The Prospects for Renewable Hydrogen Production

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Abstract

Hydrogen has long been heralded as a potentially critical element in the transition to a low carbon economy. The recent sharp cost declines for renewable energy raise the question whether an economic case can be made to produce hydrogen from renewable power sources through a Power-to-Gas process. We analyze this question from an investor perspective when a renewable power plant is combined with a suitably sized Power-to-Gas facility. Essential to the analysis is that the available capacity can be put to optimal use in real time as electricity prices and intermittent renewable power fluctuate. Calibrating our model to the current environment in both Texas and Germany, we find that renewable hydrogen is already cost competitive in niche applications but not yet for industrial scale supply. This conclusion, however, is projected to change within a decade provided recent market trends continue in the coming years.

Keywords: hydrogen, renewable energy, power-to-gas, energy storage

1 Introduction

The recent precipitous decline in the cost of wind and solar photovoltaic power creates new opportunities to also replace fossil fuels in the production of energy storing products, like hydrogen[1]. The production of hydrogen from renewable power has considerable potential to reduce carbon emissions as hydrogen is effectively a platform for a range of applications including fuel for transportation[2–4], feedstock in chemical and processing industries[5], or energy storage for power generation[6–8].

Power-to-Gas (PtG) processes encompass water electrolysis whereby (renewable) electricity infused in water instantly splits the water molecule into oxygen and hydrogen[9;10]. Our analysis examines the economic case for combining an investment in renewable power generation with a PtG facility that would then sell hydrogen in the market place. The PtG facility should be sized optimally in relation to the capacity available for power generation. 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.

We refer to renewable hydrogen production as *economically viable* if an investment in an optimally chosen combination of renewable energy and PtG capacity has a positive net present value (NPV) and furthermore this value exceeds the NPV of the renewable energy facility on its own. Our model yields necessary and sufficient conditions for the viability of such a hybrid energy system. These conditions are stated compactly in terms of the average per unit capacity costs and the average price premium for converting electricity to hydrogen, including an adjustment factor that reflects 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 in Germany and 3.54 $/kg in Texas. In the current environment, these prices are compatible with small- and medium-scale hydrogen supply but not with large-scale industrial sales. Thus our findings are consistent with PtG currently being applied only in test or niche applications[11]. 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.

Our results also quantify how this convergence process could be accelerated through policy support mechanisms such as rebates or investment tax credits.

2 Economic Model

Consider a hybrid energy system combining a renewable energy source with a PtG facility (including the electrolyzer, 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 electrolyzer for conversion to hydrogen. With an eye on reducing carbon emissions, we focus on electricity obtained from a *renewable* power source.

Let $p_e(t) \geq 0$ denote the price per kilowatt hour (kWh) at which renewable energy can be sold at time t. In our continuous time formulation t ranges between 0 and $m = 8,760$ hours. Without loss of generality, we normalize the capacity of the renewable energy facility denoted to 1 kW. The inherent intermittency of the renewable power source implies that the capacity factor, $CF(t)$, is exogenous and varies with time, such that generally $CF(t) < 1$. The variable operating costs of renewable energy production are considered 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 electrolyzer. Let p_h and w_h, respectively, denote the price and the variable cost per kg of hydrogen. We model p_h as time-invariant because buyers and suppliers typically enter into fixed-price contracts. The conversion rate of the electrolyzer (in kg/kWh) is represented by η, the amount of hydrogen that can be procured from 1 kWh of electricity. Thus the conversion value (in \$/kWh) becomes: $CV_h = \eta \cdot (p_h - w_h)$.

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:

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

Accordingly, the optimized contribution margin of the hybrid energy system in \$ for hour t

is:

$$CM(t|k_h) = p_e(t) \cdot CF(t) + CP_h(t) \cdot z(t|k_h). \tag{2}$$

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 $p_e(t) \cdot CF(t)$ can be expressed as $p_e \cdot CF \cdot \Gamma$, 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 above-average electricity prices[12].

On the cost side, we similarly focus on average cost values represented by the Levelized Cost of Electricity (LCOE) and the Levelized Fixed Cost of Hydrogen (LCFH) production[12;13]. As shown in *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 work has shown that renewable energy is cost competitive on its own, that is, an investment in one kW of power generation capacity has a positive net-present value, if and only if $\Gamma \cdot p_e - LCOE > 0$.[12]

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 *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:

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

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

Finding 1: *If $\Gamma \cdot p_e \geq LCOE$, 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, it is optimal to invest in electrolyzer capacity whenever the average hydrogen conversion premium exceeds the levelized fixed cost of hydrogen production.

Finding 2: *If $\Gamma \cdot p_e < LCOE$, a necessary condition for renewable hydrogen production to be economically viable is that:*

$$CP_h > LFCH + (LCOE - \Gamma \cdot p_e) \cdot CF. \tag{4}$$

We emphasize that the condition in (4) is only necessary for the viability of renewable hydrogen in case $\Gamma \cdot p_e < LCOE$. In *Methods*, we derive a necessary and sufficient condition that applies irrespective of whether the renewable energy source is cost competitive on its own.

3 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[14;15]. In Texas, operators of wind turbines are eligible for a Production Tax Credit (PTC), a fixed credit per kWh of produced electricity[16]. In contrast, Germany offers a Feed-in Premium per kWh[17]. Since this premium is paid only for renewable electricity fed into the grid, such a support system imposes a prohibitively large opportunity cost on the conversion of renewable power to hydrogen. We thus propose (and subsequently assume) that the current feed-in requirement will be waived and the premium be credited as an equivalent Production Premium (PP).

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 assume a Polymer Electrolyte Membrane (PEM) electrolyzer, which can operate most flexibly[14]. Table 1 summarizes the main input variables; see the *Online Appendix* 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 (3) will be met. This break-even value can then be compared to observed transaction prices for hydrogen, keeping in mind that wind

Table 1: Main input variables.

	Germany	**Texas**
PtG system price, SP_h	2,287 €/kW	2,009 $/kW
Conversion rate of PtG, η	0.19 kg/kWh	0.19 kg/kWh
Wind system price, SP_e	1,367 €/kW	1,596 $/kW
Wind capacity factor, CF	30.27 %	34.61 %
Electricity price, p_e	3.18 €ct/kWh	2.55 $ct/kWh
Subsidy: PP or PTC	6.16 €ct/kWh	2.30 $ct/kWh
Cost of capital (WACC), r	4.00 %	6.00 %

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 between 1.5–2.5 €/kg, medium-scale between 3.0–4.0 €/kg, and small-scale above 4.0 €/kg.

Based on recent data inputs, our findings yield break-even prices of 3.23 €/kg in Germany and 3.53 $/kg in Texas (Table 2) 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 upon 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 cost competitive on its own. Consistent with Finding 2, we therefore find that in order 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.

Table 2: Current economics of renewable hydrogen production.

	Germany	**Texas**
Break-even price of hydrogen	3.23 €/kg	3.53 $/kg
Co-variation coefficient	0.88	0.89
Levelized cost of electricity	5.36 €ct/kWh	3.02 $ct/kWh
Wind energy profit margin	0.63 €ct/kWh	-0.27 $/kWh
Conversion premium	2.85 €ct/kWh	4.23 $/kWh
Levelized fixed cost of hydrogen	2.54 €ct/kWh	2.47 $/kWh
Optimal PtG capacity	0.01 kW	0.29 kW

In comparison to earlier studies, we obtain lower break-even prices in large part because our calculations are based on PtG facilities that are sized optimally[9;18;19]. For alternative hydrogen prices that exceed the break-even value, Figure 1 shows the optimal size of the PtG facility in relation to a wind facility with a capacity of 1.0 kW. Consistent with our model framework, each assumed hydrogen price triggers a unique maximizing capacity choice, k_h^*.

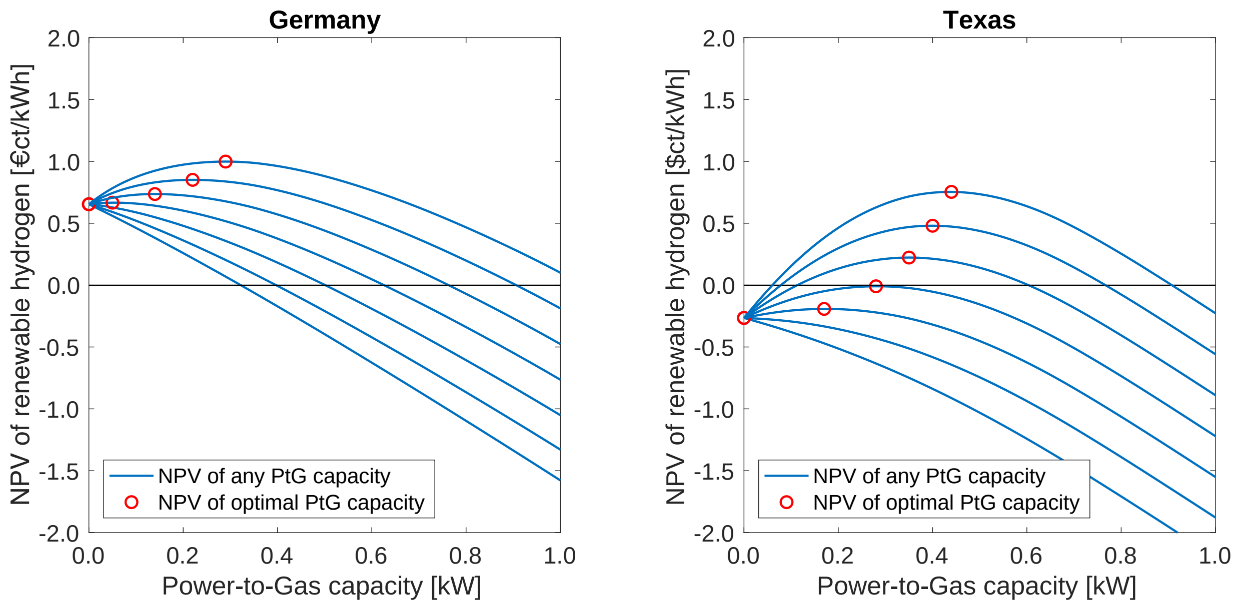

Figure 1: **Optimal Power-to-Gas capacity size and corresponding hourly profit margin.** Given a normalized wind energy capacity of 1.0 kW, the figure shows the optimized PtG capacity for alternative hydrogen prices ranging from 2.0 to 5.0 €/$ per kg (blue lines). The red circles mark the optimal PtG capacity size for alternative hydrogen price. Circles at 0.0 kW reflect that no PtG capacity should be installed.

4 Prospects for Renewable Hydrogen

Recent historical data strongly suggest continued declines in the following variables: (i) the system price of electrolyzers, (ii) the system price of wind turbines, and (iii) the wholesale market price of electricity. At the same time, the capacity factor of wind turbines is likely to increase further[20;21]. 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: $SP_h(i) = SP_h(0) \cdot \lambda^i$, 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, $\lambda = 0.9511$, with a 95% confidence interval of $\pm 1.88\%$; see Figure 2 and *Methods* for further details.

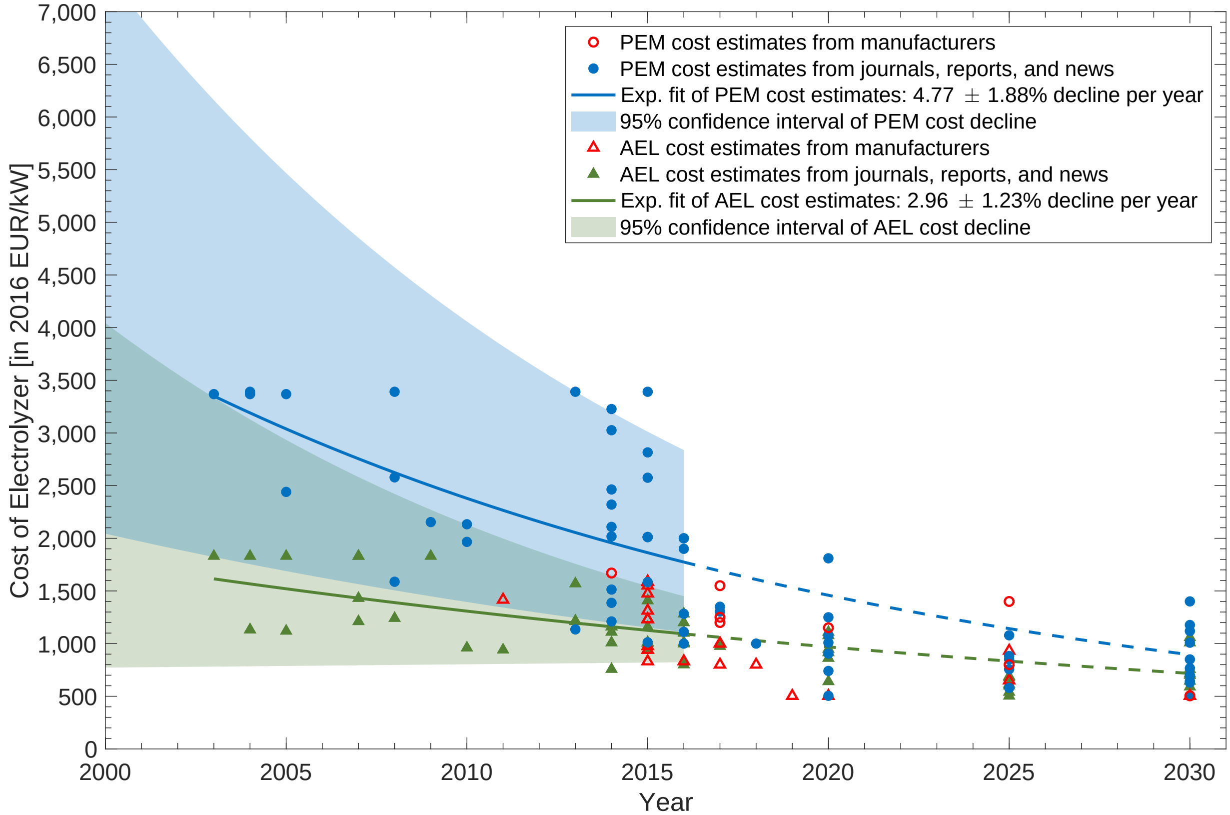

Figure 2: **Cost of electrolyzer technologies for Power-to-Gas application.** Data are from multiple sources for Alkaline Elecrolysis (AEL) and Polymer Electrolyte Membrane (PEM) electrolysis.

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%[1]. 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%[16]. Regarding the wholesale price of electricity in future years, we assume that wind power will be an effective trend setter, as suggested by several recent studies[22–24]. Accordingly, the difference between the LCOE in year i, $LCOE(i)$, and the adjusted average wholesale price, $\Gamma \cdot p_e(i)$, is assumed to decline at a constant adjustment rate such that:

$$LCOE(i) - \Gamma \cdot p_e(i) = D(0) \cdot \beta^i,$$

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

Beginning in 2017, Germany will replace the traditional fixed feed-in premium by a variable premium the magnitude of which is determined through a competitive auction mechanism[17]. Thus in year i we expect the competitive price premium to emerge as $PP(i) = LCOE(i) - \Gamma \cdot p_e(i)$. Regarding the anticipated future wholesale electricity prices, $p_e(i)$, we again make the assumption that over time the levelized cost of wind power will effectively determine the average wholesale price such that the price premium goes to zero at a constant rate with $PP(i) = D(0) \cdot \beta^i$.

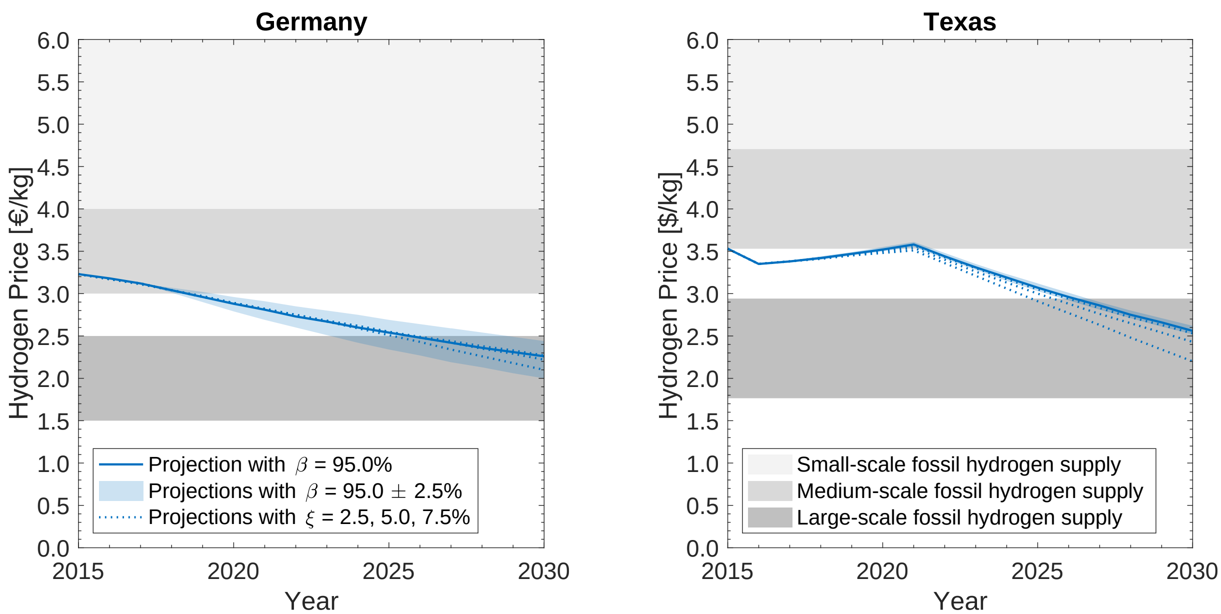

Figure 3: **Prospects for renewable hydrogen production.** The break-even price of renewable hydrogen for Germany and Texas relative to the benchmark prices for conventional hydrogen supply.

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 (Figure 3). 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, $p_e(t)$, to increase by an additional $\xi\%$ per year during those hours for which $p_e(t)$ is above the average value p_e. To keep the mean average price for year i unchanged, $p_e(t)$ is reduced by an offsetting percentage during the hours of below-average prices. In the chart for Texas, the "hump" for all four break-even price lines in 2020 reflects the anticipated phase-out of the production tax credit for wind power in the U.S.

5 Policy Implications

Recall that our findings for Germany are based on a policy change that would waive the current feed-in requirement for renewable energy and replace the feed-in premium by an equivalent production premium. In terms of other policy implications, we note that higher prices on carbon emissions would support the competitive position of renewable hydrogen to the extent that hydrogen is currently produced from hydrocarbon fuels. This would, however, demand a relatively minor impact on electricity prices, possibly buffered by a high share of renewable energy generation.

Policy makers could also accelerate the emergence of renewable hydrogen production by a straight rebate or an investment tax credit (ITC) for the investment in electrolyzers. Such support mechanisms would parallel the efforts by the U.S. federal tax code for solar photovoltaic and battery storage installations, or the California SGIP program for rebates in connection with battery storage systems. In the context of our analysis, Figure 4 quantifies the impact of three rebate levels on the system price of electrolyzers. We find that for every rebate increment of 10% the break-even prices for renewable hydrogen 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.

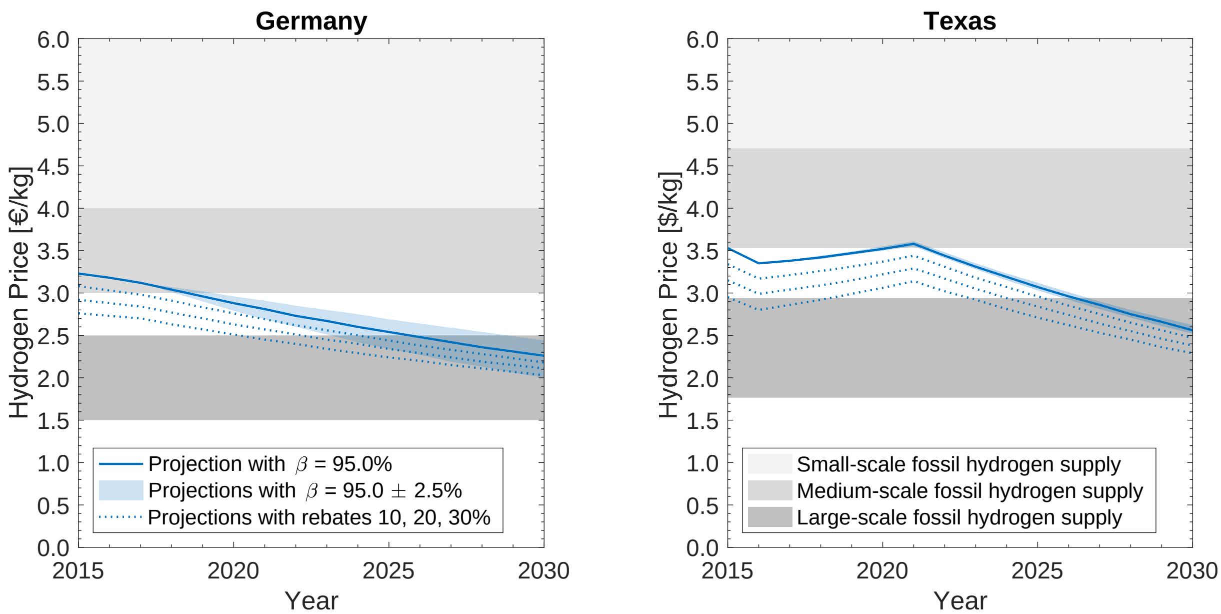

Figure 4: **Prospects for renewable hydrogen production.** The impact of rebates on the break-even price of renewable hydrogen in Germany and Texas

6 Methods

Economic Model

We first derive the levelized cost expressions for $LCOE$ and $LFCH$. The levelized cost of electricity (LCOE) aggregates all costs over the lifetime of a power facility to deliver one unit of electricity output[12]. If the variable operating costs of the renewable energy facility are negligible, the $LCOE$ can be expressed as:

$$LCOE = f_e + \Delta \cdot c_e, \tag{5}$$

where the subscript e reflects electricity generation, f denotes the levelized fixed operating cost per kWh, c the levelized capacity cost of the facility per kWh, and Δ 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 kW denoted by SP_e is divided by the discounted number of kWh that the facility produces over its useful life:

$$c_e = \frac{SP_e}{CF \cdot L}, \tag{6}$$

where $L \equiv m \cdot \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i$ 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 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 the discount factor based on the cost of capital r with $\gamma = \frac{1}{(1+r)}$. The cost of capital should be interpreted as the weighted average cost of capital (WACC) if the project is financed through both equity and debt[25]. 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 incur over the lifetime divided by the levelization and capacity factor:

$$f_e = \frac{\sum_{i=1}^{T} F_{ei} \cdot \gamma^i}{CF \cdot L}. \tag{7}$$

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 weighted average cost of capital, the tax shield associated with debt is already accounted for. Let d_i be the allowable tax depreciation rate in year i and α 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:

$$\Delta = \frac{1 - \alpha \cdot \sum_{i=1}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{8}$$

For the hydrogen subsystem, we construct the levelized fixed cost of hydrogen (LFCH) as the life-cycle capacity and fixed operating costs per kWh of electricity absorption of a PtG plant[13]. With subscript h for hydrogen, the LFCH is given by:

$$LFCH = f_h + \Delta \cdot c_h. \tag{9}$$

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:

$$c_h = \frac{SP_h}{L}, \qquad\qquad f_h = \frac{\sum_{i=1}^{T} F_{hi} \cdot \gamma^i}{L}. \tag{10}$$

On the revenue side, we denote by $\delta(t)$ the deviation of the hourly conversion premium from the mean value so that $CP_h \cdot \delta(t) \equiv CP_h(t)$ 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:

$$CM(k_h) \equiv \frac{1}{m} \int_0^m CM(t|k_h)\, dt \equiv \Gamma \cdot p_e \cdot CF + CP_h \cdot z(k_h), \tag{11}$$

where

$$z(k_h) \equiv \frac{1}{m} \int_0^m z(t|k_h) \cdot \delta(t)\, dt.$$

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:

$$\frac{\partial}{\partial k_h} z(1, k_h) = \frac{1}{m} \int_{\{t|k_h \leq CF(t)\}} \delta(t) dt. \tag{12}$$

Clearly, $\frac{\partial}{\partial k_h} z(1, k_h)$ is decreasing in k_h with $\lim_{k_h \to 0} \frac{\partial}{\partial k_h} z(1, k_h) = 1$ and $\lim_{k_h \to 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$. Consequently, $NPV(1, \cdot)$ is a single-peaked function of k_h (see Figure 1).

The overall net-present value of a hybrid energy system can be expressed as:

$$NPV(1, k_h) = (1 - \alpha) \cdot L \cdot \left[CM(k_h) - LCOE \cdot CF - LFCH \cdot k_h\right]. \tag{13}$$

We note in passing that $NPV(k_e = 1, k_h = 0) = (1 - \alpha) \cdot L \cdot CF \cdot [\Gamma \cdot p_e - LCOE]$. Given $k_e = 1.0$ kW, the optimal k_h^* is the maximizer of $CP_h \cdot z(k_h) - LFCH \cdot k_h$. 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:

$$(\Gamma \cdot p_e - LCOE) \cdot CF + CP_h \cdot z(k_h^*) - LFCH \cdot k_h^* \geq \max\{(\Gamma \cdot p_e - LCOE) \cdot CF, 0\}. \tag{14}$$

The inequality in (14) combined with the properties of $z(\cdot)$ yield the necessary and sufficient conditions identified in Findings 1 and 2, depending on whether renewable is cost competitive on its own. See the *Online Appendix* for proofs.

Cost Review of Electrolyzer 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 data bases 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. For both searches, we reviewed the top 100 search entries. The cost review is documented in an Excel file available in the online version of the paper.

We searched and interviewed for cost estimates for electrolyzer systems, in contrast to invidiual cells or entire PtG plants. The three main electrolyzer technologies we focused on were: alkaline electrolysis (AEL), polymer electrolyte membrane electrolysis (PEM), and solid oxide elextrolyzer cells (SOEC). 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 sources with original data 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 SOEC. The interviews of manufacturers and operators yielded 35 data points: 21 for AEL, 8 for PEM, and 6 for SOEC. This sums to 166 data points: 80 for AEL, 70 for PEM, and 16 for SOEC. The few data points for SOEC correspond to the novelty of the technology so that we excluded it from further analysis.

For all data points, we converted cost ranges (if given) with the arithmetic mean of the highest and the lowest points in the range. Cost estimates in other currencies 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 HCPI of the Euro Zone as provided by the European Central Bank (see the sheet "Adjustment Factors" of the Excel file). Finally, all data points were winsorized with an $\alpha = 5.0\%$.

We estimate the annual cost decline with an exponential regression of system prices from 2003 to 2016 in the form of $SP_h(i) = SP_h(0) \cdot \lambda^i$, 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 *adj.* $R^2 = 0.34$. 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 *adj.* $R^2 = 0.24$. Linear models give similar *adj.* R^2 values, but an exponential relationship especially for PEM is to be expected. The declining uncertainty was quantified with an affine regression of the falling standard deviation from 2003 to 2016.

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8 Author contributions

Both authors contributed equally.

9 Additional information

Supplementary information is available in the online version of the paper **(Link when published)**. Reprints and permission information is available online at **(Link when published)**. Correspondence and requests for materials should be addressed to G.G.

10 Competing interests

The authors declare no competing financial interests.