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The Influence of Falling Costs for Electrolyzers on the Location Factors for Green Hydrogen Production

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A fast and extensive build-up of green hydrogen production is a crucial element for the global energy transition. The availability of low-cost renewable energy at high operating hours of the electrolyzer is a central criterion in today's choice of location for green hydrogen production. It is analyzed how decreasing electrolyzer costs that are expected by many may influence this choice. The energy system optimization framework ESTRAM is used to find the optimum configuration of wind turbine, photovoltaic (PV), and electrolyzer capacity for covering a given hydrogen demand by locally produced green hydrogen in different European locations. It is found that PV is part of the cost-optimal solution in 96% of 1372 statistical regions in Europe. Decreasing electrolyzer costs are favoring the utilization of PV in wind–solar hybrid plants. At low electrolyzer costs, pure solar hydrogen outperforms the hybrid variant in many places if hydrogen storage is available, even with few full operating hours per year. At the same time, production costs are converging significantly. The article adds a new perspective to the discussion, as it is systematically shown how further technology development may lead to a shift in locational advantages for green hydrogen production, what should be considered to avoid stranded assets when building infrastructure.

1. Introduction

The future energy system will make strong use of direct electrification. However, chemical energy carriers are still needed in the future: for long-term energy storage as well as for applications that cannot be defossilized by electricity, like aviation, iron reduction, or raw material supply. The need for climate neutrality requires these energy carriers to be produced completely emission-free from renewable energies.[1] Once in place, they can be transported and traded, so that an international market for green hydrogen and its derivatives will develop.

Currently, this market does not exist. Nevertheless, companies as well as local authorities and states are drawing up concrete plans for entering the hydrogen economy. This is particularly important for the industry, which needs a clear perspective for the transition to greenhouse gas-neutral production. For this purpose, production and procurement options for green hydrogen are evaluated and initial feasibility studies and pilot projects are implemented at suitable locations. On an international scale, countries form strategic partnerships for the future trading of green fuels. Also, there is a lot of decentralized potential for green hydrogen production in European regions.[2] The focus lies on securing promising options for a cheap future hydrogen supply. With high proportions of hydrogen in the energy system, access to cheap hydrogen is a prerequisite for affordable energy.

Green hydrogen is not yet price competitive with fossil fuels. The largest shares of the hydrogen price stem from the cost of providing electricity and the cost of the electrolyzer. Thus, the local availability of low-cost renewable energy is a dominant location factor for the establishment of a local hydrogen production. Today, the best conditions for hydrogen production are offered by renewable energy (RE) sites and technologies with low levelized cost of electricity (LCOE) and high full load hours, where the cost-intensive electrolyzer can achieve a high uptime with only moderate or no RE curtailment at all.[3,4] For the evaluation of international hydrogen supply, the potentials in other countries as well as the transport costs have to be related to the respective domestic production costs.[5]

However, scenario analyses are always subject to the uncertainty of cost assumptions for future technologies, some of which can exhibit major uncertainties. The largest of these uncertainties relates to hydrogen technology, which is experiencing strong growth, especially electrolysis. The costs of electrolyzers are

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The ORCID identification number(s) for the author(s) of this article can be found under https://doi.org/10.1002/solr.202300317.

DOI: 10.1002/solr.202300317

commonly expected to decrease strongly within the next years.[6] The assumed reduction varies widely in the literature from 50% to 85% by 2030 alone, which, when coupled with varying assumptions for today's costs, results in a variation by a factor of 6 for the assumed future electrolysis cost.[6] This uncertainty transfers to any cost uncertainty for hydrogen supply using water electrolysis.[7] At very low electrolysis cost levels, especially photovoltaic hydrogen is expected to become very competitive.[8] These correlations are often not taken into account in the current literature dealing with hydrogen production in different regions of the world. In our article, we systematically exploit how decreasing costs for electrolysis influence the choice of RE technology and location for green hydrogen production.

2. Approach

The subject of our study is a green hydrogen production plant with solar PV, wind turbines, and electrolysis as well as hydrogen and a battery storage. Hydropower is not considered due to the limited potential for expansion in Europe.[2] The produced hydrogen is used to meet a year-round industrial hydrogen demand. The plant operates as an island system and has no connection to the electricity or gas grid. **Figure 1** shows the energy flow chart of the system configuration. We use the energy system optimization framework ESTRAM[9,10] developed at Leibniz University Hanover (LUH) with the linear programming solver GUROBI[11] to find the dimensioning with the lowest total costs for PV, wind, electrolysis components, and storages. This does not necessarily mean a high utilization of the electrolyzer. The analysis is carried out for different sites in Europe with respect to the regional RE location factors. The result gives us a region-specific optimum configuration and costs for green hydrogen production. Details on the simulation model and further literature on it can be found in the supplementary information.

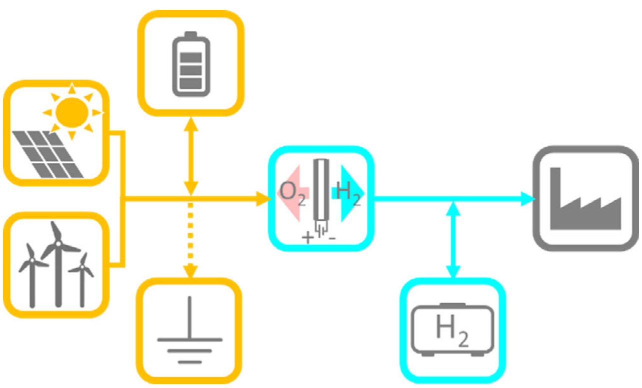

Figure 1. Flow chart of the reduced energy system used to determine the optimum configuration for green hydrogen production. The hydrogen demand is set; capacities of energy sources and storage as well as the mode of operation including curtailment of renewable energy are subject to linear optimization.

2.1. Assumptions and Boundary Conditions for the Optimization

2.1.1. Demand Profile

We assume a hydrogen demand of 200 kilotons per year, which is comparable in magnitude to the consumption of a medium-sized steel plant[12] and equals to about 8 TWh chemical energy annually. The hourly resolved hydrogen load profile is set to follow an estimated industrial process heat load profile with the maximum load (100%) being applied from Monday to Friday from 7 a.m. to midnight, 80% of the maximum load being applied from Monday to Friday from midnight to 6 a.m. and on weekends from 7 a.m. to midnight, and 60% of the maximum load being applied on weekends from midnight to 6 a.m. There is no seasonal variation. The use of a time-resolved profile of hydrogen demand is important for the estimation of the required hydrogen storage capacities, as the fluctuating renewables wind and solar can have a very different generation profiles at different locations. **Table 1** shows the estimated values for the 2030 capital expenditure (CAPEX), operating expenses (OPEX), and lifetime of the considered technological components that will be addressed individually in the following paragraphs.

2.1.2. Renewable Energy Supply

We consider the year 2030 regarding the prices and performance of RE generators and the storage components: The CAPEX for the utility-scale PV power plants is assumed to be of 378 € kW^{-1} and that for the wind turbine with 149 m hub height is 1261 € kW^{-1}. These parameters are assumed to be identical for all over Europe. Wind and solar profiles for all sites were determined using the weather year 2012 from the coastDat2-COSMO-CLM dataset.[13] Details on the cost assumptions and the determination of RE generation profiles with ESTRAM can be found in the supplementary information.

2.1.3. Hydrogen Storage

In describing hydrogen storage, we are referring to an underground cavern storage, which is cited by many as the most viable option for storing large quantities of hydrogen.[14,15] In Europe,

Table 1. Estimated 2030 values for CAPEX, OPEX, and lifetime of the technological components considered for the optimization. Details on the cost assumptions can be found in the supplementary information.

Technology	2030 CAPEX [€ kWh^{-1}]	2030 OPEX [$CAPEX^{-1}$ a^{-1}]	Lifetime [a]
PV power plant	378	2%	25
Wind power plant	1261	3%	20
Hydrogen storage	62.5 (power) 0.37 (energy)	2.5%	50
Battery storage	93 (power) 205 (energy)	1%	15
Electrolysis	variable	4%	30

cavern storage can be installed in 13 countries across the continent.[16] This location factor is, however, not considered in our article. Harnessing other, additional underground storage types for hydrogen storage, e.g., in aquifers or depleted gas fields, is the subject of current research and has the potential to significantly expand the potential sites for underground hydrogen storage.[15,17] Thus, the implementation of a site-specific hydrogen storage potential might influence or supersede the influence of the electrolyzer costs addressed within this article, but it would not bring any knowledge gain due to the large additional uncertainty of future storage options in different geological formations that are not known today.

To obtain a statement for the storage demand, we therefore choose a reverse approach. We assume a technically unlimited underground storage potential throughout Europe. We then analyze the extent to which this potential is used to create on-site storage and determine the storage demand in this way.

We derive the storage parameters from a salt cavern storage and assume an efficiency of 0.92 for hydrogen injection into the storage and 0.988 for withdrawal. We further assume that holding the hydrogen in storage is lossless. We calculate with CAPEX of 0.37 € kWh^{-1} energy capacity and 62.52 € kW^{-1} injection and withdrawal power capacity, a storage lifetime of 50 years and OPEX of 2.5% of the CAPEX. A more detailed derivation of these figures is given in the supplementary information.

2.1.4. Battery Storage

We assume CAPEX of 205.42 € kWh^{-1} energy capacity and 93 € kW^{-1} power capacity, a storage lifetime of 15 years, an OPEX of 1% of the CAPEX, and a round-trip efficiency of 90.25% for an optional battery storage option. The capacity-to-power ratio of the battery storage is being optimized. Details on that are given in the supplementary information. Expansion costs for the electricity grid, which in some European countries are statistically assigned to the costs of renewables, as well as costs for gas pipes that are not specifically linked to on-site production and usage of hydrogen are not considered.

2.1.5. Electrolysis

To investigate the influence of the differing expected cost reductions for electrolyzers, we select a wide price range. We vary the 2030 investment costs for electrolysis from 100 to 1000 € kW^{-1} related to the output power. The upper value of the investigated range corresponds approximately to today's cost level, the lower value to the more optimistic assumptions.[18] We assume an electrolyzer efficiency of 66.6% with respect to lower heating value of hydrogen, corresponding to a specific energy demand of 49.5 kWh $kg_{H2}{}^{-1}$.

2.1.6. Water Supply

Costs for water supply are neglected. According to the literature, the comparatively expensive water supply from seawater desalination plants adds up to less than one percent of the total hydrogen production costs in dry areas.[5] The cost of water will therefore not have a major influence on the choice of location for hydrogen production.

Table 2. Full load hours and corresponding levelized cost of electricity for wind and solar power for four regions in middle Europe.

Region	NUTS code	Solar PV		Wind power	
		FLH [h a^{-1}]	LCOE [€ MWh^{-1}]	FLH [h a^{-1}]	LCOE [€ MWh^{-1}]
Salzgitter	DE912	925	30.35	2895	41.01
Bitterfeld	DEE05	981	28.62	2644	44.90
Linz	AT312	1060	26.49	1388	85.53
Taranto	ITF43	1431	19.62	2595	45.75

2.1.7. Spatial Resolution

We use the European "nomenclature des unités territoriales statistiques" (NUTS) classification on level 3 (small regions) for a regionally differentiated analysis of location factors. For every region, we calculate the optimal system configuration of wind and solar power capacities, battery and hydrogen storage, as well as electrolyzer capacity for a cost-minimized hydrogen supply for the full year.

2.2. Choice of Analyzed Regions

We select four exemplary regions in central and southern Europe. All of these regions are industrial sites that are likely to have a large future hydrogen demand. From north to south these are the regions of Salzgitter in Germany (steel industry, NUTS code DE912), Bitterfeld in Germany (chemical industry, DEE05), Linz in Austria (steel industry, AT312), and Taranto in southern Italy (steel industry, ITF43). The different climatic conditions at the four regions lead to different full load hours (FLH) and LCOE for wind and solar power. **Table 2** shows a comparison of these values, details on how they are determined can be found in the Supporting Information. Salzgitter and Bitterfeld have very similar values, with Salzgitter having the slightly better wind energy conditions and Bitterfeld having slight advantages in solar energy. In Linz there are again slightly better conditions for solar energy, but very poor wind energy conditions. Taranto has similar wind conditions as Bitterfeld, but by far the best conditions for solar energy of all four regions considered.

In a second step, we investigate the impact of electrolysis costs on the distribution of different system configurations in 1372 statistical regions (NUTS-3 level) across the continent for two specific electrolyzer cost scenarios in order to make the spatial distribution of location factors in Europe apparent.

3. Results and Discussion

3.1. Hydrogen Production at Selected Industrial Sites in Central Europe

Figure 2a shows the optimum installed capacity of wind and solar power as well as electrolyzer output power for the production of

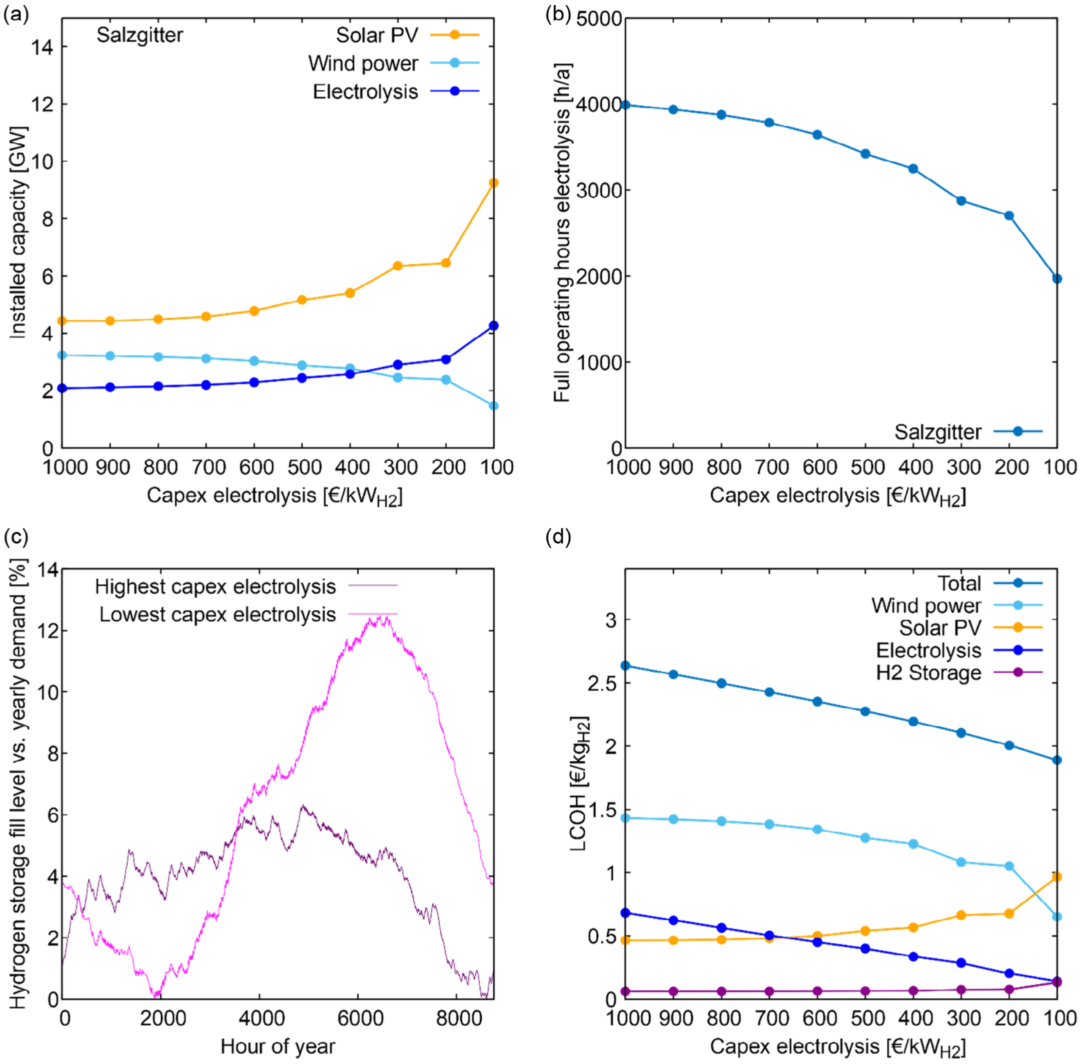

Figure 2. Simulation results for capacity-optimized hydrogen production in Salzgitter depending on the elctrolyzer costs. a) Required renewables and electrolyzer capacity to cover 8 TWh a^{-1} (200 kt a^{-1}) industrial hydrogen demand. b) Resulting electrolyzer full operating hours. c) Hydrogen storage fill level over the year for the system with the highest and the lowest electrolyzer price. d) LCOH breakdown for all scenarios.

200 kt a^{-1} of green hydrogen for the location of Salzgitter, Germany (DE912) as a function of decreasing electrolyzer costs (*x*-axis in reverse order to illustrate the trend). At all electrolyzer cost levels, the cheapest option for green hydrogen production includes a wind-and-solar-power-driven hybrid system for energy generation for the considered range of parameters. Thus, solar PV will significantly contribute to green hydrogen production in Salzgitter, which is a comparatively good wind energy location for inland Germany. However, the ratio of solar power to wind power capacity depends on the capacity-specific costs of the electrolysis. With decreasing electrolyzer prices, the system shifts toward a higher solar share in electricity production. At high electrolyzer prices, a PV capacity equal to 1.4 times that of the wind power capacity is optimal. At very low electrolyzer prices, this factor increases to a factor of 6.3. Simultaneously, the electrolyzer capacity increases.

This larger dimensioning of the electrolyzer significantly affects the operating hours of the same, which are plotted in Figure 2b. With decreasing electrolysis costs, the utilization of the electrolyzer decreases by a factor of two from 3989 to 1968 h $year^{-1}$.

The shift from wind energy to more solar energy also results in higher seasonal storage requirements as solar energy yields are less evenly distributed throughout the year than wind yields. Figure 2c plots the hydrogen storage level over the course of the year normalized to the annual hydrogen demand of 200 kt a^{-1} with the highest and lowest electrolyzer prices. It can be clearly seen that the system produces a hydrogen surplus in summer and the storage fills up, while in winter hydrogen is withdrawn from the storage and the level decreases. For low electrolyzer prices, this effect is much more pronounced and the storage capacity used is also larger, adding up to 12.5% of the annual turnover. Annual storage throughput is 42.2% of the annual consumption and thus significantly higher than the storage capacity itself. This is because the storage is used not only for seasonal storage but also for daily day–night balancing. The latter is entirely covered by the hydrogen storage system and the optimal system turns out to work without a battery. It should be noted here that we consider a pure hydrogen demand. Thus, electricity stored temporarily in a battery would have to be converted into hydrogen by electrolysis, and therefore the battery storage system does not allow an alternative utilization path with higher conversion efficiency.

Figure 2d shows the development of the hydrogen cost as a function of the electrolyzer cost. As electrolyzer costs fall, LCOH drops from 2.64 to 1.89 € kg^{-1}. The share of the electrolyzer costs within LCOH decreases from 25.9% to 7.3%, or 0.68 to 0.14 € kg^{-1}, regardless of the increasing electrolysis capacity. In contrast to that, the share of the hydrogen storage costs increases from 2.3% to 7%.

The observed trajectory for renewable capacity as a function of electrolyzer prices is highly dependent on the location factors for renewable energy production. **Figure 3a** shows the optimum ratio of renewable and electrolysis capacity in the region of Bitterfeld, which is located 140 km east-southeast of Salzgitter. The energy system optimization gives a similar result for higher and medium electrolyzer prizes compared to Salzgitter. For lower electrolyzer costs (200 € kW^{-1} and less), the system changes from a hybrid system into a solar-only system with solar PV as the only electricity source. The reason for this regime change lies in the somewhat poorer wind conditions in Bitterfeld, making the regionally achievable cost of solar electricity more competitive. As solar PV offers significantly fewer full load hours than wind energy, this is also associated with an increased demand for electrolysis capacity, which is then operated at a lower utilization rate. This does not represent an obstacle when low-cost electrolysis and hydrogen storage capacity is available.

For the city of Linz, located in Austria around 500 km southeast of Salzgitter, the optimization yields exclusively solar-supplied electricity for each of the cases considered (Figure 3b). At this location, locally produced solar electricity is significantly

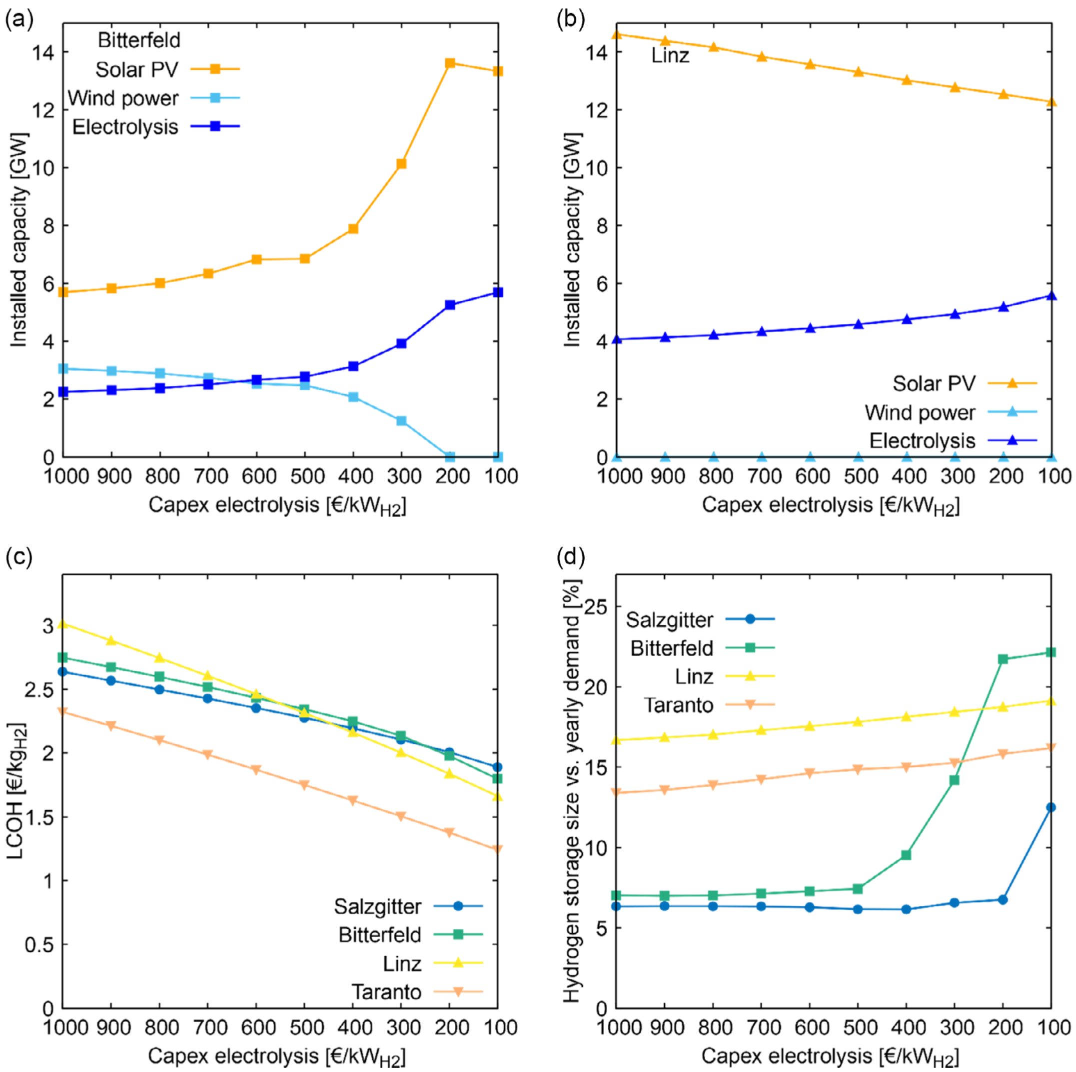

Figure 3. a,b) Optimum installed capacity of wind and solar PV power as well as electrolyzer output power for the production of 200 kt a^{-1} of green hydrogen depending on the electrolyzer costs for Bitterfeld and Linz. c) LCOH at optimum installed renewables capacity for four European locations. d) Resulting hydrogen storage size exhibiting a strong dependency on location and electrolyzer CAPEX.

cheaper than wind electricity. Annual solar irradiation is about 10% higher than in northern Germany, and good conditions for wind energy are scarce in the Alpine foothills starting south of Linz. However, to produce the same amount of hydrogen, larger electrolysis capacities must be built compared to the hybrid systems. As the cost of electrolysis decreases, less PV capacity and slightly more electrolyzer capacity are installed. At the same time, the amount of energy that is curtailed decreases.

Figure 3c shows a comparison of the development of the hydrogen costs in Salzgitter, Bitterfeld, Linz, and the south-Italian city of Taranto as a function of the electrolyzer cost. For Taranto, the simulation always suggests a solar-only electricity supply, similar to Linz, with a somewhat lower demand for PV and electrolysis capacities because solar energy in southern Italy provides more full load hours than in Upper Austria. The comparison of the hydrogen costs shows first of all that in Taranto these are always below the central European places for the whole studied electrolysis cost range.

There are some further dependencies that can be seen on closer inspection. It is plausible that systems that need a particularly large amount of electrolysis capacity benefit more strongly from decreasing electrolyzer costs. This leads to a steeper decrease of hydrogen production costs for sites that use solar electricity for green hydrogen production. This is reflected in faster dropping hydrogen costs in Linz that undercut Salzgitter or Bitterfeld at electrolyzer cost levels below $500\,€\,kW_{H2}^{-1}$ and also hydrogen costs in Bitterfeld undercutting hydrogen costs in Salzgitter at electrolyzer cost levels below $200\,€\,kW_{H2}^{-1}$, when the system in Bitterfeld switches to only solar energy. This correlation implies that the availability of wind power might become less important for green hydrogen production in the future, while the availability of suitable areas for solar energy use is gaining in importance if sufficient hydrogen storage capacity is available. Cheaper electrolysis enables the use of more solar energy, which provides fewer operating hours compared to wind energy but has a lower cost of electricity.

From the comparison between Linz and Taranto in Figure 3c, another trend can be determined. On both sites, only solar electricity is used for green hydrogen production regardless of the electrolyzer costs. Due to more solar FLH, less electrolyzer capacity is required in Taranto for producing the same amount of hydrogen. Thus, decreasing electrolyzer costs has a higher impact on the hydrogen production costs in Linz than in Taranto, and the price gap between the two sites is narrowing. This trend is also transferable to other regions: Cheaper electrolyzers reduce the global differences in the production costs for green hydrogen from solar electricity.

Greater hydrogen storage requirements for PV-only systems become obvious from the respective required storage capacity for the four locations plotted in Figure 3d. The hybrid systems in Salzgitter require less than half the storage capacity compared to the solar-only system in Linz. Storage capacity requirements increase with increasing solar energy share and also with decreasing irradiation, which is usually accompanied by higher seasonality. From the LCOH breakdown in Figure 2d we learn that larger storage requirements still only account for a smaller share of the total hydrogen price. However, this is only valid as long as the assumption made in this study that cheap underground storage is available can be met. The availability of hydrogen storage, on-site or via connection to a hydrogen grid, is therefore a prerequisite for off-grid stand-alone systems for year-round hydrogen supply to industrial complexes.

3.2. European-Wide Assessment of Hydrogen Production Location Factor Evolution

For a Europe-wide assessment of location factors of green hydrogen production, we extend our analysis to 1372 statistical regions (NUTS-3 level) in Europe. **Figure 4** shows the optimum solar share for green hydrogen production in 2030 at two different assumed electrolyzer cost levels. In Figure 4a, we assume electrolyzer costs of $728\,€\,kW_{H2}^{-1}$ in accordance with the 2019 IEA report "The future of hydrogen."[19] In Figure 4b we assume a much more optimistic scenario with electrolyzer costs of $128\,€\,kW_{H2}^{-1}$ following Mathis and Thomhill.[18] We find that for both scenarios many regions in Southern Europe exhibit a solar share of 1, which means that in these regions

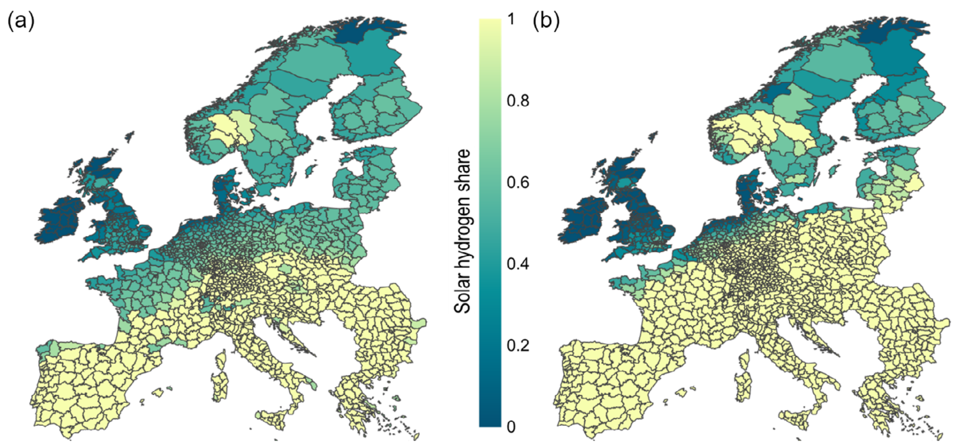

Figure 4. Optimum solar share for green hydrogen production in 1372 statistical regions in Europe at a) high electrolyzer costs of $783\,€\,kW_{H2}^{-1}$[19] and b) low eletrolyzer costs of $128\,€\,kW_{H2}^{-1}$.[18]

all-solar-electricity systems are preferred for green hydrogen production. The regions of Linz and Taranto fall within these number of regions.

Whether a hybrid solution is preferred or not seems less related to geographical latitude than to the distance to the North and Baltic Seas. For the high-electrolyzer-cost scenario, hybrid systems are preferred for a wide band of regions in Poland, Northern Germany, Benelux, and Northern France within a distance of roughly 500 km to the seashore. In countries further south, there are only sporadic regions where hybrid systems are preferred. Overall, there are 773 regions with hybrid solutions and 572 regions with only solar electricity.

For the low-electrolyzer-cost scenario, hybrid solutions exist only in closer vicinity to the North and Baltic sea, including the region of Salzgitter within a distance of roughly 200 km to the seashore. In regions with greater distances from the coast, only solar electricity is used. The region of Bitterfeld belongs to these regions that change from a hybrid system to a solar-only system. There are no regions with hybrid systems left in countries further south. There are 420 regions with hybrid solutions and 902 regions with only solar electricity. Wind-only regions play a smaller role with 27 regions in scenario A and 50 regions in scenario B. Thus, despite some individual regional cases, a global trend is apparent that falling electrolyzer prices are favoring the use of solar electricity for green hydrogen production.

Figure 5 displays the LCOH for the regions with a local solar share according to Figure 4. For the high-electrolyzer-cost scenario in Figure 5a, particularly favorable conditions for hydrogen production are found in coastal regions in Ireland, the UK, and Denmark. In the scenario with lower electrolyzer prices, on the one hand, prices are falling across Europe, but on the other hand, one also recognizes many regions along the Mediterranean coast (with high solar insolation) that can now provide hydrogen at very competitive costs.

Figure 6 shows the frequency distribution of hydrogen production costs in all regions. At high electrolysis costs, as shown

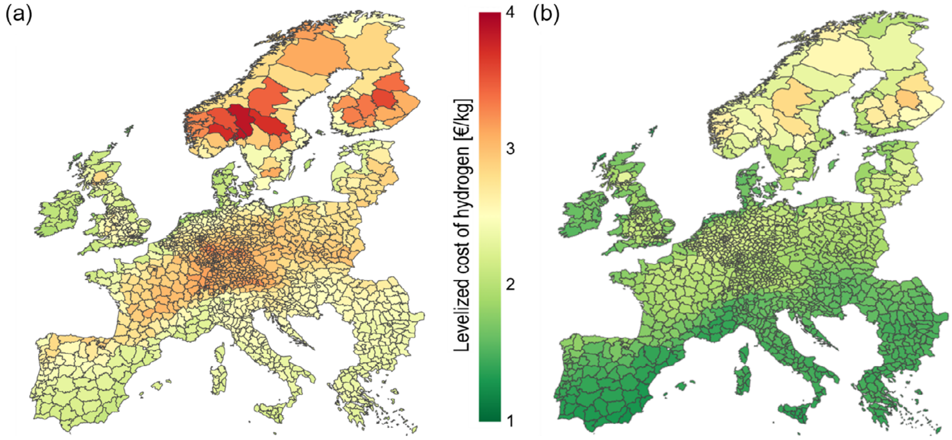

Figure 5. LCOH for green hydrogen from cost-optimized wind and solar power installations in 1372 statistical regions in Europe at a) high electrolyzer costs of 783 € kW_{H2}^{-1}[19] and b) low eletrolyzer costs of 128 € kW_{H2}^{-1}.[18]

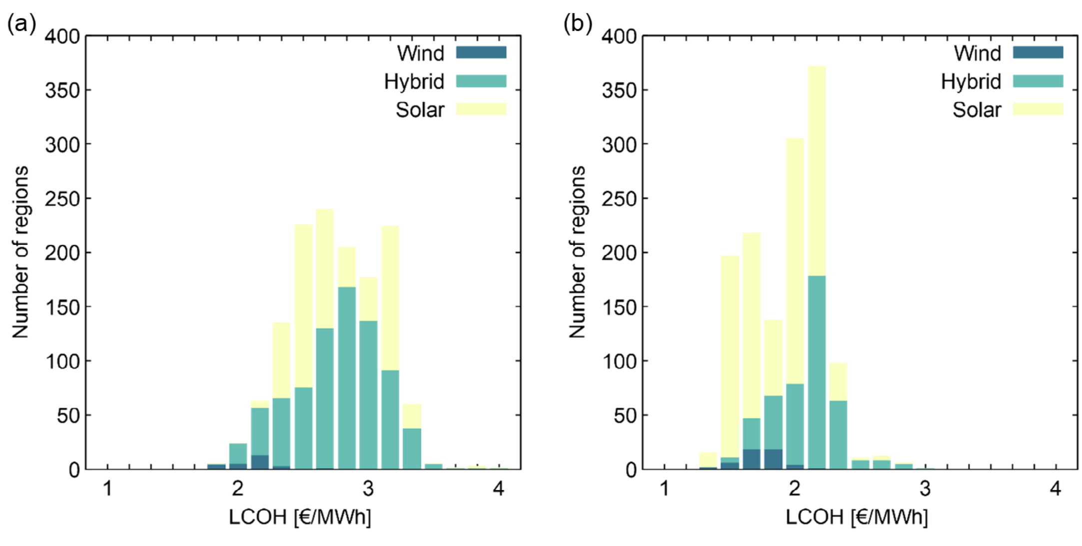

Figure 6. Distribution of hydrogen production costs in the European regions at a) high electrolyzer costs of 783 € kW_{H2}^{-1}[19] and b) low eletrolyzer costs of 128 € kW_{H2}^{-1}[18] differentiated by wind-only, solar-only, and hybrid regions.

in Figure 6a, these are in the range between 2 and 3.30 € kg^{-1} for almost all regions. The mean value is 2.67 € kg^{-1}, and the standard deviation is 0.35 € kg^{-1}. It is noticeable that the few wind-only regions are at the lower end of the cost range (2.02 ± 0.18 € kg^{-1}), while the hybrid and solar regions are spread over the entire range (the latter 2.68 ± 0.33 € kg^{-1}). At lower electrolysis costs (Figure 6b), the prices for the vast majority of regions range from 1.50 to 2.50 € kg^{-1}. The mean value is 1.85 € kg^{-1}, the standard deviation 0.29 € kg^{-1}. Thus, cheaper electrolysis lowers hydrogen costs all over Europe, and the regions move a little closer together in terms of price. The wind-only regions are still among the lowest cost regions (1.64 ± 0.15 € kg^{-1}), but there are now also a larger number of solar-only regions reaching the same cost regions (1.78 ± 0.27 € kg^{-1}). This again shows that hydrogen production at good solar sites can benefit particularly strongly from favorable electrolysis prices.

4. Conclusions

Compared to other studies,[5,7,8,20] the LCOH values calculated here tend to be relatively cheap, especially when assuming cheaper electrolysis prices. On the other hand, renewable energy technologies have had a tremendous surge in development in recent years, with reality once again outpacing even many of the most optimistic development scenarios.[21–23] Current studies suggest that a similar process could take place in the field of hydrogen technology in the next few years.[18] It is therefore extremely important to use the most up-to-date technical and economic parameters for potential studies such as those in this article. Otherwise, the potential will be underestimated. The comparison between the high-cost and low-cost scenarios makes this clear.

Our results imply that hybrid or solar-only systems are the most viable option for more than 96% of the European regions if hydrogen storage capacity is available. Therefore, PV power generation should always be evaluated as an option for contributing to electricity supply in any green hydrogen project that is not located at one of the top 5% of wind energy sites in Europe. The large proportion of hybrid systems, which all have different solar shares in the respective optimum, also hints that it is actually necessary for a comparative site analysis to first determine the optimal system configuration at each site under the respective technoeconomic assumptions made for the analysis.

As the potentials for solar energy use in Europe are much more evenly distributed than the wind energy potentials, the cost reductions for electrolysis also change not only the composition of the power sources but also the distribution of favorable locations for hydrogen production. The number of these regions will increase. The availability of wind power is becoming less important, while the availability of suitable areas for solar energy use is gaining importance.

The results also impact infrastructure risk analyses. The development of a Europe-wide hydrogen transmission network and the development of hydrogen import infrastructures at the seaports in Eastern and Central Europe are important elements of the current European energy policy and the future European energy system. However, importing hydrogen is only worthwhile if domestic production is not competitive or there is no possibility for domestic production and storage. Technological advancement in hydrogen technology (and also in RE generation) will lead to a convergence of production costs at home and abroad, and domestic production will become more attractive in many countries. If this also includes land-efficient generation with ground-mounted solar power (the land potential for solar power plants in Europe is incomparably higher than that for wind power plants), then this will also massively reduce the import requirements for green hydrogen.

However, our calculations also show that solar-only systems in particular require increased hydrogen storage. Even though our calculations are only valid for stand-alone systems, it can be assumed that comparatively large hydrogen storage facilities will also need to be built in a national energy system with a large amount of PV electricity generation and a high proportion of domestically produced hydrogen.[9] Therefore, the usefulness of building hydrogen storage facilities and a hydrogen distribution infrastructure that connects these storage facilities to the major consumption centers are not questioned by our findings, but rather supported.

The expected development in the field of green hydrogen also represents a risk for investments in alternative energy sources. A hydrogen price in the range of 2.50 € kg^{-1} corresponds to a fuel price of 75 € MWh^{-1}. It is likely that at these prices, electrical energy can be provided economically competitively, even year-round, with a combination of fluctuating renewables and hydrogen reconversion power plants. This is true not only, but especially in comparison to the provision of electricity by nuclear power plants, which already seems no longer economical even without competition from low-cost green hydrogen in the context of the energy transition.[24]

The fact that the location factors for supply solutions based on green hydrogen could significantly improve in the future due to reduced electrolysis cost should also be included in the risk assessment for investments in competing technologies. These include fossil blue hydrogen, which has a poor emissions record due to methane emissions in the manufacturing process and is insufficient to meet climate targets,[1] already without taking into account the fact that reliable long-term storage of CO_2 has not been proven, and CSP power plants in sunny countries, which can provide electricity around the clock but have higher electricity supply costs than PV power plants.[25]

The study describes however only the supply side of hydrogen and the resulting costs. The resulting prices in the market are always a result of supply and demand as well. As an example, hydrogen production competes with other electricity consumers and requires surplus electricity. Thus, if cheaply produced renewable electricity or hydrogen are in short supply, hydrogen production will also be profitable under less favorable conditions. Nevertheless, the profit to be made will always be higher in regions with good location factors than in regions with poor location factors.

We showed that falling electrolysis costs can significantly shift the location factors for hydrogen production. Especially hydrogen production from solar electricity will gain in importance. Locations that are characterized by good conditions for wind energy will lose some of their advantage over low-wind locations with similar solar irradiance. At the same time, the production costs between good and poorer RE sites in Europe are converging. The large influence of these technical parameters on the hydrogen production costs in combination with a large uncertainty concerning the future costs of hydrogen technology will make it necessary to regularly update potential studies for the production of green hydrogen, taking into account the latest findings from technological and economic developments.

A higher solar share in hydrogen production fosters the need for hydrogen storage. The development of inexpensive storage capacities, e.g., in underground storages, is important for the competitiveness of green hydrogen from solar electricity.

Increased future viability of domestic hydrogen production should also be considered in the planning and implementation of hydrogen import infrastructure to avoid stranded assets. While the projected transport costs for green hydrogen to Central Europe are already in a range that makes hydrogen imports from sunny countries similarly expensive to domestic production,[26] falling electrolysis prices will make domestic production even more attractive.[27]

Supporting Information

Supporting Information is available from the Wiley Online Library or from the author.

Acknowledgements

An earlier version of this article was presented at the 8th World Conference on Photovoltaic Energy Conversion in September 2022 in Milano. The authors thank the conference participants for their valuable comments and fruitful discussions. The authors further thank the state of Lower Saxony for financial support of this work under the grant number 74ZN1596 (MET—Modelling the Energy Transition).

Open Access funding enabled and organized by Projekt DEAL.

Conflict of Interest

The authors declare no conflict of interest.

Data Availability Statement

The data that support the findings of this study are available from the corresponding author upon reasonable request.

Keywords

energy system analysis, green hydrogen, PV, renewable energy

Received: April 28, 2023
Revised: June 21, 2023
Published online: July 4, 2023

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