IET Generation, Transmission & Distribution

Research Article

Impacts of renewables generation and demand patterns on net transfer capacity: implications for effectiveness of market splitting in Germany

ISSN 1751-8687
Received on 5th November 2014
Revised on 6th March 2015
Accepted on 22nd March 2015
doi: 10.1049/iet-gtd.2014.1063
www.ietdl.org

Michael Bucksteeg ✉, *Katrin Trepper*, *Christoph Weber*

Chair for Management Sciences and Energy Economics, University of Duisburg-Essen, Essen 45117, Germany
✉ *E-mail: michael.bucksteeg@uni-due.de*

Abstract: For the further development of an integrated European electricity market, congestion management mechanisms are one of the major market design issues. Against the background of increasing generation from renewables and resulting congestions, an efficient management of network congestions is gaining importance especially in Germany. Introducing nodal pricing as the first best mechanism is not considered to be realistic for Germany in the nearby future. Yet the splitting of the German electricity market into several market zones will also improve congestion management. A key issue in the so-called market splitting is the determination of the net transfer capacity (NTC) between the market zones as it determines the effectiveness of market splitting as congestion management mechanism. The authors therefore propose an integrated approach to incorporate the effects of renewables feed-in, load patterns and cross-border flows on NTCs. On the basis of results of a European power market model they specify typical hours using a clustering approach. Subsequently, a DC security constrained optimal power flow model is used to calculate situation-dependent NTCs. They conclude that the obtained NTCs strongly depend on renewables feed-in and that this effect has to be considered when modelling alternative congestion management mechanisms such as market splitting.

1 Introduction

The energy markets and systems in Europe experience more and more power generation far from the load centres and intermittent feed-in from renewable energy sources (RESs). Especially in Germany this leads to serious differences in the geographical distribution of power generation and load flows between the hours of the year, as today more than 80% of installed wind onshore capacity is located in the northern regions [1]. Given the nuclear phase-out and assuming that further delays in transmission grid expansion will occur in the nearby future, the extension of offshore wind energy particularly in the North Sea will amplify Germany's North–South congestion problem [2]. The German market design is characterised by uniform prices. Congestion is removed by re-dispatch. Against this background, the four German transmission system operators (TSOs) will be challenged to ensure the system security requirements. Thus, alternative congestion management mechanisms are becoming more important.

The implementation of nodal pricing as first best congestion management alternative in the nearer future is not considered to be realistic by the regulating authorities because of the need for a Europewide independent system operator (ISO) [3, 4]. Yet, a considerable improvement of the efficiency of congestion management can also be achieved by splitting the German electricity market into several market zones [5]. A key issue in this market splitting is the determination of the net transfer capacity (NTC) between the market zones as its level affects the effectiveness of market splitting.

Several studies have already addressed the impacts of wind feed-in on transfer capacity, but ignored the complexity and influences caused by the interconnection of national electricity markets and transmission grids. In [6], the impacts of wind feed-in on transfer capacities are analysed using a 24-bus system. The focus is on the analysis of the intermittent characteristics of wind generation and the geographical distribution of wind power plants. The authors find that an increase of wind generation units with loads remaining constant may cause limitations of the transfer capacity.

Moreover, in [7] the impact of wind generation on transfer capacity is identified as initial point for the determination of transmission capacities. The authors develop a new approach for calculating transfer capacities and show numerical results for a 30- and 118-bus systems. They state that depending on the locational distribution and feed-in patterns of wind plants, the transfer capacities change strongly.

In [8], Gang *et al.* develop a sensitivity method based on optimal power flow and incorporate uncertainties arising from wind generation using Latin hypercube sampling and a clustering algorithm. They find a strong correlation between intermittent wind generation and the volatility of the transfer capacity. [In the literature, most authors refer to the available transfer capability (ATC) when analysing transfer capacities. The ATC is part of the NTC and results by deducting the already allocated capacity (AAC), for example, long-term contracts between market participants from the NTC. However, in most publications the AAC is assumed to be zero. Thus the calculated ATC corresponds to the NTC.]

The publications known to us have in common the use of fictitious and small test systems with 24, 30 or 118 buses. Furthermore, the installed wind capacity is limited to 1 GW. One main issue of this paper is therefore to analyse if the same holds for large and complex power systems such as the German one with a high share of installed wind capacity.

In [9, 10], variations of power transfer distribution factors (PTDFs) in a large-scale power system are analysed. PTDFs are an input factor for computing NTCs. The authors find that PTDFs vary when reaching power system limits. However, they focus on the impact of load and not of RES generation on PTDFs.

In [11], the impact of German wind generation on the transfer capacity between Belgium and France is studied. The model used is based on [12]. Going one step further, the authors incorporate wind generation into the calculation of the base case and show that increasing wind generation leads to an increase of the transfer capacity between Belgium and France. Furthermore, they point out the importance of the geographical distribution of wind power plants for an accurate calculation of the transfer capacity.

Neuhoff *et al.* [13] analyse several design options for the European power market and assess the benefits of nodal pricing against zonal pricing (market coupling). The initial point of their analysis is the integration of intermittent RES feed-in. However, when modelling zonal pricing they neglect that with varying wind feed-in the transfer capacities would not remain constant over time.

In [14], nodal, zonal and uniform pricing and the benefits of high voltage direct current extensions for integrating large-scale wind generation in Germany are studied. The establishment of zonal pricing in Germany is based on six bidding zones proposed by Deutsche Energie-Agentur GmbH (dena) [15]. The authors conclude that the impact of zonal pricing on welfare is limited. Thereby they ignore that an appropriate delimitation of market zones should follow the main bottlenecks which may change with increasing installed wind capacities towards 2015. Furthermore, they do not consider the impact of intermittent wind generation on transfer capacities when modelling zonal pricing.

In [16], design and impact of price zones in Europe are analysed. Thereby the author proposes a clustering approach and focuses on the delimitation of bidding zones based on locational marginal prices of 72 basic regions for Austria, Switzerland, Germany, the Netherlands, Belgium and France. However, she does not discuss the determination of the transfer capacities between the constructed bidding zones when analysing the impacts of zonal pricing on congestion and re-dispatch.

The present paper adds to the current literature by filling the mentioned gaps and assesses the impacts of RES feed-in and demand patterns on the NTC for a fictitious yet appropriate market splitting scenario for Germany. Subsequently, we identify important implications for the effectiveness of zonal pricing.

The remaining paper is organised as follows. In Section 2, we describe our modelling approach and the determination of the transfer capacity between the considered market zones. Section 3 points out the impacts of RES feed-in, demand patterns and the corresponding exchange balances on load flows, power flow sensitivities and transfer capacities. Furthermore, we discuss the implications of our results for the effectiveness of market splitting. Section 4 concludes.

2 Methodology

2.1 Modelling approach

To determine the impacts of RES generation and demand patterns on load flows and the NTCs, we link two power system models via a clustering approach. The modelling approach, the relevant results and the input and output relations between the steps are shown in Fig. 1 and described as follows:

1. Since the integration of European power markets progressed in recent years, we model the dispatch at a European, but aggregated level for all 8760 h in a first step. The 'Wind Power Integration in Liberalised Electricity Markets (WILMAR) Joint Market Model' provides (among others) results on hourly imports and exports to/from Germany, intra-German flows and vertical load levels for the German transmission grid. Moreover, congestion occurring in Germany is modelled within this step.
2. Running the German DC security constrained optimal power flow (DC SCOPF) model (step III) for a full year (8760 h) implies extremely high and thus hardly manageable computational efforts. Instead we identify in step II representative scenarios by using a clustering approach. As RES generation and demand patterns affect the cross-border exchanges and intra-German flows, these results from the 'WILMAR Joint Market Model' (step I) are clustered using the '*k*-means algorithm'.
3. In the third step, we calculate load flows and PTDFs for each specific scenario (cluster) in the 'German DC SCOPF model'. In addition, we calculate NTCs for transactions between German market zones and analyse the impacts of RES generation and demand patterns within this step. When introducing market splitting, the zonal border should run along the main bottlenecks to achieve high effectiveness. On the basis of the main congestion identified within the upstream 'WILMAR Joint Market Model' in step I, Germany is split into market zones.

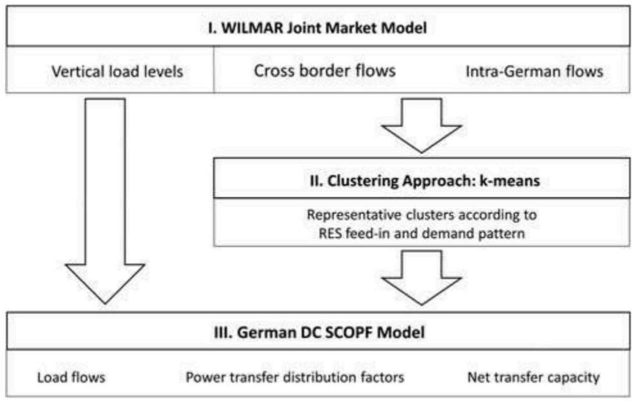

Fig. 1 *Modelling approach and relevant results*

A more detailed description of the models and the clustering approach is given in the following sections. In Section 2.5, the determination of NTCs is outlined.

2.2 WILMAR Joint Market Model – description

The 'WILMAR Joint Market Model' was developed within the EU-projects WILMAR and Decision Support for Large Scale Integration of Wind Power (SUPWIND) and can be described as a stochastic scheduling tool to analyse the impact of the fluctuating RES feed-in in energy markets. The objective function minimises the overall variable system costs over the optimisation period, covering fuel, carbon-di-oxide (CO_2), start-up and further variable costs. Several technical constraints, for example, start-up time, minimum up and down times, ramping rates, minimum and maximum generations, reserve targets and transmission capacities are covered. Beside electricity also heat demand has to be met in 8760 h of the year. The planning horizon of the 'WILMAR Joint Market Model' is up to 36 h with hourly optimisation and rolling planning. Thereby a day-ahead market for physical delivery of electricity is cleared corresponding to European Power Exchange (EPEX)-based trading, whereby total electricity demand and RES feed-in are given exogenously. Afterwards the transmission constraints are taken into account and the day-ahead committed power plants are, if necessary, re-dispatched to remove occurring congestion. More detailed information about the model including all equations can be found in [5, 17, 18].

The model covers the European Network of Transmission System Operators for Electricity (ENTSO-E) grid apart from the Baltic States. The European countries except for Germany and Denmark are mapped as 29 aggregated country nodes. Germany is modelled in more detail and is represented by 21 nodes according to the regional electricity transport model of the German TSOs [1].

One part of the relevant output of the 'WILMAR Joint Market Model' are the modelled European cross-border flows which are used for modelling imports and exports in the 'German DC SCOPF model'. Furthermore, the 'WILMAR Joint Market Model' determines intra-German flows for the interconnections of the German regional electricity transport model. These flows are used as an indicator for the utilisation of the German transmission grid and for the delimitation of the zonal border. Moreover, hourly vertical load levels are calculated.

2.3 Clustering approach – k-means algorithm

The clustering approach links both models, the 'WILMAR Joint Market Model' and the 'German DC SCOPF model', and allows determining the impacts of characteristic RES feed-in and demand patterns on load flows, PTDFs and NTCs.

Cluster analysis is a multivariate analytical method for classifying a heterogeneous set of objects to homogeneous subsets of groups or clusters [19]. This grouping should be done in such a way that the observations within a cluster are as similar as possible, but clusters are as dissimilar as possible. In the literature, hierarchical and partitioning methods are distinguished. Although hierarchical clustering methods start with one cluster for each observation and end with an optimal number of well-separated clusters, partitioning methods reallocate observations starting from an initial partitioning or cluster centres [20].

The *k*-means algorithm reallocates objects to clusters according to the chosen measure of distance. The sum of distances from each group member to its cluster centroid is minimised over all clusters. Previously, the number of clusters has to be decided [21].

For the classification of hours, the cross-border flows and intra-German flows obtained from the 'WILMAR Joint Market Model' are used as cluster criteria. The transmission flows are an adequate indicator for potential grid congestions. They are also closely linked to changes in patterns and level of RES generation and demand. In [22], a statistical analysis of the impact of wind power generation on cross-border flows is performed. The authors find that variation of wind generation in Germany causes changes in patterns of cross-border flows and induces loop and transit flows.

The *k*-means algorithm involves an iterative process, as follows. The algorithm differentiates the H data points x_h into k disjoint subsets or clusters S_n by using the least-squares method. h indicates the considered hours and x_h is given by the vector of the hourly transmission flows on the regarded tie lines. The clustering function as described in [23] is given by

$$J = \sum_{n=1}^{k} \sum_{x_h \in S_n} \left\| x_h - \mu_n \right\|^2 \rightarrow \text{Min!} \tag{1}$$

where $h = \{1, \ldots, H_n\}$, J as the sum of the squared differences between the data points x_h which belong to the cluster S_n and the centroid μ_n of the data points in this cluster has to be minimised. μ_n is the geometric centre of the data points in cluster S_n and is given by

$$\mu_n = \frac{1}{H_n} \sum_{h \in S_n} x_h \tag{2}$$

The algorithm begins by assigning an initial cluster centroid position. We performed therefore a preliminary clustering phase on a random 10% subsample of all objects. This preliminary clustering phase itself selected two objects at random. After computing the centroids as means, each data point is allocated to the nearest cluster centroid or mean. Next the means are recomputed. This iterative process is repeated as long as the recalculation of cluster centroids leads to a reallocation of data points to clusters. In other words: the *k*-means algorithm reallocates the hourly cross-border and intra-German flows to clusters until the sum of distances cannot be decreased. In this case, clusters are as compact and well-separated as possible [23].

Every cluster S_n is then represented by one scenario, corresponding to the hour which has the smallest centroid distance. This scenario may notably be characterised by its RES feed-in and demand patterns. The resulting effects on line loadings, PTDFs and NTCs are then assessed using the 'German DC SCOPF model'.

2.4 German DC SCOPF model

Load flows for the German transmission grid, PTDFs for the interconnections of the regional electricity transport model and NTCs for the fictitious zonal border are calculated after running a DC SCOPF model in PowerWorld Simulator.

The calculation of NTCs is based on several power system sensitivities (compare Section 2.5). In [10, 24], sensitivities calculated with AC and DC power flow models are compared. It is concluded that DC sensitivities are very close to sensitivities calculated with AC models. Even when incorporating outages sensitivities remain very close. Furthermore, in [25] it is pointed out that using a linear model (for determining the insecurities) has advantages in terms of computation times and efficiency especially when analysing huge and complex power systems. We therefore neglect reactive power and voltage considerations and accept small inaccuracies. We consequently decide to use a DC model. The corresponding optimisation problem is well defined and the main characteristics of a DC SCOPF model may, for example, be found in [26].

The German 'DC SCOPF model' includes a much more detailed geographical representation than the 'WILMAR Joint Market Model'. It covers the total German extra high-voltage grid (380 and 220 kV) with 601 buses (454 regular and 147 auxiliary buses), all generators with an installed capacity larger than 100 MW, superimposed offshore and onshore wind generations and the locational vertical load levels (total load minus subordinated RES feed-in and subordinated conventional generation).

The objective function in the 'German DC SCOPF model' is the minimisation of the overall costs of generation with subject to generation capacities, maximum line flow constraints and violations that would occur during contingencies. Generation and plant operating limits are modelled unit-wise and the generation costs of each unit are approximated by a linear cost function. To cover part load efficiency, we linearise the costs in-between minimum and maximum capacities. The generation costs include fuel, CO_2 and variable operation and maintenance costs. As the 'SCOPF model' is not intertemporal, we ignore time-dependent costs such as start-up and ramping costs. The maximum line flow constraints are given by the thermal limits of the branches. The set of contingencies includes possible outages of each circuit and unit. Vertical load has to be met, while imports and exports are taken as modelled in the 'WILMAR Joint Market Model'. Wind production is allowed to be curtailed in case of congestion to meet the maximum line flow constraints.

The surrounding countries are represented by country nodes that are connected to the German grid via cross-border lines. The interconnections are modelled considering their length and voltage level. The cross-border capacities are assumed to be unlimited as the cross-border flows are exogenous and based on the hourly exchange computed with the 'WILMAR Joint Market Model'. The model includes 18 interconnections to consider the import and export flows from/to Denmark, Sweden, Poland, Czech Republic, Austria, Switzerland, France, Luxembourg and the Netherlands.

2.5 Determination of NTCs

The calculation of NTCs is performed within the 'German DC SCOPF model'. Although procedures for capacity assessment provided by ENTSO-E offer a harmonised base to calculate NTCs, in power system and energy market modelling most studies ignore the need for subsequent NTC calculations to incorporate changes in load and especially RES generation patterns (compare [13, 27, 28]). Furthermore, the effects of line and unit outages should be included to meet the $N-1$ criteria.

On the basis of [27], we define NTC as the maximum commercial exchange programme between two interconnected market zones z and z' without compromising system security and taking into account uncertainties on future network conditions. As shown in (3), the $\text{NTC}_{zz'}$ is part of the total transfer capacity ($\text{TTC}_{zz'}$) which is reduced by a transmission reliability margin (TRM). The $\text{TTC}_{zz'}$ indicates the

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maximum amount of electric power that can be transferred from one market zone to another without violating security limits and assuming that all future system conditions are known with certainty in advance. The uncertainties involved are then addressed by the TRM, which specifies the amount of transmission transfer capability necessary to maintain system reliability

$$\mathrm{NTC}_{zz'} = \mathrm{TTC}_{zz'} - \mathrm{TRM} \tag{3}$$

where

$$\mathrm{TTC}_{zz'} = \mathrm{BCE}_{zz'} + \Delta E_{zz'}^{\max}$$
$$\mathrm{TRM} = \sqrt{\text{number of circuits}} \times 100\,\mathrm{MW}$$

The TRM copes with uncertainties of calculated TTCs arising from the uncertainties about future network conditions. Unanticipated events such as forecast errors of RES-feed-in and load patterns or emergency exchanges and load frequency regulation, for example, because of outages can result in unscheduled physical flows between the considered zones. As there is no (European) standard guideline for determining this security margin, we apply the heuristic formula of the German TSOs as also shown in (3) [29].

The calculation of the $\mathrm{TTC}_{zz'}$ is complex and requires detailed information on future network conditions, generation and load patterns and cross-border flows [30, 31]. On the basis of this information, we start with computing the base case exchange (BCE) between the two market zones. The calculation of the initial dispatch and load flows is carried out as to be compatible with N–1 security standards (SCOPF). Following [27], the BCE relates to the best forecast for exchanges between two zones at the considered time period. To analyse the impact of RES feed-in on $\mathrm{NTC}_{zz'}$, we already include wind and photovoltaic (PV) generations at this stage.

For a considered transaction zz' between two market zones (or nodes) z and z', the BCE is given by the sum of the base case power flows P_{ij}^0 on all transmission lines connecting zones z and z'

$$\mathrm{BCE}_{zz'} = \sum\nolimits_{ij}^{P\,0}, \quad ij \in \text{connecting transmission lines} \tag{4}$$

To find the maximum additional exchange $\Delta E_{zz'}^{\max}$ between the two market zones, a sensitivity analysis is performed. First, we calculate PTDFs for the considered transaction zz' as in (5), where z is the source and z' the sink

$$\mathrm{PTDF}_{ij,z} = \frac{\Delta P_{ij}}{\Delta T_{zz'}} \tag{5}$$

ΔP_{ij} is thereby the change in real power flow on line ij for transaction zz' obtained by a change of the transaction volume $T_{zz'}$.

To incorporate the effects of a line outage, we then compute line outage distribution factors (LODFs) based on a set of possible contingencies as indicated by Sauer *et al.* [30] and given in (6)

$$\mathrm{LODF}_{ab,ij,z} = \frac{\mathrm{PTDF}_{ij,z}^{\text{outage}} - \mathrm{PTDF}_{ij,z}^{\text{pre\_outage}}}{\mathrm{PTDF}_{ab,z}^{\text{pre\_outage}}} \tag{6}$$

In case of a line outage, the real power flow P_{ij}^{outage} on line ij can be calculated (as shown in (7) based on the real power flows before the outage $P_{ij}^{\text{pre\_outage}}$ and $P_{ab}^{\text{pre\_outage}}$, where the real power flow on line ab before the outage has to be absorbed by the transmission lines that are still online. The share of absorption for line ij is given by $\mathrm{LODF}_{ab,ij,\,z}$

$$P_{ij}^{\text{outage}} = P_{ij}^{\text{pre\_outage}} + \mathrm{LODF}_{ab,ij,z} \cdot P_{ab}^{\text{pre\_outage}} \tag{7}$$

Although P_{ij}^{outage} indicates the absolute value of the real power flow on line ij after the outage for calculating the maximum additional exchange $\Delta E_{zz'}^{\max}$ we have to define the relative percentage of the transfer that will flow on line ij after the outage (outage transmission distribution factor) as described in (8)

$$\mathrm{OTDF}_{ij,z} = \mathrm{PTDF}_{ij,z} + \mathrm{LODF}_{ab,ij,z} \cdot \mathrm{PTDF}_{ab,z} \tag{8}$$

By incorporating all possible outages and choosing the minimum of additional exchange capacity, no overloading in case of contingencies is allowed and system security is guaranteed. The maximum additional exchange $\Delta E_{zz'}^{\max}$ is finally stated as

$$\Delta E_{zz'}^{\max} = \min\left(\frac{P_{ij}^{\max} - P_{ij}^{\text{outage}}}{\mathrm{OTDF}_{ij,z}}, \quad ij \in \text{connecting transmission lines}\right) \tag{9}$$

3 Results and discussion

In the following section, the results of both models and of the clustering analysis are presented. First, a zonal delimitation of the German power market is derived from the 'WILMAR Joint Market Model' results. Subsequently, the computed zonal transmission capacities are outlined and analysed in detail for characteristic wind and solar situations. Although the focus is on NTCs, the impacts of RES generation and demand patterns on load flows and PTDFs are presented. Finally, the impacts on the effectiveness of a specific market splitting scenario for Germany are discussed.

3.1 Zonal delimitation

So far, few studies have addressed the optimal zonal delimitation of the German or European power market (e.g. [16, 32, 33] or [34]). However, this paper does not aim at finding the optimal delimitation of alternative bidding zones, but rather aims at analysing the impacts of RES generation and demand patterns on NTCs for a fictitious yet appropriate splitting of the German power market and the resulting implications for market splitting in a power system with a high share of RES.

When introducing market splitting, the zonal borders should run along the main bottlenecks [5]. For the identification of the bottlenecks, we analyse the hourly intra-German load flows and imminent line overloading derived from the 'WILMAR Joint Market Model' results. We find the main bottlenecks in 2015 to be expected between 50Hertz3-TenneT5, Amp2-Amp4 and TenneT5-TrBW1 (compare Fig. 2). The main drivers identified are high wind generation in the northern part of Germany and comparatively high load levels in the southern and western regions of Germany. Although the transmission lines between 50Hertz3 and TenneT5 were mostly congested already during the past years, the bottleneck between Amp2 and Amp4 is caused by the generation of new coal power plants combined with high RES feed-in.

Consequently, we decide to split the German power market into two market zones in order to capture the major congestion. The zonal delimitation is shown in Fig. 2. A further major bottleneck between TenneT5 and TrBW1 is found to be relieved by this market splitting. Therefore we decide against a further splitting into three market zones.

The identified delimitation is also in line with previous studies (compare, e.g. [32]). In the following DE_N is referred to as the northern market zone and DE_S refers to the South.

3.2 Zonal transmission capacity in characteristic situations

The cluster analysis of the modelled aggregate cross-border and intra-German flows allows determining the impacts of characteristic situations with regard to RES feed-in and demand patterns on load flows, PTDFs and NTCs for the described zonal delimitation. Each of these situations or clusters represents 1 h for which the German load flow situation is then calculated in more

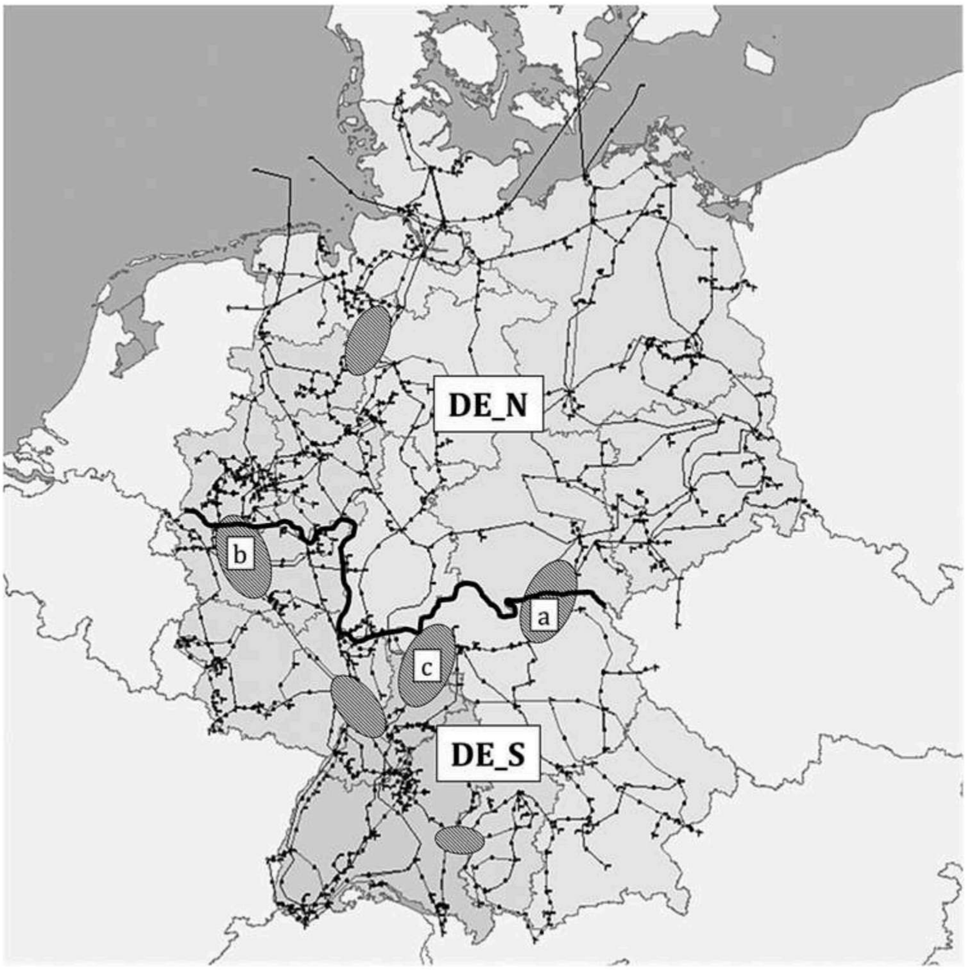


Fig. 2 *Congestions in a single German power market and delimitation of two price zones (DE_N and DE_S): (a) 50 Hertz3-TenneT5, (b) Amp2-Amp4 and (c) TenneT5-TrBW1*

detail utilising the 'German DC SCOPF model'. The cluster analysis of the aggregate cross-border and the intra-German flows obtained from the 'WILMAR Joint Market Model' provides 12 clusters or stated in other words 12 representative situations. Table 1 gives an overview of the resulting clusters which are characterised by the corresponding levels of vertical load, exchange balance, RES infeed and the calculated NTC. These values are provided for the hour closest cluster centroid (in terms of distance function (1)).

The clusters have been ordered by increasing levels of overall vertical load levels (including exchange balance). NTCs are found to vary between 7.4 GW and almost 12 GW.

A correlation analysis between the computed NTCs and the considered factors (vertical load+exchange balance, wind and solar) provides no clear results. Our results, for example, do not indicate a linear correlation between wind infeed and NTCs. This differs from the current practice of German TSOs at the South–West cross-border interconnections. There the German TSOs apply a so-called 'C function' for the determination of bilateral NTCs. This function mainly depends on the wind generation in Germany [29].

The lack of clear correlation between the considered factors and the calculated NTCs in our results can be attributed to the following factors. First, demand and RES generation are not

Table 1 Characteristic situations: vertical load level + exchange balance, RES infeed and NTCs in megawatt (MW) for resulting clusters

		in MW			in MW				
Cluster	Cluster elements	Vertical load + exchange balance	Wind[a]	PV[a]	ΔE	BCE	TTC	TRM	NTC
1	464	31 595	6047	0	3396	7321	10 717	−480	10 237
2	694	39 213	3297	30 761	13 852	−1391	12 461	−480	11 981
3	941	44 502	659	0	7044	2287	9331	−480	8851
4	878	45 322	5568	0	5963	4573	10 536	−480	10 056
5	645	46 253	893	0	8157	2262	10 419	−480	9939
6	614	47 356	13 140	16 624	8401	−423	7978	−480	7498
7	779	49 121	4552	0	4992	4517	9509	−480	9029
8	872	51 146	5425	0	5676	5021	10 697	−480	10 217
9	681	59 592	9000	34	5716	4030	9746	−480	9266
10	670	61 190	13 636	0	4416	3481	7897	−480	7417
11	746	74 179	20 607	0	4403	5706	10 108	−480	9629
12	752	81 196	31 747	0	7530	4923	12 453	−480	11 973

[a]Total wind and PV infeed: in the DC SCOPF model part of the vertical load levels (total demand – conventional generation and RES-infeed connected to the subordinated grid levels).

geographically uniform. Second, the German or European power system is characterised by a high degree of complexity. Although other studies consider small test systems and the infeed of all wind generation at only one single bus (compare, e.g. [6]), we model realistic demand and generation patterns and under consideration of import and export flows. In addition, we observe an unbalanced utilisation of transmission lines along the zonal border and bi-directional load flows that may induce indirect effects cancelling each other.

A more detailed analysis especially of the components of the NTC (BCE and ΔE) and the effect of increasing wind and solar infeed is given in Section 3.4.

3.3 Impacts of characteristic wind situations on load flows and PTDFs

Fig. 3*a* compares the resulting load flows for two situations with minimum and maximum wind feed-in (clusters 3 and 12). Three key points can be identified: first, high wind feed-in causes a North–South flow to load centres in Germany with additional imports from Denmark and Sweden and exports to the southern countries (France, Switzerland and Austria). Second, in hours with high wind feed-in loop or transit flows via interconnected countries (Germany to Netherlands and Germany to Czech Republic) can be observed. This can be explained by limited transmission capacities within Germany and the location of the load centres in Western and Southern Germany. Furthermore, market results lead in case of uniform pricing to export flows to the southern countries, so that intra-German congestion is intensified. Third, partly opposite load flows from generation to load centres in hours with low wind feed-in may occur.

As discussed in Section 2.5, PTDFs are an input factor for the calculation of NTCs or the component $\Delta E^{\max}$. Several authors already addressed differences between AC and DC PTDFs as well as impacts of load variations on PTDFs [10, 24]. They find that under normal conditions the variations in PTDFs are limited. In Germany, intermittent wind in-feed is concentrated in the northern regions, whereas a higher share of solar generation is located in the southern regions. As most RES-capacity is connected to subordinated grid levels, fluctuations of RES generation cause variations of vertical load levels. In the following, we therefore focus on the impact of intermittent RES generation on PTDFs and load flows. For this analysis, we calculate PTDFs for the tie lines of the regional electricity transport model of the German TSOs.

Fig. 3*b* depicts the frequency distribution of the deviations of DC PTDFs for the considered wind scenarios (clusters 3, 9, 11 and 12). Comparing the high and low wind scenarios, one would expect the PTDFs to differ strongly as high wind feed-in changes the generation patterns for Germany and results in heavily utilised transmission lines. However, more than 80% of the deviations of PTDFs are within the intervals −0.5 to 0 and 0 to +0.5% points. A main reason for this observation is that the PTDFs only consider a change in the distribution of flows on the tie lines between the regions and not on intra-regional transmission lines. The highest deviations (2.89 or −1.93% points) can be observed on tie lines in the northern regions as higher wind feed-in results in a change of power plant dispatch and an unbalanced utilisation of the affected transmission lines.

In Fig. 3*c*, we plot the PTDFs of the scenarios with minimum and maximum wind generation against each other. The PTDFs for both scenarios are very similar. The same holds true when different solar feed-in levels are compared. The results are not shown in this paper as the deviations of PTDFs are more driven by wind generation. This finding suggests that for the purposes of energy market modelling, the utilisation of only one PTDF-matrix does not cause major errors. However, this only applies for an aggregated representation of the transmission grid.

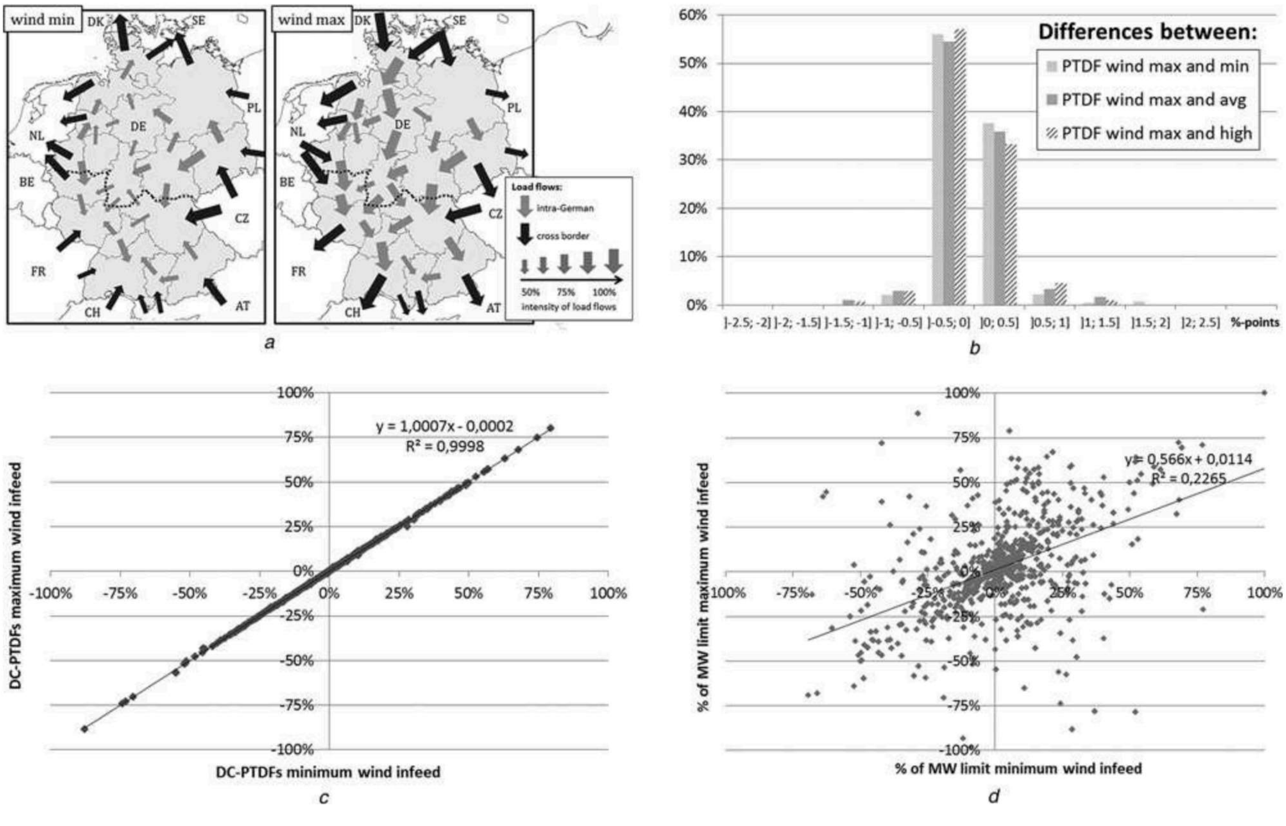


Fig. 3 *Impacts on load flows and PTDFs*

a Impact on load flows (wind scenarios minimum and maximum)
b Frequency of deviations of DC PTDFs for wind scenarios
c Comparison of DC PTDFs (wind scenarios minimum and maximum)
d Comparison of line loadings (wind scenarios minimum and maximum)

An analysis of the load flows on intra-regional transmission lines or between individual buses reveals large deviations between characteristic situations (see Fig. 3*d*). Most deviations occur for buses having high wind (or solar) generation capacity.

3.4 Impacts of characteristic situations on NTCs

3.4.1 NTC for a representative hour: To analyse the effects of RES generation and load patterns, we first calculate an NTC for a representative system state. For the average vertical load level of 43.8 GW, the average wind feed-in of 9.2 GW and the average PV feed-in of 5.7 GW we find a NTC of 10 GW for a transaction from DE_N to DE_S. As the German power system is characterised by an excess supply in the North of Germany and a North–South congestion problem, NTCs for transactions from DE_S to DE_N are not considered in this paper.

3.4.2 Focus on wind infeed – clusters 3, 9, 11 and 12: Fig. 4 shows the resulting NTCs for selected clusters with a wind feed-in from 0.7 up to 31.8 GW. The NTCs between the market zones DE_N and DE_S vary from 8.9 to 10.2 GW. The results indicate a slightly increasing maximum exchange programme between DE_N and DE_S with increasing wind infeed. At first glance this seems somewhat surprising, but can be explained by the fact that NTCs do not reflect the remaining free transmission capacities, but the possible overall power flows. Correspondingly they are not only impacted by wind generation, but rather by load and generation patterns as well as cross-border flows.

More insight is provided by an analysis of the components of NTCs:

• First, the BCE varies with the actual demand and generation situations.

Thereby, the increase of wind generation is identified as direct and indirect drivers of an increasing BCE as high wind infeed results in lower national power prices and correspondingly higher export flows from DE_S especially to France, Switzerland and Austria. Or stated in other words: increasing wind generation results in changed cross-border exchanges and consequently increases the BCE, which also results in a higher NTC.

• Second, an increase of wind infeed results in a higher utilisation of the tie lines between DE_N and DE_S and thus leads to a decrease of the additional exchange capacity ΔE. Nevertheless, the increase of BCE described above overcompensates the decrease of ΔE.

The main driver of this result is the unbalanced utilisation of tie lines between the considered market zones. In hours with low wind generation demand has to be met by thermal capacities. Important shares of the remaining nuclear capacities are located in DE_S while modern coal plants are located especially in Western Germany along the zonal border in DE_N.

This results in unevenly distributed and even reverse load flows between both market zones (see Fig. 3*a*, scenario ‘wind min’). As the BCE is given by the sum of load flows on the tie lines (compare formula (4)), a lower BCE is obtained in hours characterised by low wind generation and bi-directional North–South flows, whereas a higher BCE occurs in hours with high wind generation and one-directional North–South flows. When wind infeed increases, the cross-zonal capacities are more evenly used, resulting in an increasing overall NTC.

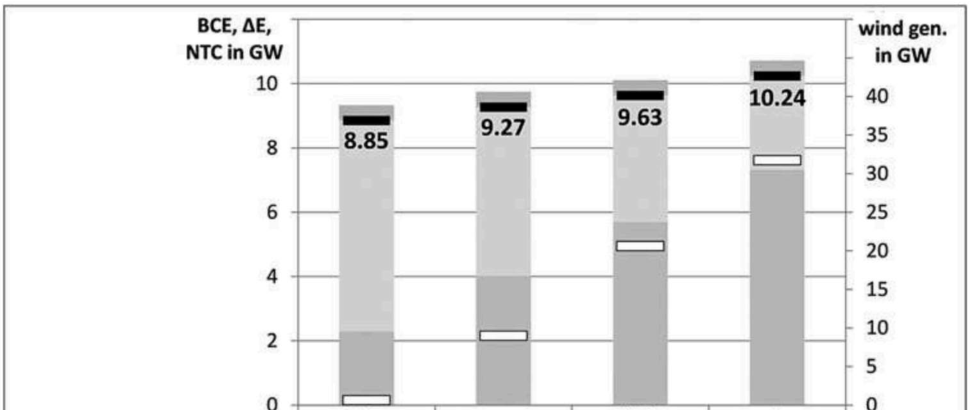
3.4.3 Focus on solar infeed – clusters 10, 6 and 2: Owing to meteorological characteristics, more than 60% of PV capacity is located in DE_S. To study the effects of PV generation on the NTC, we analyse three further typical clusters differentiated by their PV generation.

An increase of PV infeed correlates with a decrease of local vertical load levels especially in DE_S. Fig. 5 shows that an increasing PV generation and corresponding excessive supply in DE_S results in a negative BCE or South–North load flow. This effect is lowered by an increasing wind generation.

Furthermore, an increasing PV generation correlates with an increase of the additional exchange capacity ΔE between DE_N and DE_S. Or to be more precise: increasing PV infeed ‘works’ against the usual flow direction North-to-South, which is mainly caused by wind generation and modern coal plants in the northern regions. Thus, in hours according to cluster 2 solar production located in southern Germany has a stabilising effect on the transmission network.

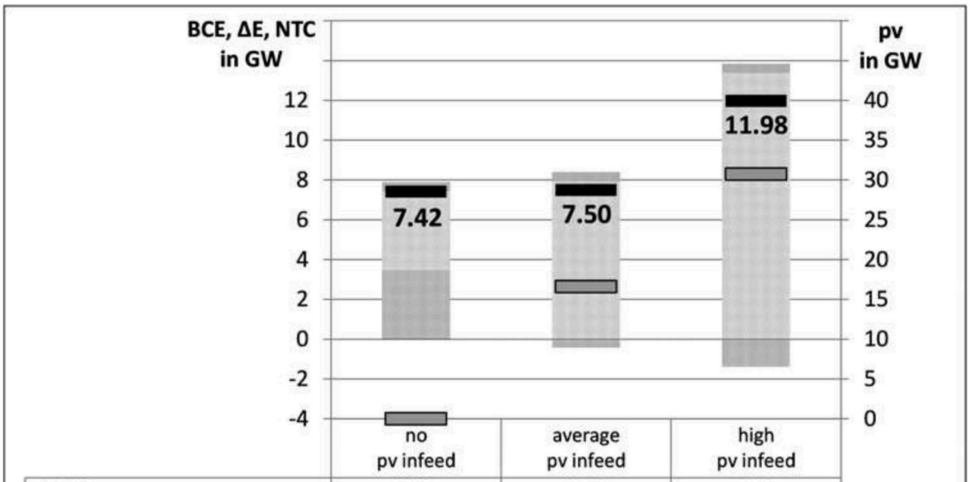
3.5 Implications for effectiveness of market splitting in Germany

The main drivers of congestions in Germany are on the one hand the fluctuating RES generation and on the other hand the spatial separation notably between wind power plants and load centres.



	minimum wind infeed	average wind infeed	high wind infeed	maximum wind infeed
TRM	0.48	0.48	0.48	0.48
ΔE - TRM	6.56	5.24	3.92	2.92
BCE	2.29	4.03	5.71	7.32
NTC	8.85	9.27	9.63	10.24
Wind generation	0.66	9.00	20.61	31.75
Vertical load + exchange balance	44.50	59.59	74.18	81.20

Fig. 4 *Impact of wind infeed and vertical load level on NTCs (PV infeed = 0)*



	no pv infeed	average pv infeed	high pv infeed
TRM	0.48	0.48	0.48
ΔE - TRM	3.94	7.92	13.37
BCE	3.48	-0.42	-1.39
NTC	7.42	7.50	11.98
PV generation	0.00	16.62	30.76
Wind generation	13.64	13.14	3.30
Vertical load + exchange balance	64.79	47.36	39.21

Fig. 5 *Impact of solar infeed on NTCs*

For the effectiveness of market splitting in Germany, this relationship is of high importance. Depending on vertical load levels and RES generation patterns, the NTCs for the considered market splitting scenario vary within a range from 7.4 to 12 GW.

Hence, introducing market splitting with a fixed NTC of, for example, 10 GW would have a negative impact on effectiveness: in hours with underestimation of the NTC, the trading possibilities between the connected market zones would be unnecessarily reduced. As a consequence liquidity and thus the efficiency of market splitting would be adversely affected. In hours with an overestimation, the NTC would not become binding and re-dispatch measures would not be reduced. Hence, system security would be compromised as excessively high trading activities would intensify and not relieve the German congestion situation.

In the longer term, the NTC between the considered market zones is also influenced by grid extension as the corresponding increase of the grid transfer capacity influences the load flow patterns. Conversely, the expansion of renewable capacities (especially offshore wind) results in a changed generation pattern which can induce additional bottlenecks. In this regard, changes in international trading activities and resulting cross-border flows are also of importance. Hence, periodical reviews of the zonal delimitation are a key issue to ensure the effectiveness of market splitting.

For the purpose of energy market modelling, variable NTCs should be taken into account, especially when analysing the effects of introducing market splitting. Although the German TSOs already incorporate the effects of wind generation when determining transfer capacities (C function for import and export flows from/to BeNeLux, France and Switzerland), transfer capacities are kept constant in most energy market models (compare, e.g. [13, 14] or [16]). Within our analysis we showed, that the components of the NTC (BCE and ΔE) strongly depend on RES generation. A higher wind infeed correlates with an increasing BCE and decreasing ΔE. In contrast, a higher PV infeed especially in the southern regions correlates with a decreasing BCE and an increasing ΔE. Since a further increase of PV capacities especially in southern Germany is to be expected, intermittent solar generation patterns should also be considered when computing transfer capacities in future.

Although the adequate configuration of bidding zones and NTCs is of major importance for the effectiveness of market splitting, further issues arise when introducing zonal pricing. So far, few studies have addressed the market implications and distributional effects of market splitting in Germany (compare [5, 34, 35]). Accordingly, the introduction of further bidding zones in Germany would affect the spot market results. Although the northern zone is characterised by an excessive generation of wind power, in the southern zone generation capacity is scarce. Thus, when the NTC becomes binding spot prices are higher in the South. In [34], the average annual electricity price differential is 1.70 €/MWh (2015). In [5], an average annual price difference of 1.40 €/MWh (2020) is found. As a consequence, consumers in the North of Germany would gain along with the producers in the South. In [5] also impacts of market splitting in Germany on the European power market are discussed. Owing to the described price effects countries with interconnection to the South of Germany see higher spot prices. In contrast, spot prices decrease in countries with interconnection to the northern zone. Although considerable distributional effects among consumers, producers and network operators occur, the impacts of market splitting on the total system costs or the total welfare are negligible (compare [5, 35]).

Moreover, the price effects of introducing market splitting would affect the market value of RES. As about 80% of the total wind generation capacity is installed in the North of Germany, the market value of wind power would be particularly affected [5].

In [34], Egerer *et al.* recommend further research on different approaches to regional pricing. Moreover, Trepper *et al.* [5] conclude that a balanced choice between zonal pricing with additional bidding zones in Germany and grid extension is needed to guarantee system security.

4 Final remarks

This paper presents an integrated approach to analyse the impacts of intermittent RES feed-in, demand patterns and the corresponding exchanges on load flows, PTDFs and NTCs. The corresponding implications for a fictitious market splitting scenario for Germany are thereby of specific interest.

We find a considerable impact of wind feed-in especially in the North of Germany on load flows intensifying the North–South congestion problem. The results regarding PTDFs suggest that for the purposes of energy market modelling the utilisation of only one single PTDF-matrix does not cause major errors.

The calculation of NTCs for a fictitious splitting of the German power market into two bidding zones reveals a high, but non-linear dependency of the results on the combination of demand patterns, RES infeed and cross-border flows. The results imply that the effectiveness of market splitting strongly depends on the considered NTC (between market zones). On the basis of these results, we argue that NTCs in dependency of wind and solar production should be implemented when it comes to the introduction of market splitting in Germany and when the benefits of zonal pricing are analysed within model calculations as well.

Further research should focus on the investigation of flow-based market coupling between German bidding zones. Thereby our findings imply that RES and demand patterns as well as the unbalanced utilisation of transmission lines and bi-directional load flows among the zonal border would impact the flow gate capacities.

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