locations with new simulation methodologies
- Compare these costs with existing energy production costs via assuming that 11% of the respective country's energy consumption is supplied by green hydrogen
- Find potential macroeconomic effects from the cost change of including green hydrogen in the energy mix, based on previous studies of energy price effects

4. Methodology

This section describes the different methods and approaches used in this study in terms of hydrogen production cost calculations and macroeconomic analyses. The study focuses on calculations and simulations for the four countries Brazil, Germany, Japan and US where three locations per country are evaluated.

4.1. Hydrogen Production Cost Calculations

This study uses an optimization tool for hydrogen production cost calculations developed at KAUST in 2025 (Vazquez-Sanchez, 2025; CERP, 2025). The tool was developed, based on several previous studies in literature, to improve the accuracy of the cost estimates for hydrogen where e.g. the electrolysis costs have been included to a larger extent compared to other models (Vazquez-Sanchez, 2025).

The optimization aims to minimize production costs and is based on a Mixed Integer Linear Programming Formulation with the wind power costs, solar power costs, electrolysis costs, battery costs, and hydrogen storage costs as input parameters. Note that the formulation is constrained by the amount of hydrogen needed, as specified by the user, and that only solar power and wind power are the considered electricity generation types in this model. This study further assumes that only onshore wind power is used due to it often being cheaper than offshore wind power (Hevia-Koch, 2019).

The green hydrogen production cost is specified on the form of LCOH which is defined as the total lifetime cost normalized by the total mass of hydrogen produced. Input values for solar power, wind power, electrolysis, hydrogen storage and batteries are given on the form of Capital Expenditures (CAPEX) and Operational Expenditures (OPEX), i.e. the cost of setting it up and the cost of operating the facility.

Based on the literature review, this study assumes that 11% of the total yearly energy used by a country today will be supplied from green hydrogen where each country is assumed self-sufficient in terms of green hydrogen production. This number gives the average daily hydrogen need which is a model input. Note that this study assumes that the daily need must not be met every single day but rather that yearly demand should be met. This means that batteries and hydrogen storage are considered but typically not included in the cost-minimizing setups. To fulfil specific daily hydrogen needs, the cost would probably increase.

Based on the location specified by the user (in map coordinates), the model utilizes data for sun hours and wind speeds during 2023 for that specific location. This data is in turn used to calculate the needed electric capacity (the maximum output from the solar power plant or the wind power plant) and the electrolyser capacity (the maximum amount of electricity the electrolyser can take as input). As an example, if a location does not experience high solar irradiation, the capacities would have to be higher to better utilize the incoming solar rays and produce the demanded hydrogen amount.

The ability to deliver output hydrogen based on the maximum possible output is measured by the Capacity Factor (CF) here. CF is defined as the actual output normalized by the maximum possible output and thus gives an indication of how well-utilized the system is. The hydrogen demand is calculated considering the lower heating value of hydrogen as:

$$Average\ Daily\ Hydrogen\ Demand\ [kg] = \frac{Yearly\ Energy\ Demand\ [TWh] * 0.11}{365\ * 33.33 * 10^{-9}\ [TWh/kg]}$$

Here, 0.11 refers to the specified percentage of green hydrogen and 33.33 kWh/kg refers to the lower heating value of hydrogen.

As mentioned, this study evaluates four countries with three locations for each country. The countries were chosen based on data availability and with the aim of evaluating countries with different prerequisites, as described in the Objectives section. Each country's three locations were chosen as one sunny location, one windy location, and one reference location. The sunny location is simply a location known to have much solar irradiance compared to other locations in the country (Global Solar Atlas, 2025), and the windy location is a location known to experience high average wind speeds (Global Wind Atlas, 2025; Climate and Weather, 2025).

Note that the sunny and windy locations are selected as points for comparison due to expected high utilization of sun -and wind power meaning expected lower hydrogen production costs in these locations. The reference location serves as a point that is not necessarily windy nor sunny to evaluate how much this increases the hydrogen production costs. The reference location is represented by the capital city in this study, which is often close to population centres which can simplify hydrogen distribution in a real-world scenario. Table 1 summarizes the twelve locations.

Table 1, Chosen locations for evaluation in each country

	Windy Location	**Sunny Location**	**Ref. Location**
Brazil	Macau	Fortaleza	Brasilia
Germany	Bremerhaven	Freiburg	Berlin
Japan	Hamamatsu	Nagoya	Tokyo
USA	Boston	Yuma	Washington D.C.

4.2. Input Data

Several forms of input data are needed to minimize the costs for hydrogen production via the utilized optimization tool. Table 2 summarizes the global input data used for every country in this study. The simulation lifetime is assumed to be 30 years, meaning that the calculations are based on supplying the specified hydrogen amount for every year during a total period of 30 years. This value was chosen based on the assumed lifetime of the solar -and wind power plants which was also set to 30 years, meaning that no new investments in solar or wind power were needed after the first lifecycle.

The hydrogen utilization ratio is assumed 100% meaning that no hydrogen is wasted as an effect of e.g. leakage. The return rate is specified as a weighted average cost of capital meaning the discount value used for e.g. future costs. Electric energy can be stored using batteries which will be included as a possibility in this study where it is assumed that the electric energy is never stored more than four hours. To simulate realistic scenarios, the batteries are assumed to never be lower than 5% of maximum capacity and never higher than 95% of maximum capacity. Fully discharging or charging a battery might decrease its lifespan and thus increase costs.

The electrolyser type is PEM which gives a fast response time and can thus be paired with renewable electricity sources (Ayers, 2021). A relatively high efficiency and low cost is assumed for this electrolyser (Vazquez-Sanchez, 2025) which in general renders a lower hydrogen production cost. The electrolyser can then be coupled with hydrogen storage tanks if necessary and if the optimization models finds that that lowers costs. These tanks are assumed to be aboveground tanks.

Note that all input values will likely change due to e.g. future resource scarcity, new technology development, or subsidies in different forms. This study does not include a sensitivity analysis on these input values but highlights the major cost areas (meaning higher sensitivity to input changes) in the Results section.

Solar power costs, wind power costs, electrolyte (water) costs, and hydrogen demand are considered country-specific input values here. Note that also batteries, hydrogen storage and electrolyser costs could vary between countries. However, these three costs are typically highly affected by global prices while other costs are more country-specific due to e.g. local labour costs. Thus, batteries, hydrogen storage and electrolyser costs are deemed non-country-specific here

Oil can be imported or exported at a global price that often differs little from country to country. Thus, this study considers the global oil price when comparing to LCOH.

Table 3 summarizes the country-specific data used where each location in a given country is assumed to experience the same costs. Note that some costs differ substantially between countries which will have a large effect on the hydrogen production price, as discussed in the Results section. One such example is the

Levelized Cost of Water (LCOW) which is taken as 1.90 $/m3 in Germany and 0.19 $/m3 in Japan here. Future studies could benefit from investigating how the water price can be brought down in different ways.

Table 2, General model input data used for all four countries (Augustine, 2024; IRENA, 2020; Macrotrends, 2024)

Global Parameters	
Simulation Lifetime	30 years
Hydrogen utilization ratio	100%
Return rate	5%
Solar cell lifetime	30 years
Wind power turbine lifetime	30 years
Battery storage duration	4 hours
Battery CAPEX	1526 $/kW
Battery OPEX	38.15 $/kW
Battery max. operating capacity	95%
Battery min. operating capacity	5%
Water efficiency as electrolyte	17.5 l/kg of hydrogen
Electrolyser type	PEM
Electrolyser CAPEX	700 $/kW
Electrolyser OPEX	14 $/kW
Electrolyser lifetime	30 years
Electrolyser efficiency	50 kWh/kg of hydrogen
Electrolyser stack size	1 MW/stack
Hydrogen storage CAPEX	1095.8 $/kg of hydrogen
Hydrogen storage OPEX	21.916 $/kg of hydrogen
Current Global Oil Price [$/kWh]	61.06 $/barrel = 0.0366 $/kWh

4.3. Macroeconomic Effects

Based on the calculated hydrogen production costs, the energy costs will change in the scenario evaluated here (with 11% of a country's energy mix being supplied by green hydrogen). This will in turn lead to macroeconomic effects as highlighted in the

Introduction section, not the least on the basis of historical oil price changes. This study aims to evaluate these macroeconomic effects based on existing energy price change studies. Mainly, the current study targets replacing oil dependency with green hydrogen dependency.

Table 3, Country-specific input data used for calculations in this study (Enerdata, 2025; IRENA, 2023; IEA, 2025; CEIC, 2022; Destatis, 2019; Statista, 2021; Statista, 2024)

Country-Specific Parameters	Brazil	Germany	Japan	USA
Yearly Energy Need [TWh]	3 910	2 861	4 547	25 022
Aver. Daily Hydrogen Demand [kg]	35 350 685	25 866 576	41 109 863	226 226 304
Solar CAPEX [$/kW]	727	731	1875	1109
Solar OPEX [$/kW]	7.56	7.56	7.56	7.56
Wind CAPEX [$/kW]	1079	1750	2384	1501
Wind OPEX [$/kW per year]	19.7	53.1	100.6	40.8
Oil Fraction of Energy Supply [%]	37	34	38	36
Water LCOW [$/m^3]	0.88	1.90	0.19	1.52

The general limitation is to mainly look at short-term and medium-term effects meaning that the energy markets do not fully stabilize in the long term here. The methodology will follow the below-described steps:

- Calculate the new energy cost based on the calculated hydrogen production cost with the 11%-assumption, focusing on replacing oil dependency with green hydrogen dependency
- Compare the energy cost change to that of historical energy cost changes in terms of magnitude

- Discuss and conclude the macroeconomic effects based on cost-change-magnitude comparisons with existing literature on historical energy price changes

The energy cost calculations are based on the following:

$$New\ Cost = Oil\ Cost * (1 - x) + Hydrogen\ Cost * x$$

Where $x = \frac{0.11}{Oil\ fraction\ of\ energy\ mix}$

This means that the energy produced is assumed to be independent of production method and energy carrier meaning a perfect substitute. It is likely that the new energy cost will be higher than the old energy cost due to the usual high costs involved in producing green hydrogen, as will be presented in the Results section.

5. Results

This section summarizes the key findings of the study, with an emphasis on the LCOH in the four countries. This focus is necessary since this cost serves as a key input for the macroeconomic analysis that follows. The cost of hydrogen production has implications for energy competitiveness, substitution effects, and broader economic outcomes, making it central to the overall analysis. The section begins with country-specific results, highlighting differences such as why production costs are higher in the US than in Brazil. This is followed by a macroeconomic analysis and a cross-country comparison. Particular attention is given to cost differences in each location and their associated macroeconomic effects.

5.1. Brazil

Brazil is one of the largest countries in the world based on area and is thus expected to experience a large difference in hydrogen production cost depending on location. Overall, the hydrogen production cost is relatively low for Brazil, which will be discussed in the country comparison section of the results.

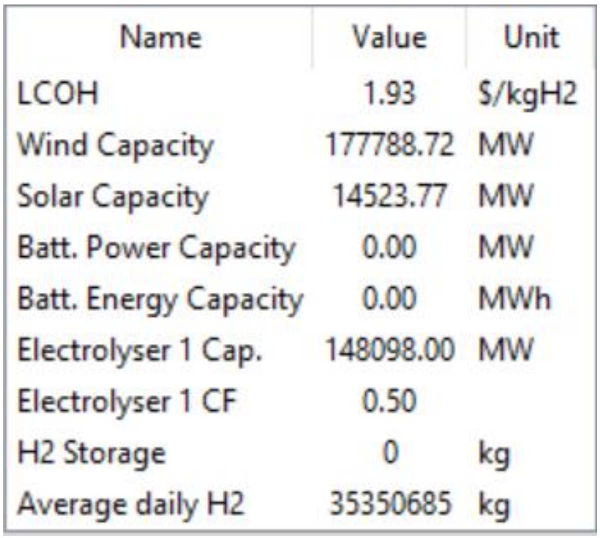
5.1.1. Macau (Windy Location)

As described in the Methodology section, Macau was chosen as a windy location for Brazil. Thus, it is not surprising when Table 4 highlights that a small amount of solar power and a large amount of wind power should be used for hydrogen production to minimize costs in this location. The solar capacity consists of only around 7.6% of the total electric power as expected for a windy location.

Table 4 further depicts how no electric batteries or hydrogen storage facilities are used since only a yearly demand is considered rather than a daily one. This means that only the average hydrogen amount per day should be 35 350 685 kg. Thus, it does not matter if it is less or more on a particular day.

Regarding the electrolyser, the CF becomes 0.5 in this scenario indicating that the hydrogen production is at 50% of what it could be. This is the highest CF for the three Brazil locations indicating that Macau is the location delivering the highest energy utilization of the three. This in turn means that the electrolyser capacity needed is lower than for the other three locations at 148 098 MW, another advantage of Macau here.

Table 4, Detailed hydrogen production output, Macau



Name	Value	Unit
LCOH	1.93	$/kgH2
Wind Capacity	177788.72	MW
Solar Capacity	14523.77	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	148098.00	MW
Electrolyser 1 CF	0.50	
H2 Storage	0	kg
Average daily H2	35350685	kg

The LCOH in Macau is 1.93 $/kg of hydrogen which is the lowest one in Brazil. Figure 1 summarizes the LCOH distribution where the largest cost contributors are the wind power and electrolyser, making up around 96% of the total LCOH. For the wind power, the major cost is related to CAPEX at 0.92 $ (see the Appendix for details on CAPEX and OPEX). Thus, if installation costs of wind power could be reduced, the hydrogen production cost would also be reduced. A similar reasoning can be driven for the electrolyser where the largest part of the cost comes from CAPEX. Also note that a small part consists of “other” costs, e.g. related to water treatment.

Overall, roughly 65% of the cost is attributed to the electricity generation alone meaning that around two thirds of the LCOH comes from electricity generation and around one third from costs related to electrolysis. This is a rough cost distribution that will be seen for many locations in this study.

5.1.2. *Fortaleza (Sunny Location)*

It is notable that Fortaleza was chosen as the sunny location for this study while no solar power will be used when minimizing the costs. Table 5 shows that the entire electricity generation comes from wind power here. This is driven by costs and highlights that although Fortaleza is sunny, it does not mean that there is no wind. So, despite solar power having lower CAPEX and OPEX per kWh than wind power, the lowest cost scenario concludes to use only wind power in Fortaleza here.

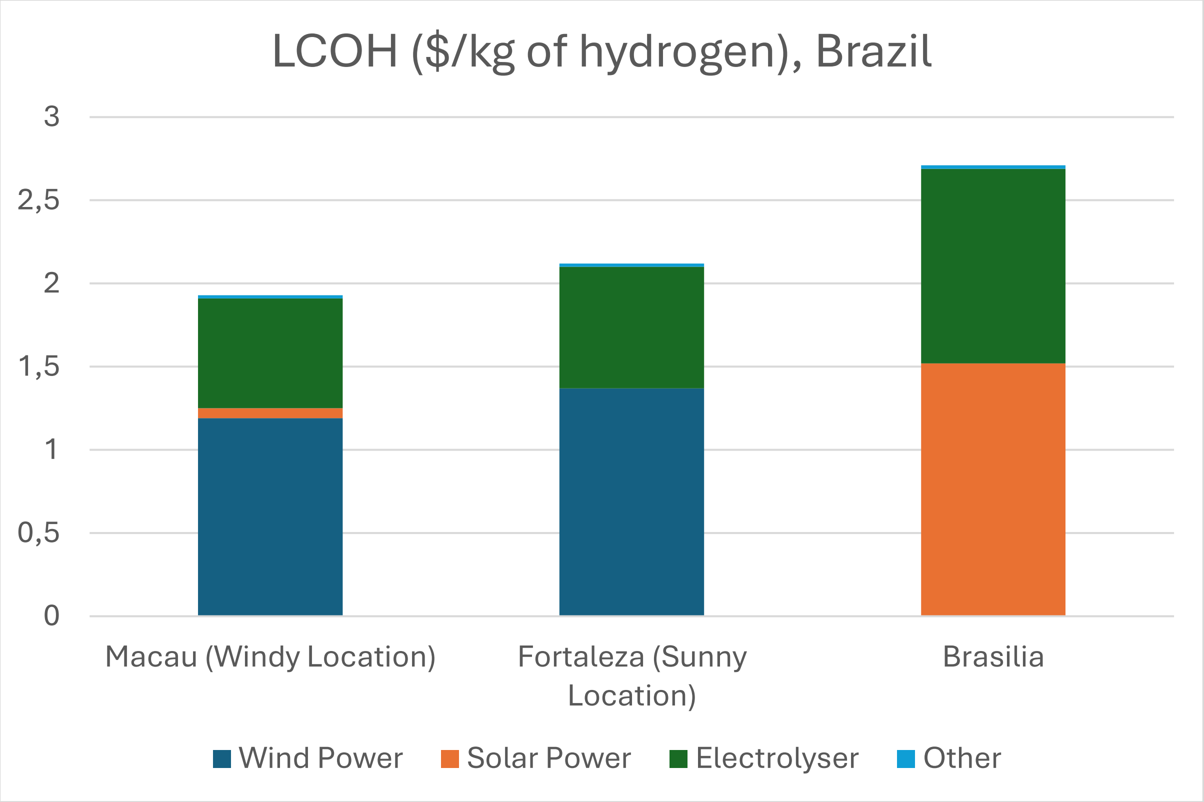


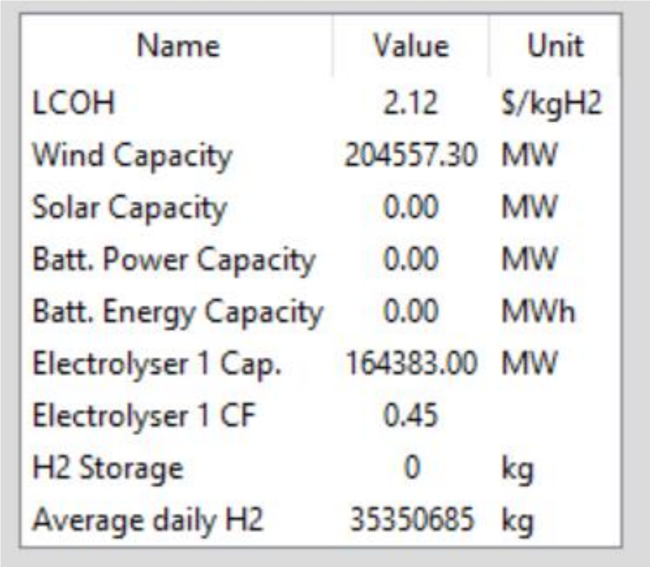
Figure 1, LCOH distribution for hydrogen production in Brazil

Table 5 further shows that the CF is 0.45 for Fortaleza which is lower than the Macau value. This is related to the larger needed electric capacity at 204 557.30 MW for Fortaleza compared to 192 313 MW for Macau, indicating that the wind and/or solar conditions are more favourable in Macau. Directly following from this, the needed electrolyser capacity is also higher in Fortaleza at 164 383 MW, compared to 148 098 MW for Macau.

The hydrogen production cost is higher in Fortaleza than in Macau at 2.12 $/kg of hydrogen, due to the less favourable electricity generation conditions described above. Figure 1 includes a total electricity generation CAPEX of 1.06 $ for Fortaleza compared to 0.97 $ for Macau. This corresponds to an 8.5% cost increase, again highlighting that Macau is a more favourable location for hydrogen production. Note that also the OPEX is slightly increased for Fortaleza compared to Macau when considering electricity generation.

For the electrolyser, the higher needed capacity also renders higher costs. Figure 1 includes a CAPEX of 0.55 $ and an OPEX of 0.18 $, compared to 0.5 $ and 0.16 $ for Macau.

Table 5, Detailed hydrogen production output, Fortaleza



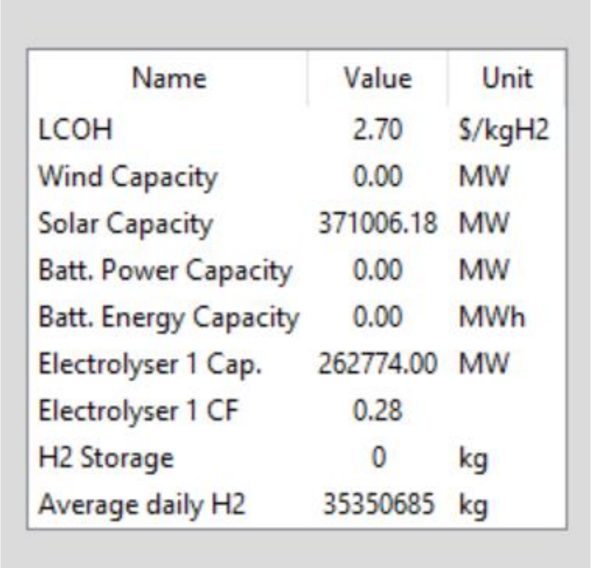
Name	Value	Unit
LCOH	2.12	$/kgH2
Wind Capacity	204557.30	MW
Solar Capacity	0.00	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	164383.00	MW
Electrolyser 1 CF	0.45	
H2 Storage	0	kg
Average daily H2	35350685	kg

5.1.3. *Brasilia (Reference Location)*

Brasilia was chosen as the reference location for Brazil and highlights a potential complication when producing hydrogen from solar -or wind power. Since the location is neither the sunniest, nor the windiest, the costs rise quickly since the needed installed capacity also increases to ensure the average daily hydrogen production.

Table 6 shows that the optimum electricity generation for Brasilia is to rely only on solar, as opposed to Macau and Fortaleza, likely due to the lower wind availability there. Note that the needed electric capacity is around 93% higher for Brasilia than Macau, directly related to the lower electrolyser CF.

Table 6, Detailed hydrogen production output, Brasilia



Name	Value	Unit
LCOH	2.70	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	371006.18	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	262774.00	MW
Electrolyser 1 CF	0.28	
H2 Storage	0	kg
Average daily H2	35350685	kg

The cost of hydrogen production is 2.70 $/kg of hydrogen which is around 40% higher than the cost for Macau, confirming Macau as the most suitable location for hydrogen production in Brazil (out of the three evaluated). This cost is mainly attributed to electricity generation via solar power and to electrolysis (see Figure 1).

The cost of electricity generation and electrolysis for Brasilia is 1.52$ and 1.17$ respectively, as compared to 1.19$ and 0.66$ for Macau, thus confirming the reason for increased costs here. It should also be noted that 43% of the LCOH comes from electrolysis for Brasilia which is higher than the other two locations. This again is a direct effect of the higher electrolyser capacity needed here.

In summary, Macau experiences the lowest hydrogen production costs compared to the other two evaluated locations in Brazil. The location for hydrogen production is important in Brazil since the cost can increase significantly if the location is non-optimal. For a future scenario where Brazil gains 11% of its energy from hydrogen, distribution may be a concern due to the country's large area where the most suitable hydrogen production location does not necessarily coincide with the most populated areas. The Brazil LCOH will be compared to the LCOH of the other three countries in the Macroeconomic section.

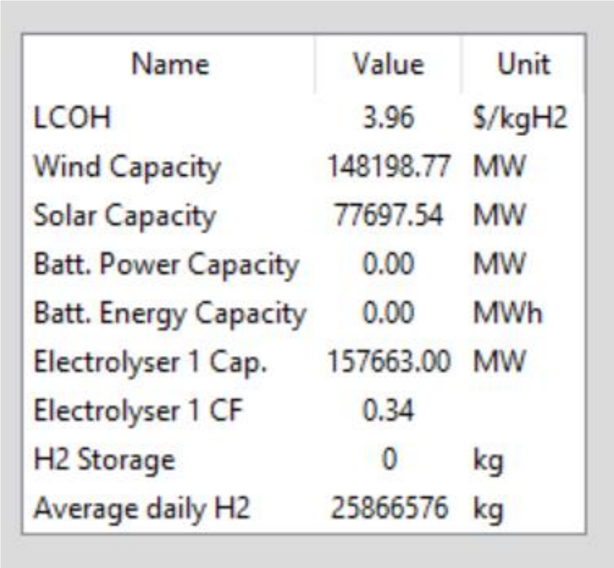
5.2. Germany

Germany is a considerably smaller country than Brazil in terms of area. Thus, smaller hydrogen cost differences are expected depending on location. Overall, the Germany hydrogen costs are larger than in Brazil explained by a 62% higher CAPEX for wind power (see the Methodology section) in combination with a less favourable location for solar power. The following sections will explain the higher production costs further.

5.2.1. Bremerhaven (Windy Location)

As opposed to the Brazil locations, Bremerhaven relies heavily on both wind -and solar power for its hydrogen production. Table 7 shows that around 34% of the electric capacity consists of solar and 66% of wind. The electrolyser capacity is higher than the Macau level as an effect of the less favourable electric generation. This is further confirmed by the low electrolyser CF at 0.34 compared to 0.5 for Macau. A value of 0.34 indicates that only around a third of the theoretical maximum production is achieved for Bremerhaven.

Table 7, Detailed hydrogen production output, Bremerhaven



Name	Value	Unit
LCOH	3.96	$/kgH2
Wind Capacity	148198.77	MW
Solar Capacity	77697.54	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	157663.00	MW
Electrolyser 1 CF	0.34	
H2 Storage	0	kg
Average daily H2	25866576	kg

The LCOH in Bremerhaven is 3.96 $/kg of hydrogen which is the lowest cost for the three Germany locations. Compared to Macau’s 1.93 $/kg of hydrogen, Bremerhaven’s value is around 105% higher suggesting challenges to produce large amounts of green hydrogen in Germany, which will be discussed more in the Macroeconomic section.

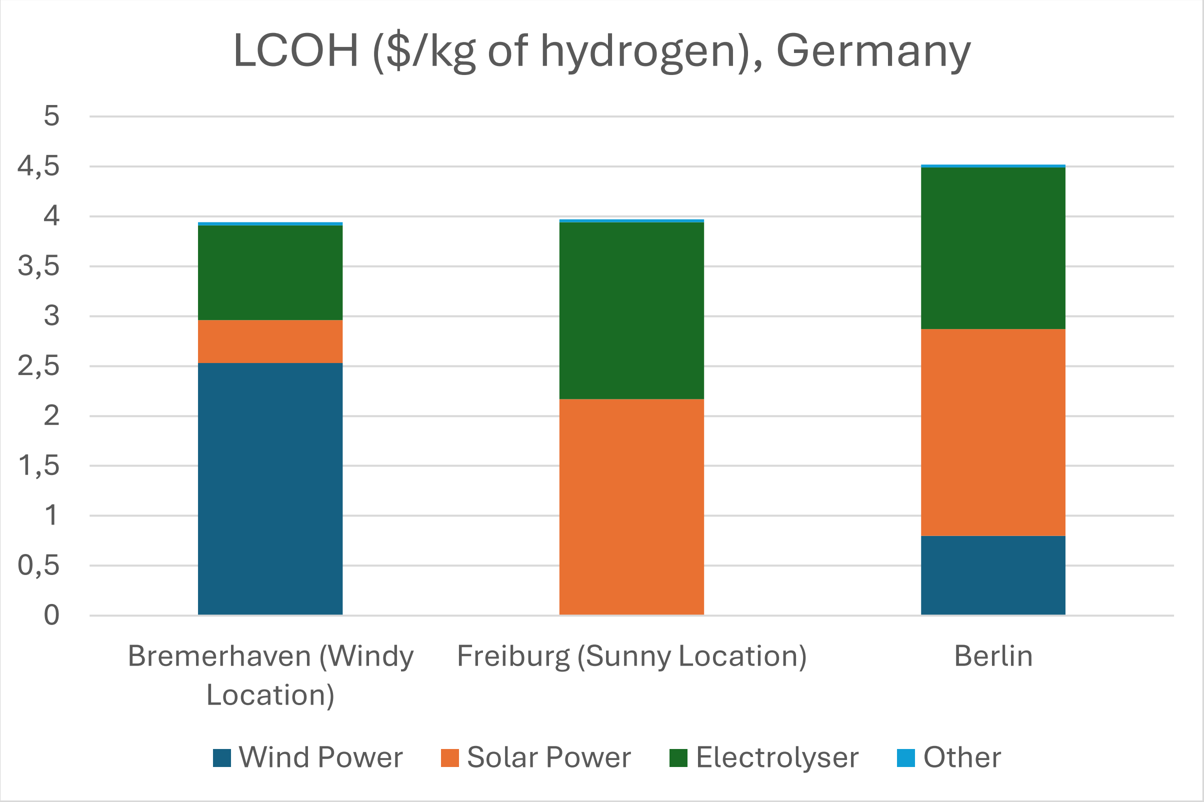


Figure 2, LCOH distribution for Germany

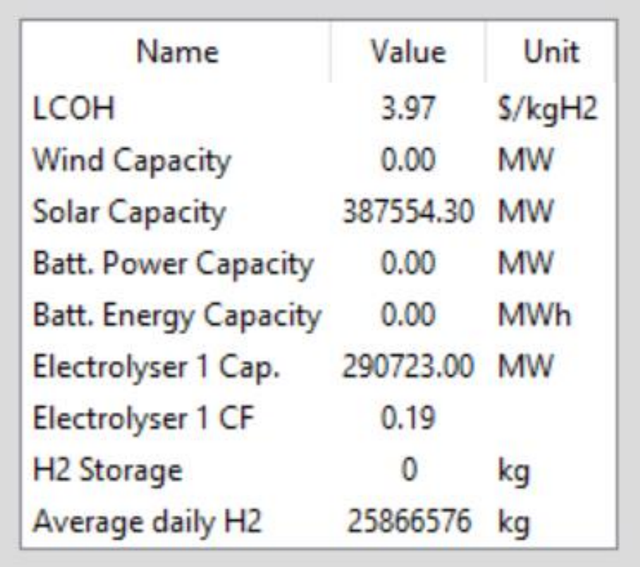
Figure 2 explains the hydrogen production costs for Bremerhaven where both the electricity generation and electrolysis are expensive compared to Brazil. However, the electricity generation constitutes the majority of the LCOH at 75%, explained primarily by the expensive wind power. The 75% corresponds to 2.96$ which is in itself higher than the total LCOH for all three Brazil locations. For Germany to produce reasonably priced green hydrogen in the future, this electricity cost likely has to be brought down.

5.2.2. *Freiburg im Breisgau (Sunny Location)*

As expected from the sunny location, the optimizer concluded that only solar and no wind power minimizes the hydrogen production costs in Freiburg. Table 8 highlights the challenges this brings with a high electric capacity needed. The value of 387 554.30 MW is almost 72% higher than for Bremerhaven, attributable to the impracticability of wind power in Freiburg, leading to a lower utilization due to sun hours dependency.

This low utilization further leads to the need of a high electrolyser capacity at 290 723 MW, explained by the low electrolyser CF at 0.19. These unfavourable values highlight that hydrogen production in Freiburg may be unfeasible.

Table 8, Detailed hydrogen production output, Freiburg



Name	Value	Unit
LCOH	3.97	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	387554.30	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	290723.00	MW
Electrolyser 1 CF	0.19	
H2 Storage	0	kg
Average daily H2	25866576	kg

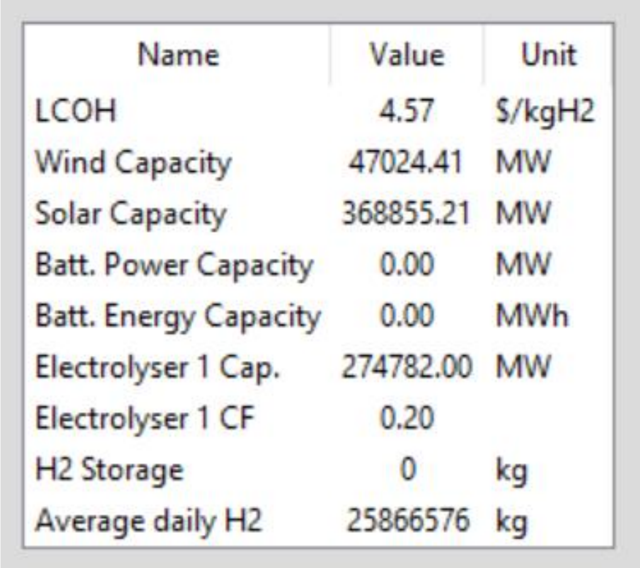
Despite the challenges with high capacity and CF, described above, the LCOH of Freiburg remains at similar levels as Bremerhaven at 3.97 $/kg of hydrogen. This is attributed to the lower cost per kW of solar power compared to wind power in Germany. Figure 2 shows that the electrolysis is responsible for almost half (44%) of the LCOH in Freiburg, which was not the case for Bremerhaven, confirming that the electricity generation as such is relatively cheap in Freiburg while the increased electrolyser capacity raises the costs. The electricity LCOH is 2.17 $ for Freiburg compared to 2.96 $ for Bremerhaven. Corresponding costs for the electrolysis are 1.77 $ and 0.95 $, which proves the need for consistent sun hours or wind hours for reducing the costs of hydrogen production.

5.2.3. *Berlin (Reference Location)*

As expected for the reference location, the electricity generation is divided between solar and wind power for Berlin (see Table 9). However, Berlin is relatively unfavourable for both solar and wind power leading to the higher needed total installed electric capacity compared to Freiburg and Bremerhaven.

Otherwise, the electrolyser capacity and CF are at similar levels as Freiburg meaning relatively unfavourable compared to Bremerhaven. This in combination with the higher electric capacity, the costs increase compared to the other two German locations. The LCOH of 4.57 $/kg of hydrogen is roughly 15% higher than Bremerhaven's value.

Table 9, Detailed hydrogen production output, Berlin



Name	Value	Unit
LCOH	4.57	$/kgH2
Wind Capacity	47024.41	MW
Solar Capacity	368855.21	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	274782.00	MW
Electrolyser 1 CF	0.20	
H2 Storage	0	kg
Average daily H2	25866576	kg

Figure 2 shows how the 4.57 $ are distributed with 2.87 $ attributed to the electricity generation and 1.67 $ to the electrolysis. Thus, the electricity generation is slightly cheaper than in Bremerhaven (2.96 $) while the electrolysis is more expensive than Bremerhaven (0.95 $). The more expensive electrolysis is a direct effect of the higher needed electrolyser capacity leading to high CAPEX compared to Bremerhaven.

To summarize, Germany experiences high hydrogen production costs compared to Brazil which will be discussed later. The geographic location is not crucial in Germany since two of three locations evaluated here experience similar costs. In general, Germany would benefit from reducing the wind power costs while also suffering from its relative lack of sun hours.

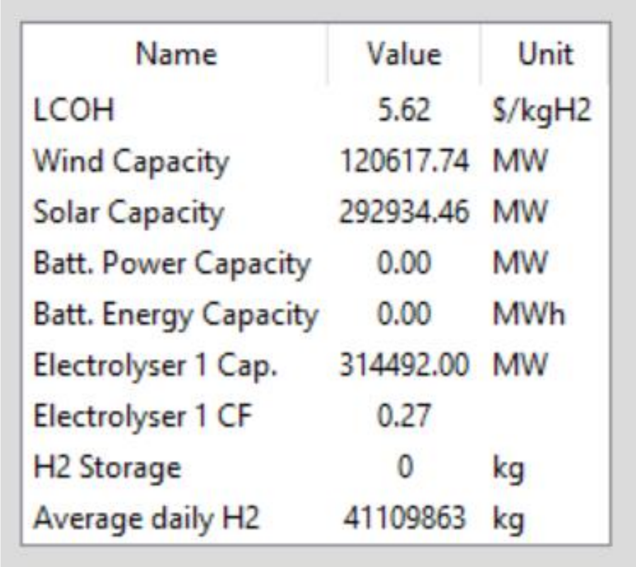
5.3. Japan

Japan is characterized by its high solar power and wind power costs compared to the other countries in this study. Thus, Japan also experiences higher hydrogen production costs as discussed in the following section. Similarly, as for Germany, Japan is also relatively small in terms of area meaning that lower differences between the three locations are expected.

5.3.1. Hamamatsu (Windy Location)

Despite being considered the windy location here, the cost-minimizing way to produce hydrogen includes electricity generation from both solar and wind in Hamamatsu. Table 10 indicates that wind constitutes roughly 29% of the installed capacity while solar constitutes around 71%. Having a large amount of solar reduces the overall LCOH of hydrogen production due to its lower costs per kW, compared to wind power (see the Methodology section). In addition to this, the electrolyser CF lies in between the Germany values indicating a roughly equally suitable wind -and solar climate in Hamamatsu.

Table 10, Detailed hydrogen production output, Hamamatsu



Name	Value	Unit
LCOH	5.62	$/kgH2
Wind Capacity	120617.74	MW
Solar Capacity	292934.46	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	314492.00	MW
Electrolyser 1 CF	0.27	
H2 Storage	0	kg
Average daily H2	41109863	kg

Figure 3 highlights that electricity generation is by far the largest contributor, at 79%, to the high LCOH at 5.62 $/kg of hydrogen in Hamamatsu. These 79% correspond to 4.42 $ which is high compared with both Germany and Brazil as a direct effect of the more expensive CAPEX and OPEX of both solar and wind power in Japan. The electrolysis is thus a much smaller part of the overall LCOH for Hamamatsu (compared with Brazil and Germany), but its absolute level at 1.20 $ is still comparable to the other locations indicating only a relative change.

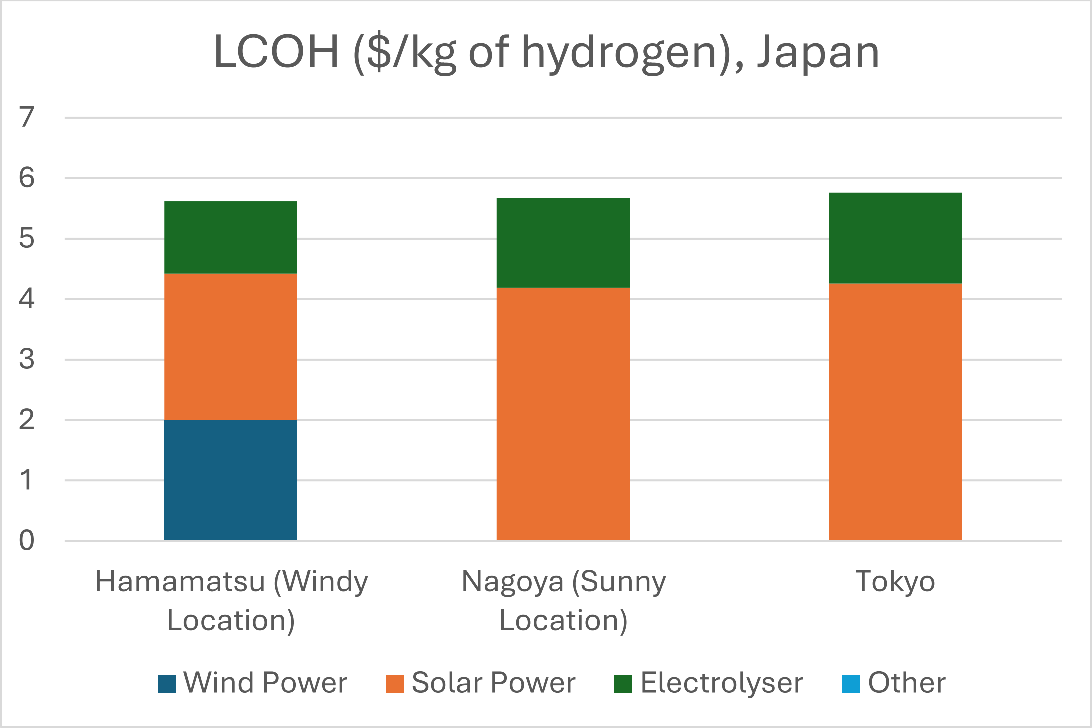
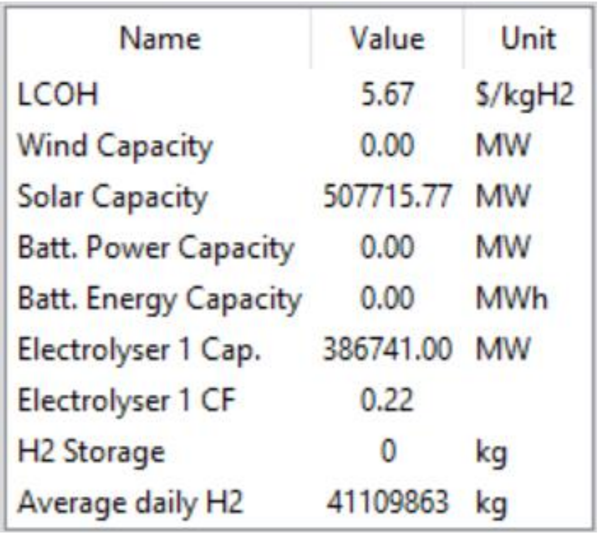


Figure 3, LCOH distribution for Japan

5.3.2. *Nagoya (Sunny Location)*

The minimum-cost hydrogen production in Nagoya consists of generating electricity from solar only, which is not surprising for the sunny location. Table 11 indicates that using only solar power comes with the expected trade-off from a lower electrolyser CF compared to Hamamatsu that used both wind and solar. This is a direct effect of that the wind cannot compensate for when the sun does not shine. However, the solar power is cheaper in Japan which is why this still gives the minimum cost.

Table 11, Detailed hydrogen production output, Nagoya



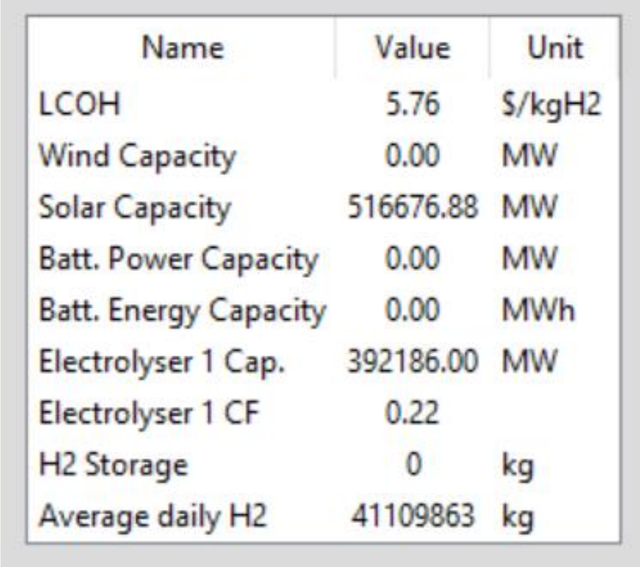
Name	Value	Unit
LCOH	5.67	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	507715.77	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	386741.00	MW
Electrolyser 1 CF	0.22	
H2 Storage	0	kg
Average daily H2	41109863	kg

The Nagoya LCOH is slightly higher than Hamamatsu at 5.67 $/kg of hydrogen. Figure 3 indicates that this is an effect of both an increased electrolysis cost and a not enough reduced electricity generation cost. The electrolyser capacity is increased for Nagoya compared to Hamamatsu leading to an LCOH of 1.48 $/kg of hydrogen compared to 1.20 $ for Hamamatsu. This can be put in relation to the LCOH of electricity being 4.19 $/kg of hydrogen for Nagoya compared to 4.42 $ for Hamamatsu leading to an overall LCOH increase of 0.05 $/kg of hydrogen which is considered a small increase here.

5.3.3. Tokyo (Reference Location)

As discussed earlier, Japan is a relatively small country in terms of area meaning that the distance between Tokyo and Nagoya is relatively small. This in turn means that the climate is not vastly different which explains that also the minimum hydrogen cost for Tokyo is achieved by using only solar -and no wind power. Table 12 shows that this means a higher installed electric capacity compared to both Hamamatsu and Nagoya. The electrolyser capacity is also high at similar levels as for Nagoya as an effect of the low electrolyser CF at 0.22.

Table 12, Detailed hydrogen production output, Tokyo



Name	Value	Unit
LCOH	5.76	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	516676.88	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	392186.00	MW
Electrolyser 1 CF	0.22	
H2 Storage	0	kg
Average daily H2	41109863	kg

With a total LCOH of 5.76 $/kg of hydrogen, Tokyo experiences the highest production costs of the three Japanese locations. This is in line with the Brazil and Germany where Brasilia and Berlin rendered the highest LCOH of the respective country. Thus, it is concluded that green hydrogen production benefits from being situated in an either sunny or windy location. It is however notable that the differences for Japan are small with Tokyo being relatively close to the other two locations in terms of LCOH.

Figure 3 summarizes the different LCOH parts where the electricity generation part is 4.26 $/kg of hydrogen which is slightly higher than for Nagoya and slightly lower than for Hamamatsu as a direct of effect of Tokyo using solar power, with a slightly higher installed capacity than Nagoya. The higher electrolyser capacity also rendered somewhat higher electrolysis costs at 1.50 $/kg of hydrogen.

5.4. USA

USA differs from Germany and Japan in terms of country size. Similarly to Brazil, USA is one of the largest countries in the world in terms of area. This means that the country consists of different climates in terms of wind speeds and solar irradiation. The following section highlights how geographical location is important for minimizing hydrogen production costs in USA, not the least due to solar power being cheaper than wind power in the country (see the Methodology section).

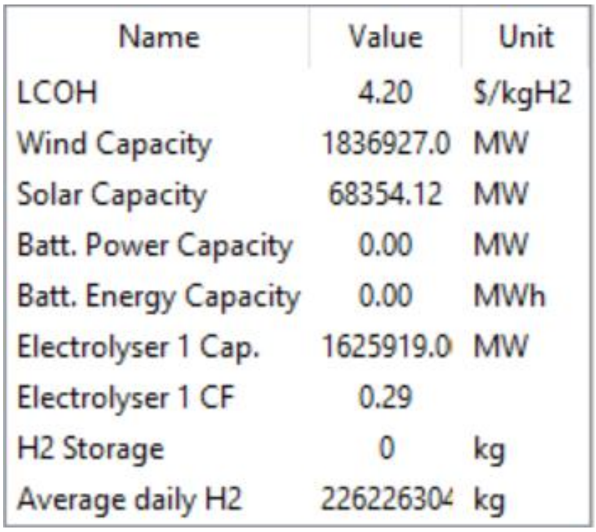
5.4.1. Boston (Windy Location)

As the windy location, Boston is expected to only utilize a small amount of solar power. Table 13 confirms that this is the case with solar constituting only around 3.6% of the electricity generated. This indicates that although solar power is cheaper, the strong winds make wind power favourable.

The electrolyser CF at 0.29 is in parity with the Japanese and German levels indicating a decent utilization of the maximum theoretical usage. Overall, the needed electric capacity and electrolyser capacity are low compared to the other two US locations.

Despite the capacities being relatively low, Boston is the least favourable location for producing hydrogen in USA (out of the three evaluated). With an LCOH at 4.20 $/kg of hydrogen, the cost is lower than the Japanese levels, but still considerably higher than Yuma as will be evaluated in the next section.

Table 13, Detailed hydrogen production output, Boston



Name	Value	Unit
LCOH	4.20	$/kgH2
Wind Capacity	1836927.0	MW
Solar Capacity	68354.12	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	1625919.0	MW
Electrolyser 1 CF	0.29	
H2 Storage	0	kg
Average daily H2	226226304	kg

Figure 4 indicates that the high LCOH is a direct effect of wind power being more expensive than solar power in USA. The wind power constitutes 2.98 $ of the total 4.20 $ corresponding to 71%. The electrolysis costs are close to the other countries at 1.13 $.

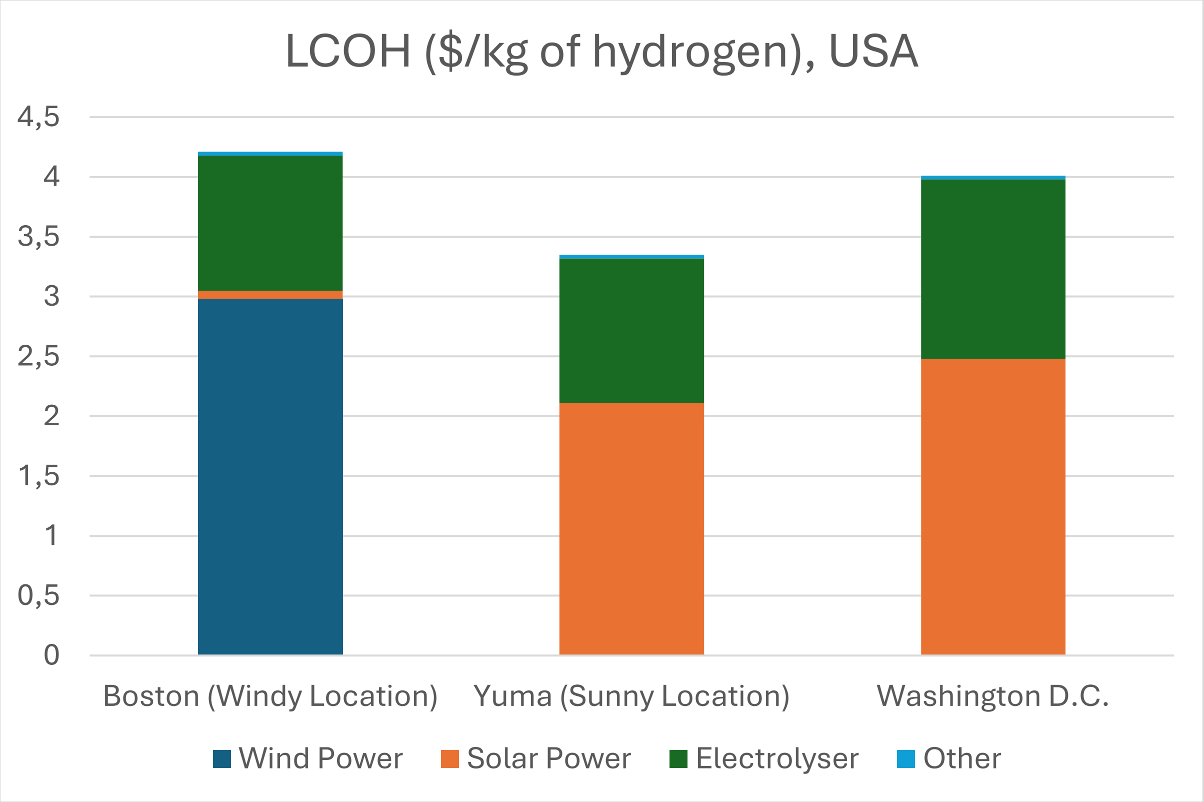
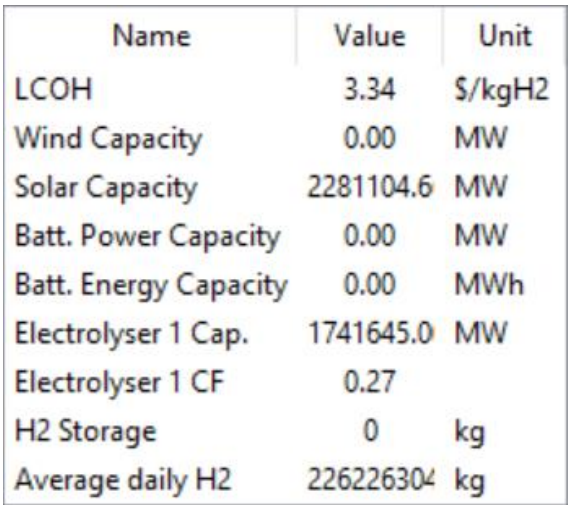


Figure 4, LCOH summary for USA depicting the cost drivers for hydrogen production

5.4.2. Yuma (Sunny Location)

As opposed to Boston, Yuma utilizes only solar power for producing its hydrogen in this scenario. The electric capacity is higher than for Boston at 2 281 104.6 MW (see Table 14), again indicating less sun hours compared to the wind hours in Boston. This in turn leads to a lower electrolyser CF and a higher needed electrolyser capacity.

Table 14, Detailed hydrogen production output, Yuma



Name	Value	Unit
LCOH	3.34	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	2281104.6	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	1741645.0	MW
Electrolyser 1 CF	0.27	
H2 Storage	0	kg
Average daily H2	226226304	kg

The LCOH is considerably lower, compared to the other two US locations, for Yuma at 3.34 $/kg of hydrogen despite the challenges described above. This is a direct effect of solar power being cheaper than wind power here. Figure 4 breaks down the LCOH into parts where it is evident that the electricity generation experiences lower cost for Yuma compared to Boston at 2.11 $/kg of hydrogen compared to almost 3 $ for Boston. This in large explains the overall lower LCOH.

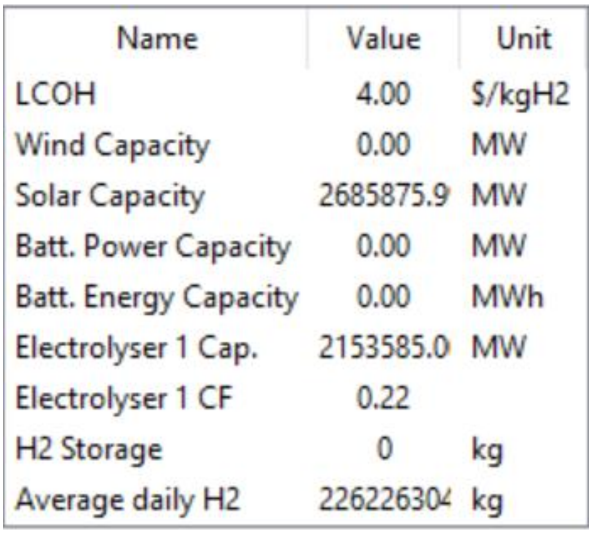
5.4.3. Washinton D.C. (Reference Location)

Similarly to Yuma, Washington D.C. utilizes only solar power for electricity generation in this cost-minimizing scenario (see Table 15). However, this location needs a higher installed capacity than Yuma since the sun hours are less favourable. The electrolyser CF is also lower than Yuma at 0.22 which in turn makes the hydrogen production more expensive per kg.

With an LCOH of 4.0 $/kg of hydrogen, Washington D.C. renders lower costs than Boston but Yuma is still a considerably better location for hydrogen production in USA. Figure 4 highlights that the main cost increase comes from electricity generation. In

Washington D.C., the solar power LCOH is 2.48 $/kg of hydrogen compared to 2.11 $/kg of hydrogen in Yuma. The higher electrolyser capacity also creates a more expensive electrolysis at 1.50 $/kg of hydrogen.

Table 15, Detailed hydrogen production output, Washington D.C.



Name	Value	Unit
LCOH	4.00	$/kgH2
Wind Capacity	0.00	MW
Solar Capacity	2685875.9	MW
Batt. Power Capacity	0.00	MW
Batt. Energy Capacity	0.00	MWh
Electrolyser 1 Cap.	2153585.0	MW
Electrolyser 1 CF	0.22	
H2 Storage	0	kg
Average daily H2	226226304	kg

In summary, Yuma is the most favourable location for green hydrogen production out of the three USA locations evaluated here. This directly comes from the favourable solar power conditions meaning a lower needed maximum capacity to fulfill the required hydrogen amounts. It should be noted that Yuma might not be the most favourable location in terms of hydrogen distribution since it is not in the most densely populated area. However, studying this lies outside of the scope of this study. Instead, the recommendation for USA is to carefully consider the geographical location for green hydrogen production since the cost differences between Yuma and Boston are substantial with Boston experiencing almost 26% higher LCOH.

5.5. Macroeconomic Analysis and Country Comparison

This section describes and evaluates macroeconomic effects of introducing 11% of hydrogen in the energy mix where the four countries are compared. At first, the locations generating lowest cost for each country are established and evaluated in terms of cost differences with a policy recommendation to lower production costs. Secondly, the energy cost is calculated for each country, if hydrogen constitutes 11% of the energy mix, and compared with current energy costs. Finally, potential macroeconomic effects are presented.

5.5.1. *Hydrogen Production Cost Comparison Between Countries*

As a summary of the earlier shown results, this section compares the lowest cost location between the four countries. Figure 5 shows that the LCOH differences are considerable between countries for producing green hydrogen. Macau in Brazil delivers the lowest LCOH at 1.93 $/kg of hydrogen, while the highest costs are found in Japan where the lowest cost is 5.62 $/kg of hydrogen for Hamamatsu. The Japanese costs are thus 191% higher than the Brazilian costs indicating substantial challenges to produce cost-effective green hydrogen in Japan. Germany experiences an LCOH of 3.96 $/kg of hydrogen, and USA an LCOH of 3.34 $/kg of hydrogen. This corresponds to 105% and 73% higher costs than in Brazil.

Figure 5 further shows the three major cost drivers wind power, solar power and electrolysis for these scenarios. The electricity generation costs differ substantially between countries while the electrolysis costs are relatively similar. This indicates that electricity generation constitutes the main costs to consider here.

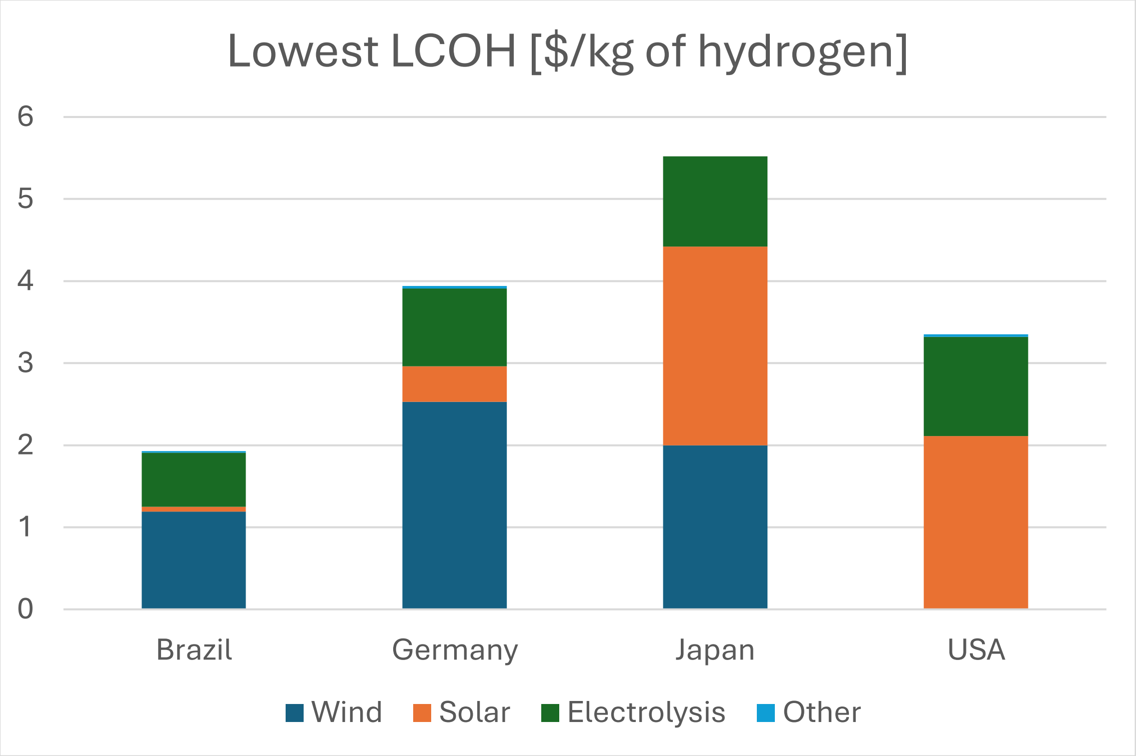


Figure 5, Lowest LCOH for each respective country with the locations Macau (Brazil), Bremerhaven (Germany), Hamamatsu (Japan) and Yuma (USA) shown

A direct correlation between CAPEX and OPEX of wind -and solar power, and LCOH of hydrogen production exists here. When considering the electricity mixes in Figure 5, Japan experiences the highest cost levels for electricity while Brazil experiences the lowest (see the Methodology section). This suggests that the major focus area for reducing green hydrogen production cost could be to reduce the costs of solar -and wind power.

Three out of four cost-minimizing locations were the windy locations, with only Yuma in USA delivering lowest costs as the sunny location. Overall, solar power was concluded cheaper than wind power in this study. However, the availability of wind and sun in the specified location meant that wind power is usually preferred for hydrogen production in the locations evaluated here.

In summary, the production costs should ideally be brought down to Brazilian levels if countries are to be self-sufficient green hydrogen producers under the scenario evaluated here. One kg of hydrogen contains roughly the same amount of energy as a gallon of gasoline. Thus, a kg of hydrogen should ideally not be more expensive than a gallon of gasoline at the pump. Today's American gasoline prices vary significantly between states, but you can often find lower prices than the 3.34$ of production cost for hydrogen in Yuma (AAA, 2025). Note that the hydrogen production costs are shown without any profit margins or taxes added.

5.5.2. Energy Cost Calculations

This section aims to compare the energy cost effects of introducing green hydrogen corresponding to 11% of the energy demand. The comparison focuses on existing oil costs and the calculated LCOH, as described in the Methodology section. Note that only the lowest LCOH for each country will be evaluated here.

Table 16 displays the input and calculated values from the analysis of this study, where calculations have followed the steps outlined in the Methodology section. For all four countries, the LCOH is higher than the current global oil price. This means that all four countries experience higher energy costs when introducing green hydrogen in the mix.

Comparing new and old energy costs, Brazil experiences the lowest cost increase at 17.3% while Japan experiences the highest at 104.4%. This is a direct effect of that the oil price is global (and not country specific), while the oil fraction of energy supply is similar in all countries. Naturally, the country with highest LCOH will also have the highest cost increase.

Table 16, New and old energy costs based on the LCOH calculations

Country	**Brazil**	**Germany**	**Japan**	**USA**
Oil Fraction of Energy Supply [%]	37	34	38	36
Global Oil Price [$/kWh]	0.0366	0.0366	0.0366	0.0366
LCOH [$/kg of hydrogen]	1.93	3.96	5.62	3.34
Hydrogen Cost [$/kWh]	0.0579	0.1188	0.1686	0.1002
New Energy Cost [$/kWh]	0.0429	0.0632	0.0748	0.0560
Percental Change, New vs Old Energy Cost [%]	+17.3	+72.7	+104.4	+53.1

Taxes or subsidies are required for the energy costs to not increase with the green hydrogen introduction (based on the LCOH calculated here). Especially, the new energy cost should ideally correspond to the old one to avoid any price shocks. This means that taxes and subsidies could be implemented in such a way that the LCOH is on par with the global oil price. In short, e.g. for Brazil, the taxes and subsidies should correspond to the 17.3% cost increase.

The next section will evaluate potential macroeconomic effects of if no such taxes or subsidies are implemented. Note that this study does not include any specific sensitivity study on potential or current tax -and subsidy levels and instead focuses on production or import costs of energy.

5.5.3. Macroeconomic Effects

As outlined in the earlier literature review, energy (particularly oil) has played a central role in shaping macroeconomic outcomes such as real GDP, inflation, and employment levels. The oil crises of the 1970s offer one of the clearest examples: a 25% increase in the real-energy-price index during that period coincided with one of the largest declines in consumer purchasing power between 1970 and 2007, which is a useful benchmark here.

In the present scenario, where green hydrogen is assumed to supply 11% of total energy demand, the resulting increase in energy prices ranges from 17.3% to 104.4%, depending on the country. These figures are substantial when compared with historical benchmarks. In many cases, they even exceed the levels observed during past oil shocks, which were themselves disruptive to economic stability. This suggests that introducing green hydrogen at such scale and cost (especially over a short time frame) could produce macroeconomic effects that mirror or surpass those seen during earlier energy crises.

The AD-AS framework can give insights on macroeconomic effects of energy price increases by evaluating aggregate supply. As energy prices increase, production becomes more expensive across all energy-using sectors of the economy. Firms face higher input costs, especially in energy-intensive industries such as manufacturing, construction, and transportation. In the absence of productivity gains or cost absorption, these firms may reduce output, cut back on investment, or pass higher costs on to consumers. According to AD-AS analysis, this corresponds to a leftward shift of the short-run aggregate supply curve, resulting in higher price levels and reduced output. Empirical studies confirm this relationship: for example, Berk (2014) and Brown (2022) find a consistent negative correlation between sharp energy price increases and real GDP growth across multiple OECD countries.

In this scenario, the scale of the modelled energy price increases suggests a high risk of GDP contraction, particularly in the short to medium term. The speed of the transition is especially important. If green hydrogen is introduced rapidly and displaces cheaper energy sources without corresponding improvements in energy efficiency or productivity, then the shock to input costs may limit the economy's ability to adjust.

By contrast, a gradual rollout over several decades (similar to the 75% rise in the energy price index experienced between 1970 and 2007) might allow for a smoother transition. During that historical period, economies adjusted and the period of 1970-2007 has seen real GDP growth despite the 75% real-energy-price increase (Our World in Data, 2025). This historical precedent illustrates the importance of timing and sequencing in managing energy transitions.

Inflation is another key concern in the evaluated scenario. Energy prices are closely linked to inflation since energy is a foundational input across production and distribution chains. Rising energy costs often translate into higher prices for goods and services across the economy, particularly in the absence of mitigating monetary policy. Historical oil price shocks have consistently preceded or coincided with inflationary periods (as described earlier), and this pattern has been reinforced in recent years by renewed energy price volatility.

Modern inflation models often incorporate energy prices as core drivers of headline and core inflation indices. In the modelled hydrogen scenario, the anticipated increase in energy prices is likely to lead to inflationary pressure, especially during the transition phase before cost reductions from economies of scale or technological innovation can be realized.

Unemployment is also likely to rise as a consequence of sharp energy price increases. Firms facing higher energy costs may respond by scaling down operations, postponing investment, or reducing labour to maintain profitability. Energy-intensive industries are especially vulnerable, but downstream sectors may also be affected as price increases ripple through supply chains.

Historical data from past oil shocks supports this link: for instance, Hamilton (2005) and Kocaaslan (2019) find that employment levels fell significantly following energy price surges, particularly in economies with low labour market flexibility. In the absence of robust labour market interventions or retraining programs, the introduction of green hydrogen at high relative prices could thus lead to higher unemployment, at least in the near term.

Another important consideration is the elasticity of energy demand. If demand is highly elastic, consumers and producers may respond to price increases by reducing energy consumption, switching to alternative inputs, or adopting energy-saving technologies. This could moderate the macroeconomic effects, reducing the pressure on output, inflation, and employment.

However, empirical estimates of energy price elasticity vary widely depending on the country, sector, and time period. For instance, Kilian (2008, p. 15) shows that inelastic energy demand (especially in the short run) can amplify the macroeconomic impact of price shocks. In the context of green hydrogen, where viable substitutes may not yet be available at scale, the elasticity of demand may be low, at least initially. This would magnify the economic disruption caused by price increases.

Finally, the broader macroeconomic implications also hinge on policy responses. Governments and central banks have several tools at their disposal to buffer against energy-induced shocks. These include monetary measures (e.g., adjusting interest rates or inflation targeting), fiscal interventions (e.g., subsidies for clean energy, income transfers), and structural policies aimed at improving energy efficiency or enhancing labour market resilience. In this regard, the evaluated scenario underscores the importance of policy preparedness. A rapid and uncoordinated introduction of green hydrogen could provoke economic instability unless accompanied by supportive policy frameworks.

In summary, the modelled scenario (in which green hydrogen supplies 11% of energy demand) produces energy price increases that are comparable to or greater than historical oil price shocks. These have previously been associated with negative macroeconomic outcomes, including slower GDP growth, higher inflation, and rising unemployment. According to the AD-AS framework, such price shocks reduce output while raising the general price level.

To mitigate these risks, governments should avoid sudden and large-scale implementation. Instead, a phased rollout, combined with well-calibrated monetary and fiscal measures, could help smooth the economic transition. In particular, exempting green hydrogen from energy taxation may be necessary to ensure its competitiveness relative to fossil fuels during the early stages of deployment. However, such exemptions may reduce government revenues, posing a trade-off that requires careful fiscal planning, though this issue falls outside the scope of the current thesis.

6. Conclusion

This study evaluated a scenario where Brazil, Germany, Japan, and USA would supply 11% of their total energy demand by domestically produced green hydrogen with the help of solar -or wind power. The green hydrogen production cost was calculated using a newly developed method from literature where three locations were evaluated per country. Since the countries face different costs related to e.g. electrolyser and electricity generation, the hydrogen production costs varied significantly. With the production cost established, potential macroeconomic effects were presented. The main conclusions follow below:

- The LCOH varied between 1.93 $/kg and 5.62 $/kg for the four evaluated countries where Brazil experienced the lowest costs and Japan the highest
- The evaluated scenario induced energy cost increases between 17.3% and 104.4% when compared with current oil prices
- The energy price increases were deemed comparable to, or larger than historic energy price shocks and increases. Since the historic shocks rendered higher unemployment, lower real GDP growth and higher inflation, this study concluded that this is also a likely effect of replacing current energy mix with large amounts of green hydrogen
- Countermeasures were recommended, to reduce the negative impact on economic indicators, for governments that plan to implement scenarios similar to the one evaluated here. Especially, the green hydrogen introduction should be implemented during longer time periods to avoid price shocks
- Green hydrogen production would benefit largely from cost reductions where electricity generation costs and electrolyser costs are deemed crucial. The location of hydrogen production is further important due to high variation in LCOH between countries

7. Future Recommendations

This study can be extended in several directions in the future due to its assumptions and limitations. Starting with the calculations on green hydrogen production costs, further analysis on the sensitivity of CAPEX and OPEX can be useful. This study found that the electricity cost (solar or wind power) is a large part of the total hydrogen production costs. This in turn means that the hydrogen costs are sensitive to changes in e.g. solar power CAPEX. New technologies could potentially make electricity generation significantly cheaper in the future and thus heavily affect hydrogen costs. A sensitivity study on this topic would give insights on what it takes to bring hydrogen costs down.

This study furthermore only considers present energy consumption levels. For future scenarios, the energy consumption could change significantly due to factors such as more efficient systems or an increasing population. Future studies should investigate the impact of this on hydrogen production costs since the hydrogen demand is then changed. These studies could further include potential future scenarios such as water scarcity.

The comparison here mainly investigates hydrogen production costs versus oil costs in different forms. However, for a future with more sources of renewable energy, a comparison between different types of renewable energy is relevant. This would be a more holistic approach to a country’s energy demands and should include distribution of energy as well. Hydrogen costs could increase if distribution methods are included. Specifically, the optimal location for hydrogen production might be closer to population centres if distribution is also considered. The energy prices also vary significantly over time and a sensitivity study would be of interest.

Future studies could further investigate more locations for green hydrogen production. There could potentially be more suitable locations than the ones evaluated in this study which could bring down the hydrogen costs further. This could in turn reduce the macroeconomic impacts of a hydrogen-dependent energy supply. Ideally, the optimum location should be found for each country not only in terms of cost, but also in terms of other factors such as environmental impact and climate impact.

The final recommended future study is to further investigate political countermeasures against an increased energy price when being dependent on green hydrogen. What tax level for different energy types is optimal? Could different incentives be optimized to increase hydrogen use? What would happen if there was a large trading system in place for hydrogen like that of natural gas? This study did not consider potential trade between countries. Considering e.g. the high hydrogen production cost in Japan, that country could probably heavily reduce the cost level by importing hydrogen.

AI Statement

ChatGPT has been used in this study for literature search, finding input data, to make some sections more concise, and to organise the references.

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Appendix

This section includes detailed results in terms of specific CAPEX and OPEX values for all evaluated locations as referred to in the Results section.

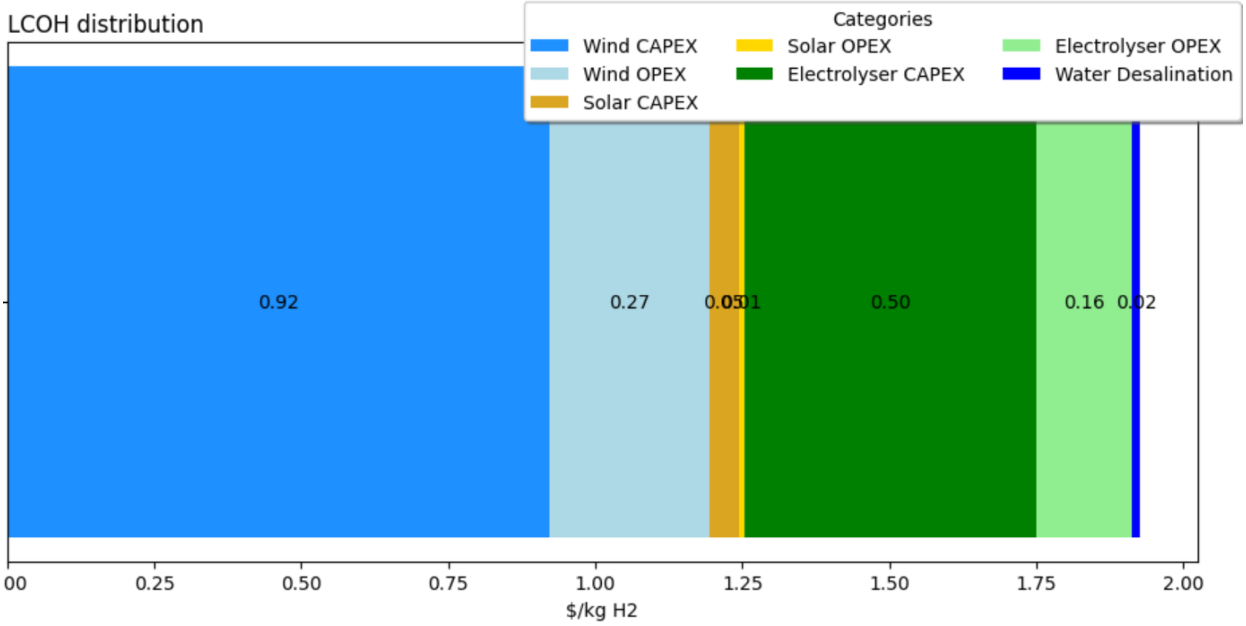

Figure 6, LCOH distribution for hydrogen production in Macau

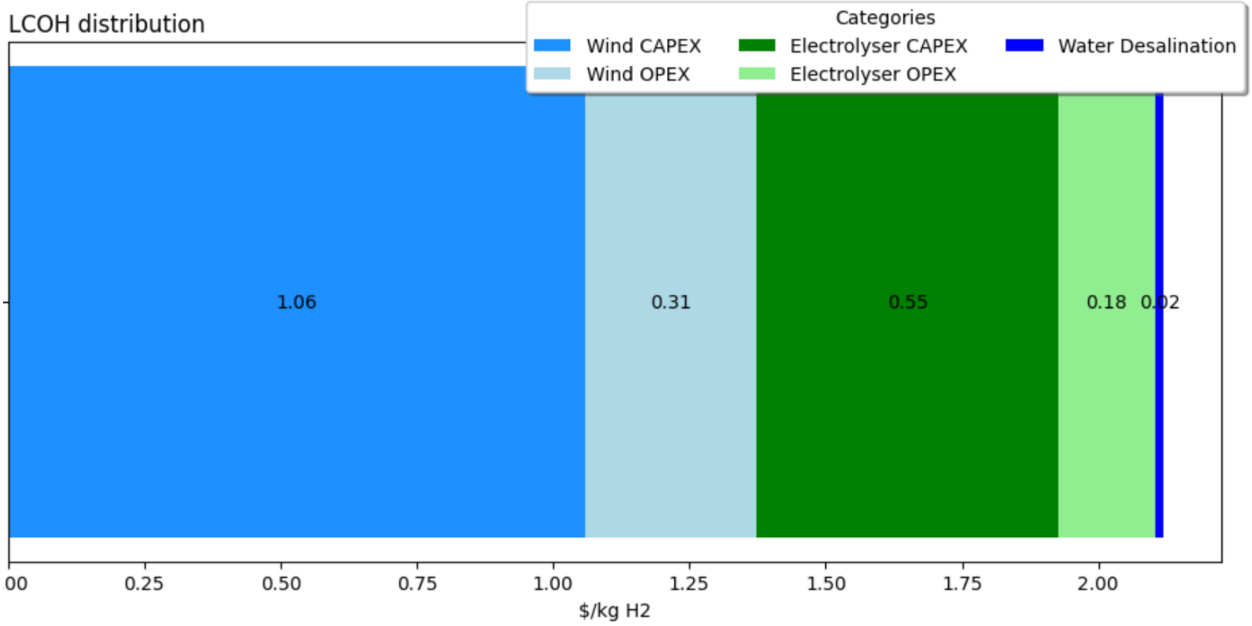

Figure 7, LCOH distribution for hydrogen production in Fortaleza

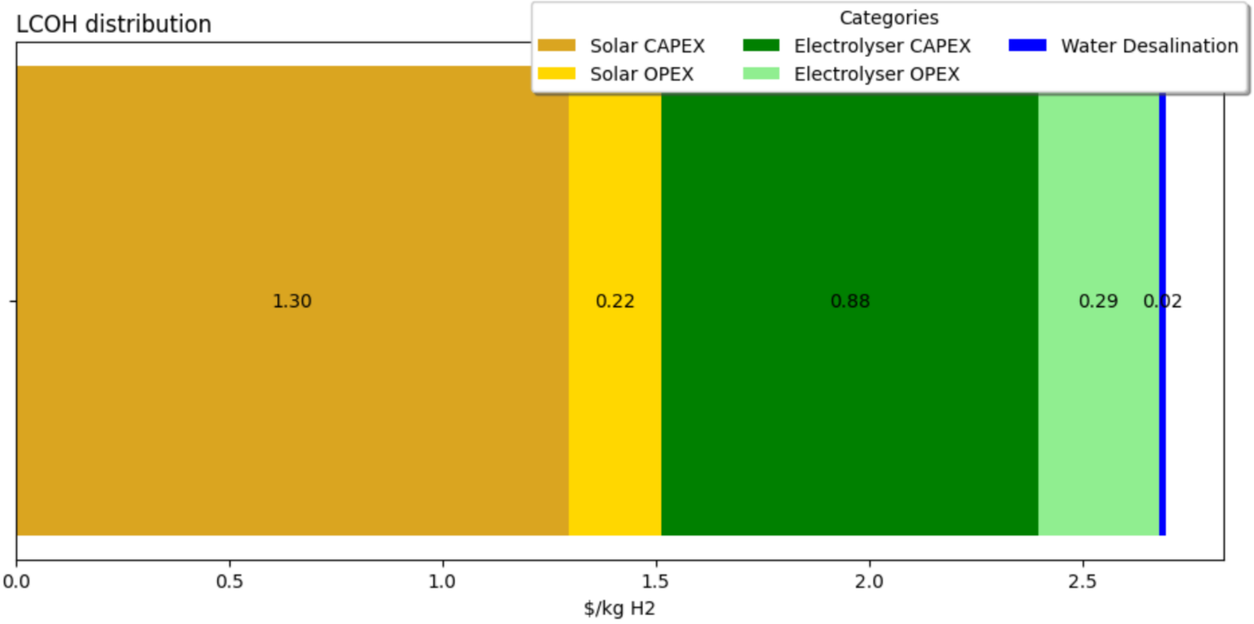

Figure 8, LCOH distribution for producing hydrogen in Brasilia

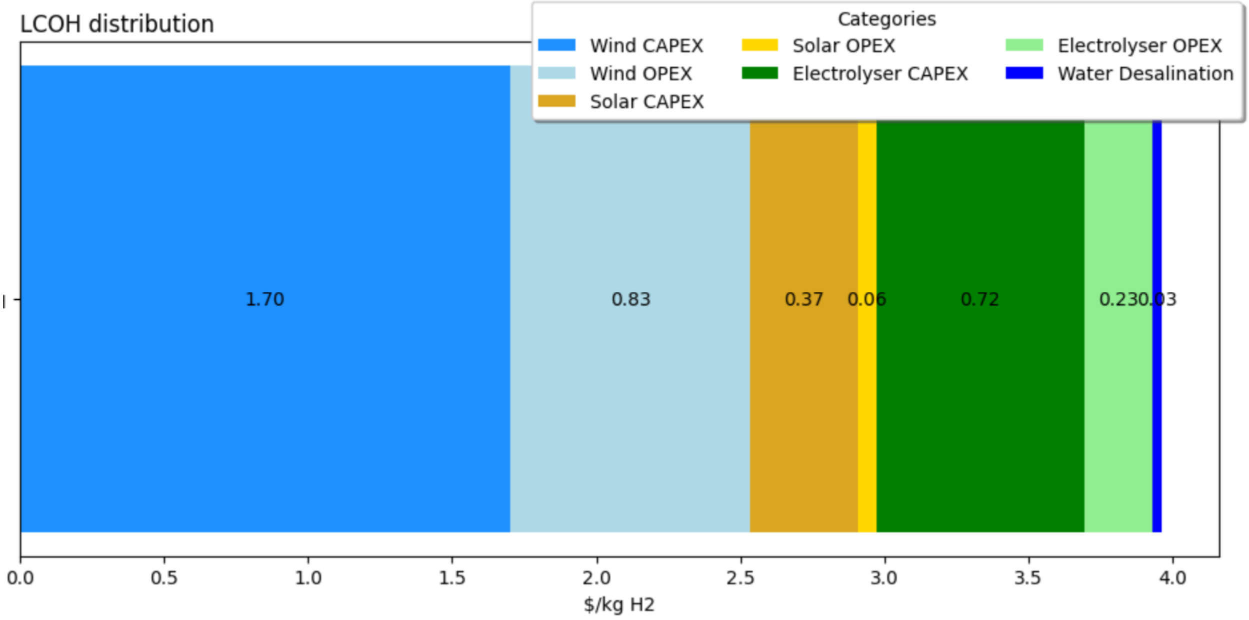

Figure 9, LCOH distribution for producing hydrogen in Bremerhaven

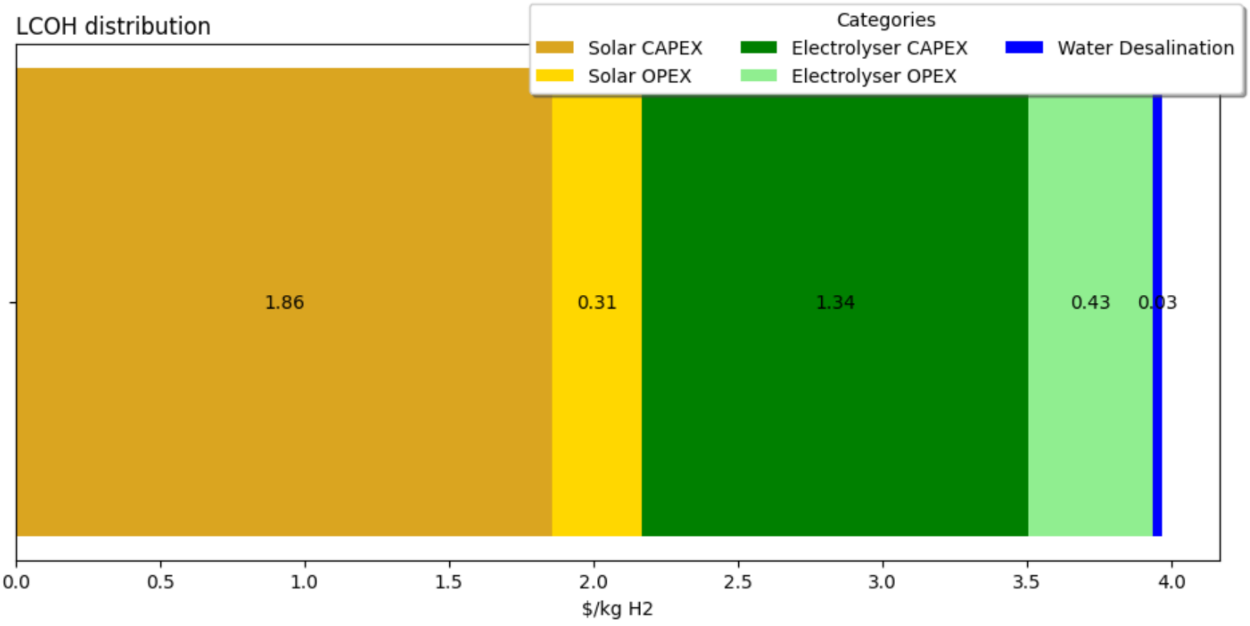

Figure 10, LCOH distribution for producing hydrogen in Freiburg

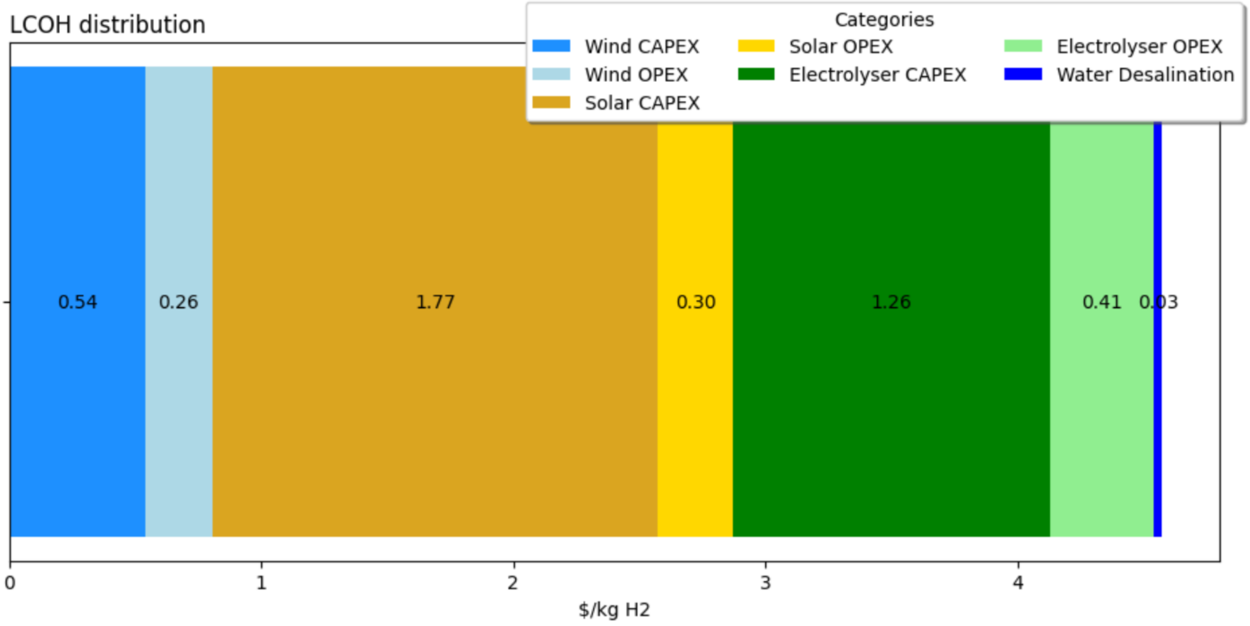

Figure 11, LCOH distribution for producing hydrogen in Berlin

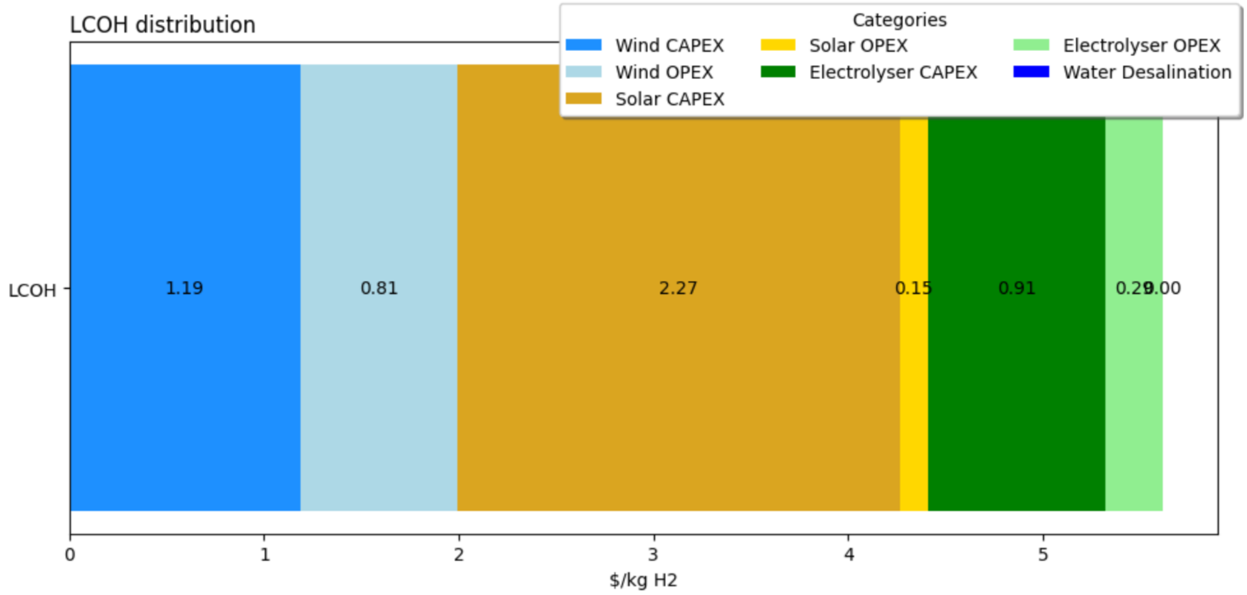

Figure 12, LCOH distribution for producing hydrogen in Hamamatsu

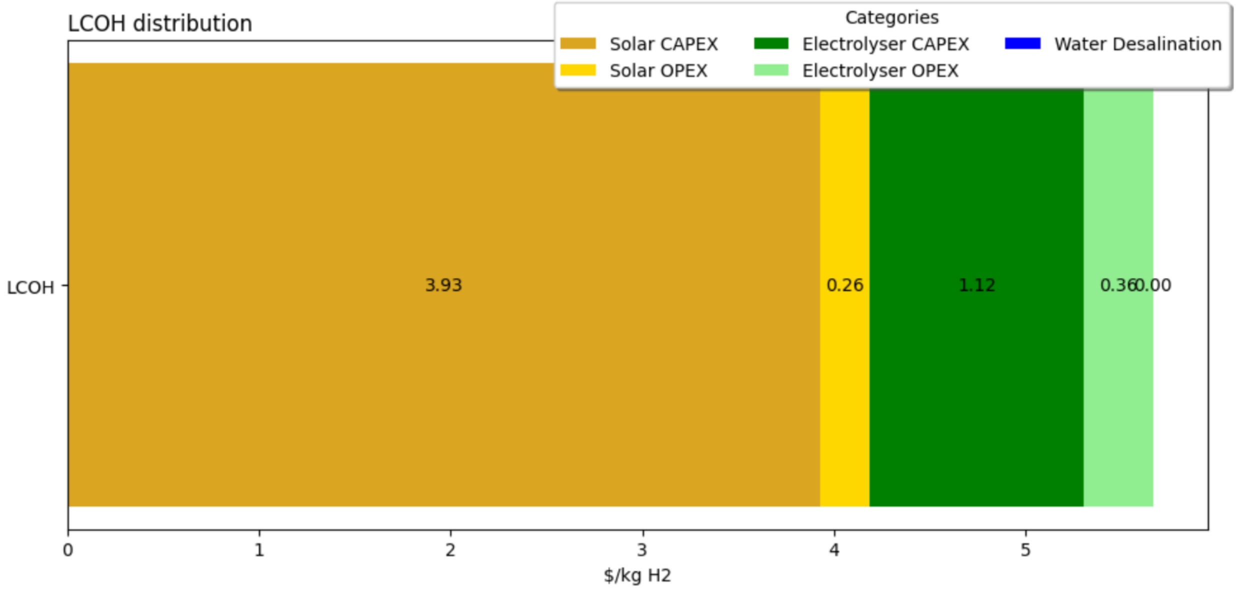

Figure 13, LCOH distribution for producing hydrogen in Nagoya

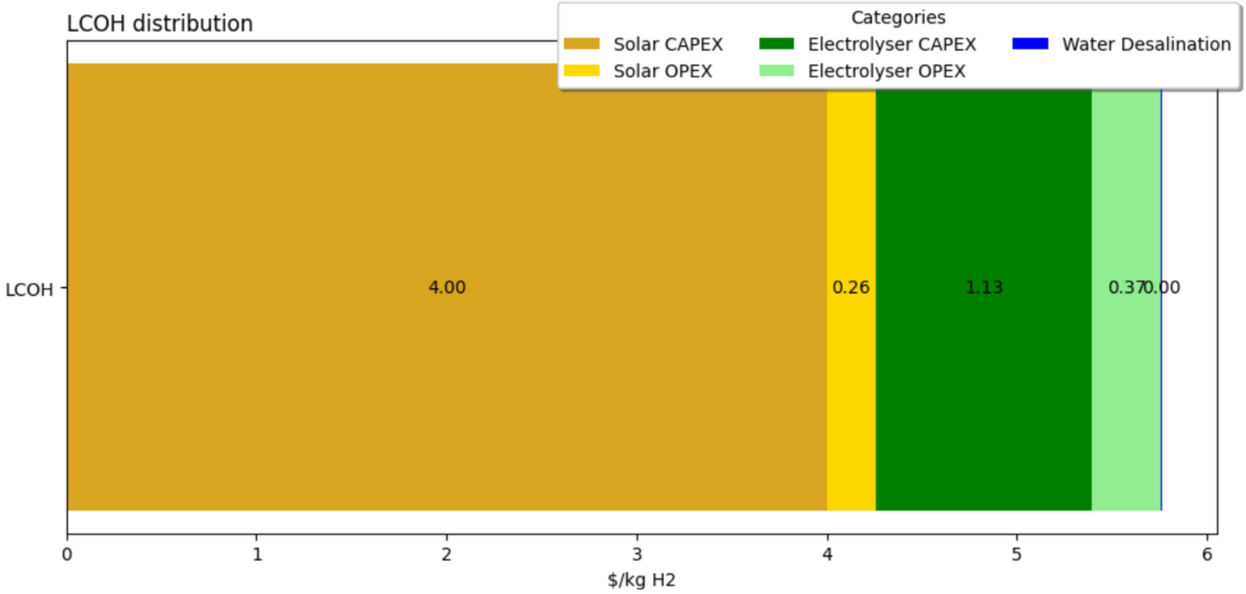

Figure 14, LCOH distribution for producing hydrogen in Tokyo

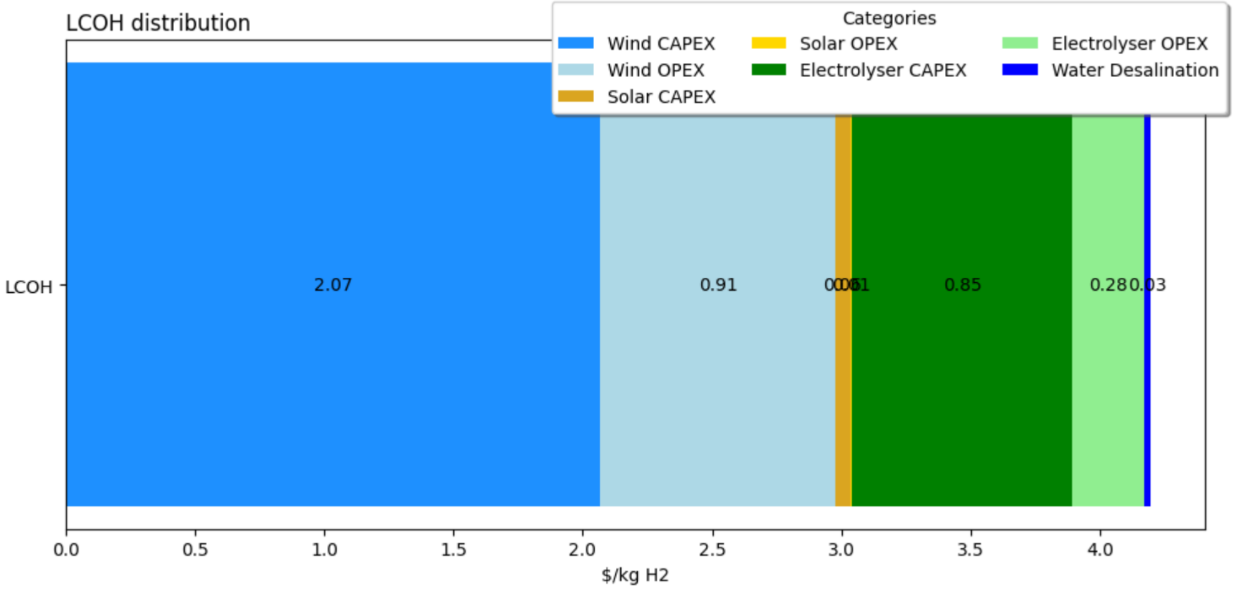

Figure 15, LCOH distribution for producing hydrogen in Boston

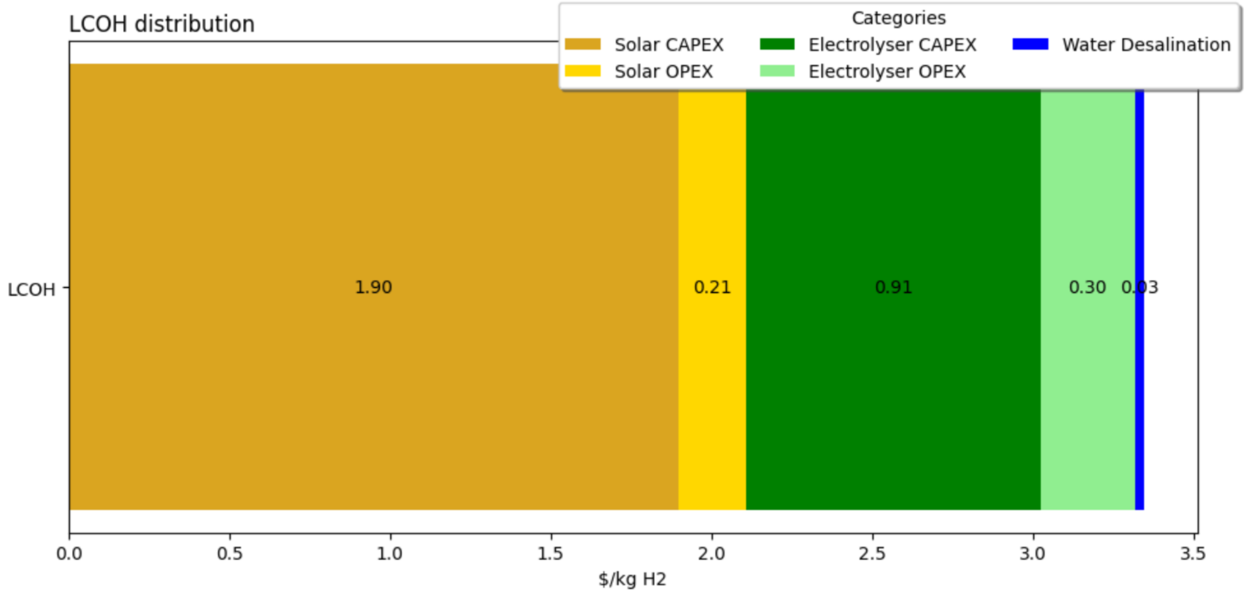

Figure 16, LCOH distribution for producing hydrogen in Yuma

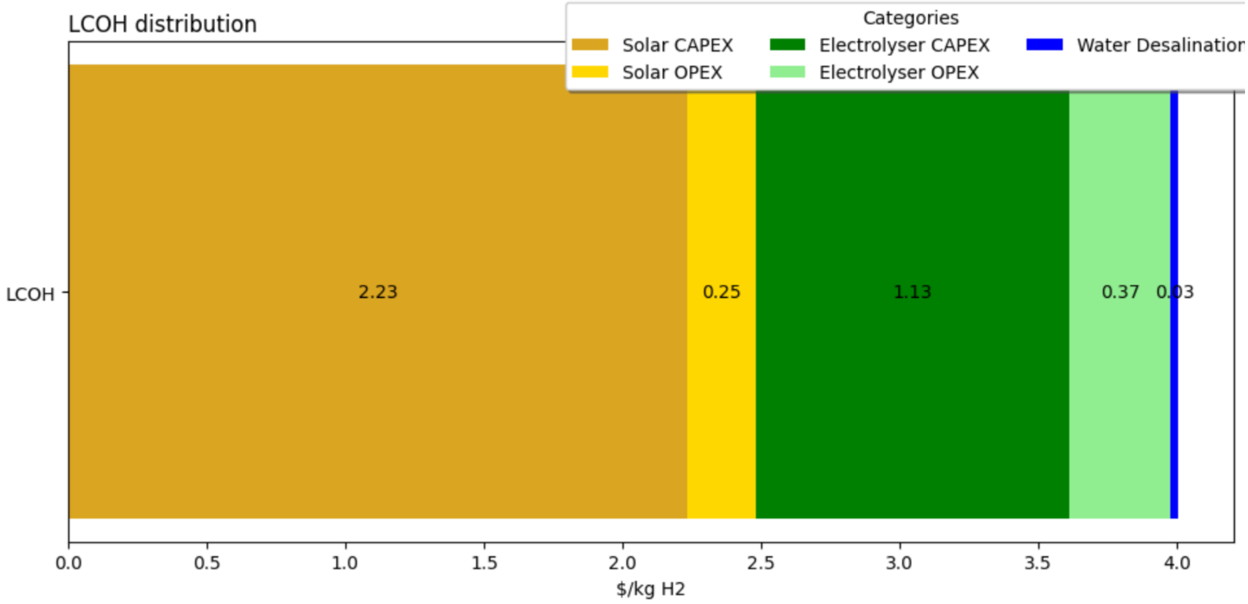

Figure 17, LCOH distribution for producing hydrogen in Washington D.C.