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EWI Working Paper, No 17/09

September 2017

Institute of Energy Economics at the University of Cologne (EWI)  
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ISSN: 1862-3808

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# Build wind capacities at windy locations? Assessment of system optimal wind locations

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## Abstract

In recent years, the installed capacities of renewable energies have steadily been increasing. This raises the question for optimal locations of renewables. Ideally, the market prices induce efficient locations. Distorting effects, i.e. non incorporation of the physical grid situations, could lead to sub-optimal regional incentives compared to a system optimal perspective. In this paper, the wind production revenues under nodal and zonal pricing are investigated. The analysis is extended to the widely used wind value factor. The analysis identifies the zonal pricing wind revenues as inefficient location signals. Location signals need to consider the grid situations. Wind revenues could face an average increase of 21% and more than 200% for certain locations. This is highly relevant to design efficient subsidy schemes or to identify regional grid and capacity extension necessities.

*Keywords:* Optimal Wind Locations, Wind Production, Market Revenues, Market Value, Electricity System Model, Nodal Pricing, Zonal Pricing

JEL classification: Q42, Q48

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<sup>\*</sup>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 and the IEWT 2017 Conference in Vienna 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 University of Cologne Emerging Group funded by the DFG Zukunftskonzept (ZUK 81/1).

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## 1. Introduction

The energy transition promotes huge extensions of renewable capacities. This was mainly achieved by subsidy schemes. Several common subsidy schemes are (to some extent) decoupled from market price signals as for instance the fixed feed-in tariff (see Couture and Gagnon (2010)). The IEA strongly encourages the market integration of renewable energies (IEA, 2016) in the long-run. This transfers market incentives to the renewable operators and should increase efficient locational investments and production decisions. Especially volatile renewables need to consider regional simultaneity effects in production (also known as regional correlation or self-cannibalization effects (Hirth and Müller, 2016; Kreuz and Müsgens, 2017)). Thus, the market situations with their timely varying electricity prices (dependent mainly on demand, supply and nowadays weather) have an increased importance to choose optimal renewable locations. From an operator's perspective, optimal locations aim for a maximization of the renewables' profits which transfers to a maximization of revenues due to almost zero marginal costs of wind production.

However, the market revenues under zonal pricing might incentivize sub-optimal system locations. In markets with zonal pricing, physical grid situations and congestion are not necessarily internalized in the market prices within the bidding zones. This holds true for instance for the European electricity markets. Thus, a discrepancy could occur between the optimal locations under *zonal pricing* (i.e. without internalized transmission situations) and the optimal locations under *nodal pricing* (i.e. with internalized transmission situation). Despite the revenues, the market value factor is widely used as an indicator to assess the contribution to the electricity market especially for renewables. The market value factor is the relation between the production-weighted revenues per MWh and the average market price. Based on regional market value analyses, insights on beneficial locations could be derived as well. However, the market value as an aggregated indicator is lacking essential information like total production levels and the corresponding time structures. Therefore, it is questionable if the market value factor is suitable to assess regional production signals.

In this paper, two relevant questions are answered to identify optimal renewable locations: (1) Are the *revenues under nodal pricing* the preferable indicator to assess optimal renewable locations compared to the *revenues under zonal pricing*? And (2), are the value factors of renewables sufficient to evaluate optimal locations? Both findings are highly relevant for the design of subsidy schemes as well as capacity and grid extension processes and of course for the adequate evaluation of wind production.

The analysis is performed on the case of wind production in Germany due to several reasons. Wind capacities contribute significantly to the German electricity production. As to AG Energiebilanzen (2017),

wind production has a share of 12.1% of the total German gross electricity production in 2016. Wind production is a main technology to achieve the energy transition to a highly renewable-based energy system in the long run. Germany has built a dominant share of its wind capacities at northern windy locations favored by an implemented feed-in tariff.<sup>1</sup> This implies challenges to the transmission grid in some situations. Primarily in situations with strong wind (and low demand), the grid is not capable to transfer the wind production to the load centers (Kunz, 2013). Therefore, strong deviations between the optimal wind locations under zonal or nodal pricing can be expected.

The underlying research is based on two literature fields: The optimal wind locations from an operator’s perspective as well as the market value factor. Existing research on optimal wind locations cover mainly the electricity systems (or markets) perspective in order to reduce integration costs or smooth the production profiles. This is the case for instance in Roques et al. (2010) who identify risk-minimal or volatility-minimal wind locations on a country level (DE, AT, FR, DK, ES) under cooperation. In contrast to this, the operators’ potential revenues are identified since this should be the economical main objective for new wind capacities. Additionally, the focus lies on inner-country effects as in Grothe and Schnieders (2011). In contrast to the underlying research, they aim at smoothed production instead of operators’ optimal locations. Burke and O’Malley (2008) and Burke and O’Malley (2011) focus on optimal wind locations under a revenue maximizing perspective. They identify optimal locations in nodal pricing test networks with consideration of physical transmission characteristics. However, they do not consider high-resolution real world data (as it is done for Germany) and they do not compare the the nodal pricing revenues to the typical zonal pricing revenues. Pechan (2015) is very close to the underlying research in that way that she compares (among others) the spatial distribution effects on wind capacity under a nodal and under a zonal market premium subsidy scheme. In contrast to the present research, she uses a strongly simplified model with six nodes and eight lines. Furthermore, she assumes additional subsidy schemes (fixed feed-in tariff or market premium under nodal and under uniform) instead of a pure market integration. The subsidy schemes may distort the optimal wind locations by its additional income stream (cf. Wagner (2016)).

The second branch of literature focuses on the *market value* of intermittent production technologies applied for instance in Joskow (2011), Fripp and Wiser (2008) and Hirth (2013). The market value widely serves as an indicator for the contributed value of renewables to the electricity markets. Hirth (2013) focuses on the estimation of the decreasing market value of wind (and solar) under a higher market share

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<sup>1</sup>An early version of the renewable feed-in tariff was implemented in 1991 (see Bundesregierung (1991) which was adjusted in between and lasts until 2012. In 2012, the feed-in tariff was changed to a feed-in premium (Bundesregierung, 2012) and adjusted in 2014 (Bundesregierung, 2014) and 2017 (Bundesregierung, 2017). However, the design of the feed-in premium is still very similar to a feed-in tariff and might favor the similar locations.

with empirically and numerically methods for different countries. This investigation is extended in Hirth (2016) (to account for hydro-electric storage potentials). Both analysis consider a country-wise investigation in contrast to the underlying regional, i.e. inner-country focus. 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 are affected (dependent on the subsidy scheme). Similar results are found by Elberg and Hagspiel (2015) who use a regional copula based methodology to estimated regional expected market values of wind in Germany. Both, Grothe and Müsgens (2013) and Elberg and Hagspiel (2015) focus only on wholesale electricity market prices and neglect the influence of the transmission grid to the market value. As mentioned in Hirth et al. (2015) and as we see in the analytical analysis of Wagner (2016), the transmission situation might have strong impacts on capacity locations. Due to inner-German grid congestion, the values as well as the revenues are expected to deviate strongly with and without consideration of the transmission situation. This research considers, identifies and compares these distorting effects.

To achieve new insights, the underlying research is based on a nodal electricity market model with a DC load flow grid representation for Germany. This allows to consider the physical transmission situations, necessary for the assessment of the optimal wind locations. The main advantage of the underlying modeling methodology is the possibility to consider one electricity system with two different pricing regimes (zonal pricing and nodal pricing). Such a comparison is not possible with classic empirical methods since zonal and nodal pricing data do not exist simultaneously. Additionally, the endogeneity between wind production and electricity prices is represented in the present model which could be hard to include within empirical models (especially for future situations). The underlying methodology is applied for the modeled year 2014. However, the methodology is easily extendable to consider future years (regarding grid and capacity situations).

The present results are distinguished between the nodal pricing perspective, which internalizes physical transmission situations, and the zonal pricing perspective, which abstracts from electricity transmission. The zonal pricing regime represents the current design of most European electricity markets (among them Germany). The nodal pricing regime is applied for instance in the US electricity markets of PJM or ISO New England (Joskow (2005) or Litvinov (2010)). It can be considered as an economic benchmark compared to the zonal pricing, since costs for transmission and congestion are internalized Hogan (1999). For the nodal and zonal perspective, the wind revenues as well as the wind value factors are analyzed and compared.

The paper is organized as follows: Section 2 describes the methodology of the (nodal) electricity dispatch

optimization model. Based on this, relevant data is derived to evaluate the revenues and value factors of wind. Section 3 compares the results under nodal pricing to the results under zonal pricing. The analysis is applied, first for the revenues and afterwards for the value factors. Section 4 discusses the results and shows the significance for locational signals as well as the design of subsidy schemes. Section 5 concludes and identifies further research.

## 2. Methodology

To identify optimal wind locations, high-resolution fundamental electricity market optimization model is applied (description in 2.1). A nodal model representation of Germany which respects inner-German transmission situations gives information about the 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 (see for instance Schweppe et al. (1988) and later discussed in Hogan (1999), Chao et al. (2000), Green (2007), Leuthold et al. (2008), Burstedde (2012)).

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 neglect inner-country transmission situations in the wholesale market prices.

In zonal electricity markets, re-dispatch is a possible congestion management mechanism. As soon as the market-driven dispatch, i.e. the planned power plant utilization, leads to critical transmission line utilizations, an adjustment is performed. The responsible TSO instructs producers (regionally) before the grid congestion to reduce their production. In the same time, producers (regionally) behind the grid congestion are instructed to increase production. This production shift reduces the electrical power flow on the congested lines. A financial compensation for the shifting producers is paid which does not affect wholesale market prices. Especially the extension of wind and PV production have increased the problem of (weather-driven) grid congestion. In 2010, 1588 hours of re-dispatch were necessary. This number steadily increased in the subsequent years to 5030 hours in 2011, 7160 hours in 2012, 7965 hours in 2013 to 8453 hours in 2014 (see Bundesnetzagentur (2016)). As one main driver, the strong increase in northern wind production is mentioned.

In contrast to a zonal model with re-dispatch, a nodal model accounts implicitly for grid congestion and leads to market price deviations. These price deviations would directly give monetary incentives for electricity production, especially for northern wind producers. Thus, it is highly-relevant to analyze the market revenues for wind producers under a realistic nodal electricity valuation (which includes grid congestion externalities)

instead of observing the artificial zonal wind valuation (with re-dispatch). To analyze the differences in wind valuation, the optimization model is applied with a nodal pricing configuration as well as a country-wise uniform (zonal) pricing configuration.

## 2.1. General model description

The applied fundamental electricity market model is a partial equilibrium model. Costs of electricity production are minimized under a inelastic demand function and subject to typical electricity market model restrictions (see next section). The model framework is PyPSA, which is an open source energy modeling framework.<sup>2</sup> 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. Overall, the model incorporates 575 nodes and 854 connecting lines. The temporal focus is the year 2014 with an hourly resolution (8760 h). The model optimization assumes perfect foresight and neglects uncertainty for the corresponding timeframe. The considered network topology is shown in figure 1 and based on *SciGRID* (Matke et al., 2016, [www.scigrid.de](http://www.scigrid.de)).

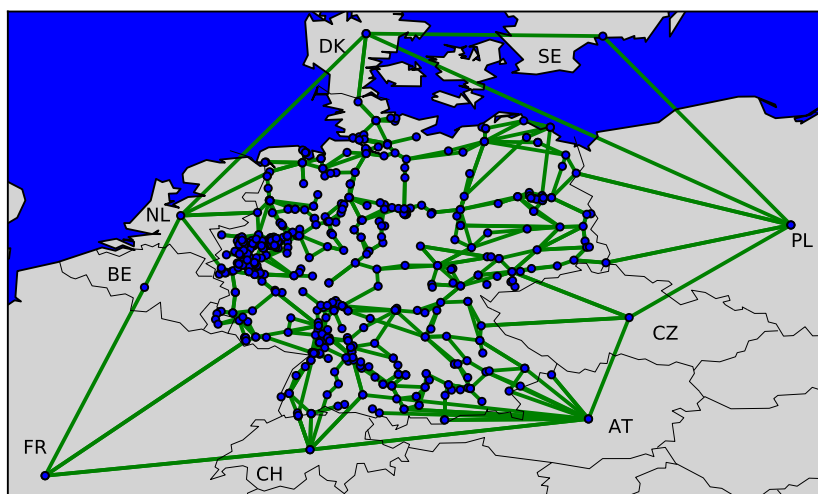


Figure 1: Network topology of the optimization model. The focus is a nodal resolution in Germany with its surrounding neighbor countries. Each dot represents one node, which are connected via transmission lines (220 kV and 380 kV).

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<sup>2</sup><http://pypsa.org/>, PyPSA Version 0.4.2, release date 17 Jun 2016

## 2.2. Fundamental equations

The model minimizes short run total system costs of the electricity production, which are the sum of the short run marginal generation costs times the generation over all nodes  $n$ , supply technologies  $s$  and timesteps  $t$ :

$$\min Totalcosts = \sum_{n,s,t} marginalCosts_{n,s,t} * gen_{n,s,t} \quad (1)$$

This is subject to following main restrictions:

- *Nodal power balances:* The electricity supply needs to equal the demand for each node  $n$  and each timestep  $t$ . Electricity supply can be provided by nodal generation  $gen_{n,s,t}$  as well as electricity flow from connected nodes  $flow_{l,t}$ :

$$\forall n, t : \quad \sum_s gen_{n,s,t} + \sum_l K_{n,l} flow_{l,t} = demand_{n,t} \quad (2)$$

Here,  $K_{n,l}$  denotes the incidence matrix which determines the connection of each line  $l$  to the corresponding nodes  $n$ . The generation  $gen_{n,s,t}$  reflects production of conventional power plants, renewable power plants and storage units. Note that production by storage units and electricity flow can be negative in the case of storage uptake or power outflow, respectively.

- *Generation constraints:* Each generators' production (conventionals, renewables and storages) for each timestep  $t$  is restricted by its total capacity adjusted by the time-dependent availability:

$$\forall n, s, t : \quad 0 \leq gen_{n,s,t} \leq availability_{n,s,t} capacity_{n,s}. \quad (3)$$

The availability for renewable energies (i.e. wind and solar) is restricted to the exogenous capacity factors.

- *Storage constraints:* Each storage unit (e.g. pumped-hydro storage) is bounded by maximum and minimum storage levels (similar to equation (3)) as well as storage uptake and storage dispatch speeds and efficiencies. Storage inflow and losses may apply, dependent on the exact storage technology. Uncertainty is neglected, which generally tends to underestimate the value of storages (and flexible power plants).
- *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 on voltage magnitudes. For a line  $l$  which is defined from node  $n$  to node  $m$ , the

following equation holds:

$$\forall l, t : \quad flow_{l,t} = \frac{\delta V_{n,t} - \delta V_{m,t}}{resistance_l} \quad (4)$$

in which  $\delta V_{n,t}$  represents the voltage magnitude. For details, see for instance Gabriel et al. (2012, Appendix C). For the zonal 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](http://pypsa.org); among them efficiency losses or ramping constraints. The applied model is configured to not allow for capacity extensions of generators or lines.

### 2.3. Input Data

For conventional generation in Germany, the power plant list of the German regulator Bundesnetzagentur is used.<sup>3</sup> The power plants are matched to the nodes by its smallest distance. 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

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 the share of the regional GDP and the regional population. A detailed description can be found in Appendix A. The distribution accounts for annual values and neglects hourly demand variations.

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 2.7. The production profile of solar energy is modeled based on the German solar production data of EEX in combination with a regionalization approach. This is described in Section 2.8

<sup>3</sup>[https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen\\_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/Kraftwerksliste\\_2016.xlsx](https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/Kraftwerksliste_2016.xlsx). Version of 03. Mar 2016, filtered for end of 2014 running power plants

The transmission grid (i.e. 220 kV to 380 kV voltage levels) is based on the SciGRID dataset<sup>4</sup>. The distribution grid (i.e. voltage levels below 220 kV) cannot be considered due to insufficient data availability. Neighboring countries are considered as one node, such that no inner-country grid information is required. 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 is applied with two configurations which will be compared to each other in the latter analysis. First, the dispatch model will be applied with a nodal pricing configuration of Germany. The inner-German transmission restrictions must not be violated which results in different nodal prices. Second, the zonal pricing configuration is applied which means that no inner-German transmission restrictions hold. This is similar to the current German market design with one wholesale electricity price. In the real market, re-dispatch is applied to ensure network stability. In this modeled zonal pricing system, the consideration of re-dispatch is not necessary since the focus is on the market revenues and not on the technical feasibility of the load flows. Thus, the costs of re-dispatch (which increase total system costs but not the market revenues e.g. of wind production) are out of the scope of the investigation.

#### *2.4. 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 as applied in 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 (perfectly 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 situations such that long-term effects as investments and capacity extensions are not included (as e.g. in Bertsch et al. (2016)). This reduces the model size and allows for a high number of inner-country nodes (>500 nodes and >800 lines) instead of a country-wise representation. The model has perfect information over each optimization interval and does not include e.g. stochasticity (as described for instance in Wallace and Fleten (2003) or Birge and Louveaux (1997)), which reduces model complexity. Heat production is neglected which implies that we overestimate in the model the cost of combined heat and power.

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<sup>4</sup>[www.sci-grid.de](http://www.sci-grid.de), release date 18. July 2016, Matke et al. (2016)

## 2.5. Revenues of wind

In the results chapter, we investigate and compare the revenues of wind turbines as these are the relevant criteria for the regional investment decisions of operators. Marginal costs of wind production are almost zero and thus profit maximization translates to revenue maximization. Regional site costs are assumed to not deviate across the nodes and are thus neglected. The wind revenues  $R_{n,wind}$  at a given node  $n$  from the electricity market (without subsidies) can be expressed via:

$$R_{n,wind} = \sum_{t \in T} p_t \text{ gen}_{n,wind,t} \quad (5)$$

$$\tilde{R}_{n,wind} = \sum_{t \in T} p_{n,t} \text{ gen}_{n,wind,t} \quad (6)$$

where  $T$  is the total time span (here: 8760 hours of the year 2014),  $p_t$  is the electricity price [€/MWh] in hour  $t$ , and  $\text{gen}_{n,wind,t}$  is the generation in [MWh] at bus  $n$  for supply tech *wind* in hour  $t$  normed to 1 MW (for comparison reasons). Note that the difference between the revenues is the electricity price which is uniform in the first case and node-differentiated in the second case. Thus,  $R$  reflects the revenues under zonal pricing whereas  $\tilde{R}$  reflects the revenues under nodal pricing and consideration of internal physical transmission situations. Note that the modeled revenues in general do not incorporate any subsidy payments. Figure 2 illustrates the difference between the zonal and nodal revenues with a simplified two-nodes example. In

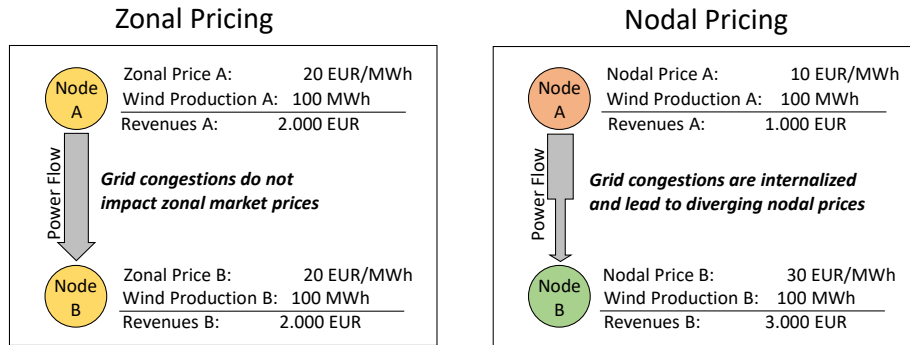


Figure 2: Simplified two-node illustration of the difference between the revenues under zonal pricing (left) and nodal pricing (right). Assume that we have two nodes which are connected by one transmission line. In the case where the transmission line is congested, we still face the same prices for Node A and Node B in the zonal pricing regime. The same situation could lead to price differences under nodal pricing. For identical wind production at both nodes, the revenues are identical in the zonal pricing regime (independent of the grid situation) and deviating in the nodal pricing regime.

case of a grid congestion, the market prices are nevertheless identical in the zonal pricing regime, whereas price deviation could occur in the nodal pricing regime. Under identical wind production at both nodes, the revenues are identical under zonal pricing whereas the prices deviate under nodal pricing. Note that for the German case, typically, the northern wind production is higher due to higher wind speeds and higher wind

power capacities. In windy situations, this leads to potential grid congestion from north to south. However, under zonal pricing, one MWh northern wind production is remunerated equally to one MWh southern wind production even in the case of grid congestion. Under nodal pricing, equal remuneration of one unit wind production is not necessarily the case. Thus, wind production receives the regional market price of energy.

## 2.6. Value of wind

We calculate the *market value factor of wind* according to the definition of Joskow (2011) and Hirth (2013). Thus, the market value factor of wind can be interpreted as the relation between the production-weighted wind revenues and the average market price.<sup>5</sup> It is defined as

$$\forall n : \quad v_n := \frac{\mathbf{p}^T \mathbf{g}_n}{\mathbf{p}^T \mathbf{1}} = \frac{\left( \frac{\sum_t p_t \text{gen}_{n,wind,t}}{\sum_t \text{gen}_{n,wind,t}} \right)}{\left( \frac{1}{n} \sum_t p_t \right)} \quad (7)$$

where  $\mathbf{p}$  is the vector of market prices (modeled system marginal costs), upper  $T$  denotes the transposition,  $\mathbf{g}_n$  is the generation weights vector at node  $n$ ,  $t$  denotes the hours, and  $\mathbf{1}$  is a vector of ones of corresponding length. The denominator of the average market price transforms the market value from EUR/MWh to a percental factor for comparability. A market value factor of 90% indicates that a producer is able to derive 90% of the average market price with its (volatile) production compared to a permanent operating producer. That could be the case, if the (volatile) production has a market price reducing effect, as it is the case of zero-marginal-cost renewable production like wind and PV. A market value factor of above 100% is possible, for instance if production is available in peak price situations. Due to different regional wind production profiles at each node, we derive different market value factors of wind even under a zonal pricing regime.

Since the market value factor of wind does not internalize inner-German grid situations, we define the *nodal market value factor of wind* which considers regional prices by:

$$\forall n : \quad \tilde{v}_n := \frac{\mathbf{p}_n^T \mathbf{g}_n}{\mathbf{p}_n^T \mathbf{1}} = \frac{\left( \frac{\sum_t p_{n,t} \text{gen}_{n,wind,t}}{\sum_t \text{gen}_{n,wind,t}} \right)}{\left( \frac{1}{n} \sum_t p_{n,t} \right)}. \quad (8)$$

## 2.7. Description of wind data

Since this research focuses on the wind revenues and wind values, much emphasis is put on accurate wind production data. The data is based on Henckes et al. (2017). Here, the novel meteorological weather model COMSO-REA6 is applied, which calculates among others, high-resolution wind speeds for the analyzed year on a  $6\text{km} \times 6\text{km}$  grid and several vertical layers. Henckes et al. (2017) uses the derived wind speed data

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<sup>5</sup>The value factor is more suitable for later comparison since it is denominated by the base price and shows the relative value drop instead of the absolute value drop.

in combination with a European wind park dataset, which includes locations (latitude, longitude), installed capacity, hub-height, turbine 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 high-detailed wind production per wind park in Germany (and Europe). Figure 3 visualizes the capacity distribution, the capacity factors as well as the regional production correlations (aggregated to hexagons) for Germany (cf. Henckes et al. (2017)). The hexagon's production correlation is compared to the total German production timeseries. The wind

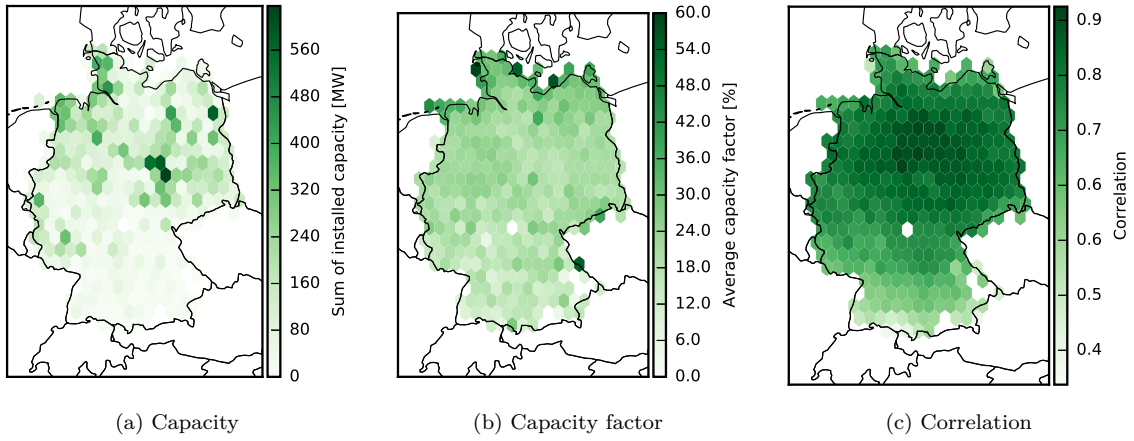


Figure 3: Wind data for Germany aggregated to hexagons: a) Sum of installed capacity within each hexagon, b) average capacity factor of wind turbines in each hexagon, and c) correlation of energy production in each hexagon with the total German wind energy production. Data from Henckes et al. (2017).

production per wind turbine is allocated to the nodes by the smallest distance in the electricity market model approach. The wind data of 2014 is chosen for this investigation from the total dataset (covering each year from 1995-2014 in hourly resolution). First reason is consistency to the demand and solar production year. The second reason is an almost average occurrence of extreme situations (low wind and high wind situations) as well as capacity factor in 2014 compared to the 20-year average (cf. Henckes et al. (2017)). The modeled wind production from Henckes et al. (2017) is equally scaled to the reported production of AG Energiebilanzen (2016), to compensate for the annual production difference.

## 2.8. 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*, a

register for all subsidized renewable production facilities in Germany. The register covers a total PV capacity of 35.19 GW in 2014 which corresponds to 92% of the total installed PV capacity (38.23 GW) in 2014. This regionalization approach has two drawbacks: (1) For whole Germany, the regional solar radiation is assumed to be the same and (2) the distribution of the installed capacities by the register is assumed to be fixed when the available installed PV capacity data is scaled to Germany's installed PV capacity. 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 can not (yet) be 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 used but with the drawback of a unified capacity factor. The second assumption of a fixed distribution in the scaling process to Germany's total PV capacity is rather uncritical since the register covers 92 % of the total installed PV data.

### 3. Results

The results focus on two major indicators for the assessment of wind production. First, the regional wind revenues are analyzed. Afterwards, the wind value factors are analyzed.

#### 3.1. Wind revenues

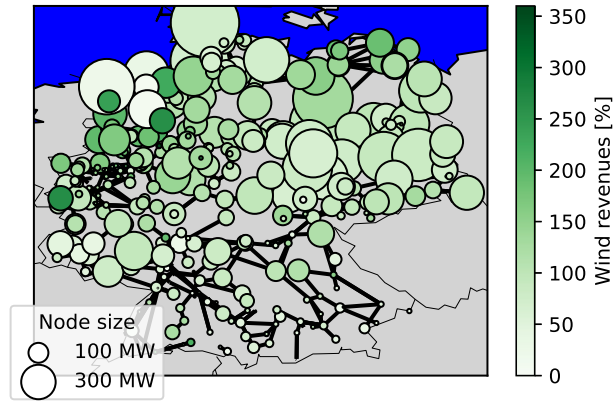
To assess regional wind location incentives, the wind revenues are analyzed. The (efficient) *nodal revenues of wind* are identified and compared to the *zonal revenues of wind* (current implemented design). Note that both revenues do not consider any subsidy payments and are based purely on market prices, i.e. a 100% market integration of wind energy.

##### 3.1.1. The nodal revenues: Efficient benchmark with consideration of the transmission grid

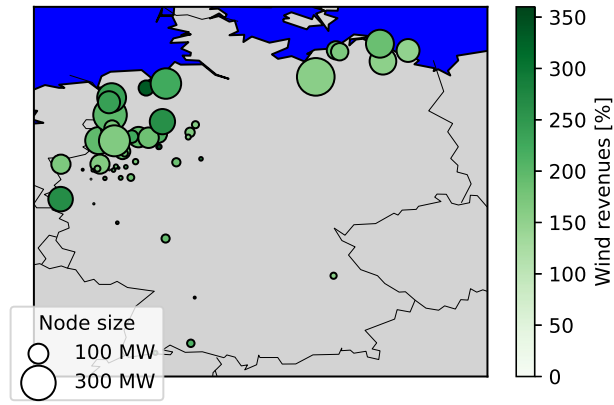
Figure 4 shows the modeled wind revenues under nodal pricing, i.e. with consideration of the physical transmission characteristics. The revenues are in relative terms to the capacity weighted average German wind revenue.

Following aspects become obvious:

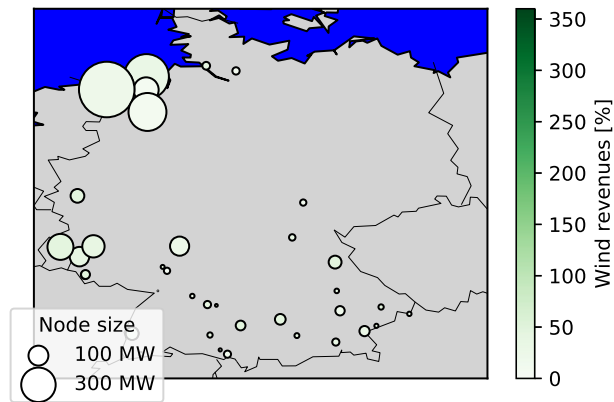
- Highest relative revenues are concentrated in the north-western area. The nodal revenues in the north-western area are mainly in the range between 100% and 200% (or higher) of the average German wind revenues and with peak-revenues up to 350%. However, the strongest wind speeds are typically located at the northern coast (cf. Henckes et al. (2017)). Due to the German transmission situation with mainly



(a) Nodal revenues for all nodes



(b) Nodal revenues for nodes with highest revenues (above 150%)



(c) Nodal revenues for nodes with lowest revenues (below 50%)

Figure 4: Wind revenues per node within Germany under *nodal pricing*. (a) Different revenues at each node, (b) at nodes with revenues above 150%, (c) at nodes with revenues below 50%. All nodal revenues in percent compared to the capacity weighted average German revenue. Darker nodes represent higher percental revenues. The size of the nodes indicates the installed wind capacity per node.

north-south congestion, the revenues in the north-western area are higher than the northern coast. The north-western wind locations are located slightly behind the mainly congested lines, which are also identified in Bundesnetzagentur (2016).

- Most of the low revenues are concentrated in the southern area but a few are located at the northern coast. In these northern nodes, typically high wind situations occur. Nevertheless, several revenues are below 50% of the capacity weighted German average revenues. This can be explained via the before mentioned grid situation. Additionally high installed capacities lead to simultaneity production and thus strongly reduce electricity prices. These effects are also denoted as cannibalization effects and may further decrease revenues.
- The eastern area with highest installed wind capacities (cf. Figure 3) has mostly revenues below 100%, but no extreme high or low revenues. Those effects are mainly driven by the cannibalization effects.

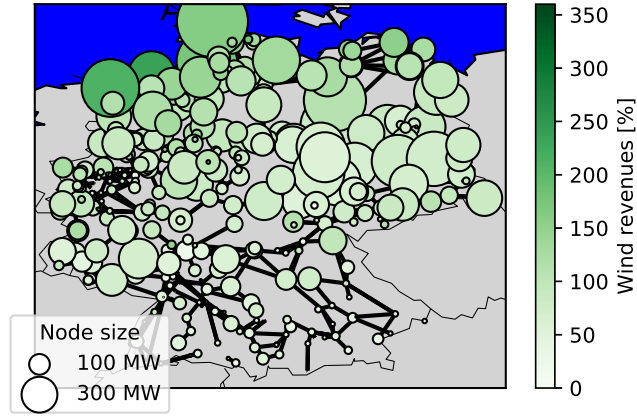
The modeled revenues under nodal pricing can be considered as efficient benchmark with internalization of the power flow characteristics. Under this assumption, regional advantageous and disadvantageous locations are identified.

### *3.1.2. The market revenues: Today's market situation in Germany (without subsidies)*

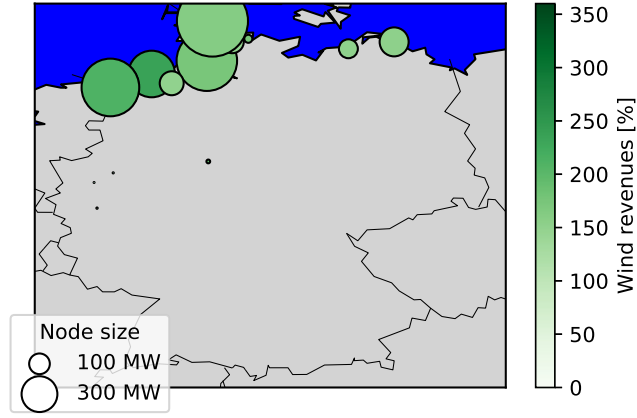
Figure 5 performs the same calculation like before but considers zonal pricing which is the current applied market pricing regime in Germany and does not consider physical transmission flow characteristics. The modeled revenues are relative to the capacity weighted average German wind revenues.

The scale is identical to the former results to guarantee comparability, although the maximum and minimum market revenues have a smaller range and lower deviations. The main findings of the market revenues are the following.

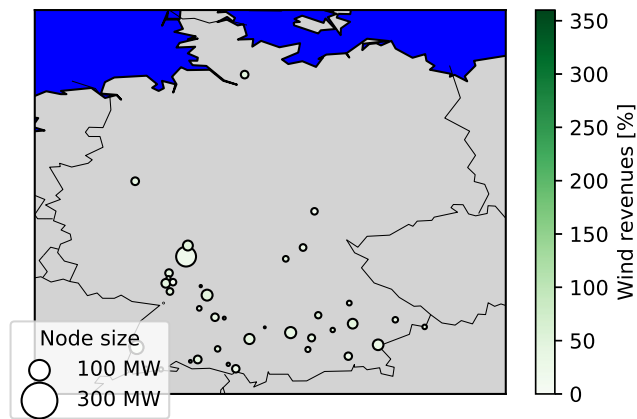
- The concentration of the highest relative revenues are at the northern coastal area with few representatives in the western area. Only few revenues exceed 150% of the capacity weighted average German wind revenue.
- Almost all of the lowest values are in the southern area.
- Many nodes show only slight deviations (between 50% and 150%) to the German average revenue. Locations with a high concentration of the installed capacity (i.e. the eastern-central area) are not below 50% and thus not shown in Figure 5c.



(a) Zonal revenues for all nodes



(b) Zonal revenues for nodes with highest revenues (above 150%)



(c) Zonal revenues for nodes with lowest revenues (below 50%)

Figure 5: Wind revenues per node within Germany under *zonal pricing*. (a) Different revenues at each node, (b) at nodes with revenues above 150%, (c) at nodes with revenues below 50%. All revenues in percent to the capacity weighted average German revenue. Darker nodes represent higher percental revenues. The size of the nodes indicates the installed wind capacity per node.

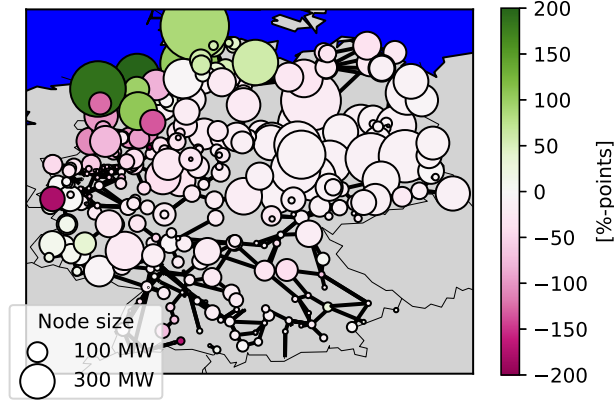
### 3.1.3. Comparison of the revenues under nodal pricing to the revenues under zonal pricing: Zonal revenues might incentivize inefficient wind locations

Figure 6 compares the revenues under nodal pricing to the revenues under zonal pricing (zonal pricing revenues minus nodal pricing revenues). The revenues are relative to the capacity-weighted German average wind revenue per MW (both for nodal and zonal pricing, respectively). The modeled relative nodal pricing revenues deviate strongly from the modeled relative zonal pricing revenues. The capacity-weighted average nodal pricing revenue is 21% higher than the capacity-weighted average zonal pricing revenue (107% compared to 86%). Differences between the zonal pricing revenues and the nodal pricing revenues can be up to  $\pm 200\%$ -points. Additionally, the nodal pricing revenues have a broader range (standard deviation of 56%) compared to the zonal pricing revenues (standard deviation of 35%). Detailed statistics can be found in B.2. The regional differences deviate regionally. The nodal pricing revenues tend to be higher in the western and southern area and lower at the northern coastal area than the zonal pricing revenues. Cannibalization effects (which have a strong impact on the nodal pricing revenues) are mainly smoothed across Germany, since no transmission congestion restrict the inner-German exchange.

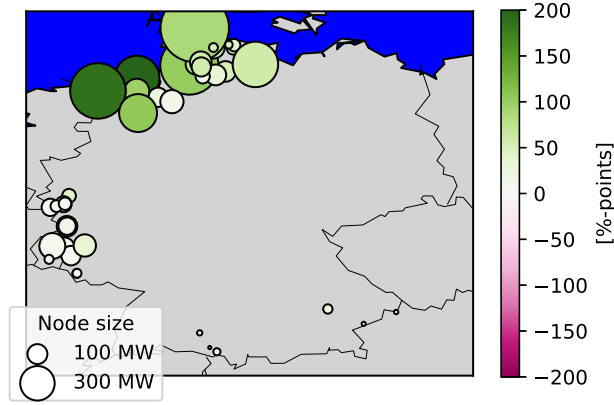
### 3.1.4. Implications of the revenues

The regional differences between the nodal pricing revenues and the zonal pricing revenues are driven by the regional deviating electricity situation in combination with the transmission characteristics. The well-known German north-south transmission congestion leads to price differences in several (i.e. windy) situations. The electricity price differences induce a differentiation in the wind revenues. Additionally, the cannibalization effects decrease the revenues of certain locations which have high concentrations of installed wind capacities. Both reasons imply that wind capacities in the western area are higher valued to the electricity system under consideration of the physical transmission characteristics. Northern coastal areas seem to be high valued locations under the current market design but under consideration of the grid situations they face lower revenues.

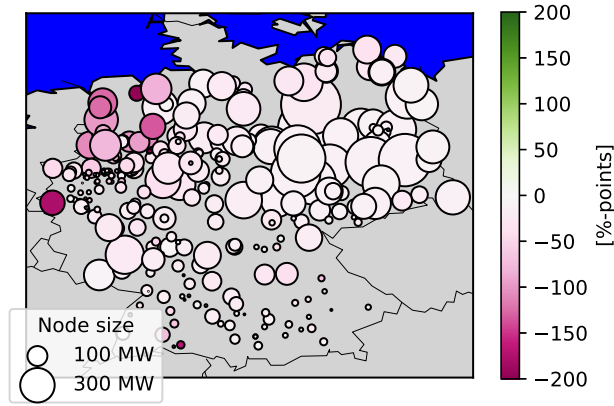
As wind operators act profit maximizing, they aim for building new wind capacities at most profitable locations. Under *nodal pricing revenues*, wind investments seem to be more profitable in the western area than in the northern area as identified under *zonal pricing revenues*. This points to a locational discrepancy of profit optimal wind locations between both pricing regimes. Thus, the neglecting of the transmission situation in the current market design causes wind capacities at system-unfavorable locations. Under a future increase in wind capacities, to tackle this inefficiency may become more important.



(a) Deltas for all nodes



(b) Nodes with a positive deltas (which are above 5%-points)



(c) Nodes with a negative deltas (which are below -5%-points)

Figure 6: Difference of relative wind revenues between zonal pricing and nodal pricing for each node within Germany. Wind revenues are relative to the capacity-weighted German average wind revenue under zonal/nodal pricing and then differentiated. A positive value indicates higher market revenues under zonal pricing. The size of the nodes indicates the installed wind capacity per node. Results are for (a) all nodes, (b) nodes with a positive delta, and (c) nodes with a negative delta.

### 3.2. Value factor of wind

From an operators' perspective, the wind revenues are the main aspect to assess the value of wind production. However, the market value of wind is widely used as an indicator to assess the value of wind to the electricity markets (e.g. Hirth (2013); Lamont (2008); Hirth et al. (2015); Ackermann (2005); Obersteiner and Saguan (2011)). A similar indicator is the electricity base price, which neglects time structure information as well but provides aggregated information. Thus, the investigation of the market value with its aggregated information is of high interest. The following section provides an analysis of the nodal pricing value factors of wind as well as the zonal pricing value factors of wind (cf. Section 2.6 for details of the definition). For comparison reasons, the focus lies on the value factor (instead of the value itself), which is denominated by the (regional) base prices.

#### 3.2.1. Nodal pricing value factor of wind

The modeled nodal pricing value factor of wind production as to definition (8) is calculated under a nodal pricing regime with respect to physical power flow characteristics. The resulting nodal pricing value factors of wind production are shown in Figure 7. Statistics can be found in Appendix C. Note that for comparison reasons, the lower range of the scale is limited to the 1%-quantile threshold of the results, which represents a nodal pricing value factor of wind of 75%. The upper range limit is chosen symmetric to this (i.e. 125%), although the maximum nodal pricing value factor does not exceeds 111%.

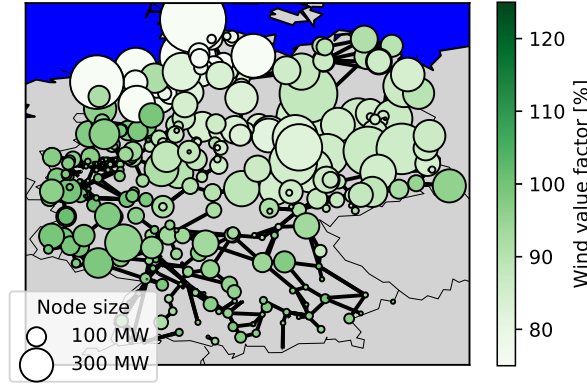


Figure 7: Markte value factor of wind production under nodal pricing for each node within Germany. The size of the nodes indicates the installed wind capacity per node.

A structural difference between 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 under nodal pricing have value factors of wind between 75% and 90% whereas southern nodes have in general higher values, in the range from 95% to 100% (up to 110%). The structural break represents

insufficient grid transmission capacities which leads to regional price differences, e.g. in hours of high wind feed-in. Breuer et al. (2013) and Burstedde (2012) identified similar structural breaks caused by insufficient the grid capabilities. The mainly congested lines are reported in Bundesnetzagentur (2016) and correspond to the congested lines which are identified within this model.<sup>6</sup>

### 3.2.2. Comparison of the market value factor for wind under nodal pricing to zonal pricing

Figure 8 shows the modeled regional value factor of wind under nodal pricing and zonal pricing. Note

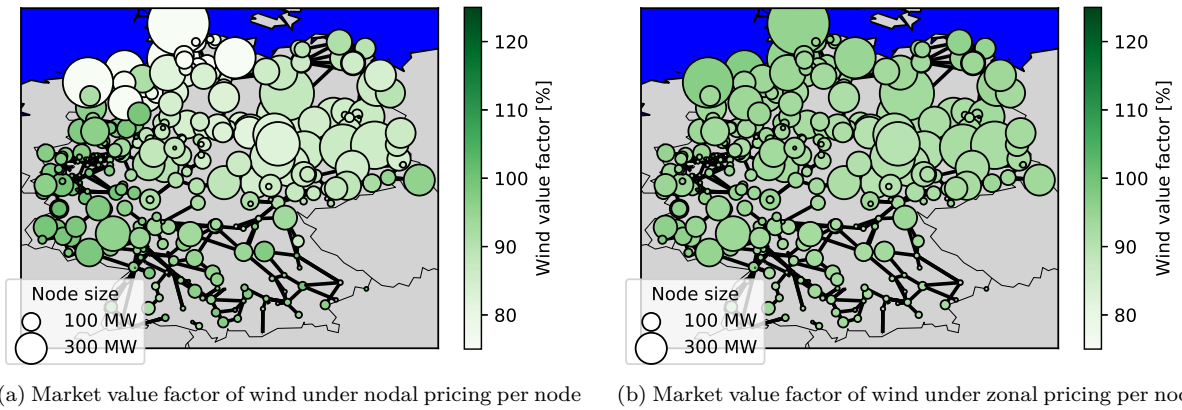


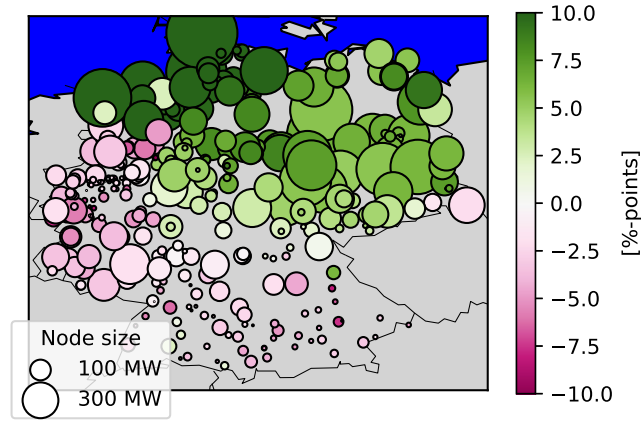
Figure 8: Comparison of the regional market value factors of wind production for each node within Germany: (a) under nodal pricing, (b) under zonal pricing. The size of the nodes indicates the installed wind capacity per node.

that the colormaps are cut to the range from 75% to 125% for comparison reasons and that, for the nodal pricing value factor of wind, wind values down to 30% exist (cf. C.10 in the appendix). The regional value factor of wind has an average value of 94% and a smaller standard deviation of 1% under zonal pricing compared to nodal pricing (mean: 91%, standard deviation: 10%). Details can be found in C.3. The lowest zonal pricing value factors of wind are concentrated in the eastern-central area in Germany. In contrast to the zonal pricing value factors of wind, the nodal pricing value factors of wind are low in that area as well, but are even lower at the northern coast.

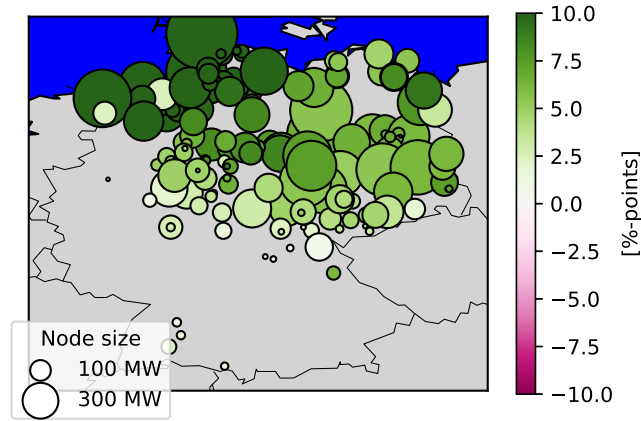
### 3.2.3. Differences in the nodal pricing and zonal pricing value factors

The difference between the regional wind value factor under nodal pricing and zonal pricing is shown in Figure 6. For comparison, the colormaps are restricted to  $\pm 10\%$ -points. The total differences are shown in a line plot in Figure C.11.

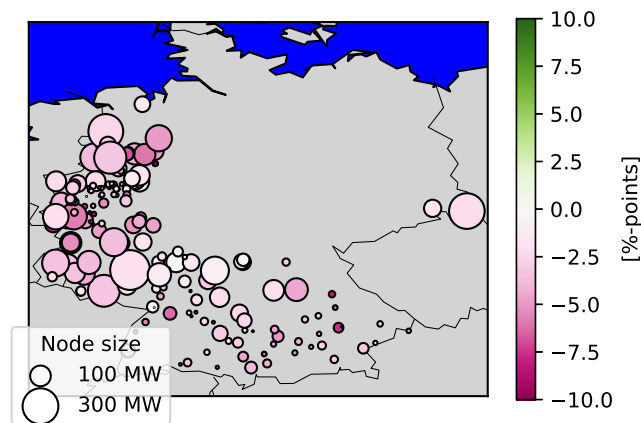
<sup>6</sup>Further research on the effects of a German market splitting assume a separation along a horizontal line further southwards based on some heuristics, e.g. re-dispatch amount or reported congestion (Trepper et al., 2015; Egerer et al., 2016). Based on own calculations, the paper is in line with research on optimal zone configurations of (Breuer et al., 2013) or Burstedde (2012) with a mainly diagonal congestion structure.



(a) Deltas for all nodes



(b) Nodes with positive deltas



(c) Nodes with negative deltas

Figure 9: Difference between the market value factor of wind production under zonal pricing to nodal pricing within Germany. A positive value indicates a higher market value factor under zonal pricing. The size of the nodes indicates the installed wind capacity per node.

The value factor may strongly deviate between zonal and nodal pricing. Differences up to -17%-points and +63%-points may arise. Additionally, the zonal pricing smooths the regional effects which, in contrast, exist in the nodal pricing regime. For the investigated case, the zonal pricing value factor has a 3%-points higher mean and a 9%-points lower standard deviation compared to the value factor under nodal pricing.

The difference in the value factors arises mainly due to the internalization of the physical power flow 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 value of wind. Especially windy situations cause such grid congestion.

#### *3.2.4. Implications of the value factor analysis*

The comparison shows that the market value factor of wind under zonal pricing overestimates the value of wind in the northern area and underestimates it in the southern area in comparison to the nodal pricing value factor of wind. The zonal pricing value factor does not reflect the value of wind under consideration of the transmission characteristics. Thus it is not suitable to assess the value of wind to electricity systems. The nodal pricing value factor considers physical flow restrictions and is therefore much more suitable to assess the value of wind to the electricity system.

The value factor neglects the real production. It is not sufficient for detailed assessments. For this, the wind revenues are recommended (as discussed in Section 3.1). However, the value factors may serve as a rough indicator, e.g. to compare the wind contribution of different countries to each other.

## **4. Discussion**

The results have highly relevant implications on different aspects of wind energy.

- Market revenues under zonal pricing incentivize inefficient locations compared to the market revenues under nodal pricing. The revenues for wind under zonal pricing do not consider the grid situations. Thus, zonal pricing revenues would favor windy locations. Under consideration of the grid situation (nodal pricing), different locations are favorable which are identified within this analysis. Optimal wind locations should thus be estimated under consideration of the grid situations. The underlying approach with a nodal pricing optimization model reflects one opportunity to identify optimal wind locations.
- The value factor may serve as an indicator but does not reflect the wind revenues accurately. The discrepancy between the revenues (cf. Figure 4a) and value factor (cf. Figure 7) might serve as an

example. The reason is that the value factor does not consider the actual wind production. The definition of the value factor is solely an aggregation of the wind-production-weighted electricity prices. Thus, the value factor is not sufficient to assess locational investment decisions in detail. However, the aggregated information in the value factor might be suitable for various other investigation and is a widely used indicator.

- The derived results are highly relevant for the design and implementation of subsidy schemes. Wind capacity extensions are usually incentivized by additional subsidy payments. It is not finally answered which design of a subsidy scheme is economically beneficial in which situation. This is subject of current research (e.g. Pechan (2017) and Wagner (2016)). The underlying research provides new insights for the design of optimal subsidy schemes. It shows that market integrated subsidy schemes could be distorting if they do not incorporate the physical transmission situation. Thus, the transmission situation should be considered in the subsidy scheme definition. Furthermore, subsidy schemes which are partially or fully based on the wind production (e.g. fixed feed-in tariffs, fixed feed-in premiums) and have no grid component might incentivize non-system-favorable locations. This could lead to more grid congestion and should be avoided. The German government tries to avoid over-investment of wind in system-unfavorable northern areas by a politically given capacity restriction (cf. Bundesnetzagentur (2017)). The underlying approach allows to identify and evaluate such suggestions. Moreover, in combination with an adjusted subsidy scheme, a market driven solution could be implemented to avoid over-investments. Dependent on the subsidy adjustment, more risk is transferred to the wind producers (i.e. operators). The increased risks could lead to increased investment costs. Therefore, adjustments should be applied carefully.

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 wind results (revenues and value factors) are dependent on (1) the grid structure and (2) complementary installed (wind) capacities. Further investments may change the regional revenues and value factors of wind. Additionally, further wind capacities at the same or near-by nodes cause additional correlation effects. This cannibalization effect would tend to decrease the regional revenues as well as the regional value factors.

## 5. Conclusion

This paper investigates the modeled wind revenues and modeled wind value factors under two pricing regimes: zonal pricing and nodal pricing. Focus is the German electricity market due to a high share of

wind production and regional different wind speed structures. The revenues and the value factors of wind are assessed (1) under *nodal pricing* with internalized transmission situations and (2) under *zonal pricing* without internalized transmission situations. The nodal pricing regime is considered as the economic efficient benchmark whereas the zonal pricing regime represents the current European market design.

The contribution to existing literature is twofold: First, the regional revenues for wind production under nodal pricing and zonal pricing are quantified and compared. The revenues show strong deviations dependent on the transmission situations. The revenues incentivize wind locations. Under zonal pricing (without grid consideration) the regional incentives are identified as system-unfavorable. This might lead to congestion increasing wind investments.

Second, the value factor is identified. It does not reflect the operators' revenue-optimal locations. Thus, the value factor is not suitable as a detailed indicator. Furthermore, the market value factor under zonal pricing overestimates windy locations in contrast to the nodal pricing regime.

The derived results are highly relevant for the design and adjustment of wind energy subsidy schemes which should consider the grid situations to achieve system optimal wind locations.

Further research is necessary to account for dynamic investment decisions and to find long-run optimal wind locations. This is technically possible with the underlying model but simplifications might be necessary to guarantee tractable model size. Another extension would consider the interdependency between the grid extension and the capacity extension and analyze the robustness of a dynamic solution.

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# Appendix

## Appendix A. Load Distribution

For the nodal electricity market model, all relevant location parameters have to be matched to the nodes. For electricity production this is performed by the smallest distance approach of the production's location to the nodes. For the load distribution, this approach is not suitable. Thus, a regression is performed which estimates the load consumption based on GDP and population.

The load distribution weights are derived via a least squares estimation of the dependent variable load by the independent variables GDP and population, i.e.

$$Load_i = \alpha + \beta_1 GDP_i + \beta_2 population_i + \varepsilon_i \quad , \text{ for country } i. \quad (A.1)$$

The observations are on a European national level based on public available data from Eurostat for the years 2011 to 2014. The estimated coefficients are  $\beta_1 = 0.41$  and  $\beta_2 = 0.59$ . Those coefficients represent the weights which are used to distribute the total German load to the German counties (NUTS-3 areas), for which the GDP and the population are known but the load is unknown. For each German county, this reads as

$$Load_{county} = Load_{Germany} \cdot \left[ 0.41 \frac{GDP_{county}}{GDP_{Germany}} + 0.59 \frac{Population_{county}}{Population_{Germany}} \right]. \quad (A.2)$$

Furthermore, the areas are upsampled to the specific nodes by Voronoi diagrams. For each node a surrounding area is determined which is characterized such that no other node is closer for the surrounding area. In this way, complete Germany is partitioned. In a second step, the calculated load distribution of the counties (NUTS-3 areas) are matched to the nodes dependent on the share of the overlapping Voronoi areas. That means, if a county contains two nodes with equal area of the belonging Voronoi diagrams, both nodes derive 50% of the county's load. If the Voronoi diagram of a node also contains other counties' shares, the counties' corresponding load share is added.

## Appendix B. Statistics of the wind revenues per node under nodal pricing and zonal pricing

Table B.2 shows statistics of the nodal and zonal wind production revenues which are compared in Figure 8. The wind revenues are relative to the capacity-weighted average wind revenue for Germany. The average wind revenue under a nodal pricing is 107% and above the zonal pricing average wind revenue of 87%. Note that the revenues reflect the unweighted average of each node. Since more nodes are behind the typical wind-driven grid congestion, the average wind revenue is higher under nodal pricing. The statistics

show that the nodal pricing leads to a broader range of wind revenues compared to zonal pricing. The minimum and maximum are more extreme as well.

	Nodal pricing wind revenues [%]	Zonal pricing wind revenues [%]	Difference between zonal and nodal wind revenues [%-points]
<b>mean</b>	107	87	-21
<b>std</b>	56	35	45
<b>min</b>	6	5	-214
<b>25%</b>	75	64	-31
<b>50%</b>	97	84	-18
<b>75%</b>	131	106	-9
<b>max</b>	361	279	205

Table B.2: Statistics of the wind revenues under nodal pricing, zonal pricing and the difference (zonal – nodal pricing) per node. Percentage to the capacity-weighted average wind revenues under nodal or zonal pricing, respectively. The nodes are not weighted, i.e. each node counts as one observation.

### Appendix C. Statistics of the market value factor of wind per node under nodal pricing and zonal pricing

	Market value factor under nodal pricing [%]	Market value factor under zonal pricing [%]	Difference between the market value factor of zonal to nodal pricing [%-points]
mean	91	94	3
std	10	1	10
min	31	89	-17
25%	87	93	-3
50%	94	94	-1
75%	98	94	6
max	111	98	63

Table C.3: Statistics of the wind value factor per node under nodal pricing, zonal pricing and the difference (zonal value factor - nodal value factor).

Figure C.10 shows the histograms of the market value factor of wind under nodal and zonal pricing. The value factor under nodal pricing has a broader range and less values around 100% in comparison to zonal pricing.

Figure C.11 shows the differences between the market value factor of wind production under nodal pricing and zonal pricing for each node in a lineplot (sorted ascending).

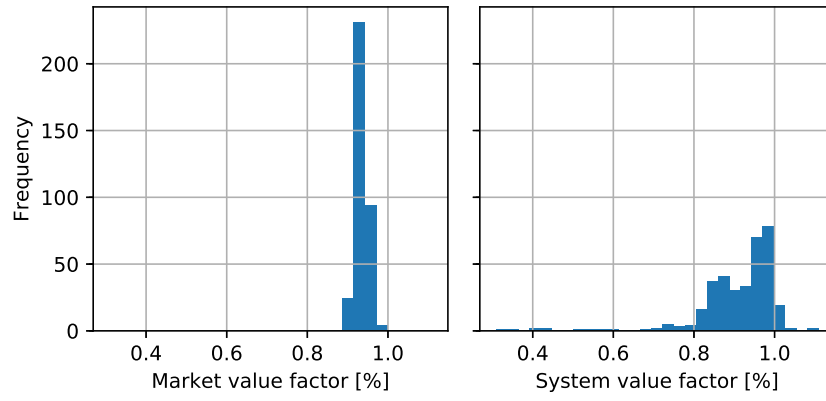


Figure C.10: Histogram of the modeled market values of wind production per node under zonal pricing (left) and nodal pricing (right)

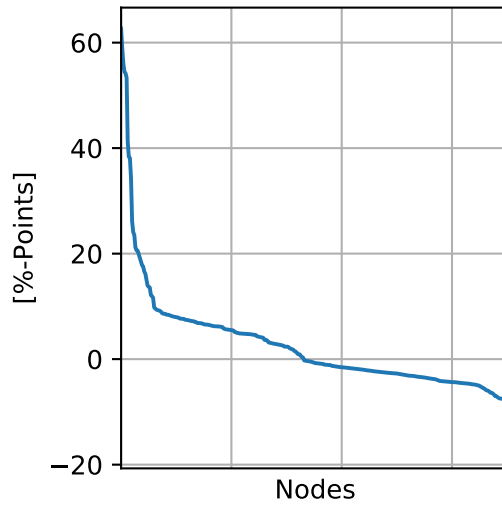


Figure C.11: Lineplot of the difference between the market value factor of wind production per node under nodal pricing and zonal pricing. Values are the percental point difference of the market value factors of zonal to nodal pricing.