How flexible electricity demand stabilizes wind and solar market values: the case of hydrogen electrolyzers

This version: April 2021 – Previous version: December 2020 (link)

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Abstract. Wind and solar energy are often expected to fall victim to their own success: the higher their share in electricity production, the more their revenue on electricity markets (their "market value") declines. While in conventional power systems, the market value may converge to zero, this study demonstrates that "green" hydrogen production, through adding electricity demand in low-price hours, can effectively and permanently halt the decline. With an analytical derivation, a Monte Carlo simulation, and a numerical electricity market model, I find that – due to flexible hydrogen production alone – market values across Europe likely converge above €19 ± 9 MWh^{-1} for solar energy and above €27 ± 8 MWh^{-1} for wind energy in 2050 (annual mean estimate ± standard deviation). This lower boundary is in the range of the projected levelized costs of renewables and has profound implications. Market-based renewables may hence be within reach.

Keywords. Renewable energy, hydrogen electrolysis, electricity market, electricity economics, integrated energy system, flexible electricity demand.

1 Introduction

Wind and solar energy play a key role in mitigating climate change [1]. The share of these renewable energy sources in power generation has been increasing rapidly, a development sparked by policy support and amplified by cost reductions due to economies of scale and technological learning. Renewable energy sources can currently produce electricity at a levelized cost comparable to that of conventional technologies [2,3].

Nevertheless, the full market integration of wind and solar energy may be challenging because of two distinct characteristics of these energy sources: their time-varying availability and their (near-)zero marginal cost. Hence, when they are available, their additional low-cost supply depresses electricity prices, leading to below-average market revenues [4–12]. This "self-cannibalization" effect is substantial. At an assumed 30% market share, the market value of wind energy is estimated to decline by 20-50% [6]; the value of solar energy may decline even more [10]. As a result, it has often been thought that renewable investors cannot recover their costs on the market alone and that renewable support schemes will need to continue indefinitely [6,13–17].

Meanwhile, using renewable electricity in electrolyzers to produce hydrogen without the emission of carbon has recently become increasingly popular [18,19], and the investment cost of electrolyzers is expected to decrease [20–23]. Not only could electrolytic hydrogen substitute fossil fuels in non-electric applications [24], but also could a flexible operation of electrolyzers help the market integration of variable renewables by absorbing wind and solar energy when and where it is abundant [25,26]. Previous studies have investigated the competitiveness of green hydrogen versus hydrogen produced from fossil fuels [20–22,27,28], but electrolyzers have not yet been the focus of the literature on mitigating the decline in the value of renewable energy [29–36].

In this study, I argue that flexible hydrogen production can effectively and permanently halt the decline in the market value of renewables. This is because low wholesale electricity prices caused by renewables trigger merchant investment in electrolyzers, which produce hydrogen whenever electricity prices are low, and because the electrolyzers' additional electricity demand in turn stabilizes market prices and with them the value of renewables. Exploiting this mechanism, I derive an analytical formula for the minimum market value of renewables, I quantify this minimum market value for a wide range of parameters in a Monte Carlo analysis, and I validate the results with a numerical electricity market model. The results indicate that in 2050 electrolyzers will stabilize the value of solar energy above €19 ± 9 MWh^{-1} and the market value of wind energy above €27 ± 8 MWh^{-1}. This finding is shown to be substantial when compared to other options for mitigating the renewable value decline and when compared to recent estimates for the future costs of renewables. The variance in the estimates reflects uncertainty regarding the future hydrogen price and the future investment cost of hydrogen electrolyzers. I conclude that flexible electrolyzers are promising solutions for the integration of variable renewables, which should be considered when analyzing and regulating future electricity systems.

More generally, this study contributes to the literature on how flexible electricity demand can help integrating variable renewable energy supply. In this context, hydrogen electrolysis has two distinct characteristics. First, hydrogen can be stored in large quantities at low costs, which implies that the dispatch of electrolyzers can almost perfectly respond to electricity prices. By contrast, individual electric heat pumps and electric vehicles must follow specific, volatile demand profiles, and previous studies find that the entailed flexibility has limited implications for renewable market values [35,36]. Second, hydrogen can be used in many sectors and transported to different locations at relatively low costs, which implies that the investment in electrolyzers can also respond to electricity prices. By contrast, the investment in electric district heating is limited to the local heat demand, even though its dispatch can be very flexible and hence supportive to renewable market values [36]. These distinct characteristics motivate this study's focus on electrolytic hydrogen. Further research may build on this contribution to jointly analyze various types of flexible electricity demand. From the perspective of variable renewables, this may stabilize market values at even higher levels.

The remainder of this article is structured as follows. Section 2 develops an analytical framework for optimized dispatch of and investment in electrolyzers, based on which a formula for the minimum market value of renewables is derived. Section 3 describes the two methods used to quantify and validate this minimum market value: Monte Carlo simulations and an electricity market model. Section 4 presents the results of both methods. Section 6 draws conclusions.

2 Analytical framework

This section introduces an analytical framework for market-based dispatch of and investment in electrolyzers. On this basis, a formula for the minimum market value of renewables is derived.

2.1 Optimized dispatch of and investment in electrolyzers

Standard frameworks in electricity economics, which have been used to study the market effect of variable renewables, traditionally take the electricity demand as given [37,38]. This subsection further develops two of these frameworks, the merit order model and the price duration curve, to include demand-side dispatch and investment decisions for electrolyzers.

The merit order model holds that power generators are dispatched in the order of their marginal cost[1]. Time-varying electricity prices emerge at the intersection of the resulting upward-sloping supply curve and the traditionally price-inelastic, vertical demand curve. In this model, renewables producing at zero marginal cost shift the supply curve outwards and hence depress prices – possibly even to zero [37] (Fig. 1a). Note that this article abstracts from negative prices induced by renewable support schemes [39].

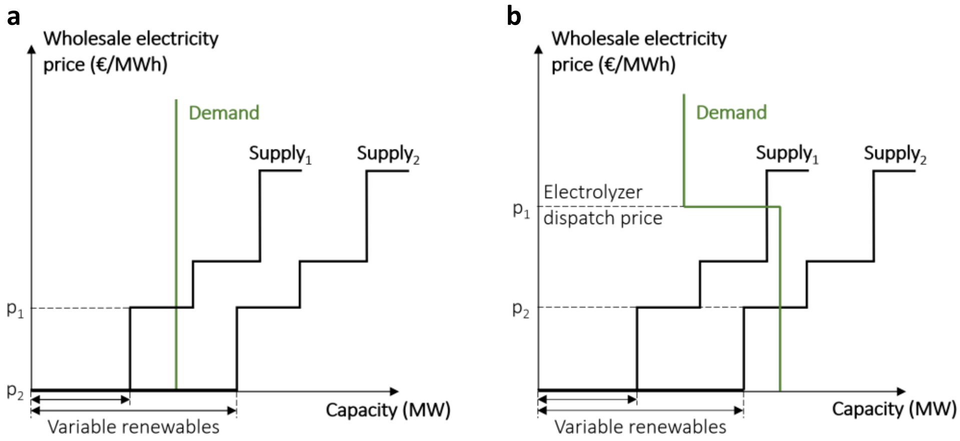

Figure 1: Merit order model with renewables and electrolyzers. Electricity prices p_1 and p_2 at two different times with varying supply from renewable sources. (a) Without electrolyzers, the demand curve is vertical and electricity prices are relatively low (p_1) or even zero (p_2). (b) With electrolyzers, their additional demand can increase (p_2) or even set (p_1) electricity prices.

Electrolyzers start operating when electricity prices fall below their willingness to pay. This threshold, hereafter referred to as the electrolyzer dispatch price, $P_{dispatch}$, depends on the hydrogen price, P_{H2}, the variable operational cost of electrolyzers, $C_{OPEX,var}$, the supplement that electrolyzers pay on top of the wholesale electricity price such as taxes or grid fees, C_{sup}, and on the electrolyzers' conversion efficiency, η:

$$P_{dispatch} = \left(P_{H2} - C_{OPEX,var}\right) \cdot \eta - C_{sup} \tag{1}$$

Including hydrogen electrolyzers in the merit order model yields higher demand below the dispatch price, which can increase or even set electricity prices (Fig. 1b). Note that this calculation assumes a

[1] Note that the merit order model abstracts from inter-temporal dependencies in real-world dispatch decisions and electricity prices, due to ramping costs and storage utilization. Nevertheless, the model explains the essential impact of variable renewables on electricity prices.

time-invariant hydrogen price, justified by the low cost of hydrogen storage relative to electricity storage. This assumption will be relaxed later.

The price duration curve allows analyzing investment decisions. It displays all electricity prices over one year in descending order. The price-depressing effect of renewables results in a downward-shifted price duration curve with a steeper slope (Fig. 2a).

Merchant investment in electrolyzers will be made if their profit margin covers their fixed cost. The annual margin of electrolyzers is the difference between their dispatch price and the price duration curve. The annualized fixed cost of electrolyzers can be calculated as

$$AFC = \frac{i}{1-(1+i)^{-T}} \cdot C_{CAPEX} + C_{OPEX,fix}, \quad (2)$$

where C_{CAPEX} is the electrolyzers' investment cost, $C_{OPEX,fix}$ is their fixed operational cost, T is the systems' lifetime, and i is the interest rate.

Including hydrogen electrolyzers in the price duration curve limits its downward shift caused by renewables. If electricity prices fall so low that the annual margin of electrolyzers exceeds their annualized fixed cost, new electrolyzers will be installed, whose electricity demand stabilizes market prices. In the long term, an equilibrium arises that fulfills the zero-profit condition: the electrolyzers' annual margin equals their annualized fixed cost (Fig. 2b).

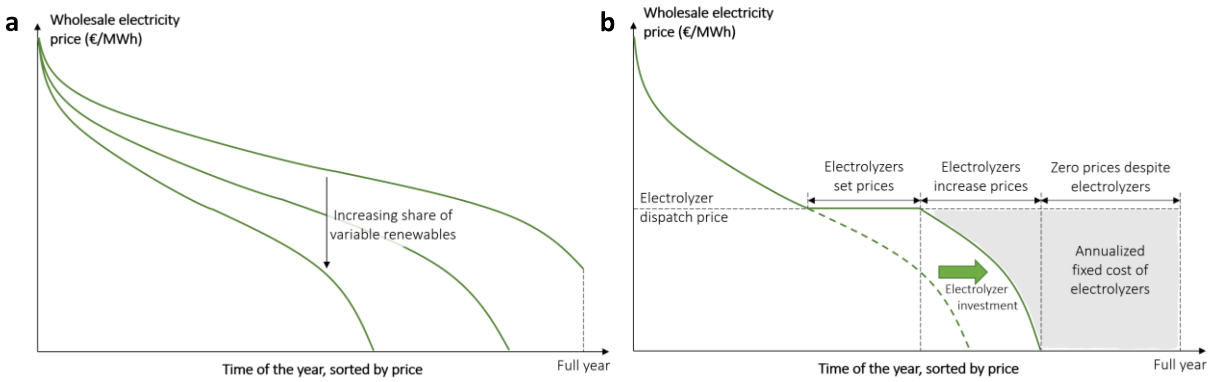

Figure 2: Price duration curves with renewables and electrolyzers. (a) Renewables amplify the downward slope of the price duration curve. (b) Through the additional electricity demand, merchant investment in electrolyzers increases or even sets electricity prices until the annual margin of electrolyzers equals their annualized fixed cost.

2.2 A formula for the minimum market value of renewables

From the electrolyzers' zero-profit condition, this subsection derives an analytical formula for the minimum market value of renewables. Deriving this analytical *minimum* complements existing analytical expressions for the *decline* in the value of renewables [11,12]. The derivation builds on two conservative assumptions (see Methods for a mathematical proof).

First, I assume that electricity prices are either zero or equal to the dispatch price of electrolyzers (Fig. 3a). Consequently, electrolyzers will earn a margin only when the electricity prices are zero, and the margin then equals their dispatch price. Using the zero-profit condition, the maximum number of hours with zero-prices, Z_{max}, can be estimated from the dispatch price, $P_{dispatch}$, and the annualized fixed cost, AFC, of electrolyzers:

$$Z_{max} = \frac{AFC}{P_{dispatch}} \tag{3}$$

This is an equilibrium condition: if the number of hours in which prices drop to zero exceeds Z_{max}, additional electrolyzer investments are profitable, reducing the number of zero price hours again.

Second, I assume that the hours with a relatively high renewable production coincide with zero prices. Due to the first assumption, the remaining generation during hours without zero prices will then receive the electrolyzer dispatch price. Considering the ascending sorted hourly capacity factors of variable renewables over one year, $RE(t)$, as depicted in Fig. 3b, this assumption yields a conservative estimate for the market value of variable renewables, $value_{RE,\,min}$:

$$value_{RE,\,min} = \frac{\int_0^{8760-Z_{max}} RE(t)\,dt}{\int_0^{8760} RE(t)\,dt} \cdot P_{dispatch} \tag{4}$$

Eq. (4) can be rewritten to characterize the functional relationship between the minimum market value and flexible electrolyzers. Using the annual capacity factor of renewables, $\overline{RE}$, the average capacity factor during hours with zero prices, $\overline{RE}_Z$, and Eq. (3) yields

$$value_{RE,\,min} = \frac{8760 \cdot \overline{RE} - Z_{max} \cdot \overline{RE}_Z}{8760 \cdot \overline{RE}} \cdot P_{dispatch} = P_{dispatch} - \frac{\overline{RE}_Z}{\overline{RE}} \cdot \frac{AFC}{8760}. \tag{5}$$

By approximation, this implies that the minimum market value of renewables increases linearly with the electrolyzer dispatch price and that it decreases with the electrolyzers' annualized fixed cost times the ratio between the average renewable capacity factor during zero price hours and during the entire year.

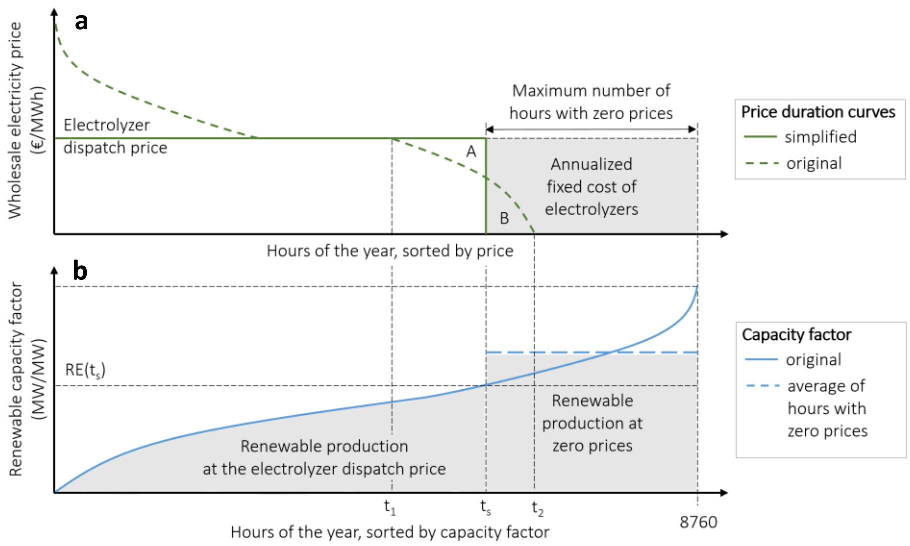

Figure 3: Deriving an analytical minimum to the market value of renewables. (a) Assuming that the electricity price is either zero or equal to the electrolyzers' dispatch price, the annualized fixed cost of electrolyzers defines a maximum number of hours with zero prices. (b) Assuming that the highest production of variable renewables coincides with zero prices, the remaining production receives at least the electrolyzer dispatch price.

This simplistic derivation of the minimum market value has strengths and limitations. Concerning strengths, this approach isolates and thereby helps to understand the pivotal role of the economics of hydrogen electrolyzers for the competitiveness of renewables. Furthermore, it is agnostic about many parameters of the power system, particularly about other electricity demand, supply, and storage. Hence, results can easily be generalized. The main limitation is the focus on the *minimum* market value, not the market value itself. As part of the conservative estimation, the above derivation deliberately ignores high prices, as well as scarcity prices, which could significantly increase the market value. Likewise, the capacity value of renewable is not considered. Furthermore, other mitigation options for the decline in renewable market values, including different types of flexible electricity demand, can be expected to stabilize the market value above this lower boundary [29–36]. At the same time, the assumption of a time-invariant hydrogen price may cause an overestimation of the minimum market value when compared to considering potential hydrogen price fluctuations. In addition, the transmission problem of both electricity and hydrogen, as well as forecast errors of renewables, are neglected, which may further aggravate this bias. The following numerical analyses will address and assess some of these limitations by comparing the simplistic estimates for the minimum market value (based on Eq. (5)) with market value estimates from a more detailed electricity market model.

3 Methods

This section describes the two numerical methods applied in this study. First, Monte Carlo simulations are used to quantify the above-derived minimum market value for a wide range of assumptions. Second, a more detailed electricity market model is employed to put the estimated minimum market value into perspective.

3.1 Monte Carlo simulations to estimate the minimum market value of renewables

Based on the analytically derived Eq. (5), Monte Carlo simulations are performed to quantify the minimum market value of solar photovoltaics (PV), wind onshore, and wind offshore, accounting for the great uncertainty of a potentially highly renewable energy system in 2050. As an input to the calculation of $\overline{RE}$ and $\overline{RE}_Z$, hourly renewable generation profiles are randomly drawn from a large dataset covering 34 European countries and 10 historic weather years [40] (Fig. 4).

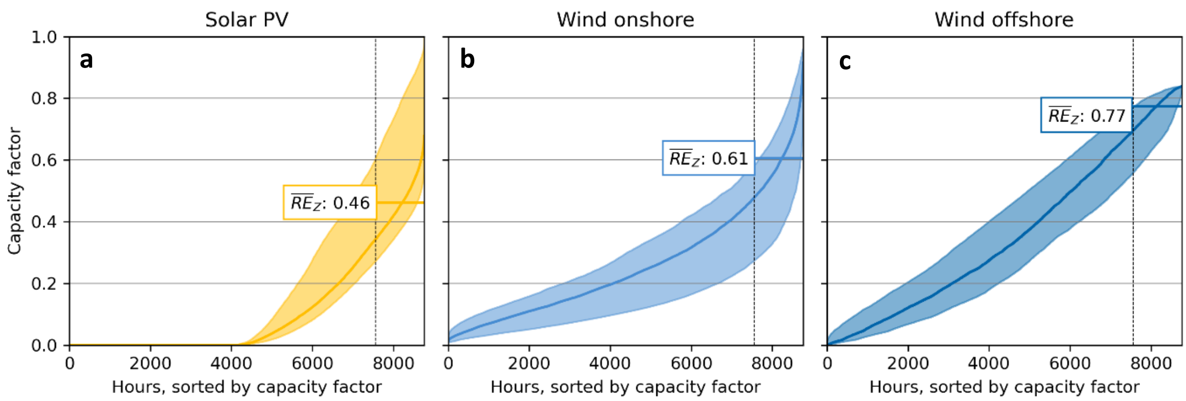

Figure 4: Hourly profiles of renewable capacity factors. (a) Solar PV, (b) wind onshore, and (c) wind offshore based on [40]. The profiles are sorted in ascending order. The dark curve indicates the median and the light area the 5-95% quantile of all profiles. The horizontal lines indicate the average of the 1,200 highest capacity factors ($\overline{RE}_Z$ for the example of Z_{max}= 1,200).

The other input parameters are randomly chosen within sensitivity ranges based on the most recent literature (Table 1), assuming a uniform distribution within these ranges. Note that these parameters reflect projections for the year 2050, which implies lower investment cost for hydrogen electrolyzers than today.

Table 1: Parameter sensitivity ranges for the Monte Carlo simulations. CAPEX: capital expenditure, OPEX: operational expenditure.

Parameter	Unit	Sensitivity range	Source(s)
General			
Interest rate, i	%/a	4…10	
Hydrogen price, P_{H2}	€/kg_{H2}	1.5…2.5	[22,27]
Hydrogen electrolyzers			
CAPEX, C_{CAPEX}	€/kW_{el}	100…800	[20–23]
Fixed OPEX, $c_{OPEX,fix}$	% of CAPEX	2	[28]
Variable OPEX, $C_{OPEX,var}$	€/kg_{H2}	0.1	[27]
Lifetime, T	a	20…30	[27,28]
Efficiency, η	kg_{H2}/MWh_{el}	20…22	[22]

To investigate the regional sensitivity of the results, further Monte Carlo simulations are performed which randomly draw renewable profiles from only one specific country. Moreover, to isolate the effect of the single parameters on the minimum market values, additional simulations are carried out for each of the uncertain parameters from Table 1, with this parameter being fixed to specific values. Note that the supplement that electrolyzers pay on top of wholesale electricity prices is set to zero throughout the previously mentioned simulations. A separate sensitivity analysis is dedicated to the effect of this regulatory parameter on minimum market values.

3.2 The electricity market model EMMA with electrolyzers

To contrast the simplistic estimates for the minimum market value based on Eq. (5), this study develops further and applies the more detailed electricity market model EMMA, which has been used for market value analyses before [6,29,30]. EMMA is a techno-economic model of the integrated Northwestern European electricity market, originally developed by Hirth [41]. Technically, EMMA is a linear program, minimizing the total cost of the electricity system. The main decision variables concern investment in and dispatch of electricity generation, storage, cross-country transmission, and – newly – hydrogen electrolyzers and storage. The investment and dispatch decisions as calculated by the model can be interpreted as economically efficient from a public perspective. Furthermore, the results reflect the partial equilibrium of the electricity market with perfect competition. More precisely, as investment is optimized on the "green field" without considering existing power system assets, results reflect the *long-term* partial equilibrium. The corresponding power prices are read from the dual variables of the electricity balance constraint. This constraint, and hence power prices and dispatch decisions, feature an hourly resolution, while investment decisions are based on one entire year. The model can be interpreted as energy-only market with investment in generation capacity being triggered by scarcity prices[2]. The model is deterministic, which means all decisions are made with perfect foresight. Regionally, the model covers Germany and four neighboring countries, namely France, Belgium, the

[2] There is an ongoing debate on whether scarcity prices can provide sufficient investment incentives or whether the energy-only market needs to be complemented with capacity mechanisms. However, regarding the focus of this study, neither scarcity prices nor capacity mechanisms will strongly affect the value of renewables because of their low capacity credit [42].

Netherlands, and Poland. Reflecting zonal pricing in European electricity markets, grid congestion is modeled between countries, but not within the national bidding zones ("copperplate assumption").

For this article, the model includes six renewable supply, five non-renewable supply, and two storage technologies. Within the subset of renewables, the variable technologies wind onshore, wind offshore, and solar PV are included with exogenously varied capacities. Corresponding profiles are taken from the METIS study [40] (as for the Monte Carlo analysis), selecting the weather year 2010. The other renewable technologies include hydro reservoir, hydro run-off-river, and bioenergy, of which the power generation fixed to 2018 levels because of resource constraints. I assume a constant temporal profile for bioenergy and seasonal profiles for the hydro inflow. The hydro reservoir usage is optimized by the model. The five non-renewable technologies comprise coal with carbon capture and storage (CCS), three types of combined cycle gas turbines, one fired with hydrogen and two fired with natural gas, either with or without CCS, and one type of open cycle gas turbines, fired with natural gas and without CCS. Dispatch of and investment in these technologies are freely optimized but for a minimum cogeneration capacity which needs to supply heat to district heating networks and industrial processes, and which is therefore limited in flexibility. No must-run for ancillary services is considered in this study, assuming that, by 2050, these can also be supplied by renewables and electricity storage. Electricity storage technologies include pumped hydro and batteries.

On the demand side of the electricity system, I newly introduce hydrogen electrolyzers and hydrogen storage with optimized investment and dispatch to the model, and the results are compared to those without electrolyzers. The parameters in Table 1 are now fixed to the center of the sensitivity ranges, including a hydrogen price of €2 kg_{H2}^{-1} and an electrolyzer investment cost of €450 kW_{el}^{-1}. Three electrolyzer scenarios are compared:

1. The *H2 flex* scenario considers a constant hydrogen *price*, as assumed for the derivation of the minimum market value. This implies a perfectly flexible operation of electrolyzers.
2. The *H2 storage* scenario enforces a constant hydrogen *supply*, which may be required by some industrial processes. To still enable a flexible operation of electrolyzers, this scenario includes optimized hydrogen storage in salt caverns at investment cost of €2 kWh_{H2}^{-1} [43].
3. The *H2 inflex* scenario also enforces a constant hydrogen *supply*, but without hydrogen storage. This implies a perfectly inflexible operation of electrolyzers, which may result from regulatory incentives for steady electricity consumption.

These scenarios are implemented as follows. For the *H2 storage* scenario, a hydrogen balance constraint links the hourly dispatch of hydrogen electrolyzers and storage to a time-invariant supply of hydrogen, for which the revenues are considered in the objective function. For the *H2 flex* scenario, the same implementation is used but with the cost of hydrogen storage being set to zero, which results in a perfectly flexible operation of electrolyzers. For the *H2 inflex* scenario, hydrogen storage is excluded from the model to enforce a time-invariant dispatch of electrolyzers. Note that assuming a constant hydrogen supply and non-zero storage cost (or no storage being available) implies that the hourly hydrogen price fluctuates, even though I fix the yearly base price to the same value as for the constant price scenario.

In addition to the electricity consumption of hydrogen electrolyzers, the conventional electricity load is considered according to historic profiles from 2010 (same weather patterns as for the renewables). The annual conventional load is scaled to the average of 2016-2019. Load shedding is possible at costs of €1,000 MWh^{-1}. Other key model inputs include a carbon price of €100 t_{CO2}^{-1} and assumptions on electricity generators and storage, based on the long-term estimates from the European ASSET project [44]. Further sensitivity runs are conducted with 50% higher and 50% lower values for electricity storage costs and carbon prices, respectively.

For the different electrolyzer scenarios and sensitivity runs, EMMA is applied here to calculate wind and solar market values at different market shares of variable renewable generation. The market value is calculated based on the deterministic generation profile and zonal wholesale prices, ignoring balancing and grid costs. Different market shares of variable renewables are reached by scaling the pre-curtailment electricity generation of variable renewables, $generation_{VRE}$, to values between zero to 140% of the yearly conventional load, $load_{conventional}$. This scaling affects wind onshore, wind offshore, and solar PV such that they equally contribute to the overall generation of variable renewables in energy terms. The market share of variable renewables, $share_{VRE}$, is calculated post annual $curtailment$, and considers the additional annual load from hydrogen electrolyzers, $load_{electrolyzers}$:

$$share_{VRE} = \frac{generation_{VRE} - curtailment}{load_{conventional} + load_{electrolyzers}} \qquad \text{(M10)}$$

Note that this share of variable renewables excludes the non-variable renewable sources bioenergy and hydro, such that the overall share of renewables is higher.

4 Results

This section in turn describes the results from the Monte Carlo simulations and from the electricity market model.

4.1 Monte Carlo estimates for the minimum market value of renewables

The Monte Carlo simulations reveal a hydrogen-induced minimum market value which is significantly above zero for all renewable technologies (Fig. 5). For solar PV, the simulations yield an expected value of €19 MWh^{-1} with a standard deviation of €9 MWh^{-1} and a slightly skewed distribution. The estimated minimum market value of wind onshore is somewhat higher and less uncertain (€27 ± 8 MWh^{-1}), which is as expected because wind has a higher annual capacity factor than solar PV (Eq. (5)). The estimates for wind onshore and offshore are similar, despite wind offshore having a substantially higher annual capacity factor. This can be explained by the fact that the average capacity factor during hours with zero prices ($\overline{RE_Z}$) is also higher for wind offshore (see Eq. (5) and Fig. 4). Despite the simplicity of the approach and despite the expectedly large uncertainty, the results in Fig. 5 suggest that renewable market values in future energy systems will likely not fall to zero. Recall that this result is agnostic about many parameters of the power system, particularly about other electricity demand, supply, and storage (Subsection 2.2).

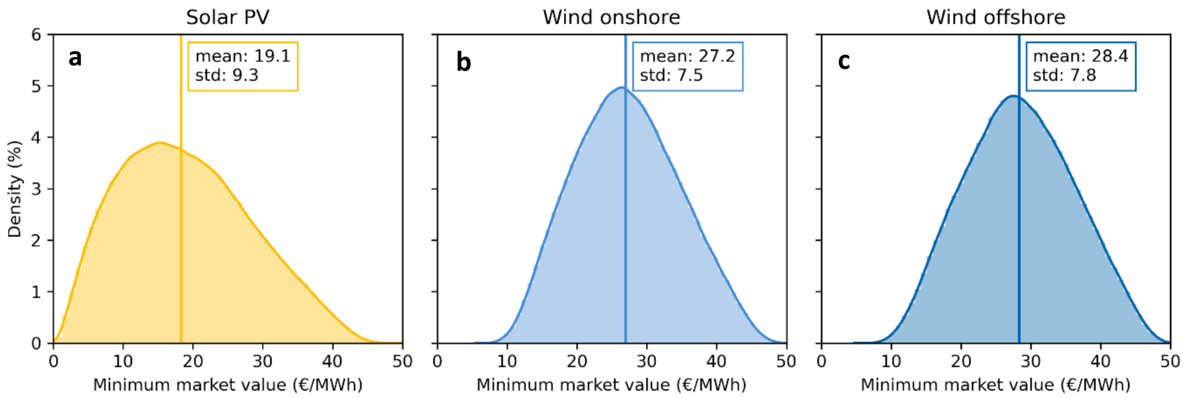

Figure 5: The estimated minimum market value of renewables. (a) Solar PV is characterized by a wide, right-skewed distribution. (b) For wind onshore the distribution is narrower, and the mean is substantially higher when compared to solar PV. (c) Wind offshore features the highest mean, and the distribution is similar to wind onshore. The density functions are based on Monte Carlo simulations (N = 1m), vertical lines indicate the means of the distributions, and the standard deviations (std) are given in the boxes.

The results in Fig. 5 can be compared to cost projections for renewable electricity by 2050. For solar PV and wind onshore, the estimated mean of the minimum market value falls within the range of the projected levelized cost of €14-50 MWh^{-1} [45] and €20-30 MWh^{-1} [46], respectively. This implies that the market values of solar PV and wind onshore are likely to stabilize at levels where market-based investment in these technologies is feasible. The mean of the minimum market value for wind offshore, €28 MWh^{-1}, remains slightly below the corresponding levelized cost projections of €30-70 MWh^{-1} [46]. Nevertheless, a substantial part of the minimum market value's density function overlaps with these cost projections such that market-based investment in wind offshore seems also conceivable under certain circumstances. The following sensitivity analyses aim at identifying the circumstances driving the large uncertainty related to the minimum market value of all renewable technologies.

While the previous results included renewable profiles from 34 European countries at the same time, further Monte Carlo simulations were carried out for each of the countries separately. The resulting regional variation in the minimum market value is surprisingly small (Fig. 6). While the minimum market values of wind and solar energy are higher for sunny and windy countries, respectively, the variation is much smaller than the variation in the annual capacity factor. For the example of solar PV, the minimum market value in Spain is only 25% higher than in Estonia, while the local annual capacity factors differ by a factor of more than two. This discrepancy can be explained by the average capacity factor during the hours with highest production, which are assumed to coincide with zero prices when calculating of the minimum market value. This factor increases almost proportionately with the average capacity factor (Fig. 7). This means that, while the annual renewable generation per capacity installed is much higher in some countries, the share of renewable generation during presumably zero-price hours in these countries is almost as high as in countries with less renewable resources. As a result, the regional variation in the minimum market value is small. Nevertheless, market-based investment is more likely in renewable-rich regions because of the lower levelized cost resulting from high annual capacity factors. The regional variation in the minimum market value is also small in absolute terms (€4-6 MWh^{-1}) when compared to the above-reported overall standard deviation (€8-9 MWh^{-1}). This suggests that a larger part of the variation in the minimum market value is driven by other input parameters, which are investigated in the following.

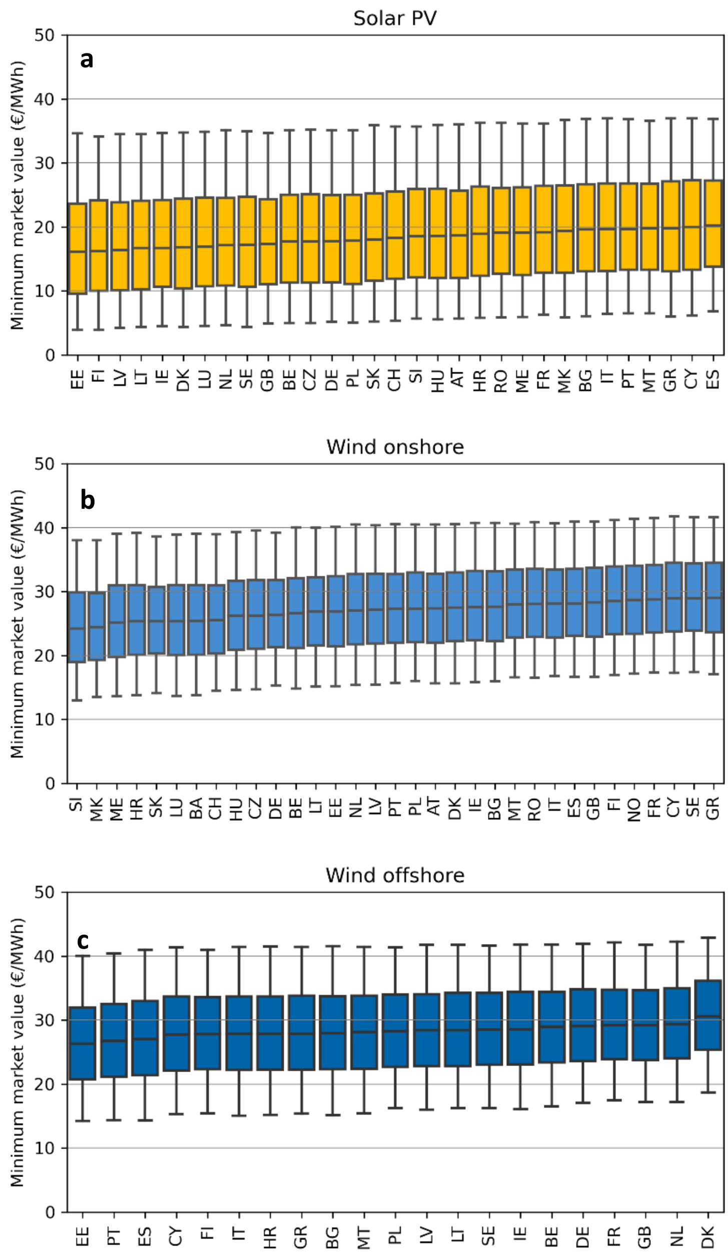

Figure 6: Regional variation in the minimum market value of renewables. (a) Solar PV, (b) wind onshore, and (c) wind offshore. Each boxplot is based on Monte Carlo simulations (N=100k) with renewable profiles being randomly drawn from the subset of data corresponding to the country indicated on the x-axis. The black lines in the middle of the boxes indicate the median, the boxes extend from the first to the third quartile (inter-quartile range), and the whiskers include the 5-95% confidence interval of the observations.

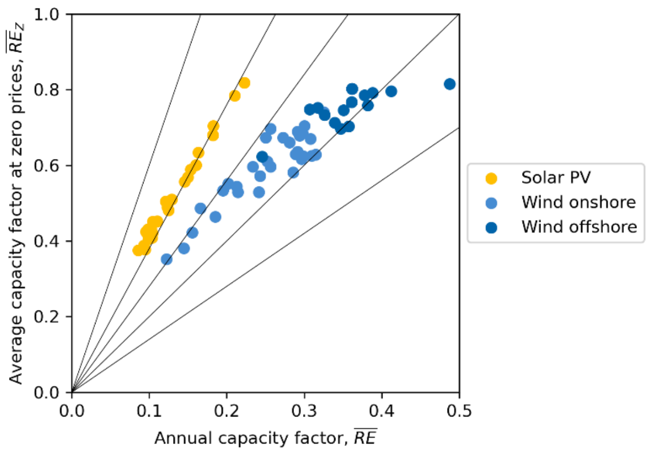

Figure 7: Annual capacity factors versus average capacity factors during the 1,200 hours with the highest production. (a) Solar PV, (b) wind onshore, and (c) wind offshore based on [40]. The points indicate country averages across multiple years. The grey lines indicate a constant ratio between the two average capacity factors.

Most uncertainty involved with the minimum market value can be traced back to two hydrogen-related parameters, namely the price of hydrogen and the investment cost of electrolyzers (Fig. 8a, b). On the one hand, the hydrogen price increases the minimum market value almost linearly (approx. €20 MWh_{el}^{-1} per €1 kg_{H2}^{-1}). Different renewable energy sources are similarly affected, which is as expected because the hydrogen price is reflected in the electrolyzer dispatch price based and because the influence of the dispatch price is independent from renewable profiles (Eq. (5)). The strong influence of the hydrogen price is particularly interesting against the background of a potential scarcity of clean hydrogen in net-zero energy systems. Such scarcity may drive up the hydrogen price and with it the market value of renewables. On the other hand, lower investment cost of electrolyzers have the potential to not only increase but also harmonize the minimum market value across different technologies (approx. €30-40 MWh^{-1} at €100 kW_{el}^{-1}). This illustrates the technology-specific impact of the electrolyzers' investment cost, which are reflected in the annualized fixed cost. At low investment cost of electrolyzers, the term in Eq. (5) which depends on the capacity factors of renewables diminishes. This finding implies that industrial policy targeting at cost reductions for electrolyzers will indirectly also help the competitiveness of variable renewable energy sources. Note that the relationship between the investment cost of electrolyzers and the minimum market value of solar PV is non-linear. Lower investment cost disproportionately drives up the minimum market value, which explains the skewness in the distribution function of the minimum market value of solar (Fig. 5a).

Further analyses reveal how sensitive the hydrogen-renewable relationship is to the supplement that electrolyzers pay on top of the wholesale electricity price (Fig. 8c). For every €1 MWh^{-1} increase in the supplement, the minimum market value of renewables decreases proportionally by about €1 MWh^{-1}. This relates to the ongoing political debate on exempting electrolyzers from electricity price supplements. Such exemptions can help trigger investment not only in flexible electrolyzers but also, through an increased market value, in variable renewable energy sources. This rational is, however, not limited to flexible hydrogen production. More generally, these results give reason to reconsider electricity price supplements for all types of flexible electricity demand.

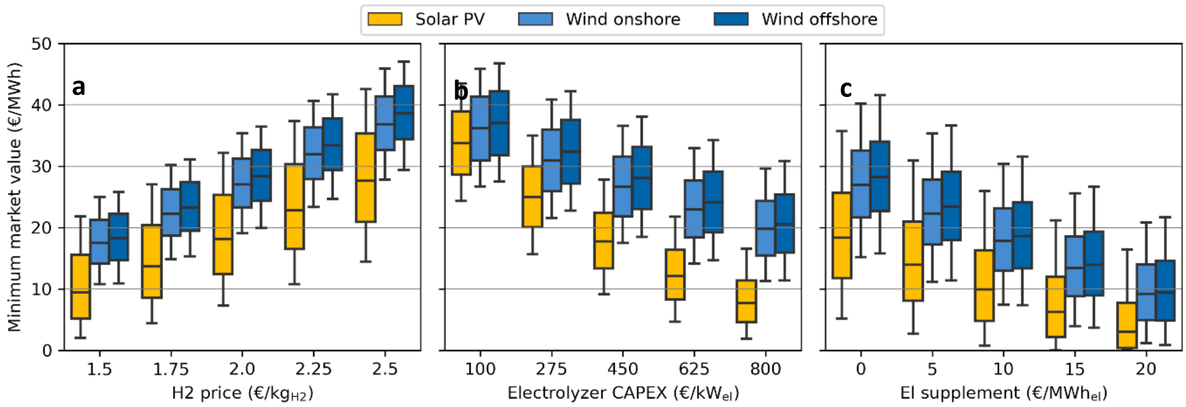

Figure 8: Major determinants of the minimum market value of renewables. (a) The hydrogen (H2) price drives up the minimum market value of all renewable technologies in a linear manner. (b) Lower investment cost (CAPEX) of electrolyzers increase and harmonize the minimum market value of renewables across technologies. (c) The supplement that electrolyzers pay on top of the wholesale electricity price depresses the market value of renewables. Each boxplot is based on Monte Carlo simulations (N=100k) with the hydrogen price, the electrolyzer investment cost, or the supplement being fixed to the value indicated on the x-axis. For an interpretation of the boxplot elements, see Fig. 6.

The other uncertain input parameters have much less influence on the minimum market value of renewables (Fig. 9). In most cases, minimum market values across various assumptions on the interest rate as well as on the electrolyzers' lifetime and efficiency vary by less than €5 MWh^{-1}. Only for the market value of solar PV, the impact of the interest rate is somewhat higher.

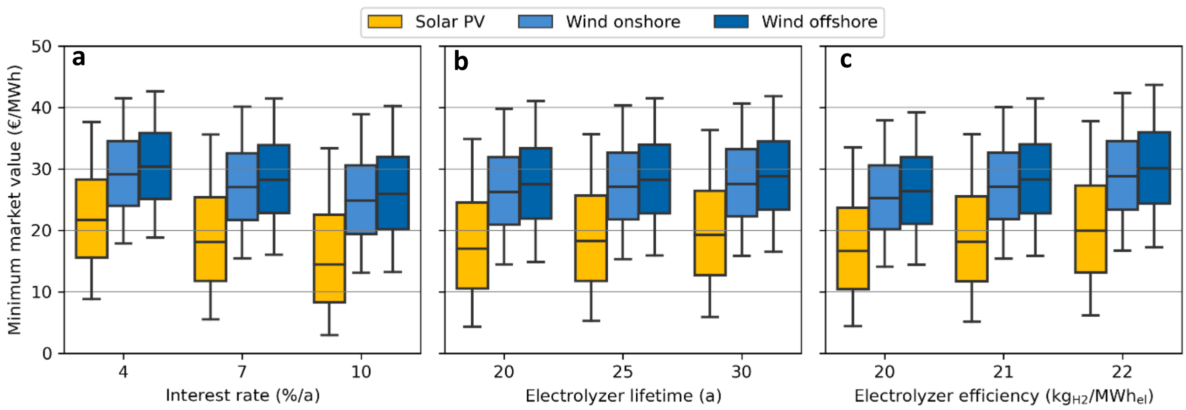

Figure 9: Minor determinants of the minimum market value of renewables. An increase in (a) the interest rate leads to a slight decrease in the minimum market value, while an increase in (b) the electrolyzer lifetime and efficiency increases the minimum market value by a bit. Each boxplot is based on Monte Carlo simulations (N=100k) with the interest rate, the electrolyzer lifetime, or the electrolyzer efficiency being fixed to the value indicated on the x-axis. For an interpretation of the boxplot elements, see Fig. 6.

4.2 Renewable market values in an electricity market model with electrolyzers

The above Monte Carlo simulations are based on simplifying assumptions. These simplifications allow for estimating a general lower boundary to the market value of renewables with very few hydrogen-related assumptions while being agnostic about many other influencing factors. At the same time, the role of the hydrogen-defined minimum market value remains unclear vis-à-vis different market shares of variable renewables and in the context of other options for the system integration of renewables. Furthermore, the derivation of the minimum market value relies on the assumption of a time-invariant hydrogen price, which may bias the results. To address these limitations, this section contrasts the simplistic estimates for the minimum market value with results from the more detailed electricity market model EMMA. Recall that, while the above results are agnostic about the mix of renewables, I now assume solar PV, wind onshore, and wind offshore to be equally deployed in energy terms.

The results of the numerical model are in line with the analytical findings above: with electrolyzers, the market values of renewables stabilize; without electrolyzers, the market values continue to decline (Fig. 10). More precisely, market values in the *H2 flex* scenario converge well above the analytical minimum (plus €7-9 MWh^{-1}). This is as expected because the *H2 flex* scenario implies a constant hydrogen price, and the minimum market value was proven a conservative estimate for this assumption.

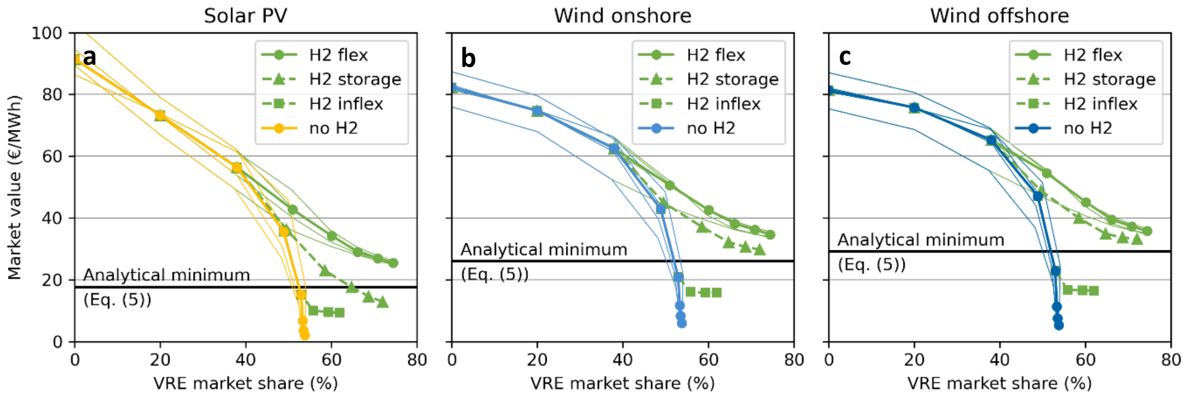

Figure 10: The impact of flexible electrolyzers on the market value of renewables. (a) Solar PV, (b) wind onshore, and (c) wind offshore market values when these technologies are deployed simultaneously in equal shares. Market values with flexible electrolyzers (H2 flex) converge above the analytical minimum market value (Minimum); market values with electrolyzers that need storage for flexible operation (H2 storage) converge to somewhat lower values; market values with inflexible electrolyzers (H2 inflex) converge significantly lower; market values without electrolyzers (no H2) continue to decline. The main scenarios (dark colors) are contrasted with sensitivity runs with different electricity storage costs and carbon prices (light colors). While the results are reported for Germany only, four neighboring countries and corresponding cross-border trades are also modeled.

The *H2 storage* scenario relaxes the assumption of a constant hydrogen price. In this scenario, the market values of wind and particularly solar decrease further. However, they still seem to converge above (wind) or somewhat below (solar) the analytical minimum. This is plausible because, for the market value of renewables, the implications of considering additional investment cost for hydrogen storage are comparable to those of an increase in the investment cost of electrolyzers (see Eq. (5) and Fig. 8b). Higher investment costs are most harmful to solar PV. Furthermore, in north-western Europe, solar PV features larger seasonal variation than wind power, which implies larger storage needs and costs.

In contrast, the market values in the *H2 inflex* scenario converge substantially below the analytical minimum. This demonstrates the benefit of operating electrolyzers in a flexible manner and has political implications. Traditional network tariffs for large customers often include a capacity-based charge incentivizing *steady* electricity consumption. Instead, future regulation should ensure a flexible operation of electrolyzers, based on wholesale market prices, to maximize synergy with renewables.

Remarkably, electrolyzers have no impact on market values below a 40% market share of variable renewables (Fig. 10). This is because market prices are too high and zero-price hours are too seldom at lower renewable shares for electrolyzers to be installed on a market basis. This finding illustrates that high renewable shares are a prerequisite for electrolytic hydrogen to become profitable. Once high shares of variable renewables are reached, flexible electrolyzers (and to a lesser extent inflexible electrolyzers) help increasing the market *share* of renewables even further. This means they disproportionately consume renewable electricity that would have been curtailed otherwise. Recall that the overall share of renewables is even higher than the share of variable renewables due to hydro power and bioenergy. Moreover, at high CO_2 prices, the residual conventional generation is fueled by hydrogen, which originates from renewable electricity. Thus, the role of hydrogen can include long-term electricity storage, enabling a 100% renewable electricity system. However, its role is not limited to the power sector: the model assumes that excess green hydrogen is sold to other energy sectors at a fixed price.

While this study focuses on hydrogen electrolyzers, the results can be compared to previous studies on other types of flexible electricity demand. One the one hand, these studies find that the flexibility and market value implications of electric vehicles and individual heat pumps in buildings are limited [35,36]. On the other hand, power-to-heat complementing combined heat and power in district heating offers much more flexibility and support to renewable market values [36]. In this context, my substantial findings on hydrogen electrolyzers are comparable with the findings on power-to-heat, and a study on multiple types of highly flexible electricity demand seems an interesting avenue for further research. A combination of power-to-heat and hydrogen electrolysis can be expected to stabilize the market value of renewables at even higher levels than hydrogen alone.

Meanwhile, this study's additional sensitivity analyses highlight the importance and robustness of the effect hydrogen electrolyzers have on market values relative to changes in the carbon price and in the cost of electricity storage (Fig. 10, light solid lines). While these other options for mitigating the decline in renewable market values have a distinct impact up to 50% renewables, they are negligible at higher renewable shares. For electricity storage, this is in line with Schill [47], who highlights the growing importance of additional flexible electricity demand relative to electricity storage for the utilization of renewables at high market shares. The low sensitivity to CO_2 prices results from fossil generators switching to hydrogen, for which I assume a fixed price. In the absence of carbon capture and storage, however, CO_2 prices may drive up the price of hydrogen as a substitute for fossil fuels and thereby increase the market value of renewables, as demonstrated by Brown and Reichenberg [33].

Finally, the market model provides further insights into the characteristics of merchant electrolyzers (Fig. 11). First, their electricity consumption seems conceivable when compared to the electricity equivalent of the projected German hydrogen consumption in 2050 [19]. Hence, there will likely be enough demand to justify market-based investment in hydrogen electrolyzers as needed to stabilize the renewable market value at the above reported levels. However, as the present analysis neglects other types of flexible electricity demand, which will compete with flexible hydrogen electrolysis, the reported hydrogen volumes should be interpreted as an upper boundary. Second, the utilization of *flexible* electrolyzers is relatively low (20-45% in the *H2 flex* and 40-55% in the *H2 storage* scenario), and fixing the utilization of electrolyzers to 100% significantly reduces the market-based investment in electrolyzers and the related hydrogen production (*H2 inflex*). This finding contrasts with the widespread notion that high full load hours would generally lead to a better profitability of electrolyzers [28]. This is only true for equal (opportunity) costs of the electrolyzers' electricity consumption. When electrolyzers are optimized within the wider electricity system, however, there is a trade-off between low capital costs at high utilization rates and low operational costs when operating flexibly during times with low wholesale electricity prices only [22]. Lower capital costs of hydrogen electrolyzers will tilt this balance towards a more flexible operation, which is important not only for the market value of renewables but also for total system costs, as discussed by Cloete et al. [48].

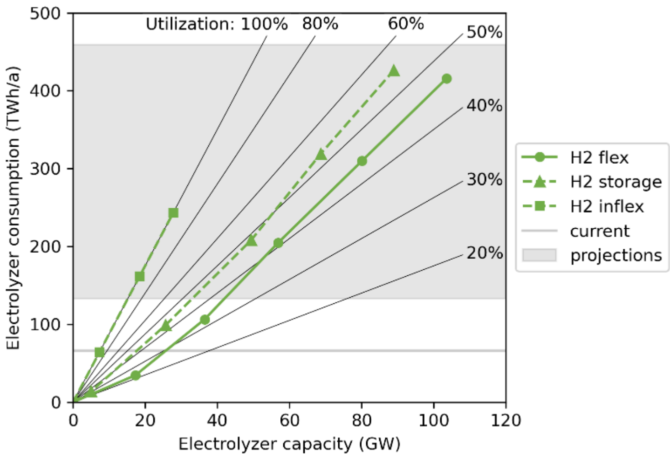

Figure 11: Details on flexible electrolyzers. Optimal electrolyzer capacity, consumption, and utilization for different shares of variable renewables. The results for the different electrolyzers scenarios (H2 flex, H2 storage, H2 inflex) are contrasted with the electricity equivalent of the current and projected hydrogen demand in Germany [19].

5 Conclusions

This article demonstrates the strong synergy between variable renewables and flexible hydrogen production in wholesale electricity markets. Renewables can, by depressing market prices, trigger merchant investment in flexible electrolyzers, and these electrolyzers will, through their additional electricity demand, stabilize the market value of renewables. This finding has profound implications: by 2050, investment in renewables may be less in need of guaranteed state support than often thought. At the same time, electrolytic hydrogen becomes more economical at higher renewable market shares. As an ideal type of flexible electricity demand, hydrogen electrolyzers are a promising solution for the large-scale integration of renewables into the electricity system, and the simultaneous deployment of variable renewables and flexible electrolyzers appears beneficial from a public economic perspective.

Furthermore, this article illustrates how policy can facilitate the renewables-hydrogen synergy. First, politically defined supplements that electrolyzers pay on the wholesale electricity price are shown to reduce the market value of renewables. By contrast, exempting electrolyzers from electricity price supplements can help trigger investment in flexible electrolyzers and thereby increase both the market value and the market share of renewables. Hence, foregone supplement revenues can be worthwhile to reach higher renewable targets at lower cost of renewable support. Second, traditional regulation of electricity demand may incentivize *steady* electricity consumption, impeding the market-based deployment of electrolyzers and synergy with renewables. Instead, regulation should support a *flexible* operation of electrolyzers, based on wholesale market prices.

This article focuses on the case of hydrogen electrolyzers, but it highlights more generally the importance of considering flexible demand when analyzing variable renewables. While excess electricity from variable renewable sources has been perceived as a problem [49], it may also entail an opportunity for flexible demand. The presented framework for investment in and dispatch of flexible demand may be valuable to assess this opportunity.

One aspect which merits further investigation is the impact of sub-national grid restrictions. Such grid restrictions imply a spatial variation in the value of electricity, which can be reflected in market prices through market splitting or nodal pricing. Even though this article neglects such variations, its main analytical finding holds its generality: flexible electrolyzers can stabilize the value of renewables also locally, and the presented framework can be used to quantify the *local* minimum market value.

Moreover, hydrogen production is only one example of flexible electricity demand, and the presented framework may be extended and adapted to other applications, including electric heating, transport, and industry. Further research is needed to characterize the role of various types of flexible electricity demand relative to each other. Eventually, different applications will compete for using renewable electricity when electricity prices are low, jointly contributing to stabilizing the market value of renewables.

Acknowledgements

I thank Anselm Eicke, Benedikt Gerber, Lion Hirth, Raffaele Sgarlato, Schalk Cloete, Silvana Tiedemann, Tarun Khanna, and four anonymous reviewers, as well as the participants of the 9th INREC conference and of the PIK CAEP seminar for valuable comments and inspiring discussions.

Data and code availability

The code for the Monte Carlo simulations is available at https://github.com/oruhnau/minimum-market-value. The code for the electricity market modeling, including all model inputs and a full model description, is available at https://github.com/emma-model/EMMA/tree/minimum-market-value. Both repositories are published under an open-source license.

Annex: Mathematical proof of the minimum market value

The following is to proof mathematically that Eq. (4) is a lower boundary to the market value of renewable energy. To this end, consider the original price duration curve, $P(t)$, and let t_1 be the number of hours per year with electricity prices greater or equal to the electrolyzer dispatch price and let t_2 be the number of hours per year with above-zero electricity prices (Fig. 2a). Then, the zero-profit condition implies for the market equilibrium that:

$$AFC = \int_{t_1}^{t_2} \left(P_{dispatch} - P(t)\right)\, dt + \int_{t_2}^{8760} P_{dispatch}\, dt \tag{M1}$$

Now consider the simplified price duration curve resulting from the assumption that the electricity price is either zero or at least the electrolyzer dispatch price. Let $t_s = 8760 - Z_{max}$ be the number of hours with electricity prices equal or above the electrolyzer dispatch price under this assumption (Fig. 2a). The zero-profit condition still needs to be fulfilled, hence:

$$AFC = \int_{t_s}^{8760} P_{dispatch}\, dt \tag{M2}$$

Combining Eq. (M1) and Eq. (M2) yields:

$$\int_{t_1}^{t_s} \left(P_{dispatch} - P(t)\right)\, dt + \int_{t_s}^{t_2} \left(P_{dispatch} - P(t)\right)\, dt = \int_{t_s}^{t_2} P_{dispatch}\, dt \tag{M3}$$

This is equivalent to the following expression, which can be graphically interpreted as $A = B$ in Fig. 2a:

$$\int_{t_1}^{t_s} \left(P_{dispatch} - P(t)\right)\, dt = \int_{t_s}^{t_2} P(t)\, dt \tag{M4}$$

Now consider the definition of the market value of renewables for the original price duration curve:

$$\begin{aligned} value_{RE} &= \frac{1}{FLH_{RE}} \int_0^{8760} RE(t) \cdot P(t)\, dt \\ &= \frac{1}{FLH_{RE}} \left(\int_0^{t_1} RE(t) \cdot P(t)\, dt + \int_{t_1}^{t_2} RE(t) \cdot P(t)\, dt + \int_{t_2}^{8760} RE(t) \cdot P(t)\, dt \right) \end{aligned} \tag{M5}$$

For $t \leq t_1$, the original load duration curve exceeds the electrolyzer dispatch price, $P(t) \geq P_{dispatch}$, and for $t \geq t_2$, the original load duration curve is zero, $P(t) = 0$. Hence:

$$\begin{aligned} value_{RE} &\geq \frac{1}{FLH_{RE}} \left(\int_0^{t_1} RE(t) \cdot P_{dispatch}\, dt + \int_{t_1}^{t_2} RE(t) \cdot P(t)\, dt \right) \\ &= \frac{1}{FLH_{RE}} \left(\int_0^{t_1} RE(t) \cdot P_{dispatch}\, dt + \int_{t_1}^{t_s} RE(t) \cdot P(t)\, dt + \int_{t_s}^{t_2} RE(t) \cdot P(t)\, dt \right) \end{aligned} \tag{M6}$$

This can be rewritten as follows:

$$\begin{aligned} value_{RE} &\geq \frac{1}{FLH_{RE}} \Bigg(\int_0^{t_1} RE(t) \cdot P_{dispatch}\, dt + \int_{t_1}^{t_s} RE(t) \cdot P_{dispatch}\, dt - \int_{t_1}^{t_s} RE(t) \cdot P_{dispatch}\, dt \\ &\quad + \int_{t_1}^{t_s} RE(t) \cdot P(t)\, dt + \int_{t_s}^{t_2} RE(t) \cdot P(t)\, dt \Bigg) \\ &= \frac{1}{FLH_{RE}} \Bigg(\int_0^{t_s} RE(t) \cdot P_{dispatch}\, dt - \int_{t_1}^{t_s} RE(t) \cdot \left(P_{dispatch} - P(t)\right)\, dt \\ &\quad + \int_{t_s}^{t_2} RE(t) \cdot P(t)\, dt \Bigg) \end{aligned} \tag{M7}$$

The assumption that the highest production of variable renewables coincides with zero prices implies that $RE(t) \leq RE(t_s)$ for $t \leq t_s$ and $RE(t) \geq RE(t_s)$ for $t \geq t_s$ (Fig. 2b). Hence:

$$value_{RE} \geq \frac{1}{FLH_{RE}} \left(\int_0^{t_s} RE(t) \cdot P_{dispatch}\, dt - RE(t_2) \left(\int_{t_1}^{t_s} \left(P_{dispatch} - P(t)\right)\, dt - \int_{t_s}^{t_2} P(t)\, dt \right) \right) \tag{M8}$$

Using Eq. (M4) and $t_s = 8760 - Z_{max}$, this equation simplifies to:

$$value_{RE} \geq \frac{\int_0^{8760 - Z_{max}} RE(t)\, dt}{FLH_{RE}} \cdot P_{dispatch} \tag{M9}$$

Hence, Eq. (4) is a lower boundary to the market value or renewable energy, which was to be proven.

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