Future Economic Perspective and Potential Revenue of Non-Subsidized Wind Turbines in Germany

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Abstract. Thanks to the Renewable Energy Act todays wind turbine operators in Germany are dealing with low risk on the revenue side. Fixed feed-in compensation ensures planning security and high system utilisation. Anyhow, the level of federal financial support is being reduced consecutively. Tomorrow's plant operators must trade self-sufficiently on European electricity markets hence generate revenue only by marketing electricity. Therefore, uncertain future market developments will influence investment considerations and may lead to stagnation in the expansion of renewable energies. It is of interest to estimate future revenue potentials of those non-subsidized wind turbines to reduce those risks. This paper introduces and analyses a forecasting model that generates data specifically suited for revenue estimation of wind turbines. The model is solely based on open access data and applies a modified merit order approach to forecast long-term day-ahead prices on European electricity markets at an hourly resolution. In doing so, the dynamic feed-in profile of wind turbines can be mapped over several years in conjunction with fluctuations in the electricity price. Levelized Revenue of Energy are used to assess both dynamic variables within the same measure. The results show how changes in the German power generation landscape like dismantling of coal and nuclear power plants as well as different emission prices impact the potential revenue of wind energy. A brief case study then highlights that for the given results most of today's wind turbines in Germany are not able to yield financial profit over their lifetime without guaranteed subsidies. This underlines an urgent need for technical development and new business models. Possible business models could be Power Purchase Agreements for which the model results can be used for setting and negotiating appropriate terms, such as energy price schedule or penalties.

Overall, the information obtained by the given model contributes to reducing investment risks, deducing development goals and finally supports the expansion of tomorrow's wind turbine technology.

1 Introduction

Renewable electricity generation technologies have been heavily subsidised by the German Renewable Energy Act (EEG, Erneuerbare Energien Gesetz) in the past to achieve energy policy goals by reducing greenhouse gas emissions. Fixed feed-in tariffs decoupled revenues from the electricity exchange price which made investments in the renewable energy sector particularly attractive and led to a strong expansion. In the form of a tendering procedure, an attempt was then made to increase competition and promote the competitiveness of wind energy. However, at the same time more strict requirements alongside lengthy approval and licensing procedures led to stagnation in onshore wind energy expansion in Germany (Bundesministerium für Wirtschaft und Energie, 2018, 2019). In the future case of direct marketing revenues will depend solely on the current electricity exchange price and the power fed into the grid.

The final investment and thus expansion decision usually take place on a local and project-specific basis. Whether a new wind farm is erected is therefore a new consideration for each individual case. In this context, the development of the electricity exchange price represents a crucial and uncertain external factor for the investment decision. In Germany, relevant decision-makers are often located at municipal level (Hirschl et al., 2010).

The aim of this research is to address the barrier of uncertain market revenues from wind turbines (WT) without subsidies in Germany by estimating future electricity exchange prices. Due to the changing political conditions, it is also advantageous to be able to calculate different future scenarios. For this macroeconomic topic, national and European electricity markets must be considered. However, due to the decentralised nature of renewable energies it is also necessary to investigate individual expansion projects on a microeconomic, municipal scale. With respect to the dynamic electricity supply from wind turbines, a long-term forecast (over 20 years) with a relatively high (hourly) temporal resolution is carried out. Compared to most state-of-the-art forecasting models, this is a rather unusual combination. In this special case, however, this makes sense in order to take the dynamic characteristics into account when calculating revenue.

By forecasting future prices, it is desired to support and enable municipal decision-makers at planning and designing local expansion more independently.

In the following Section 1.1 the current market situation for WT operators in Germany is summarized. Afterwards in Section 1.2 existing forecasting and system analysis models with a similar scope are being discussed. Based on these two sections the elaborated forecasting model will be derived and discussed in Section 2. Finally, in Section 3 model results are interpreted along a brief case study and conclusion.

1.1 Revenue situation for wind turbine operators in Germany

In 2017, the whole EEG support scheme has been overhauled. The level of subsidization is now being determined through tendering. The operator receives an individual market premium after successfully taking part in a tendering procedure (Bundesverband WindEnergie e.V., 2018). In addition, the EEG 2017 defines a maximum tender volume for each year. Bids that exceed the set limit are not receiving financial support (Fachagentur Windenergie an Land).

Since 2016 new power plants with an installed capacity of over 100 kW are bounded to direct marketing (§21 EEG 2017, §EEG 2014). For operators of WTs that have been approved before EEG 2014 direct marketing is optional. (EEG 2014, §100, subsection 1, number 6) The first step towards direct marketing is to choose a direct marketer and then conclude a contract, which regulates payment terms, possible compensation payments and the remote controlling. The latter is required for direct marketing. The direct marketer then needs to register the new plants at the distribution grid and include them into his accounting grid to be finally able to enter the electricity exchange market.

An alternative for selling electricity from renewable sources are long-term Power Purchase Agreements (PPA). These enable bilateral trading including consultation between contracting parties. Those agreements normally cover a period of up to ten years and are established individually each time by the contract parties. PPAs define the following aspects of power purchase: amount of electricity, price, contract terms and penalties for breach of contract (Javadi et al., 2011). A distinction is made between on-site and off-site PPAs with different subcategories. On-site PPAs include a direct physical electricity delivery from the producer to the customer. That is the reason why a geographical proximity is significant for these types of PPAs. The costumers minimize their risks by outsourcing power generation while long-term contracts ensure economic viability and calculability for the operator. (Elwakil and Hegab, 2018)
Off-site PPAs on the other hand deliver the defined electricity amount through the public electricity grid. No direct physical delivery of electricity between producer and costumer is happening. A network charge needs to be paid for these PPAs, but also geographical flexibility exists. This means that producers can choose their location by site-specific factors, which allows production to be optimized. Plants may enter several PPAs with different customers at the same time (Elwakil and Hegab, 2018). Both, on-site as well as off-site PPAs are possible alternatives for selling electricity from WTs.

So far long-term PPAs are highly controversial. Proponents state that they are a good and necessary tool to support renewable energy. Opponents criticize that the PPA price is currently often set well below the exchange market price and thus makes the economic operation of plants even more difficult. Existing non-subsidized WTs that have exceeded the 20-year limit can either be repowered, deconstructed or further operated (Steinhausen et al., 2018). First contracts for PPAs have been concluded for old WTs, but also new WTs. Compared to other European countries the PPA market in Germany is much less developed. In a lot of neighbouring countries PPAs are already an established procedure (Fischer et al., 2019; Tang and Zhang, 2019).

1.2 Existing forecasting models

Extensive literature is available in the field of modelling and forecasting electricity exchange prices. However, there is no consensus on the approach and methodology of modelling. Most models are designed for a specific market situation or forecasting horizon in which they perform well and deliver robust results (Weron, 2014). However, many models aim to predict EEX price movements reliably. In the following, some practical examples of forecasting models of electricity exchange prices are presented which are of methodological interest for this work.

In 2010 Jonsson et al. investigate the influence of wind energy forecasts and actual wind volume on the Danish electricity exchange price. They use a non-parametric regression model and the statistical distribution of the spot price for different scenarios and conclude that a high forecast feed-in from wind turbines lowers the exchange price. The actual amount of wind energy also influences the price. In both cases the correlations are strongly non-linear. The authors observe growing price volatility and weather-related price patterns (Jónsson et al., 2010). Jonsson et al. focus on the impact of wind energy onto the electricity price, whereas the given paper will reverse this focus and analyse the impact of the electricity price onto economic efficiency of WTs.

In 2013 Jonsson et al. then pursue a two-step approach to model the short-term spot prices in Denmark for the years 2010 and 2011. They forecast grid load and feed-in from wind turbines. Non-linear and transient influences of these two variables are considered in the first step of the model by a non-parametric regression. Subsequently, time series-based models are used to represent remaining autocorrelations and seasonal effects. The authors conclude that models with variable parameter estimation can yield better results over time than those with static parameters (Jonsson et al., 2013). However, robust parameter estimation has the advantage that models are less vulnerable to abrupt parameter changes e.g. due to excessive price peaks.

Fanone et al. can generate both negative and positive price peaks with a forecast model of the German intraday market with hourly resolution. The model parameters are calibrated using historical EPEX intraday data. The hourly spot price is divided into two components, namely a time-dependent adjustable component and a deterministic component containing long-term variations and seasonal effects. When investigating daily spot prices an annual and a half-yearly periodicity can be observed (Fanone et al., 2013). A possible disadvantage of this approach is that calibration based on historical data against the background of fundamental market changes such as dismantling of coal powered plants could lead to long-term forecasting errors.

Šumbera and Dlouhý model the German spot market based on the assumption that the demand for electricity and the system load always equal the generation capacity provided by all power plants. A merit order approach is used for pricing, which is subsequently extended. The power plants are divided into dispatchable and non-dispatchable power plants and others. The dispatchable power plants and their schedules are presented in high detail. Non-dispatchable power plants are grouped together in the model according to energy source and defined as "must-runs". Power plants whose generation depends only on their availability are modelled with variable costs of zero (Šumbera and Dlouhý, 2015). A disadvantage of this methodology is that a set of all generation units or at least a representative data set must be available.

A general criticism of existing models that are not open access is the lack of transparency and accessibility of the calculation methods and databases. Therefore, only openly accessible data is used for the presented forecasting model, except for the historical exchange market price data of EPEX Spot used for validation. However, these are not necessary for the subsequent use and functionality of the tool.

Next to the discussed forecasting models there is also a broad variety of equilibrium models that analyse energy systems and consequently may be used for electricity price estimation. The Balmorel model will be discussed as representative for this group. Balmorel is a partial equilibrium model for analyzing the electricity and combined heat and power sectors in a large geographical and international perspective. It has been directed towards the solution of an optimization problem in GAMS to determine entities like generation, consumption, transmission and prices of electricity and heat as well as emission. Especially positive is that the source code of Balmorel is openly available since 2001. (Wiese et al., 2018) Due to the wide range of performance and the necessity to solve an optimization problem, the model imposes comparatively high demands on the level of technological detail and data, even if these can be reduced by later model adjustments. It is questionable whether a leaner model might not be sufficient to achieve one of these goals at less computational effort.

2 Methodology and forecasting model

To make investment decisions based on the revenue potential of wind turbines the entire life cycle must be considered, which lies usually in the range of at least 20 years. Therefore, the long-term development of the electricity exchange price must be estimated. At the same time microscopic market effects like increased volatility due to feed-in of renewables should also be considered. These effects are represented better by short-term forecast models. In conclusion, a long-term forecast period with a high temporal resolution will be simulated.

2.1 Forecasting objective

The given model is oriented towards the mechanisms of the existing power exchange. The EEX markets and electricity exchanges represent a highly relevant objective for forecasting, due to their central location and economic influence. One of the most relevant markets for trading electricity from wind turbines is the day-ahead market. On this market, electricity is traded for every hour of the following day. In practice most over the counter (OTC) trades are based on the current level of the (day-ahead) spot market. When drafting PPAs, it is customary to use the course of the electricity exchange price as reference. The forecasting objective of this study is therefore the day-ahead spot price for the next twenty years. This automatically satisfies the initially formulated requirement for a high temporal resolution.

Figure 1 shows which input variables and calculations are necessary to describe this objective and how they have been connected within the presented model. In the following, the input data and intermediate steps used are explained in more detail. The elaborated forecasting model is based on a merit-order approach and can therefore be categorized as a fundamental model following Weron (Weron, 2014). An object-oriented approach has been chosen for implementation of power plants, where individual characteristics and cost can be set. This model design adds a more agent-based approach, yielding additional benefits over a solely fundamental procedure. The object-oriented design makes it easy to adapt parameter variations and can be used to check plausibility of results on plant level. The presented model is therefore finally to be classified as a hybrid model. The required data and calculation steps are descried in the following subchapters.

The average annual electricity demand and the annual installed plant capacity are the only data to be provided by the user. Reference values are available for all other parameters.

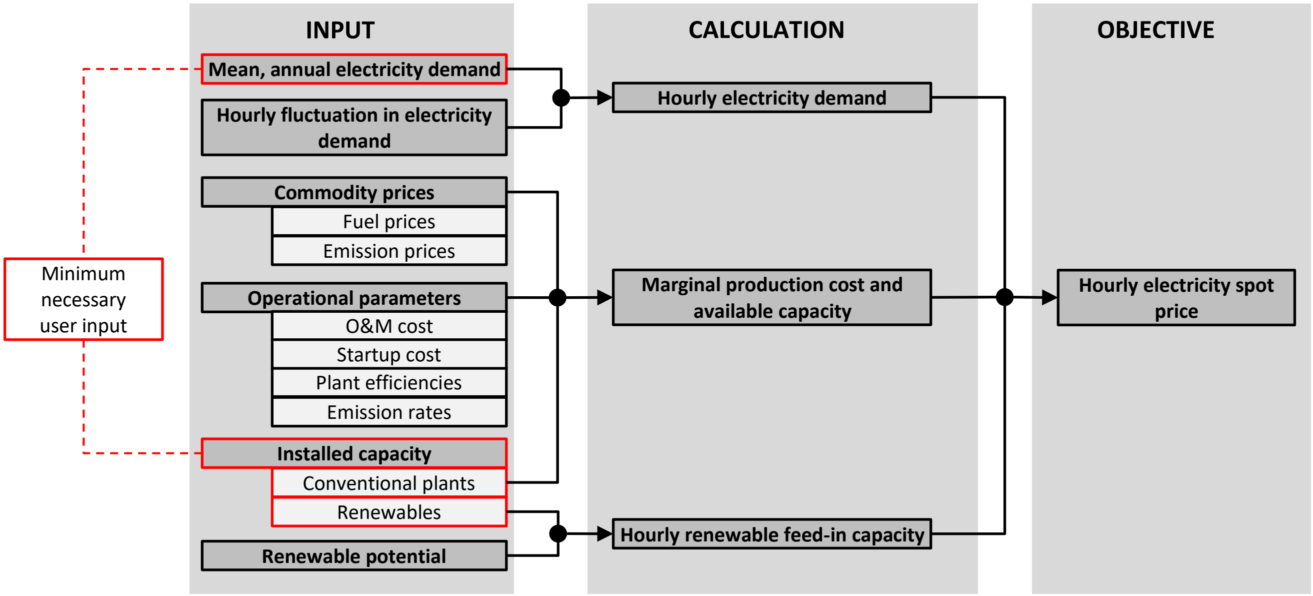

Figure 1: Schematic model structure and input data requirements

2.2 Hourly electricity demand

155 The hourly electricity demand of a country for each year is composed of an annual mean value D_{mean} and an hourly fluctuation factor f_{var} according to Eq. (1). D_{mean} is derived from the total annual demand required as model input while f_{var} remains the same for any scenario. For this paper, the annual demand for Germany and Austria is assumed to be at a constant 579,23 TWh. The time series for f_{var} is derived from data of the Ten Year Network Development Plan (TYNDP18) of the European network of transmission system operators (Entso-e, 2018b). Figure 2 shows annual (a), weekly (b) and daily (c) sections of f_{var}. It can 160 be observed how f_{var} covers different cyclic characteristics of the actual electricity demand like higher demands during winter as well as peak and off-peak hours. All long-term demand trends must be considered within D_{mean}. The hourly electricity demand is equivalent to the load profile used for the merit order approach.

$$D(t) = D_{\mathrm{mean}} \cdot (1 + f_{\mathrm{var}}(t)) \tag{1}$$

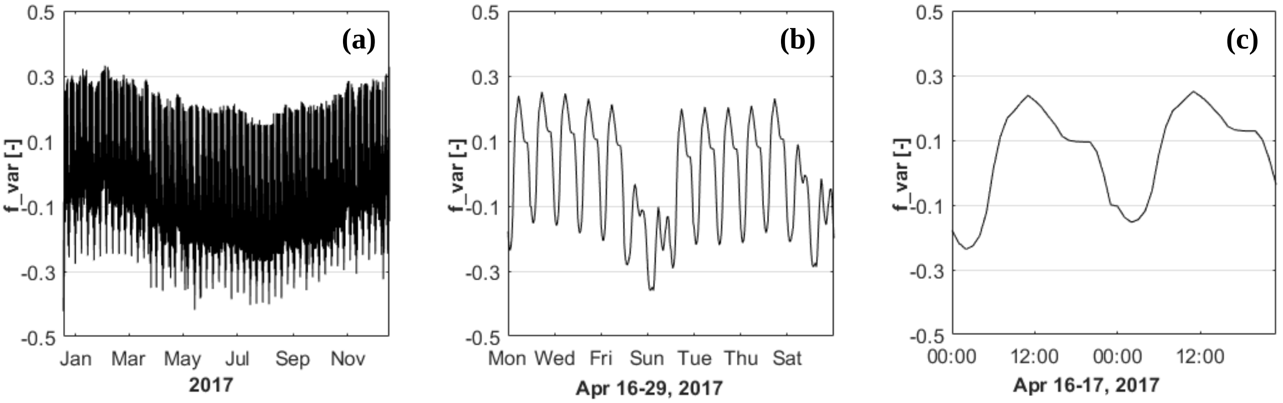

Figure 2: Demand variation factor f_{var} for Germany in 2017 with annual (a), weekly (b) and daily (c) characteristics

2.3 Available generation capacity and marginal cost

The national installed capacity and generation plants are classified by conventional and renewable plants, where gas, hard coal, lignite, oil and nuclear fuelled plants are considered as conventional. On the other hand, hydro, solar, wind (onshore and offshore) and others (mainly biomass) are considered as renewable.

Based on these categories a total installed capacity per year is required as user-input. In a next step the model derives individual objects to generate an object-oriented plant fleet based on reference data. Afterwards each object can also be parametrised individually. Marginal generation cost c_{var} is then calculated for every plant following Eq. (2)

$$c_{\text{var}} = c_{\text{fuel}} + c_{\text{o\&m}} + c_{\text{CO}_2} \quad \text{with} \quad c_{\text{fuel}} = \frac{p_{\text{fuel}}}{\eta} \quad \text{and} \quad c_{\text{co}_2} = \frac{p_{\text{CO}_2}}{\eta} \cdot f_{co_2} \tag{2}$$

where c_{var} is the marginal generation cost of a specific power plant used for the merit order approach. Commodity prices are split into fuel prices p_{fuel} and emission (CO_2) prices p_{CO_2} which are both assumed to be constant over time during a simulation run. The resulting cost are then calculated regarding both, efficiency η of plants as well as emission rate f_{CO_2}.

During this research values given in Table 1 have been assumed as reference for commodity prices and efficiencies. The values have also been derived from TYNDP18 data. The specific cost terms can be varied for each individual power plant. Also, when adding additional plants, cost values can be set individually. For the plant efficiency it was assumed that over all power plants the efficiency follows a beta-distribution defined by η_{min}, η_{mean} and η_{max} where the oldest plants operate at the lowest efficiency and vice versa. Every plant is also given a date of commission and shutdown date. Outside the resulting time span, the respective power plant is not considered for the price calculation.

The given emission factors refer exclusively to emissions occurring during operation. Holistic life cycle analysis (LCA) approaches would provide an emission factor greater than zero in the case of nuclear power plants, since greenhouse gases are released during fuel transport and plant construction and dismantling.

Table 1: Reference values for commodity prices and plant efficiencies (Entso-e, 2018a)

Property	Sign	Unit	Gas	Hard Coal	Lignite	Oil	Nuclear
O&M cost	$c_{o\&m}$	€/MWh	1.46	3.3	3.3	2.57	9
min efficiency	η_{min}	%	25	30	30	25	30
mean efficieny	η_{mean}	%	44	40	40	36	33
max efficiency	η_{max}	%	60	46	46	43	35
fuel price	p_{fuel}	€/MWh	21.96	8.28	3.96	50.76	1.69
emission rate	$f_{\mathrm{CO_2}}$	kg/MWh	205.2	338.4	363.6	280.8	0

2.4 Hourly renewable generation capacity and weather time series data

For the implementation of weather-dependent electricity generation technologies such as photovoltaic plants and WT are essential and of fundamental importance. The influences of wind speed and solar radiation are taken into account by referring to previous studies of Staffell and Pfenninger. The authors use weather data from global reanalysis models and satellite observations to generate synchronized national time series data for solar and wind generation capacity for the years 1985 to 2016 at an hourly resolution (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). The capacity factors given by their studies are then scaled with the overall installed generation capacity of WT and solar panels. This data is used for forecasting by shifting it into the future, meaning that the original data for the year 1985 will be used for the first year of the forecasting period. The influence of the ambient temperature on the electricity demand was investigated in a previous study, with the result that for Germany there is no significant influence (Blickwedel, 2018). Therefore, it is assumed that weather data and load profile do not need to be synchronized. All other weather and climate influences are neglected in the model. In addition, the assumption is made that there are no long-term climate trends within the next twenty years regarding wind and radiation supply and that capacity factors will not change. The latter poses a simplification because an increase in capacity factors may be expected due to technological progress.

2.5 Implementation of cross-border transactions

The general idea to implement cross-border transactions within the given approach is to depict neighbouring countries as single power plants (agents). These agents are assigned individual capacity and dynamic marginal cost so that they can be included into the merit order plot. The net transfer capacity (NTC) provided by the European network of transmission system operators is assumed to be the technical upper bound for cross-border electricity transfer. Regarding the merit order plot, this corresponds to the capacity (bar width) of the agent. NTC values for Germany are implemented as given in Table 2. At this state, NTC is assumed to be constant over time for all countries.

Table 2: Cross-border NTC capacities for Germany (Entso-e, 2018b)

Country	AT	BE	CH	CZ	DK	FR	LU	NL	NO	PL	SE
NTC [MW]	5000	1000	4600	2100	2765	1800	2300	4250	1400	2500	615

In case of the neighbouring countries the NTC can function as both, demand capacity and supply capacity, depending on the current electricity spot price of the country. The spot price is set as the marginal cost (bar height) for neighbouring countries. The bar height of the neighbouring countries determines whether they import or export at a certain hour. If the local price of a neighbouring country is lower than the German price, it is assumed that the Germany will import electricity from this country to the extent of available NTC. It thereby acts as a supplying power plant. On the other hand, if the local price in a neighbouring country is higher than the German price, it is assumed that Germany will export electricity to the extent of available NTC. In this case the available NTC enlarges the current electricity demand. To estimate local prices of the neighbouring markets a simplified pre-simulation for each country must be executed where import and export are neglected. This pre-simulation is based on the current plant portfolio and annual demand of each neighbouring country and thereby also respects its generation mix.

Figure 3 illustrates this approach for one hour within the model. The electricity demand on the German market is depicted by the dotted line at 80 GW. Whenever the market price on a neighbouring market is lower than the local price, the neighbouring market is handled as a power plant that supplies electricity for the German market. This applies to the two countries at the left of the dotted line. When a country exhibits a higher market price than the local price it is assumed to be a potential market for export of electricity. Within the model this means that the actual demand must be extended by the NTC of the according countries. The continuous line at 105 GW shows the resulting total demand that finally defines the price. In this case the German spot price increases due to cross-border transactions, because there are several markets available for export.

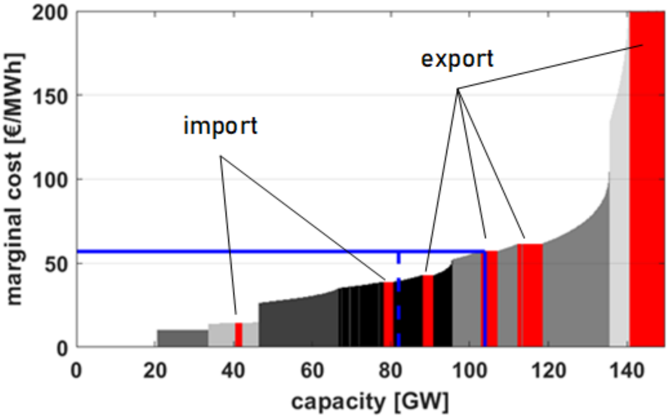

Figure 3: Exemplary merit order plot from forecasting model with cross-border considerations

2.6 Model validation

To validate the model, calculated prices for a past year have been compared to actual prices on the EPEX Spot day ahead market (EPEX Spot, 2018). Since in the past Germany and Austria have been a coupled market, back testing has also been done for both countries together. Figure 4 shows the ordered annual price duration curve for Germany and Austria as well as the prices calculated by the presented forecasting model for the year 2017. The year 2017 has been chosen, because in 2018 the two countries markets have been separated.

It can be stated that the model provides satisfactory results at a mean absolute error of 2.38 €/MWh over the course of a year.

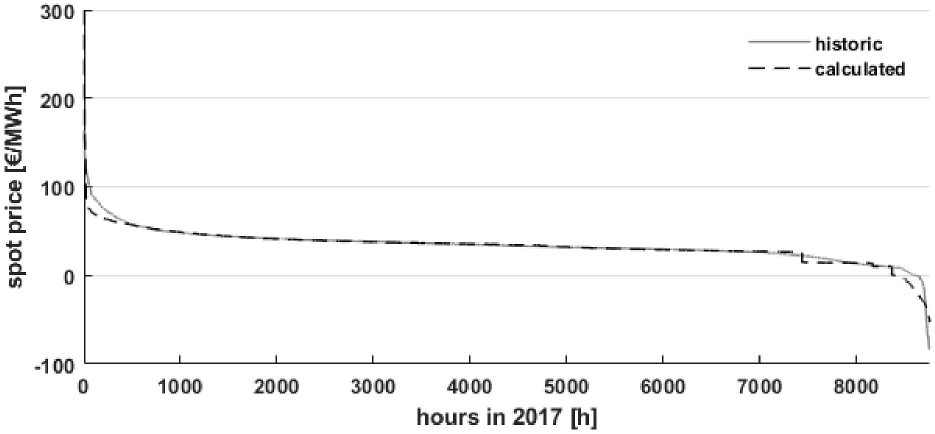

Figure 4: Validation results, comparison of model results against historic values from EPEX Spot for Germany in 2017

3 Model application, results, and case study

In the following section the forecast market results are being analysed and put in perspective in a brief case study. For this purpose, a measurand for evaluation of model results based on the levelized revenue of energy (LROE) is introduced.

In most cases the overall performance of wind turbines (or other generation plants) is evaluated based on the levelized cost of energy (LCOE). The LCOE are defined as the total lifetime cost over the total lifetime energy production (Kost et al., 2018). Since the scope of this paper does not include specific cost but deliberately only market revenue, the commonly used LCOE is no appropriate measure to interpret model results. Instead the levelized revenue of energy based on their discussion by Thomas Baker in 2011 will be introduced (Baker, 2011). The LROE are understood as the total lifetime revenue over total lifetime energy yield following (Eq. 5) where $W_{t,el}$ describes the quantity of electricity produced in the respective year t and i the calculatory interest rate. Model results can be evaluated independently from plant specific cost when using LROE instead of LCOE. Results based on LROE thereby have a more general and global applicability.

$$LROE = \frac{\sum_{t=1}^{n} \frac{Revenue_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{W_{t,el}}{(1+i)^t}} \tag{5}$$

To differentiate between LCOE and LROE, one can assume that the economic efficiency of a WT can be assessed based on three essential quantities: Cost, market revenues and electricity yield. LCOE then considers the cost and electricity yield for a specific case or a specific plant. The LCOE value can be interpreted as the minimum revenue required for an economical plant operation. LROE on the other hand provides information about the market revenue potential as well as given site conditions and electricity yield. The value is therefore not just a plant information, but it also considers the market in which the plant is operating in. The main advantage and difference to the LCOE concept lies in the additional market information. Furthermore, plant costs and associated uncertainties are not included in the measured variable. The latter also leads to a good transferability to different plant concepts. The following must apply for the economic operation of a plant in a given market:

$$LROE \geq LCOE \tag{6}$$

According to this equation, the LROE can be regarded as the expectable constant revenue in a given market to cover the costs of a plant. LROE vary for the same plant in different markets.

3.1 Market results and analysis

An important question which can be answered with this model approach is, how do future energy supply scenarios influence the revenues of wind projects. For this study, two different expansion scenarios are being evaluated for the years 2019 to 2040 (22 years in total). In Figure 5 the overall installed capacity for Germany is shown for Scenario A (renewable energy expansion pursuant to the statutory expansion path of EEG 2017) and Scenario B (additional dismantling of coal and nuclear plants).

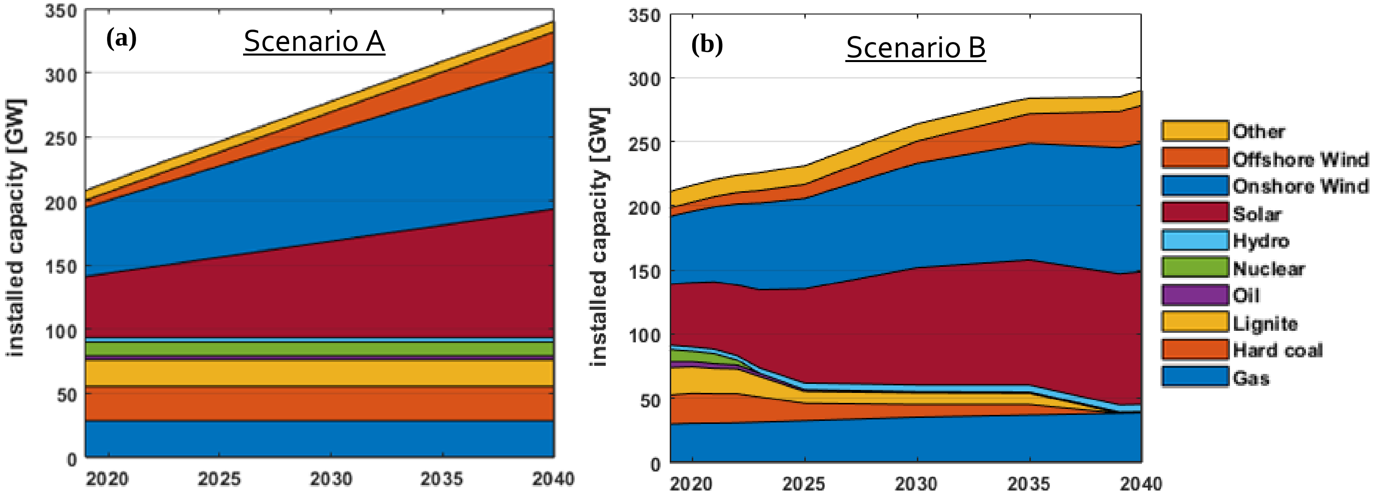

Figure 5: Installed capacity in Germany pursuant to statutory expansion (a) and additional dismantling of conventional plants (b)

It should be emphasised that Scenario A with the pure addition of renewables is not a realistic scenario. Still it can be used to indicate the influence of the renewable energy expansion on the German spot market price. Figure 6 shows the impact of the additional feed from renewables on the average spot price and price volatility while holding all remaining parameters at a constant level. Comparing Figure 6(a) and 6(b), it is visible that a higher renewable feed-in causes a decrease of the spot market price. As expected, almost constantly falling prices can be observed. The annual fluctuations are merely due to different weather conditions in the individual years. From the wind energy perspective this effect is further amplified at the hourly resolution as low prices occur especially during hours of high wind potential. Price volatility is represented in Figure 6(c) by the floating standard deviation of spot prices at a window size of 365 days. It is clearly observable how additional feed from renewables leads to an increasing fluctuation.

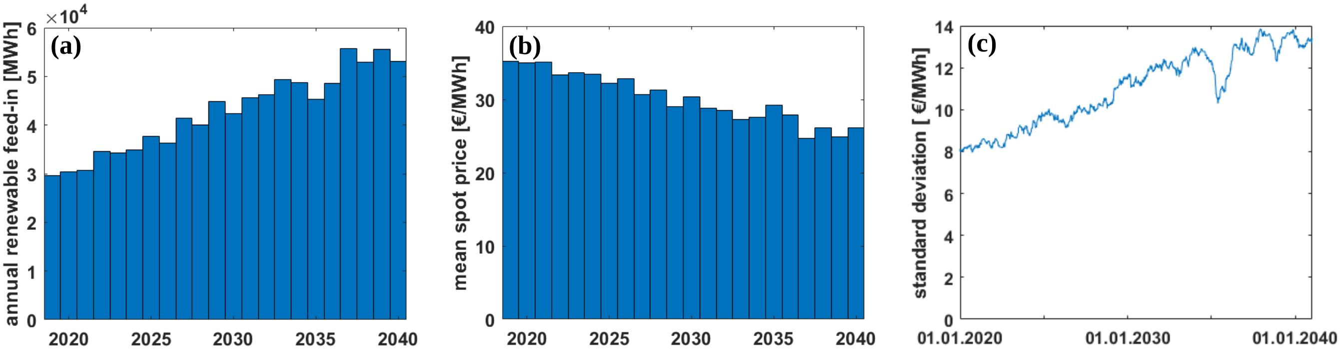

Figure 6: Influence of rising feed from renewables (a) on annual mean spot price (b) and price standard deviation (c) at otherwise constant conditions for scenario A

In contrast to the hypothetical scenario A, scenario B represents a more realistic future development. Figure 7(a) shows the model results for the average annual spot price for this scenario. In comparison to the previous, hypothetical scenario rising prices can be observed for the next five years due to the phase-out of nuclear energy. Prices will then fall until 2035 along the renewable energy expansion and finally rise again with the complete dismantling of coal energy. In this case the average price level unexpectedly remains roughly the same.

In addition to considering the two expansion scenarios, a variation in the CO_2 price for Scenario B is also investigated. Four different specific prices are respected, namely 10, 18, 30 and 60 €/t. Figure 7(b) shows the corresponding results and sensitivity of spot prices against the CO_2 price. It can be observed how an increased emission price leads to higher mean spot prices. This influence becomes stronger the more conventional plants operate within the market. The converging lines in Figure 7(b) along the expansion shown in Figure 5(b) emphasizes this relation. For Scenario A, a constant CO_2 price is assumed at 18 €/t.

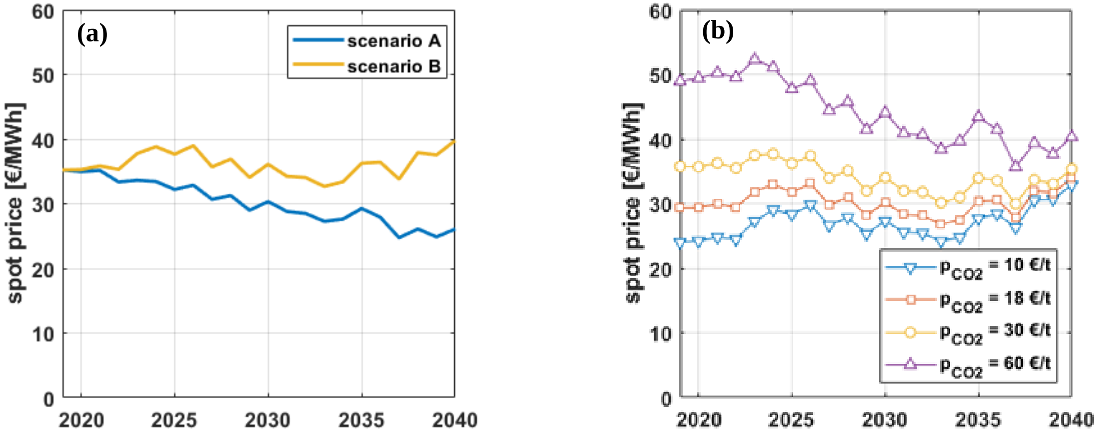

Figure 7: (a) Mean annual German spot price for the evaluated scenarios at 18€/t emission price; (b) Calculated mean annual spot price in Germany for scenario B at different CO_2 prices

3.2 Case study observing a small onshore wind park in Germany

The applicability of the model results for wind energy related investment considerations shall be demonstrated in a brief case study. Therefore, hourly SCADA data of a German wind park with 5 turbines of the 3 MW class with average full load hours of 1920 h/a has been used. Potential market revenue has been calculated based on the extrapolated SCADA data and the modelled spot price forecast over the course of the next twenty years. Figure 8 shows the LROE of the wind farm investigated for direct marketing and expansion scenario B with two different emission prices (orange bars). Finally, the results are compared by LROE to market revenue based on hypothetic PPAs with different base prices. The LROE for marketing using PPAs with different purchase prices are also shown by Figure 8 (blue bars). The two prices quoted for this study are fictitious. They can be understood as if e.g. the WT operator prepares possible price concepts prior to PPA price negotiations and compares these with various exchange price scenarios for valuation purposes. In order to assess the profitability, the results are then compared to current estimates of the LCOE of onshore wind turbines in Germany (Kost et al., 2018; IWR Online, 2019; Wallasch et al., 2019). These are shown in Figure 8 as green box plots.

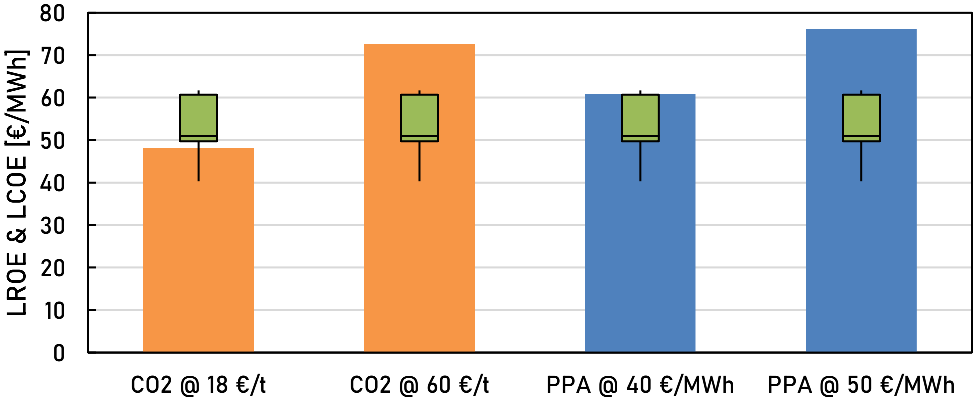

Figure 8: LROE of the observed wind park over 22 years at different emission prices for expansion scenario B (orange bars) and different PPAs (blue bars) compared to currently estimated LCOE of onshore WT in Germany (green box plots)

On the one hand, it can be stated that in the event of higher electricity exchange prices, higher revenues can be expected from direct marketing (orange bars). Furthermore, it can be observed that PPAs do not necessarily lead to higher revenues than direct marketing on the electricity exchange. Against the background of the great uncertainty at the electricity market this should be evaluated critically.

In accordance with Eq. (6) it is visible that most turbines will not be profitable without subsidies for the current case of emission prices at 18 €/t because the range of LCOE lies mostly above the LROE. For the other three situations most or all turbines would be economically efficient.

3.3 Conclusion

Different conclusions can be drawn from the above chapters. First, it can be shown based on the model presented in Sections 2.1 to 2.5 and its validation in Section 2.6 that forecasting electricity exchange prices, which are suitable for investment considerations in WTGs, is possible with low data requirements and low computational costs. Furthermore, the influences of renewable energy expansion and the decommissioning of conventional power plants can be shown in two calculation scenarios in Section 3.1. The model results in Figure 6a-c show that a pure expansion of renewables would lower the electricity price in Germany and increase its volatility. In addition, Figure 7a shows that the forecast expansion of renewables in Germany, in conjunction with the coal and nuclear power phase-out, could on average lead to constant exchange market prices with increasing volatility. Figure 7b also shows that the pricing of emissions in the coming years will have a strong influence on the exchange price, as long as many conventional power plants are still on the grid. This effect will decrease as fossil power plants are increasingly dismantled. Overall, the level of a CO2 price in the next 20 years has a very strong influence on both the exchange price and the profitability of non-subsidised WTs. Figure 8 shows that at a CO2 price of 18€/t most of the onshore wind turbines in Germany could not be operated without additional funding. Regarding the evaluation of revenue potential, LROE, as presented in Section 3, has proven to be an interesting benchmark for evaluating market developments. Just like

LCOE, LROE can be used to define and evaluate technical and financial development goals for engineering. Moreover, they allow a consideration detached from plant costs and can be used both in the negotiation of alternative sales models such as PPAs or as a benchmark for policymaking, for example in determining a suitable CO2 price, as shown in Figure 8. The subsidies in the form of the tendering procedure follow the LCOE. Accordingly, a funding which considers the LROE for different technologies would be a more holistic approach and a more indirect technology support.

4 Discussion and outlook

In the present study a model has been presented that estimates future electricity exchange prices to conclude on potential revenue of non-subsidized wind turbines. The electricity spot price is calculated using a modified merit order concept by extension with a multi-agent approach for every hour of the time period under consideration.

The developed model is constructed deliberately simple with low data requirements, mainly based on open source data to allow unproblematic adaptation and modification, which is often described as a disadvantage of modern complex optimization models. Despite the model's simplistic design, very satisfactory solutions can be obtained in terms of model evaluation and back testing for Germany. Due to the high resolution of hourly prices, a detailed analysis of daily price developments is possible.

The model results are suited for revenue estimation of wind turbine marketing models that orient by electricity exchange markets like EEX/EPEX. Also, it enables comparison of new business models like PPA against direct marketing. Therefore, the results can be e.g. used during negotiation of contract conditions and thereby strengthen the position of wind farm operators. On the other hand, the model results can be used as reference at derivation of development goals and LCOE. In this context the model delivers the corresponding break-even values at considerations like cost reduction, increase in reliability or annual energy production.

The presented model could be particularly useful in conjunction with energy yield prognosis models. During the planning phase, it could be used in combination with planning and optimization tools such as the wind farm optimizer WIFO to generate a more reliable economic yield prognosis in addition to the energy yield prognosis. (Roscher et al., 2018)

During further studies, the model shall be further extended, e.g. by implementing dynamic time series for economic parameters like emission and fuel prices. Also, additional expansion scenarios for Germany or other European countries could be simulated.

Finally, the above leads to overall reduced investment risks and therefore supports wind energy and its expansion. This in the end is a supportive step towards an ecologic electricity supply.

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