

Economics of converting renewable power to hydrogen

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The recent sharp decline in the cost of renewable energy suggests that the production of hydrogen from renewable power through a power-to-gas process might become more economical. Here we examine this alternative from the perspective of an investor who considers a hybrid energy system that combines renewable power with an efficiently sized power-to-gas facility. The available capacity can be optimized in real time to take advantage of fluctuations in electricity prices and intermittent renewable power generation. We apply our model to the current environment in both Germany and Texas and find that renewable hydrogen is already cost competitive in niche applications (€3.23 kg⁻¹), although not yet for industrial-scale supply. This conclusion, however, is projected to change within a decade (€2.50 kg⁻¹) provided recent market trends continue in the coming years.

In the search for alternatives to carbon-intensive fossil fuels, hydrogen has considerable potential as it effectively presents a platform for a range of applications including fuel for transportation^{1–3}, feedstock in chemical and processing industries⁴ or energy storage for heat and power generation^{5–8}. While hydrogen can be obtained through multiple processes, its production from renewable electricity via power-to-gas (PtG) bears the advantage of complementing the intermittent power supply from wind and solar energy installations. However, such electrolytic production of hydrogen, whereby electricity instantly splits water molecules into oxygen and hydrogen^{9–11}, has so far been regarded as too expensive¹². The recent precipitous decline in the cost of renewable power^{13,14} now suggests that the economic fundamentals of PtG facilities are about to change.

The possibility of combining an investment in renewable energy with a PtG facility and converting a share of the generated power to hydrogen has lately become a topic of substantial debate^{15,16}. An investor in such a hybrid energy system effectively acquires a ‘real option’ that allows for real-time optimization by either selling electricity at the current market price or converting it to hydrogen. Such flexibility is valuable in an environment in which both electricity prices and renewable power generation fluctuate over time^{17,18}. Renewable hydrogen production will then be considered economically viable if investing in a combined facility has a positive net present value (NPV) and furthermore this value exceeds the NPV of the renewable energy facility on its own.

Here we develop an analytical framework that applies to general hybrid energy systems and yields necessary and sufficient conditions for their economic viability. These conditions can be stated compactly in terms of average per unit capacity costs and the price premium for converting electricity to hydrogen, after including an adjustment factor that accounts for both the temporal fluctuations of renewable power generation and electricity prices. Applying our model to wind parks in Germany and Texas, we find that renewable hydrogen turns economically viable if hydrogen is sold at prices of at least €3.23 kg⁻¹ in Germany and US\$3.53 kg⁻¹ in Texas. In the current environment, these prices are compatible with small- and medium-scale hydrogen supply but not with large-scale industrial sales. However, if the acquisition prices for electrolyzers and wind

turbines continue on their respective recent learning curves, our findings project that, in about a decade, renewable hydrogen will also become competitive with the lower prices paid for large-scale industrial hydrogen.

Model framework

Consider a hybrid energy system combining a renewable energy source with a PtG facility (including the electrolyser, piping and hydrogen compressor) that converts electricity and water into hydrogen. At each point in time, the electricity that is generated can be sold externally at the current market price or it can be fed to the electrolyser for conversion to hydrogen. Since our interest is in ‘renewable’ hydrogen that does not cause an atmospheric release of CO₂, we focus on electricity obtained purely from a renewable power source.

In our continuous time formulation, t ranges between 0 and $m = 24 \times 365 = 8,760$ h. The price per kilowatt hour (kWh) at time t at which renewable energy can be sold is denoted by $p_e(t)$. For select hours of the year, wholesale electricity markets have been exhibiting patterns of negative market prices caused in part by the intermittency of renewable power sources. Since the output from wind and solar production facilities can be curtailed without delays, we specify that $p_e(t) \geq 0$. This specification is without loss of generality, because at times of negative prices the power from the renewable energy source can be either curtailed or converted to hydrogen in which case the external market price does not affect the revenue attained (a comprehensive list of all symbols and acronyms is provided in Supplementary Table 1).

Without loss of generality, we normalize the capacity of the renewable energy facility to 1 kW. The capacity factor, $CF(t)$, represents the percentage of the available capacity that is used at time t . As a result of the inherent intermittency of renewable power, $CF(t)$ is exogenous, varies with time and generally satisfies $CF(t) \leq 1$. The variable operating costs of renewable energy production are considered to be negligible.

The conversion value of hydrogen is the selling price of hydrogen minus the variable operating cost (including water and other consumable inputs) multiplied by the conversion rate of the electrolyser.

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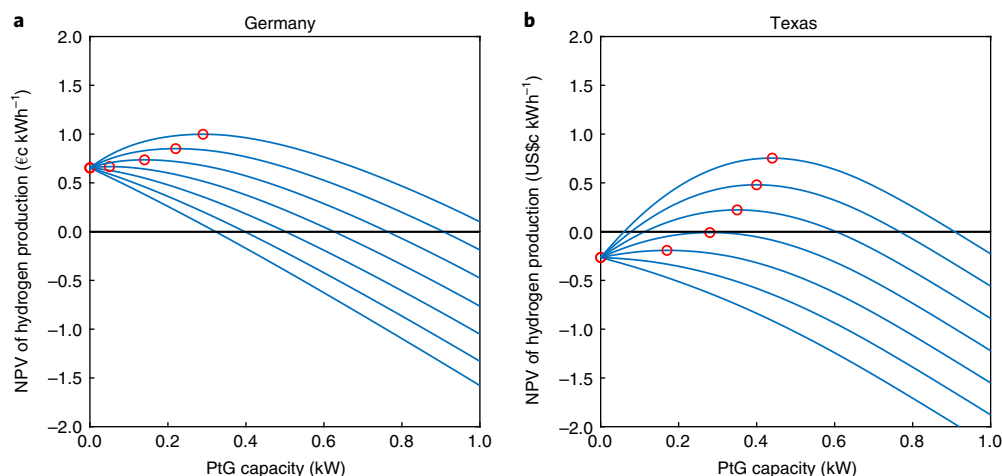


Fig. 1 | Optimal PtG capacity size and corresponding NPV. a,b, Given a normalized wind energy capacity of 1.0 kW, the figure shows the NPV of an optimized hybrid energy system in Germany (**a**) and Texas (**b**) for alternative hydrogen prices ranging from €/US\$2.0 to 5.0 kg⁻¹ (blue lines). The red circles mark the optimal PtG capacity size for each alternative hydrogen price. The circles at 0.0 kW reflect that no PtG capacity should be installed.

The price and the variable cost per kg of hydrogen are denoted by p_h and w_h , respectively. We model p_h as time-invariant, because buyers and suppliers typically enter into fixed-price contracts. The conversion rate of the electrolyser (in kg kWh⁻¹) is represented by η , the amount of hydrogen that can be procured from 1 kWh of electricity. Thus, the conversion value (in US\$ kWh⁻¹) becomes: $CV_h = \eta(p_h - w_h)$.

The contribution margin of the hybrid energy system can then be expressed as follows: all renewable energy is sold at the market price, and, if the conversion value of hydrogen exceeds the selling price of electricity, the facility earns a conversion premium up to the capacity maximum given by $z(t|k_h) \equiv \min\{CF(t), k_h\}$, with k_h denoting the capacity of peak power conversion (in kW). The conversion premium is given by:

$$CP_h(t) \equiv \max\{CV_h - p_e(t), 0\} \quad (1)$$

Accordingly, the optimized contribution margin of the hybrid energy system in US dollars for hour t is:

$$CM(t|k_h) = p_e(t) CF(t) + CP_h(t) z(t|k_h) \quad (2)$$

To determine when renewable hydrogen production is economically viable, we first consider the average annual contribution margin of renewable energy on its own. The average value of all $p_e(t)CF(t)$ can be expressed as $p_e CF \Gamma$, where p_e denotes the average selling price of electricity per kWh, with the average taken across the 8,760 hours of the year, CF denotes the average capacity factor and Γ represents the co-variation coefficient between intertemporal prices and capacity factors. By construction, $\Gamma = 1$ if either prices or capacity factors are time-invariant and $\Gamma < 1$ if the renewable energy source produces more energy during hours of below-average electricity prices^{19–21}.

On the cost side, we similarly focus on average cost values represented by the leveled cost of electricity (LCOE) and the leveled fixed cost of hydrogen (LFCH) production^{19,22}. As shown in the Methods, both of these are standard unit cost measures per kWh that account for the initial system price, any applicable fixed operating costs, corporate income taxes and the time value of money. Earlier work¹⁹ has shown that renewable energy is cost competitive on its own, that is, an investment in 1 kW of power generation capacity has a positive NPV, if and only if $\Gamma p_e - LCOE > 0$.

Table 1 | Main input variables

	Germany	Texas
PtG system price, SP_h	€2,287 kW ⁻¹	US\$2,009 kW ⁻¹
Conversion rate of PtG, η	0.019 kg kWh ⁻¹	0.019 kg kWh ⁻¹
Wind system price, SP_e	€1,367 kW ⁻¹	US\$1,596 kW ⁻¹
Wind capacity factor, CF	30.27%	34.61%
Electricity price, p_e	€c3.18 kWh ⁻¹	US\$c2.55 kWh ⁻¹
Subsidy: PP or PTC	€c6.16 kWh ⁻¹	US\$c2.30 kWh ⁻¹
Cost of capital (WACC), r	4.00%	6.00%

The expression for the NPV of a hybrid energy system with a renewable energy capacity of $k_e = 1$ kW and a PtG capacity of k_h kW is derived in the Methods and will be denoted by $NPV(1, k_h)$. Renewable hydrogen production will be referred to as economically viable if the NPV of an optimized hybrid energy system is positive and exceeds the value of $NPV(k_e = 1, k_h = 0)$, provided renewable energy is cost competitive on its own. Formally:

$$NPV(1, k_h^*) > \max\{NPV(1, 0), 0\} \quad (3)$$

for some optimally chosen k_h^* . We subsequently refer to the lowest hydrogen price, p_h , for which the inequality in equation (3) can hold as the break-even price for hydrogen. The following two claims delineate conditions for the economic viability of renewable hydrogen production in terms of the average conversion premium, the LFCH and the unit profit margin of renewable energy generation.

Finding 1: if $\Gamma p_e \geq LCOE$, a necessary and sufficient condition for renewable hydrogen production to be economically viable is that $CP_h > LFCH$.

Thus, if the renewable energy source is cost competitive on its own, investment in electrolyser capacity generates additional economic value whenever the average hydrogen conversion premium exceeds the LFCH production. If the renewable energy source is not cost competitive on its own, we obtain the following finding.

Finding 2: if $\Gamma p_e < LCOE$, a necessary condition for renewable hydrogen production to be economically viable is that $CP_h > LFCH + (LCOE - \Gamma p_e)CF$.

We emphasize that the second inequality is merely necessary for the viability of renewable hydrogen in the case $\Gamma p_e < LCOE$.

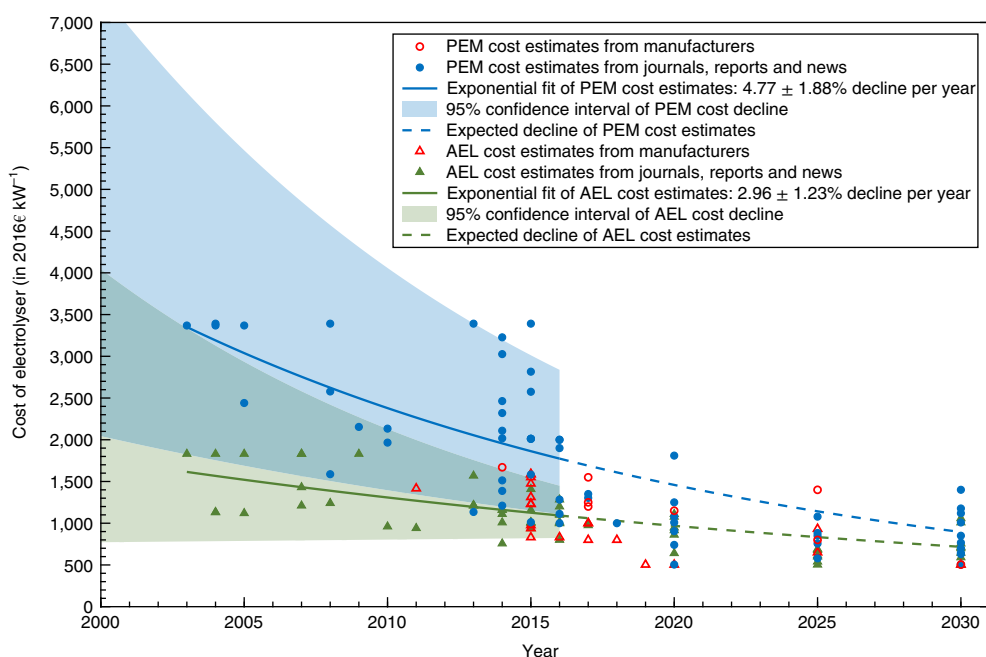


Fig. 2 | Cost of electrolyser technologies for PtG application. Cost data are from multiple sources for alkaline electrolysis (AEL) and PEM electrolysis (see Methods for details).

A condition that is both necessary and sufficient and applies irrespective of whether the renewable energy source is cost competitive on its own is derived in the Methods.

Current economic viability of renewable hydrogen

The preceding model framework is now applied to wind energy in both Germany and Texas. PtG naturally complements wind energy, which tends to reach peak production levels at night when demand from the grid and power prices are relatively low^{23,24}. In Texas, operators of wind turbines are eligible for a production tax credit (PTC), a fixed credit per kWh of produced electricity²⁵. In contrast, Germany offers a Feed-in Premium per kWh²⁶. In its current form, this premium is paid only for renewable electricity fed into the grid and therefore imposes a prohibitively large opportunity cost for onsite conversion of renewable power. In our calculations below, we assume that the current feed-in requirement will be waived and the same premium will be credited as an equivalent production premium (PP). Such a policy change would be supportive of the frequently discussed goal of connecting the different energy segments, such as electricity, heat and transportation. Supplementary Table 5 details the change in the break-even price for hydrogen that would result if the feed-in requirement was maintained in its current form.

The following calculations are based on data inputs from journal articles, industry data, publicly available reports and interviews with industry sources. For the PtG system, we consider a polymer electrolyte membrane (PEM) electrolyser, which can be ramped up rapidly and attain a near-constant efficiency once a small threshold utilization has been reached^{27,28}. Table 1 summarizes the main input variables (see Supplementary Tables 2–4 for further detail).

To assess the economic viability of renewable hydrogen, we first determine the break-even hydrogen price, that is, the lowest p_h at which equation (3) will be met. This break-even value can then be compared to observed transaction prices for hydrogen, keeping in mind that wind energy in combination with PtG can frequently be installed onsite or adjacent to a hydrogen buying site. The transaction prices for hydrogen currently comprise three segments that vary primarily with scale (volume) and purity: large-scale supply

Table 2 | Current economics of renewable hydrogen production

	Germany	Texas
Break-even price for hydrogen	€3.23 kg ⁻¹	US\$3.53 kg ⁻¹
Co-variation coefficient	0.88	0.89
LCOE	€c5.36 kWh ⁻¹	US\$c5.02 kWh ⁻¹
Levelized PP	€c4.73 kWh ⁻¹	US\$c0.00 kWh ⁻¹
Levelized PTC	€c0.00 kWh ⁻¹	US\$c1.99 kWh ⁻¹
Wind energy profit margin	€c0.65 kWh ⁻¹	US\$c-0.27 kWh ⁻¹
Conversion premium	€c2.85 kWh ⁻¹	US\$c4.23 kWh ⁻¹
LFCH	€c2.54 kWh ⁻¹	US\$c2.47 kWh ⁻¹
Optimal PtG capacity	0.01 kW	0.29 kW

in the range €1.5–2.5 kg⁻¹, medium-scale in the range €3.0–4.0 kg⁻¹ and small-scale above €4.0 kg⁻¹ (refs.^{29,30}) (corroborated through interviews with industry experts).

On the basis of recent data inputs, our findings yield break-even prices of €3.23 kg⁻¹ in Germany and US\$3.53 kg⁻¹ in Texas (Table 2, see Supplementary Table 5 for further detail), making renewable hydrogen production cost competitive with small- and medium-scale but not with large-scale fossil hydrogen supply. In Germany, wind energy is cost competitive on its own so that the NPV of the hybrid energy system must only marginally improve on the stand-alone value of wind energy (Finding 1). At the break-even price for hydrogen, the corresponding optimal PtG capacity is small (our calculations proceed in increments of 0.01 kW or 1.0% of the normalized wind capacity). In Texas, wind energy is not competitive with current wholesale prices on its own³¹. Consistent with Finding 2, we therefore find that for a hybrid energy system to be viable, the PtG facility must also compensate for the stand-alone loss of the wind power source. This will happen at a higher break-even price and a correspondingly larger optimal PtG capacity of 0.29 kW.

Our findings explain that PtG is currently applied only in niche applications^{32–34}. In comparison to earlier studies on the economics of hydrogen production, our results are more favourable regarding

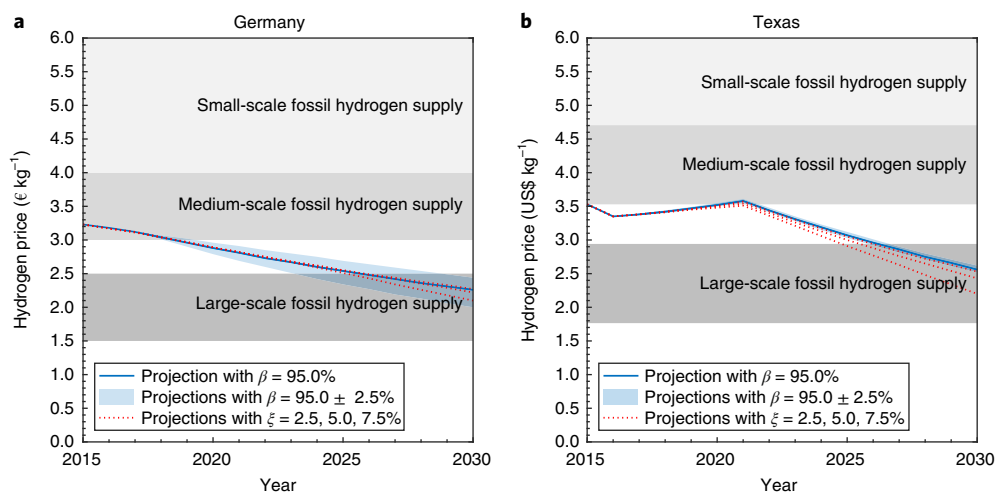


Fig. 3 | Prospects for renewable hydrogen production. a, b, The break-even price of renewable hydrogen for Germany (**a**) and Texas (**b**) relative to the benchmark prices for fossil hydrogen supply.

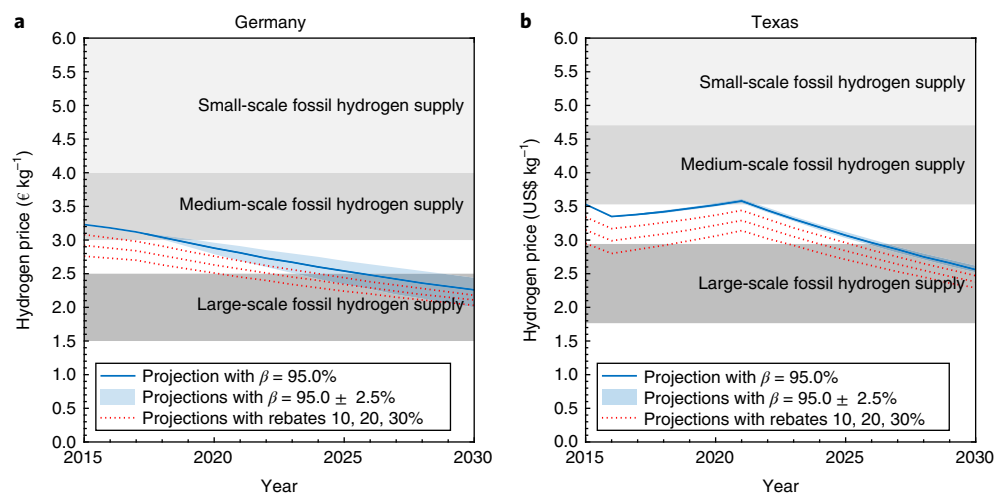


Fig. 4 | Prospects for renewable hydrogen production. a, b, The impact of rebates on the break-even price of renewable hydrogen in Germany (**a**) and Texas (**b**) relative to the benchmark price for fossil hydrogen supply.

the competitive position of hydrogen obtained from renewable energy sources^{16,17,35,36}. The resulting differences reflect that our calculations are based on hybrid energy systems that are optimized both in terms of the relative capacity sizes of the two subsystems (renewable power and PtG) and the real-time operation of the system. Optimality of the relative capacity size is of particular importance for systems where the initial capital expenditure for capacity acquisition is a dominant cost factor^{18,37}. In addition, our calculations reflect the general favourable trend in the operational and cost parameters of both wind energy and PtG.

For alternative hydrogen prices that exceed the break-even value, Fig. 1 shows the optimal size of the PtG facility in relation to a wind facility with a capacity of 1.0 kW (see Supplementary Note 2 for further sensitivities). Consistent with our model framework, each assumed hydrogen price triggers a unique maximizing capacity choice, k_h^* .

Prospects for renewable hydrogen

Recent historical data strongly suggest continued declines in the system price of electrolyzers^{38,39}, the system price of wind turbines¹³

and the wholesale market price of electricity. At the same time, the capacity factor of wind turbines is likely to increase further^{13,40}. Our projections for the system prices of electrolyzers are based on hand-collected data from manufacturers, operators of PtG plants, articles in peer-reviewed journals and technical reports. Covering the years 2003–2016, we ran a univariate regression for a constant elasticity functional form of the type: $SP_h(i) = SP_h(0)\lambda^i$, where i refers to years. For PEM, our data set comprises $N=70$ observations. The regression provides an estimate for the annual price decline of 4.77%, that is, $\lambda = 0.9523$, with a 95% confidence interval of $\pm 1.88\%$ (see Fig. 2 and Methods for further details).

The acquisition price of wind turbines is projected to decline at an annual rate of 4.0%, while the capacity factor is forecast to increase annually at a rate of 0.7%¹³. To project the LCOE of wind energy in future years, we take into consideration that in Texas the PTC is scheduled to be phased-down linearly from its initial value to zero in annual increments of 20.0%²⁵. Regarding the wholesale price of electricity in future years, we assume that wind power will become an effective price trend setter, as suggested by several recent studies^{41–43}. Accordingly, the difference between the LCOE in year

i , $LCOE(i)$, and the adjusted average wholesale price, $\Gamma p_c(i)$, is assumed to decline at a constant adjustment rate such that:

$$LCOE(i) - \Gamma p_c(i) = D(0)\beta^i$$

where $\beta < 1$ denotes the adjustment rate and $D(0) \equiv LCOE(0) - \Gamma p_c(0)$.

Since 2017, Germany has begun to replace the traditional fixed feed-in premium by a variable premium the magnitude of which is determined through a competitive auction mechanism²⁶. Thus, in year i we expect the competitive price premium to emerge as $PP(i) = LCOE(i) - \Gamma p_c(i)$. Regarding the anticipated future wholesale electricity prices, $p_c(i)$, we again make the assumption that over time the levelized cost of wind power will effectively set the average wholesale price such that the price premium goes to zero at a constant rate with $PP(i) = D(0)\beta^i$.

Our assumptions regarding the dynamics of the price of wind turbines, their capacity factors, the price of electrolyzers and wholesale electricity prices yield a trajectory of break-even prices for hydrogen through 2030 (Fig. 3, see Supplementary Tables 6–23 for further details). The central finding is that renewable hydrogen is projected to become cost competitive with large-scale fossil hydrogen supply within the next decade. The solid line assumes an adjustment rate of $\beta = 0.95$, while the shaded areas represent slower and faster adjustment rates in the range of 0.975 and 0.925, respectively. The dotted lines quantify the potential impact of a higher variance in the distribution of electricity prices. Specifically, we allow for the wholesale price of electricity, $p_c(t)$, to increase by an additional $\xi\%$ per year during those hours for which $p_c(t)$ is above the average value p_c . To keep the mean average price for year i unchanged, $p_c(t)$ is reduced by an offsetting percentage during the hours of below-average prices. In the chart for Texas, the ‘hump’ for the break-even price lines in 2020 reflects the anticipated phase-out of the PTC for wind power in the United States.

Policy implications

We recall that our findings for Germany presume a modification of the rule for granting a price premium to renewable energy. By waiving the requirement that renewable energy be fed into the grid to be eligible for the price premium, policymakers would lend critical support to the economic viability of hydrogen produced from renewable sources. Alternative policy tools for accelerating the emergence of renewable hydrogen production include a straight rebate or an investment tax credit for investments in electrolyzers. Such support mechanisms would parallel the efforts by the US federal tax code for solar photovoltaic and battery storage installations, or the California Self-Generation Incentive Program for rebates in connection with battery storage. In the context of our analysis, Fig. 4 quantifies the impact of three alternative levels of rebates granted on the acquisition cost of electrolyzers. For every rebate increment of 10%, the break-even prices for renewable hydrogen are shown to accelerate the competitiveness with large-scale fossil hydrogen supply by about 1.5 years.

As one might expect, greater fluctuations in the distribution of wholesale energy prices and a partial rebate on the acquisition cost of electrolyzers would reinforce each other in accelerating the cost competitiveness of renewable hydrogen. For instance, a 20% rebate combined with a higher variance factor of $\xi = 5.0\%$ would imply that in Texas the break-even price for hydrogen could reach the price level of industrial sale as early as 2023.

Finally, we note that the preceding framework can readily be used to gauge the impact of higher fossil fuel prices or the impact of higher charges placed on carbon emissions. Since industrial hydrogen is currently produced from hydrocarbon fuels, policymakers can quantify the impact of higher costs associated with fossil fuel prices on the competitive position of renewable hydrogen.

Conclusion

While renewable hydrogen has considerable potential to reduce carbon emissions, it has thus far been regarded as too expensive. We have analysed the economic prospects for renewable hydrogen through the lens of a potential corporate investor. The investor is presumed to choose the size of the renewable power source efficiently in relation to the PtG facility, while taking advantage of real-time fluctuations in electricity prices and intermittent renewable power generation. Calibrating the model to the current market environment in Germany and Texas, we find that renewable hydrogen is already cost competitive in niche applications and is projected to become competitive with industrial-scale supply within a decade if recent market trends continue and current policy support mechanisms are maintained.

In future extensions of this line of work, it would be insightful to consider hybrid energy systems such that the PtG facility can also source electricity from the external electricity market. While the hydrogen produced would then no longer be ‘renewable’ due to the carbon emissions associated with grid electricity, such systems would achieve higher capacity utilization and thereby potentially result in substantially lower break-even prices for hydrogen. An alternative extension of our framework could view hydrogen as a form of electricity storage. Since recent electrolyser technologies can operate reversibly, hydrogen conversion and reconversion of intermittent renewable electricity may effectively compete with dispatchable power plants and other storage systems such as batteries.

The analysis in this paper has focused on hydrogen production from renewable electricity via a PtG process, because electrolyzers are already commercially available and entail the immediate potential of creating a buffer for the growing volume of intermittent wind and solar power. We note that there is already substantial research on alternative technologies for hydrogen production that also avoid fossil fuel feedstocks. Applicable examples include thermochemical water splitting and artificial photosynthesis, both of which skip the intermediate electricity production and directly convert solar energy to hydrogen⁴⁴. While these technologies are commercially still at a comparatively early stage, they may improve the economics of renewable hydrogen production due to higher conversion efficiencies.

Methods

Economic model. We first derive the levelized cost expressions for the LCOE and the NPV of a renewable energy source alone. The LCOE aggregates all costs over the lifetime of a power facility to deliver one unit of electricity output¹⁹. Assuming that the variable operating costs of the renewable energy facility are negligible, LCOE can be expressed as:

$$LCOE = f_c + \Delta c_e \quad (4)$$

where the subscript e reflects electricity generation, f denotes the levelized fixed operating cost per kWh, c is the levelized capacity cost of the facility per kWh and Δ is the tax factor covering the impact of income taxes and the depreciation tax shield. To obtain the levelized capacity cost per kWh, the system price per kWh denoted by SP_e is divided by the discounted number of kWh that the facility produces over its useful life:

$$c_e = \frac{SP_e}{CF \times L} \quad (5)$$

where $L \equiv m \sum_{i=1}^T x^{i-1} \gamma^i$ denotes the levelization factor that expresses the total discounted number of hours that the system produces over its lifetime. T represents the economic lifetime of the facility in years, x represents the system degradation factor so that x^{i-1} quantifies the percentage of the initial capacity that is still operating in year i , and γ represents the discount factor based on the cost of capital r with $\gamma = (1+r)^{-1}$. The cost of capital should be interpreted as the weighted average cost of capital (WACC) if the project is financed through both equity and debt⁴⁵. For technical reasons, we assume that $CF(t) > 0$ for all t and that the function $CF(t)$ assumes any value in the interval $[0, 1]$ at most finitely many times. These assumptions appear descriptive for the average capacity factor of wind turbines.

Similarly, the levelized fixed operating cost per kWh is the total discounted fixed costs that occur over the lifetime divided by the levelization and capacity factor:

$$f_e = \frac{\sum_{i=1}^T F_{ei} \gamma^i}{CF \times L} \quad (6)$$

Completing the LCOE, we include corporate taxes and the depreciation tax shield, which result from depreciation charges for tax purposes reducing taxable income. Since we interpret the cost of capital as the WACC, the tax shield associated with debt is already accounted for. Let d_i denote the allowable tax depreciation rate in year i and α denote the effective corporate income tax rate. Since the tax lifetime of renewable energy sources is often shorter than their actual economic lifetime, the tax depreciation rate is zero ($d_i = 0$) for the remaining years. The tax factor is then given by:

$$\Delta = \frac{1 - \alpha \sum_{i=1}^T d_i \gamma^i}{1 - \alpha} \quad (7)$$

On the revenue side, the inherent intermittency of the renewable source and the continuous fluctuations in electricity prices demand to account for covariances between renewable power generation and market prices. Let $\epsilon(t)$ denote the multiplicative deviation of $CF(t)$ from its average value CF and $\mu(t)$ denote the multiplicative deviation of $p_e(t)$ from the average selling price, p_e :

$$\epsilon(t) = \frac{CF(t)}{CF} \quad \text{and} \quad \mu(t) = \frac{p_e(t)}{p_e} \quad (8)$$

By definition:

$$\frac{1}{m} \int_0^m \epsilon(t) dt = \frac{1}{m} \int_0^m \mu(t) dt = 1 \quad (9)$$

The co-variation coefficient then captures the variation between output and price:

$$\Gamma = \frac{1}{m} \int_0^m \epsilon(t) \mu(t) dt \quad (10)$$

The co-variation coefficient is non-negative and zero only if the renewable energy source generates electricity exclusively at times when prices are zero. Clearly, the economics of a renewable energy source improve if it generates more power during peak prices and thus increases the co-variation coefficient.

In terms of after-tax cash flows, the NPV of a renewable energy source on its own can then be stated as:

$$NPV = (1 - \alpha)L(\Gamma p_e - LCOE)CF \quad (11)$$

As stated in the main body of the paper, the US federal government provides a PTC for wind energy, which is a fixed credit per kWh of produced electricity. Since the duration of the PTC is limited to 10 years, and therefore shorter than the lifetime of the wind power plant, we need to levelize the stream of the PTC payments for the first 10 years:

$$ptc = PTC \frac{\sum_{i=1}^{10} x^{i-1} \gamma^i}{(1 - \alpha) \sum_{i=1}^T x^{i-1} \gamma^i} \quad (12)$$

For Texas, the PTC-adjusted NPV of a wind power facility can therefore be expressed as: $(1 - \alpha)L(\Gamma p_e - LCOE + ptc)CF$.

In Germany, wind energy is eligible for a PP, which is accounted for as additional revenue and is therefore subject to taxation. Since the duration of the PP is limited to 20 years, and therefore shorter than the lifetime of the wind power plant, we levelize the stream of the PP payments for the first 20 years:

$$pp = \frac{\sum_{i=1}^{20} PP x^{i-1} \gamma^i}{\sum_{i=1}^T x^{i-1} \gamma^i} \quad (13)$$

For Germany, the PP-adjusted NPV of a wind power facility can therefore be expressed as: $(1 - \alpha)L(\Gamma p_e - LCOE + pp)CF$.

For the hydrogen subsystem, we construct the LFCH as the life-cycle capacity and fixed operating costs per kWh of electricity absorption of a PtG plant²². With subscript h for hydrogen, the LFCH is given by:

$$LFCH = f_h + \Delta c_h \quad (14)$$

We recall that the capacity factor of the PtG plant equals one. The levelized cost elements then are the capacity cost per kW and fixed operating cost per kW divided by the lifetime aggregate output of the PtG plant:

$$c_h = \frac{SP_h}{L}, \quad f_h = \frac{\sum_{i=1}^T F_{hi} \gamma^i}{L} \quad (15)$$

On the revenue side, we denote by $\delta(t)$ the deviation of the hourly conversion premium from the mean value so that $CP_h \times \delta(t) \equiv CP_h(t)$ and the mean of $\delta(\cdot)$ equals one. The average contribution margin of a hybrid energy system with capacities ($k_e = 1, k_h$) then becomes:

$$CM(k_h) \equiv \frac{1}{m} \int_0^m CM(tk_h) dt \equiv \Gamma p_e CF + CP_h z(k_h) \quad (16)$$

where

$$z(k_h) \equiv \frac{1}{m} \int_0^m z(tk_h) \delta(t) dt$$

The function $z(\cdot)$ is increasing and concave such that $z(k_h) \leq k_h$ and $z'(0) = 1$. To see that, note that the partial derivative of $z(1, k_h)$ with respect to k_h is given by:

$$\frac{\partial}{\partial k_h} z(1, k_h) = \frac{1}{m} \int_{t|k_h \leq CF(t)} \delta(t) dt \quad (17)$$

Clearly, $\frac{\partial}{\partial k_h} z(1, k_h)$ is decreasing in k_h with $\lim_{k_h \rightarrow 0} \frac{\partial}{\partial k_h} z(1, k_h) = 1$ and $\lim_{k_h \rightarrow 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$.

Consequently, $NPV(1, \cdot)$ is a single-peaked function of k_h (see Fig. 1).

The overall NPV of a hybrid energy system can be expressed as:

$$NPV(1, k_h) = (1 - \alpha)L[CM(k_h) - LCOE \times CF - LFCH k_h] \quad (18)$$

Given $k_e = 1.0$ kW, the optimal k_h^* is the maximizer of $CP_h \times z(k_h) - LFCH \times k_h$. The properties of $z(\cdot)$ imply that $0 \leq k_h^* \leq 1$.

In summary, renewable hydrogen production is economically viable if and only if:

$$(\Gamma p_e - LCOE)CF + CP_h \times z(k_h^*) - LFCH \times k_h^* \geq \max\{(\Gamma p_e - LCOE)CF, 0\} \quad (19)$$

The inequality in equation (19) combined with the properties of $z(\cdot)$ yield the necessary and sufficient conditions identified in Findings 1 and 2, depending on whether renewable energy is cost competitive on its own. See Supplementary Note 1 for proofs.

Cost review of electrolyser technologies. We gathered cost estimates from manufacturers, operators of PtG plants, scientific articles in peer-reviewed journals and frequently cited grey literature including reports by agencies, consultancies and industry analysts. Cost estimates from industry were collected in individual interviews with 16 of 28 contacted companies. Scientific articles were found by searching the databases Web of Science, Scopus, Sciencedirect and Google Scholar using the keyword 'power-to-gas cost', and the grey literature by searching the web with Google's search engine using the same keyword. The keyword 'electrolyser cost' was discarded because it yielded cost estimates for individual electrolyser stacks rather than full PtG systems. For both searches, we reviewed the top 100 search entries. The cost review and the entire data set is documented in an Excel file available as part of the Supplementary Data.

We searched and interviewed for cost estimates for electrolyser systems, in contrast to individual cells or entire PtG plants. The three main electrolyser technologies we focused on were: alkaline electrolysis (AEL), PEM electrolysis and solid-oxide electrolyser cells (SOECs). With the literature review, we retrieved 146 sources, which we filtered by the method used in the article for achieving the cost estimates. We excluded sources without clear cost data (41) and sources referencing other articles (36). These latter references were traced back to the original source and if the original was new, it was added to the pool. We also excluded sources without clear references or method (14). As a result, we were left with 55 original data sources from industry or an original review of multiple sources. The literature provides 131 unique data points: 59 for AEL, 62 for PEM and 10 for SOECs. The interviews of manufacturers and operators yielded 35 data points: 21 for AEL, 8 for PEM and 6 for SOECs. This sums to 166 data points: 80 for AEL, 70 for PEM and 16 for SOECs. The few data points for SOECs correspond to the novelty of the technology so that we excluded it from further analysis.

For all observations, we converted cost ranges (if given) to the arithmetic mean of the highest and the lowest points in the range. Cost estimates in currencies other than euro were converted using the average exchange rate of the respective year from the European Central Bank. Historic cost estimates were adjusted for inflation using the harmonized index of consumer prices of the eurozone as

provided by the European Central Bank (see the sheet 'Adjustment Factors' of the Excel file in the Supplementary Data). Finally, all data points were winsorized at the 5% level.

We estimate the annual cost decline with an exponential regression of system prices from 2003 to 2016 in the form of $SP_i(i) = SP_i(0)\lambda^i$, where i denotes the year. We base the cost declines on time rather than cumulative industry output due to scarce data on the latter. The regression for PEM is based on $N=70$ unique estimates and yields an average cost decline of $\lambda=4.77\%$ with a 95% confidence interval of $\pm 1.88\%$ and an adjusted $R^2=0.34$. The regression for AEL is based on $N=80$ unique estimates and yields an average cost decline of $\lambda=2.96\%$ with a 95% confidence interval of $\pm 1.23\%$ and an adjusted $R^2=0.24$. Linear models give similar adjusted R^2 values, but an exponential relationship especially for PEM is to be expected.

Data availability

The data used in this study are referenced in the main body of the paper and the Supplementary Information. Data that generated the plots in the paper are provided in the Supplementary Information. Additional data and information are available from the corresponding author upon reasonable request.

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Author contributions

The authors jointly developed the research question, the model framework and the analytical findings. G.G. led the literature review, the data collection and the calculations. Both authors contributed substantially to the writing of the paper.

Competing interests

The authors declare no competing interests.

Additional information

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