Build wind capacities at windy locations? Assessment of system optimal wind locations under feed-in tariffs

Frank Obermüller[a]

[a] *Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321a, 50827 Cologne, Germany*

Abstract

In recent years, wind power capacities have increased in many countries, mainly due to subsidy schemes. One subsidy scheme is the fixed feed-in tariff which reimburses a fixed rate for every produced kWh wind energy. This gives incentives to build wind capacities at windy locations independent of grid congestions or market price incentives. In this paper, I investigate the discrepancy between profit optimal wind locations under a fixed feed-in tariff in contrast to system optimal wind locations. The results point to structural differences between optimal locations from a profit and a system perspective. Furthermore, the analysis shows that a uniform pricing (as it is common in Europe) has significant disadvantages in incentivizing system optimal wind locations. Overall, subsidy schemes should internalize market prices as well as the transmission situation.

Keywords: Feed-in Tariff, Optimal Wind Locations, Wind Production, Electricity System Model, Nodal Pricing, Transmission Grid, Congestions

JEL classification: Q42, Q48

1. Introduction

In recent years, the installed capacities of renewable energies have steadily been increasing. This trend was achieved mainly by an additional support of subsidy schemes. The design of the subsidy scheme may differ but has a major impact on the operators' chosen location for new capacities. Since operators act mainly profit maximizing, they build new capacities at optimal locations from their investment perspective.

Dependent on the design of the subsidy scheme, the operators' optimal locations do not necessarily need to reflect optimal locations from the market or the system perspective. In case the subsidy scheme

☆I want to thank Felix Hoeffler, Andreas Knaut, Philipp Henckes, Marina Cavalcanti-Braun as well as the participants of the ASSA/AEA Annual Meeting 2017 in Chicago for their helpful support, comments and discussions. The work was carried out within the research group on Energy Transition and Climate Change (ET-CC). ET-CC is an UoC Emerging Group funded by the DFG Zukunftskonzept (ZUK 81/1).

Email address: frank.obermueller@ewi.uni-koeln.de, +49 22127729308 (Frank Obermüller)

neglects important aspects such as market price incentives, correlation effects or grid congestions, unwanted allocations from a system perspective can occur. One target could be, to adjust the subsidy scheme such that operators build capacities at optimal locations from the system perspective.

To approach this, there are two major challenges: (1) identify the system optimal locations and (2) adjust the subsidy scheme to set the right investment incentives.

I perform this analysis on the case of wind production in Germany due to several reasons. Wind capacities contribute significantly to the German electricity production. As to Energiebilanzen (2016), wind production has a share of 12.3% of the total German gross electricity production in 2015. Wind production is a main technology to achieve the energy transition to a fully renewable-based energy system in the long run. Germany have had a pure fixed feed-in tariff from 2000 to 2012 and the current scheme is still very similar to the feed-in tariff.[1] Thus, high wind production is favored which set the incentives to build wind capacities concentrated at windy locations, i.e. in windy Northern regions.

To identify system optimal locations, I base my research on the concept of the *market value* for intermittent production technologies described in Joskow (2011), Fripp and Wiser (2008) and Hirth (2013).

Hirth (2013) focuses on the estimation of the decreasing market value of wind (and solar) under a higher market share with empirically and numerically methods for different countries. He quantifies a decreasing market value trend dependent on the technologies total production share. This investigation is extended in Hirth (2016) to focus on markets with a high share of hydro-electric storage potentials. The finding is that countries with high storage potentials benefit by a dampening effect on the market value drop. Both analysis focus on a country-wise investigation.

Grothe and Müsgens (2013) extends the market value definition of Hirth (2013) and uses locational wind generation. They compare 37 exemplary wind parks within Germany and find that the locational profits of a wind turbine can be affected by up to 5-6 EUR/MWh under the German direct market regime in contrast to the fixed feed-in system. Similar results are found by Elberg and Hagspiel (2015) who use a regional copula based methodology to estimated expected market values of wind in Germany under statistically interrelations. They find a market value drop of up to 15% dependent on the specific wind turbine location. Both, Grothe and Müsgens (2013) and Elberg and Hagspiel (2015) neglect the influence of the transmission grid to the market value and focus only on electricity market prices.

However, since strong wind situations cause often inner-German grid congestions due to lagging grid

[1] An early version of the renewable feed-in subsidy scheme was implemented in 1991, see Bundesregierung (1991). The feed-in tariff was changed to a feed-in premium in 2012 (Bundesregierung, 2012) and adjusted in 2014 (Bundesregierung, 2014) and 2017 (Bundesregierung, 2017). However, the design of the feed-in premium is similar to a feed-in tariff.

extensions, the transmission situation need to be internalized in order to evaluate the system value of wind. Since Germany uses a zonal pricing approach without internalized transmission costs, the necessary information about regional prices are not available. The above described methodologies can therefore not be applied. This would result in reduced system costs and increase welfare.

In this paper, I investigate the research question, if and to what extent the fixed feed-in tariff favors investments at system optimal wind locations. To answer the questions, I need two steps: (1) Identify system optimal wind locations. (2) Compare the system optimal wind locations to the reimbursements of the fixed feed-in tariff. In contrast to above cited literature, my approach internalizes grid congestions via a nodal pricing model with an DC load flow grid representation. I derive information about the regional *market value of wind* within a zonal pricing (i.e. the current German market design) as well as the regional *system value of wind* within the nodal model (i.e. the efficient economic benchmark). My results show that the system value of wind may deviate from the market value of wind by up to 60%. Furthermore, my results show regional discrepancies between a high system value of wind and a high reimbursement by the fixed feed-in tariff. This implies inefficient investment incentives to build wind capacities compared to system friendly wind installations.

The paper is organized as follows: Section 2 describes the methodology of the nodal electricity dispatch optimization model as well as the renewable subsidy scheme (fixed feed-in tariff). Section 3 presents the results which contain the regional system value and market value of wind and the comparison to the feed-in tariff reimbursements. Section 5 concludes and identifies further research needs.

2. Methodology

To identify system optimal wind locations I use a high-resolution fundamental electricity market optimization model (description in 2.1). A nodal model representation of Germany which accounts for inner-German transmission situations gives information about the system optimal wind locations. In line with economic literature, the nodal model definition can be considered as the economic efficient benchmark due to internalized transmission costs (Burstedde, 2012; Leuthold et al., 2008; Hogan, 1999; Green, 2007).

In contrast to the theoretical efficient nodal representation, Germany and most other European countries have implemented a zonal (i.e. country-wise) market design with uniform pricing and neglection of inner-country transmission situations. Thus, I apply the optimization model as well as a country-wise uniform pricing model to account for the current market design. The differences between the regional system value of wind (under nodal pricing) and the regional market value of wind (under uniform pricing) is the increase in information by the internalization of the grid compared to the existing regional analysis of Grothe and Schnieders (2011) and Elberg and Hagspiel (2015). Note that their research focus on uniform pricing due to the current market design. However, to assess the regional system value of wind, grid situations should be considered as to Hirth et al. (2015).

I compare the regional system value of wind to the reimbursements of the German fixed feed-in tariff. This allows to identify structural differences in the relative system value and the relative reimbursements.

2.1. Model description

The applied fundamental electricity market model is a partial equilibrium model. Costs of electricity production are minimized subject to several restrictions. The model framework is PyPSA, which is an open source energy modeling framework.[2] The regional focus of the model is Germany with a nodal resolution. Neighboring countries are modeled simplified as one node without inner-country grid restrictions. The temporal focus is the year 2014 with an hourly resolution (8760 h). The used network topology is based on *open street map* and shown in figure 1.

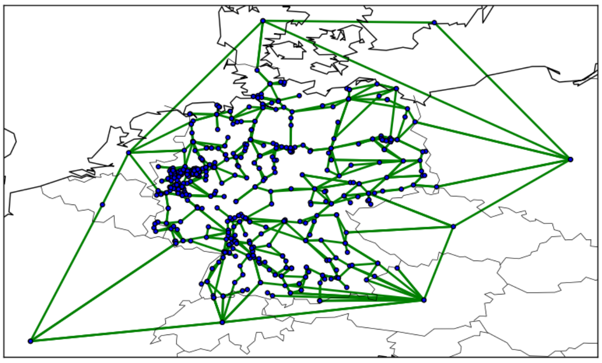


Figure 1: Network topology of the optimization model

2.1.1. Fundamental equations

The model minimizes costs of electricity production at each node subject to following main restrictions:

- *Nodal power balances:* The electricity supply needs to equal the demand at each node at each point in time. Electricity supply can be production by conventional power plants, renewable power plants,

[2] http://pypsa.org/, PyPSA Version 0.4.2, release date 17 Jun 2016

storage units as well as electricity transmission from other connected nodes. Note that production by storage units and electricity transmission can be negative in the case of storage uptake or power outflow, respectively.

- *Conventional generation constraints:* Each generators' production is restricted by its total capacity.
- *Renewable generation constraints:* Each volatile renewable generators' production (e.g. wind and solar) is restricted by an hourly differentiated capacity factor. Exact definition is described subsequently.
- *Storage constraints:* Each storage unit (e.g. pumped-hydro storage) is bounded by maximum and minimum storage levels as well as storage uptake and storage dispatch speeds.
- *Power flow:* Electricity transmission between nodes is only possible if a line exists. It is subject to line resistance and voltage magnitudes at the nodes. Note that the model is applied with a DC grid representation. For the uniform pricing electricity model, inner-German line restrictions are neglected, which is consistent with the German electricity market design.

Further typical electricity market modeling restrictions apply which can be found at `pypsa.org`. The model is not allowed to extend capacities of generators or lines.

2.1.2. Input Data

For conventional generation in Germany, the power plant list of the German regulator Bundesnetzagentur is used.[3] Neighboring countries are based on public available sources, e.g. Eurostat.

Marginal costs of conventional generations are assumed as to table 1 and have no regional differentiation.

Fuel	Marginal Costs [EUR/MWh]
Nuclear	8
Lignite	10
Hard coal	25
Gas	50
Oil	100

Table 1: Model input: Marginal costs of production

[3] `https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/Kraftwerksliste_2016.xlsx;jsessionid=918D3138AC5571338DF0C41852C766DA?__blob=publicationFile&v=2`. Version from 03. Mar 2016, filtered for end of 2014 running power plants

The demand time series is the hourly national demand from the ENTSO-e transparency platform for 2014. The German demand is distributed to the nodes via a linear regression as to the regional GDP and the regional population.

The production profile of wind energy is based on a high-resolution meteorological weather model in combination with a wind park database and described in detail in section 2.1.5.

The production profile of solar energy is modeled based on the German solar production data of EEX in combination with an regionalization approach. This is described in section 2.1.6

The transmission grid is based on the SciGRID dataset.[4]. Neighboring countries are considered as one node, such that no inner-country grid information need to apply. However, connections between neighboring countries are restricted by ENTSO-e transmission capacity data. Grid connections between neighboring countries and Germany are connected to the correspondent nodes in Germany and the typical grid characteristics (resistance, voltage magnitude) based on SciGRID.

The dispatch model will be applied with a nodal and with a uniform pricing parametrization of Germany. In the uniform pricing definition, no inner-German transmission restrictions hold. This is similar to the real-world market result. Thus, there exists one price for whole Germany. In the nodal parametrization, each transmission equations hold which results in different nodal prices.

2.1.3. model limitations

The model underlies some simplifications to make it tractable in reasonable computational time. The model is a linear optimization model and does not incorporate minimum load constraints such as unit commitment models (mixed integer linear programming, see e.g. Carrion and Arroyo (2006)). In contrast to unit commitment models, linear models have the relevant advantage that the dual variable of the electricity-balance equation can be interpreted as (perfect competitive) marginal prices which is not possible in classical mixed integer models due to non-convexities (Bjørndal and Jörnsten, 2008; Ruiz et al., 2012). The model focuses on the short-term dispatch situation such that long-term effects as investments and capacity extensions are not included. This allows to optimize pure short-run marginal costs instead recovering of full investment costs. The model has perfect information over each optimization interval and does not include e.g. stochasticity (Wallace and Fleten, 2003; Birge and Louveaux, 1997), which reduces model complexity. Heat production is neglected which overestimates production costs of combined heat and power plants. These power plants are mainly gas-fired in Germany and have comparable high marginal costs. However,

[4]`www.scigrid.de`, release date 18. July 2016, Matke et al. (2016)

the above simplifications are reasonable since the impact on the investigation focus can be considered as limited. Relevant characteristics (e.g. wind production) are modeled with high details.

2.1.4. Value of wind

We calculate the *market value of wind* according to the definition of Joskow (2011) and Hirth (2013). Thus, the market value of wind is the annual wind production weighted electricity market price divided by the annual base price:[5]

$$v_n := \frac{\mathbf{p}^T \mathbf{g}_n}{\mathbf{p}^T \mathbf{1}} = \frac{\left(\frac{\sum_t p_t g_{n,t}}{\sum_t g_{n,t}}\right)}{\left(\frac{1}{n}\sum_t p_t\right)} \qquad , \forall\ n, \tag{1}$$

where $\mathbf{p}$ is the vector of market prices (modeled system marginal costs), upper T denotes the transposition, $\mathbf{g}_n$ is the generation vector at node n, t denotes the hours, and $\mathbf{1}$ is a vector of ones of corresponding length. The denominator (mean of the marginal costs or, in other words, the annual base price) transforms the market value from EUR/MWh to a percental factor for comparability. An example calculation of the market value can be found in AppendixA in the appendix. Due to different regional wind productions at each node, we derive different market values of wind even under a uniform pricing regime.

Since the market value of wind does not internalize inner-German grid situations, we define an extended but corresponding *System Value of Wind* by following definition:

$$\tilde{v}_n = \frac{\mathbf{p}_n^T \mathbf{g}_n}{\mathbf{p}_n^T \mathbf{1}} = \frac{\left(\frac{\sum_t p_{n,t} g_{n,t}}{\sum_t g_{n,t}}\right)}{\left(\frac{1}{n}\sum_t p_{n,t}\right)} \qquad , \forall\ n. \tag{2}$$

Here, we use the nodal prices instead of the uniform prices to calculate a wind value which internalizes grid transmissions. In the nodal model, prices at two nodes may differ as the transmission between those nodes is restricted by the power flow equations.[6]

2.1.5. Description of wind data

Since the research focus is on the wind value, much emphasize is put on accurate wind production data. The data is based on Henckes et al. (2017). Here, the meteorological weather model COMSO-REA6 is applied, which calculates high-resolution wind speeds for the analyzed year on a $6km \times 6km$ grid and several vertical layers. Henckes et al. (2017) uses the derived wind speed data in combination with an European wind park dataset, which includes locations (latitude, longitude), installed capacity, hub-height, turbine

[5] More precisely, this is the definition of the *market value factor*, which will be referred subsequently as the market value for the ease of readibility and comparability.

[6] Note that the flow is restricted by the total capacity on the one hand, but also by the magnitude differences between nodes on the other hand. The magnitude difference between two nodes has also influence on the power flow to and from further connected nodes. For further information see for instance Hogan (1999).

data (incl. cut-in and cut-off wind speeds to calculate the correspondent power curves). A horizontal linear interpolation from the grid coordinates to the exact wind park location is used. On the vertical level, a logarithmic interpolation between the grid layers and the real hub-height of the wind turbines is performed. Overall, this enables to estimate wind production per wind park in Germany (and Europe). This wind production per wind turbine is allocated to the nodes in the electricity market model approach. To compensate for the difference between modeled and reported annual wind production (Energiebilanzen, 2016), the modeled wind production is equally scaled to the reported production.

2.1.6. Description of pv data

The PV production at each node is derived from the German ex-post PV production timeseries of the power exchange EEX in 2014. The total production was distributed via the regional installed capacities to the nodes. The regional installed PV capacities were taken from the *EEG Anlagestammdaten Register*, an register for all subsidized renewable production facilities in Germany. This regionalization approach has two major drawback: (1) For whole Germany, the solar radiation is assumed to be the same and (2) the distribution of the installed capacities by the register is assumed to be fixed in the upscaling process. The first assumption of a regional invariant PV capacity factor is a rather strong assumption, since the solar radiation in the South of Germany is higher than in the North (see, for instance, the *Global Atlas for Renewable Energies* from IRENA `http://irena.masdar.ac.ae/`). However, solar radiation cannot (yet) derived by the used COSMO-REA6 model due to, e.g., instantaneous clouds, fogs or snow on the PV panels. Thus, in this approach, real production data is preferred but with the drawback of a unified capacity factor. The second assumption is rather uncritical since the register covers a broad range of PV facilities.

2.2. Calculation of the wind production reimbursements by the fixed feed-in tariff

The regional reimbursements of the German subsidy scheme need to be estimated for the comparison to the modeled values of wind. The calculation is based on the fixed feed-in tariff of the German renewable energies law from 2014 (Bundesregierung, 2014).

The reimbursement for a wind turbine is dependent on the wind production and consists of two phases. In an initial phase of 5 years, a wind turbine gets an reimbursement of 8.90 €cents/kWh. Dependent on the wind production of the starting 5 years, this reimbursement is payed for a longer period (varying between 0 and 15 additional years). The lower the wind production of a wind turbine compared to the same turbine class at a (hypothetical) reference location, the longer the extension of the initial reimbursement. The exact formula can be found in the AppendixB. After the 5 years + extension duration, the reimbursement is set to 4.95 €cents/kWh. This reimbursement period (called basement reimbursement) lasts until an overall reimbursement duration of 20 years is reached (initial reimbursement period + extension + basement reimbursement period). After the total reimbursement period of 20 years, no further subsidies will be payed, but the facility may still participate in the market.

In the following, for comparison reasons, the reimbursement of an exemplary wind turbine in Germany is used. The reimbursements of the current wind park fleet would be distorting, since the wind turbines with respective hub-heights are not homogeneously distributed across Germany. The exemplary wind turbine is a 1 MW wind turbine with a hub-height of 66 m and $2380m^2$ swept area of the rotors (which can be considered as an average 1MW turbine). The theoretical reference production in the first 5 years is estimated to be 10.2 GWh, based on the data of FGW e. V. as to Bundesregierung (2014, Appendix 2).[7]

3. Results

3.1. System Value of Wind

The modeled System value of wind production as to definition (2) is calculated with the nodal model, i.e. a nodal pricing with internalized transmission costs. Nodal models are considered as the economic benchmark for the electricity system. The resulting regional system values of wind production are shown in figure 2. Statistics can be found in section AppendixC. Note that for comparison reasons, the lower range of the scale is limited to the 1%-quantile, which represents a system value of wind of 75%. The upper range is chosen symmetric to this, although the maximum system value is 111%. A structural difference between

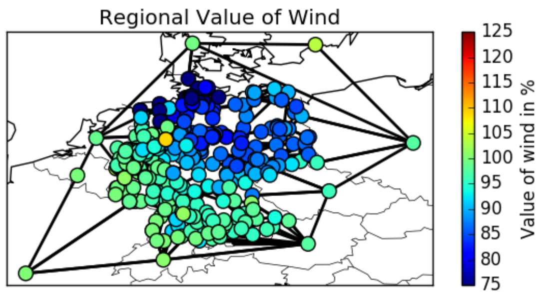


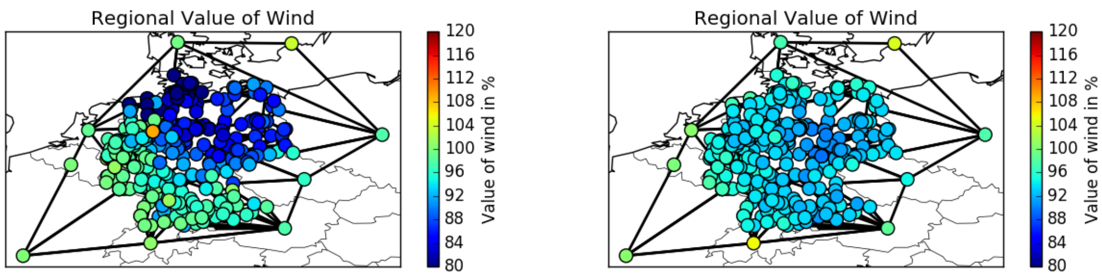
Figure 2: System value of wind production

Northern and Southern nodes becomes obvious. The structural break crosses Germany along an imaginary diagonal line from North-West to South-East. Most Northern nodes have system values of wind between 75% to 90% whereas Southern nodes have in general higher values, in the range from 95% to 100% (up to 110%).

[7]Foerdergesellschaft Windenergie und andere Erneuerbare Energien www.wind-fgw.de

3.2. Comparison of the system value to the market value of wind

Figure 3 shows the regional modeled system value and the regional market value of wind.



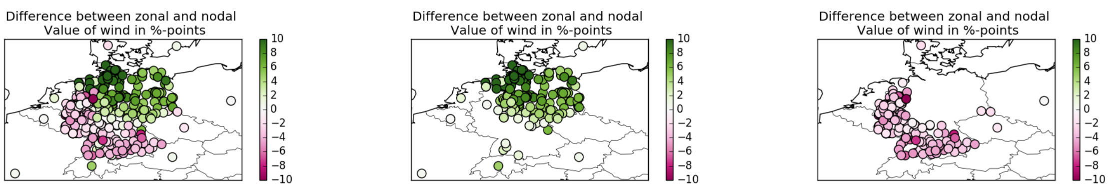
(a) Regional system value of wind

(b) Regional market value of wind

Figure 3: Comparison of the regional values of wind

Note that the colormaps are cut to the range from 80% to 120% for comparison reasons and that, for the system value of wind, wind values down to 30% exist (cf. C.8 in the appendix). The regional market value of wind has an average value of 94% and a smaller standard deviation of 2% compared to the system value of wind (mean: 91%, standard deviation: 10%). The lowest market values of wind are concentrated in the Eastern-Central part in Germany. Here, the system value of wind is low as well, but the lowest system values of wind are concentrated at the Northern coast.

The difference between the regional system value and market value of wind is shown in figure 4.



(a) All deltas

(b) Positive deltas

(c) Negative deltas

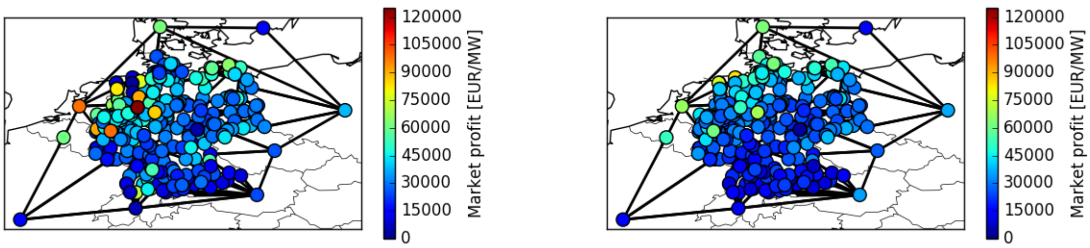
Figure 4: Difference between the system value of wind and the market value of wind

For comparison, the colormaps are restricted to ±10%. The total differences are shown in a lineplot in figure C.9 The market value of wind overestimates the value of wind in the Northern area and underestimates in the Southern area in comparison to the system value of wind.

This difference arise due to the internalization of the physical characteristics of the grid to the dispatch model. The internalized cost of transmission lead to different market prices (i.e. nodal prices) and finally to a different valuation of wind. Especially in Northern windy situations which cause grid congestions, the system value is stronger affected than the market value.

3.3. From the value of wind to wind profits

The market profits of a wind turbine are the results of the value of wind and the wind production over a certain time span. We investigate the exemplary 1 MW wind turbine for the modeled year 2014. Figure 5 shows the wind profits under nodal pricing (with the system value of wind) and under uniform pricing (with the market value of wind).



(a) Modeled wind profit under nodal pricing

(b) Modeled wind profit under uniform pricing

Figure 5: Comparison of the regional wind profits

The different valuation of wind (in combination with the regional wind production) leads to higher wind profits in the western part under nodal pricing. Northern coastal regions, which have high wind profits under uniform pricing, have lower wind profits under nodal pricing. Thus, uniform pricing may favor different locations than nodal pricing. Since nodal pricing can be considered as the efficient benchmark in this analysis, the favorable locations from the system perspective are identified in figure 5(a).

If the wind reimbursement scheme is based on the regional wind profit, this should be derived by a nodal pricing scheme. The uniform pricing would set incentives to build wind capacities at windy locations and neglect the value drop caused by the grid situation. Those locations can be less favorable from the system perspective.

Several subsidy schemes are designed to reimburse the market value of wind, at least to a certain degree. Exemplary subsidy schemes are, e.g., a full market integration or market premiums dependent on the specific electricity prices. Those subsidy schemes should be based on a nodal pricing design. Whenever uniform pricing is used to identify reimbursements, one needs to take care of unwanted disturbing effects e.g. based on grid congestions which are not internalized in the uniform pricing design.

3.4. Comparison of the system value to the fixed feed-in remuneration

The estimated reimbursement of the exemplary wind turbine at each location in Germany is calculated. The estimation is based on the formula in Bundesregierung (2014) which can be found in AppendixB and the description in section 2.2. The result can be found in figure 6. Here, the regional reimbursements are

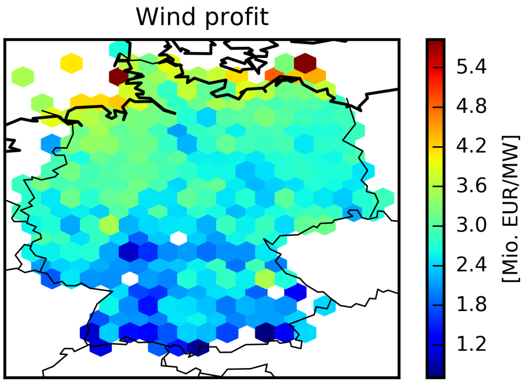
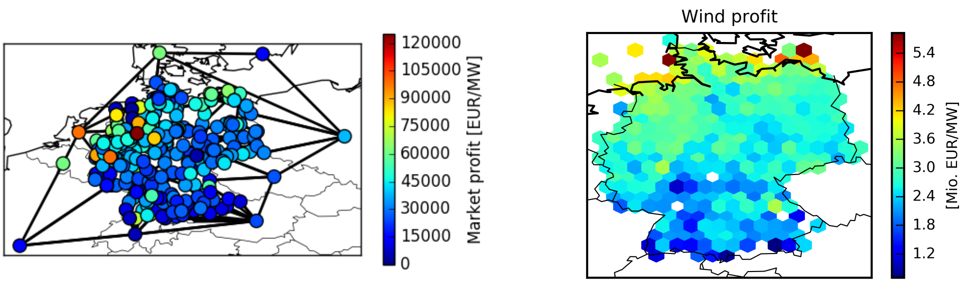


Figure 6: Regional wind reimbursements for an exemplary wind turbine

aggregated (by taking the average) to hexagons. However, finer resolutions as well as turbine representations are possible.

Figure 7 shows the comparison of the wind profits under nodal pricing (regional system value of wind) to the regional modeled feed-in tariff subsidies.



(a) Modeled annual market profit

(b) Modeled wind reimbursements of 20 years

Figure 7: Comparison of Regional Wind Profit as to EEG 2014 and regional wind value

There is a discrepancy between the modeled market profit of wind under nodal pricing and the modeled reimbursements of the fixed feed-in tariff. The feed-in tariff point to higher reimbursements in Northern regions whereas the market profit is comparable low in those areas. In the Western area, the market profits are higher but the feed-in tariff sets only limited incentives to build new wind capacities in those region.

Thus, the fixed feed-in tariff would favor other regions than it would be favorable under a nodal pricing regime.

4. Discussion

The results from section 3 imply several findings.

- If wind production would be totally integrated to a nodal electricity market without subsidies, the wind production would face the estimated regional system values of wind (cf. 3(a)). Highest system values could lead to strong investment incentives to build wind capacities in the Southern area and respect the transmission situation.

- The main reason for the structural difference of the regional system values of wind in 3(a) are major grid congestions between the North and the South along the diagonal line. Those grid congestions lead to market price differences in the nodal pricing model. Mainly congested lines were already identified by the German regulator (Bundesnetzagentur, 2016) but transmission expansions are lagging behind.

- Market integrated wind production without nodal pricing (i.e. the regional market value of wind, cf. 3(b)) would lead to structural different profits and thus investment incentives for wind in contrast to the system value of wind. New capacities could be incentivized to be built in the Northern region. This could result in further grid congestions.

- The modeled reimbursement of the fixed feed-in tariff would incentivize producers to build new wind capacities in the Northern region. Similar to the market value of wind, this could lead to increased number of grid congestions. Those grid congestions need to be managed via congestion mechanisms, e.g. re-dispatch, and cause additional costs. These reimbursements are in contrast to the system optimal wind locations which would minimize total system costs.

As wind operators act profit maximizing, they aim for building new wind capacities at most profitable locations. The findings point to a locational discrepancy between profit optimal wind location and system optimal wind location. This is also true for optimal locations under the market value with uniform picing. Thus,the neglection of the transmission situation causes wind allocation at system-unfavorable locations.

However, the derived results have a drawback. The performed analysis is static, i.e. a one-shot analysis of a current state without investment decisions. The modeled value of wind is dependent on (1) the grid structure and (2) other installed (wind) capacities. Further investments may change the regional value of wind. Additionally, further allocation of wind capacities at the same or near-by nodes cause additional correlation effects and tend to reduce the regional value of wind.

A non-regionalized fixed feed-in tariff (as been implemented in Germany) puts no incentives according to market prices or grid situations to the wind operators. Thus, non-system-favorable locations could be profit optimal. Steps to improve the subsidy scheme could be:

1. define a regionalized feed-in tariff with a substantial locational component. This approach needs regulatory knowledge about market circumstances which should be tendentially avoided
2. integrate market price incentives to a subsidy scheme (e.g. via a fixed feed-in premium or an initial capacity payment, see e.g. Pechan (2015) or Gawel and Purkus (2013))
3. internalize transmission grid situation to the subsidy scheme (via nodal prices or via a connection charges, see for instance Hiroux (2005), Hiroux and Saguan (2010) and Ackermann (2005)))

Dependent on the subsidy adjustment, more risk is transferred to the wind producers (i.e. operators). The higher risks could lead to increased investment costs (if the risk is internalized to the capital costs).

Nevertheless, a suitable subsidy scheme should incorporate the regional incentive structure. These subsidy schemes and adjustments are up to further research and can be investigated in detail with the used approach.

5. Conclusion

This paper investigates optimal wind locations from an operators perspective (given a fixed feed-in tariff) in contrast to the optimal locations from a system value perspective. Focus is the German electricity market due to a high share of wind production and regional different wind speed structures. The value of wind is assessed (1) as the *system value* of wind under nodal prices and internalized transmission congestions and (2) as the *market value* under a uniform pricing and without internalized transmission congestions. Variant (1) is considered as the economic efficient benchmark whereas (2) represents the current European market design.

The contribution to existing literature is threefold:

First, the regional system value and the regional market value of wind are quantified. The regional system values are lower for Northern locations (down to 30%) and higher for Southern locations (up to over

100%) and show a structural disruption. The regional market values are more homogenous, i.e. have smaller regional differences and smoother structural effects. Lowest market values of wind can be identified in the Central-Eastern area.

Second, the system value and the market value are compared to each other. Differences between the regional system value and market value of wind point to an overestimation of Northern wind locations (windy area with high installed wind capacities) and an underestimation of Southern wind locations (low wind area with less installed capacities) in contrast to the system value of wind, i.e. where the grid situation is neglected. The delta ranges from +10%-points to -70%-points in the wind values.

Third, the modeled system value of wind is compared to the exemplary modeled reimbursements of a fixed feed-in tariff as implemented in Germany in 2012. The analysis shows a discrepancy between the system value of wind and the investment incentivizing subsidies. Northern wind locations receive higher reimbursements and thus have an higher investments incentive than Southern locations. Additional Northern wind investments would therefore enlarge cannibalization effects as well as grid congestion effects and lead to a further decrease of the Northern system value of wind. The profit maximizing locations under the fixed feed-in tariff are thus non-system-favorable.

To achieve homogenous (or at least not further diverging) regional system values of wind, an extension of the fixed feed-in tariff with stronger regional subsidy incentives need to be investigated as well as other subsidy schemes as market premiums or initial capacity payments. The used methodology can be applied.

References

Ackermann, T. (2005). Wind Power in Power Systems. In *Wind Power in Power Systems*. John Wiley & Sons, Ltd.

Birge, J. and Louveaux, F. (1997). *Introduction to stochastic programming*, volume 9. Springer-Verlag.

Bjørndal, M. and Jörnsten, K. (2008). Equilibrium prices supported by dual price functions in markets with non-convexities. *European Journal of Operational Research*, 190(3):768–789.

Bundesnetzagentur (2016). Monitoring Report 2015. Technical report, Bundesnetzagentur.

Bundesregierung (1991). Gesetz über die Einspeisung von Strom aus erneuerbaren Energien in das öffentliche Netz (Stromeinspeisungsgesetz) vom 07. Dezember 1990 (BGBl I S. 2633).

Bundesregierung (2012). Gesetz zur Neuregelung des Rechtsrahmens für die Förderung der Stromerzeugung aus erneuerbaren Energien Vom 28. Juli 2011.

Bundesregierung (2014). Erneuerbare-Energien-Gesetz vom 21. Juli 2014 (BGBl. I S. 1066), das durch Artikel 1 des Gesetzes vom 13. Oktober 2016 (BGBl. I S. 2258) geändert worden ist.

Bundesregierung (2017). Gesetz zur Einführung von Ausschreibungen für Strom aus erneuerbaren Energien und zu weiteren Änderungen des Rechts der erneuerbaren Energien Vom 13. Oktober 2016.

Burstedde, B. (2012). From nodal to zonal pricing: A bottom-up approach to the second-best. In *2012 9th International Conference on the European Energy Market*, pages 1–8.

Carrion, M. and Arroyo, J. M. (2006). A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem. *IEEE Transactions on Power Systems*, 21(3):1371–1378.

Elberg, C. and Hagspiel, S. (2015). Spatial dependencies of wind power and interrelations with spot price dynamics. *European Journal of Operational Research*, 241(1):260–272.

Energiebilanzen, A. (2016). Bruttostromerzeugung in Deutschland ab 1990 nach Energieträgern.

Fripp, M. and Wiser, R. H. (2008). Effects of Temporal Wind Patterns on the Value of Wind-Generated Electricity in California and the Northwest. *IEEE Transactions on Power Systems*, 23(2):477–485.

Gawel, E. and Purkus, A. (2013). Promoting the market and system integration of renewable energies through premium schemes—A case study of the German market premium. *Energy Policy*, 61:599–609.

Green, R. (2007). Nodal pricing of electricity: how much does it cost to get it wrong? *Journal of Regulatory Economics*, 31(2):125–149.

Grothe, O. and Müsgens, F. (2013). The influence of spatial effects on wind power revenues under direct marketing rules. *Energy Policy*, 58:237–247.

Grothe, O. and Schnieders, J. (2011). Spatial dependence in wind and optimal wind power allocation: A copula-based analysis. *Energy Policy*, 39(9):4742–4754.

Henckes, P., Knaut, A., and Obermüller, F. (2017). Twenty Years of European Wind Power Production – Balancing Effects in Europe with a Focus on Germany (Submission-ID WIW16-127). In *Proceedings of the 15th Wind Integration Workshop, Vienna.*

Hiroux, C. (2005). The integration of wind power into competitive electricity market: the case of the transmission grid connection charges. In *28th annual IAEE international conference. Taipei, June*, pages 3–6.

Hiroux, C. and Saguan, M. (2010). Large-scale wind power in European electricity markets: Time for revisiting support schemes and market designs? *Energy Policy*, 38(7):3135–3145.

Hirth, L. (2013). The market value of variable renewables: The effect of solar wind power variability on their relative price. *Energy Economics*, 38:218–236.

Hirth, L. (2016). The benefits of flexibility: The value of wind energy with hydropower. *Applied Energy*, 181:210–223.

Hirth, L., Ueckerdt, F., and Edenhofer, O. (2015). Integration costs revisited – An economic framework for wind and solar variability. *Renewable Energy*, 74:925–939.

Hogan, W. A. (1999). Transmission congestion the nodal-zonal debate revisited.

Joskow, P. L. (2011). Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies. *The American Economic Review*, 101(3):238–241.

Leuthold, F., Weigt, H., and von Hirschhausen, C. (2008). Efficient pricing for European electricity networks – The theory of nodal pricing applied to feeding-in wind in Germany. *Utilities Policy*, 16(4):284–291.

Matke, C., Medjroubi, W., and Kleinhans, D. (2016). *SciGRID - An Open Source Reference Model for the European Transmission Network (v0.2).*

Pechan, A. (2015). The Effect of Market Design on Spatial Distribution of Wind Energy Installation. *Oldenburg: Carl von Ossietzky Universität.*

Ruiz, C., Conejo, A. J., and Gabriel, S. A. (2012). Pricing Non-Convexities in an Electricity Pool. *IEEE Transactions on Power Systems*, 27(3):1334–1342.

Wallace, S. W. and Fleten, S.-E. (2003). Stochastic Programming Models in Energy. In Science, B. H. i. O. R. a. M., editor, *Stochastic Programming Models in Energy*, volume 10 of *Stochastic Programming*, pages 637–677. Elsevier.

Appendix

AppendixA. Example of the calculation of the market value

Table A.2 shows an exemplary calculation of the market value which is the wind production weighted market price divided by the annual base price.

Hour	Market price [EUR/MWh]	Wind production [MWh]	Market price x Wind production [EUR]	Market value [EUR/MWh]
1	40	20	800	16
2	45	15	675	13,5
3	50	10	500	10
4	55	5	275	5,5
5	60	0	0	0
	Mean = 50	Sum = 50	Sum = 2250	Sum = 45

Table A.2: Example of the calculation of the market value

The market value factor as used in the analysis is given by the fraction of the market value (here: 45 EUR/MWh) and the mean market price (here: 50 EUR/MWh) which results in 90%.

AppendixB. Formula for the calculation of the reimbursement duration of a wind turbine

The additonal duration for the initial reimbursement is based on

$$months = \left\lfloor 1.3 - \frac{Production}{ReferenceProduction} \cdot \frac{100}{0.36} \right\rfloor + \left\lfloor \frac{Production}{ReferenceProduction} \cdot \frac{100}{0.48} \right\rfloor \tag{B.1}$$

here, $\lfloor\ \rfloor$ is the floor (or round-off) function, $referenceProduction$ is the estimated production in the starting 5 years of a same-technology wind turbine with 5.5 m/s average wind speed in 5 years on 30 meters hub-height, corrected for the real hub-hight via a logarithmic wind increase and roughness length of 0.1 meter. A description can be found in Bundesregierung (2014, Appendix 2 (4))

AppendixC. Statistics to the system value and the market value of wind

	System value of wind	Market value of wind
mean	91.16	93.78
std	10.37	1.79
min	30.88	89.44
25%	86.69	92.76
50%	94.23	93.72
75%	97.77	94.54
max	110.87	105.71

Figure C.8 shows the histograms of the system value and the market value of wind. The system value

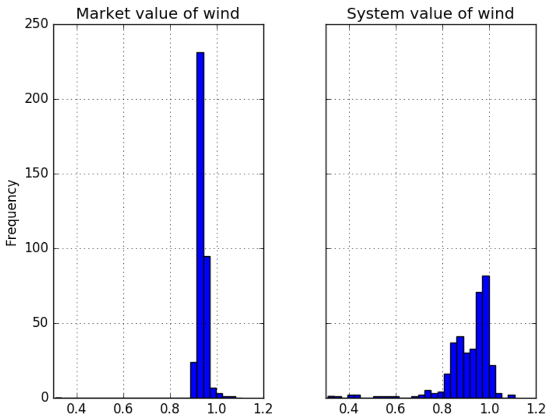


Figure C.8: Histogram of the modeled values of wind

has a broader range and less values around 100% in comparison to the market value.

Figure C.9 shows the differences between the system value of wind and the market value of wind for the nodes in a lineplot with ascending order.

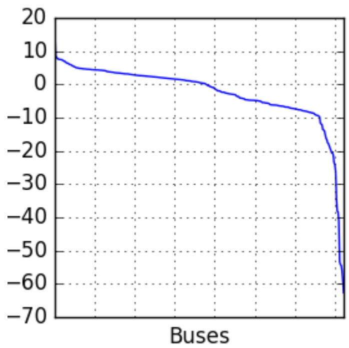


Figure C.9: Lineplot of the difference between the system value and the market value of wind (y-axis is delta in %-points)