Congestion Management in Germany - The Impact of Renewable Generation on Congestion Management Costs

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May 27, 2011

Abstract

In this paper we analyse the German congestion management regime and assess future congestion management costs given a higher share of intermittent renewable generation. In this context, cost-based redispatching of power plants and technical flexibility through topology optimization are considered as market-based and technical congestion management methods. To replicate the current market regime in Germany a two-step procedure is chosen consisting of a transactional spot market model and a congestion management model. The results show that currently congestion can mainly be managed by optimizing the network topology. However, congestion costs tend to increase significantly even if proposed network extensions are taken into account due to higher wind generation and proposed power plant investments, both located mainly in northern Germany. We conclude that there is a need for improving the current congestion management regime.

Keywords: Electricity, Congestion Management, Network Modeling, Germany
JEL-code: L94, L51, D61

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1 Introduction

Several European countries have implemented special support schemes for renewable energy sources in order to reduce domestic emissions of carbon dioxide in the energy sector. Especially in northern Europe, wind energy became the dominating renewable energy source due to the geographical conditions. However, the characteristics (intermittency and dispatch priority) of wind energy limit the response to market signals and significantly affect electricity markets.

Renewable energy generation especially wind generation is characterized by high capital and low fuel or operational costs. Hence, wind generation is placed in the beginning of the merit order and should be dispatched first in the short run. Furthermore, the location of wind turbines strongly depends on regional wind conditions. In Germany significant wind capacities are located in the northern part of the country. On the other hand, electricity demand is mainly located in the mid-western and southern part of Germany. Both aspects will result in an increasing flow of electricity from northern to southern Germany. Especially in years with high wind generation, network congestion increases and congestion management costs are affected (Deutscher Bundestag, 2010). In the future a further increase of congestion management costs is expected firstly due to higher wind generation and significant fossil generation investments in northern Germany. Therefore, recent studies emphasize the need for significant investments in transmission capacity to reduce future network congestion (50Hertz Transmission et al., 2010). On the other hand, the option to adjust or extend the current congestion management regime could reduce the need for transmission investments through a better utilization of transmission network. Furthermore, price signals resulting from congestion management could give market participants adequate incentives to locate generation or demand.

This paper investigates the impact of physical network constraints on spot market results and total costs. Therefore, a model is described which replicates the current market regime in Germany consisting of a spot market and a congestion management model. After clearing of the spot market the final power plant dispatch is determined by the system operator given the physical network constraints. Re-dispatching of power plants and optimization of network topology are considered as congestion alleviation methods and

interpreted as lower and upper bound on congestion management costs.
The paper is structured as follows. An overview on different congestion management methods and the German market regime is provided in the next section. The model and the underlying dataset are described in Section 3. The results are presented and discussed in Section 4. Section 5 concludes.

2 Principles of Congestion Management

2.1 Congestion Management Methods

Congestion represents the situation when technical constraints (e.g., line current, thermal stability, voltage stability, etc.) or economic restrictions (e.g., priority feed-in, contract enforcement, etc.) are violated and thus restrict the power transmission between regions. Congestion management is aimed at obtaining a cost optimal power dispatch while accounting for those constraints (Kumar et al., 2005). According to Androcec and Wangensteen (2006) congestion management mechanisms can be classified into transmission capacity allocation and congestion alleviation methods.
Transmission capacity allocation methods aim to optimally allocate existing capacity and can be clustered into: explicit auctions (first come, first served; pro rata rationing; bilateral and coordinated explicit auctions) and implicit auctions (bilateral implicit auctions; market splitting, market coupling). Furthermore, a differentiation can be made according to the inclusion of physical power flows: Non flow-based methods assume that electricity can be transported from every specific location to another one in the grid whereas flow-based methods respect the physical characteristics of the grid in particular loop flows. A detailed description and evaluation of different congestion allocation methods is presented in Krause (2006).
Congestion alleviation methods aim to manage existing or expected congestion using technical or market-based methods. Technical methods comprise optimization of network topology through switching actions, active loadflow management through phase-shifting transformers or FACTS, or the temporary increase of transmission capacity through active heat monitoring of transmission lines. Cost- or market-based (counter-trading) re-dispatching of power plants are examples for market-based congestion alleviation methods (de Vries, 2001).

2.2 Electricity Market and Congestion Management Regime in Germany

The German electricity market is characterized by a decentralized market structure as market participants are responsible for planning their unit commitment mainly without considering physical restrictions of the power system. Given the commitment decisions of the market participants the system operator is in charge of managing physical transmission restrictions and of maintaining the balance between generation and demand. The German electricity market comprises four sub-markets namely the futures market, day-ahead or spot market, the intraday market, and the reserve market. Whereas the futures market, day-ahead and intraday market are organized by the European Energy Exchange (EEX) and European Power Exchange (EPEX), the reserve market is organized by the system operators. Beside the organized (standardized) markets, market participants can trade on a bilateral basis except for reserve capacities. The daily market procedure is displayed in Figure 1 and described in this section.

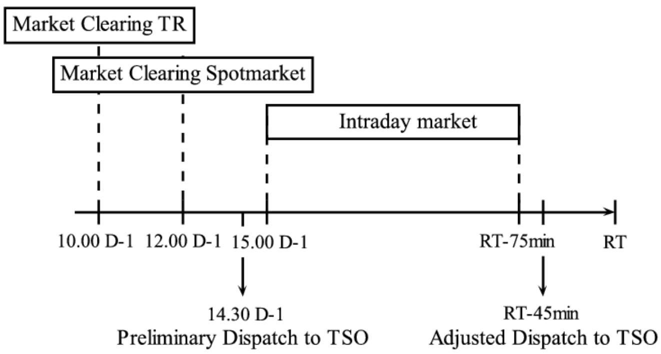


Figure 1: Daily market procedure of the German electricity market

The day-ahead market or spot market is organized as a power exchange and operated by the EPEX Spot SE in Paris. The standardized day-ahead market comprises a central daily auction which is cleared at 12.00 a.m. for all hours of the following day. Demand and generation bids are matched and a hourly market price is determined. National network restrictions are not considered in the market procedure, whereas international trades are constrained by the net transfer capacity between countries.[1] Market par-

[1]Allocation of net transfer capacity depends on the considered border. In 2010 Germany joined the market coupling procedure initiated by France, Belgium, and the Nether-

ticipants are not obliged to trade at the power exchange and can also trade bilaterally 'over the counter' (OTC). Based on the contractual obligations of the day-ahead market and bilateral trading power plant generators have to inform the responsible transmission system operator of their proposed dispatch timetable at 2.30 p.m. for the day ahead (§5 (1) StromNZV).
The intraday market starts at 3.00 p.m.. Market participants can trade electricity either standardized through the market platform provided by the EPEX or on a bilateral basis. Standardized trading at the intraday market is possible until 75 minutes before physical delivery.
Generators are obliged to inform the transmission system operator about their adjusted power plant dispatch 45 minutes[2] prior to real time for each 15 minute interval (§5 (2) StromNZV). Contrary to the initial dispatch timetable submitted after clearing of the spot market, transmission system operators can reject dispatch adjustments resulting from intraday trades (§5 (2) StromNZV). Given the final dispatch timetables of the power plants the transmission system operators are in charge to manage physical network limitations through congestion alleviation methods. To do so the transmission system operators have two general control options to ease network congestion, namely technical and market based methods (§13 (1) EnWG). Active loadflow management can be done technically through adjustments of network topology (e.g. switching actions) or network characteristics (e.g. changes of transformer taps). On the other hand market-based congestion management methods comprise the adjustment of nodal generation or load through market-based methods. In Germany cost-based re-dispatching of power plants is applied (Inderst and Wambach, 2007; Borggrefe and Nüßler, 2009). Power plants in regions with excess generation[3] have to decrease their output to reduce congestion in the transmission network. On the other hand, the reduced generation output in the surplus region has to be compensated by an increase of generation output in the deficit region to ensure equality of demand and supply. The increase and decrease of generation is associated with costs which are interpreted as congestion management costs.
The historical costs for congestion management (cost-based re-dispatching

lands. Interconnector capacity on remaining borders (Poland, Czech Republic) are allocated through explicit auctions.

[2]Nowadays, the time is reduced to 15 minutes prior to real time.

[3]This means, planned generation which cannot be physically exported due to physical network congestion.

of power plants) are displayed in Table 1. According to Deutscher Bundestag (2010), costs for congestion management are signficantly affected by wind generation in Germany. Whereas congestion management costs increased in 2008, costs are reduced by 44% in 2009 caused by lower wind generation in this year (Deutscher Bundestag, 2010). In the future a further increase of congestion management costs is expected due to higher wind generation and significant fossil generation investments in northern Germany. Furthermore, electricity demand is mainly located in the mid-western and southern part of Germany. Both aspects will result in a significant flow of electricity from northern to southern Germany.

Year	**2007**	**2008**	**2009**
Re-dispatching costs [*million EUR/a*]	30	45	25

Table 1: Re-dispatching costs in Germany, Source: Deutscher Bundestag (2010)

3 Model

Our analysis is based on ELMOD, a model of the European electricity market including the physical transmission network. ELMOD is a bottom-up model combining electrical engineering and economics. The model was developed in order to analyze various issues of market design, congestion management, and investment decisions (Leuthold et al., 2010). We adjust the basic model formulation in order to represent the German market procedure consisting of a spot market and the congestion management by national transmission system operators.

3.1 The Spot Market Model

The spot market model minimizes the total generation costs $\sum_p mc_p G_p$ of each power plant p for a given level of load q_n. The load is defined for each system node n representing substations of the physical transmission network. The minimization of total generation costs (Eq. 1) is subject to the market clearing constraint, the individual power plant capacity restrictions, and the restriction of international trade. The market clearing constraint (Eq. 2) ensures the equality of load q_n, wind generation g_n^{wind}, generation of thermal power plants G_p, and international exchanges $TF_{n,nn}$. The dual or marginal on the market clearing condition is the marginal price $price_n^{DA}$. Renewable wind generation is defined as a parameter and reduces the load at each node. This assumption is founded in the priority feed-in of renewable generation according to the German renewable energy sources act (Erneuerbare-Energien-Gesetz, EEG). On the other hand, generation of thermal power plants is an optimization variable of the model and restricted by the installed capacity g_p^{max} of power plant p (Eq. 3). As the model aims to optimize the spot market, trade $TF_{n,nn}$ between system nodes refers to transactional volumes rather than physical exchanges. The trade between countries depends on the direction and is restricted by the net transfer capacity $ntc_{c,cc}$ between country c and country cc (Eq. 4). Thus international transfer is limited whereas transfers between national nodes is unlimited. The final linear problem is optmized for one hour.

$$\min_{G_p} \sum_p mc_p G_p \tag{1}$$

$$q_n - g_n^{wind} = \sum_p G_p - \sum_{nn} TF_{n,nn} + \sum_{nn} TF_{nn,n} \qquad \forall n \tag{2}$$

$$G_p \leq g_p^{max} \qquad \forall p \tag{3}$$

$$\sum_{n \in c} \sum_{nn \in cc} TF_{n,nn} \leq ntc_{c,cc} \qquad \forall c, cc \tag{4}$$

$$TF_{n,nn}, G_p \geq 0$$

3.2 The Congestion Management Model

Given the results of the spot market model, the different congestion management methods are evaluated using a congestion management model. Cost-based re-dispatching of power plants and network topology optimization methods are considered as options for market-based and technical congestion management methods.

The congestion management model optimizes the total re-dispatching costs (Eq. 5) based on the results of the spot market model, namely the contracted generation of power plants g_p^{DA} and the marginal prices $price_n^{DA}$. Contracted spot market generation can be adjusted by increasing (G_p^{UP}) or decreasing (G_p^{DOWN}) the generation of power plants. Power plants which increase their generation are paid their marginal cost mc_p whereas the decrease of generation is compensated by the lost profit, namely the difference between the spot market price minus marginal costs $price_n^{DA} - mc_p$. Similar to the spot market model, the market clearing condition (Eq. 6) and the generation capacity restriction (Eq. 7) are considered as constraints of the optimization problem. Furthermore, as the congestion management model aims to determine re-dispatching costs resulting from physical network constraints, a DC loadflow approach is used to reflect technical restrictions of the transmission network. Given the technical network characteristics ($b_{n,nn}$ and $h_{l,n}$), the lineflow on physical transmission lines LF_l (Eq. 9 and 10) as well as the physical netinput at each system node NI_n (Eq. 8)are determined by the load angle Δ_n . Physical transmission limits are represented by p_l^{max} (Eq. 11). Flexibility of the network topology is considered as a congestion management method and reflected by the binary variable $ONLINE_l$ in the model (Fisher et al., 2008). The mixed integer problem is solved in the relaxed version to retrieve a lower bound on congestion management costs. The final linear mixed integer problem is optimized for one hour given the results of the spot market model.

$$\min_{G_p^{UP}, G_p^{DOWN}} \sum_p mc_p G_p^{UP} + (price_n^{DA} - mc_p) G_p^{DOWN} \tag{5}$$

$$q_n - g_n^{wind} = \sum_p (g_p^{DA} + G_p^{UP} - G_p^{DOWN}) - NI_n \qquad \forall n \tag{6}$$

$$G_p^{UP} - G_p^{DOWN} \leq g_p^{max} - g_p^{DA} \qquad \forall p \tag{7}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \qquad \forall n \tag{8}$$

$$LF_l \leq \sum_n h_{l,n} \Delta_n + (1 - ONLINE_l) * m \qquad \forall l \tag{9}$$

$$LF_l \geq \sum_n h_{l,n} \Delta_n - (1 - ONLINE_l) * m \qquad \forall l \tag{10}$$

$$LF_l \leq |p_l^{max}| ONLINE_l \qquad \forall l \tag{11}$$

$$G_p^{UP}, G_p^{DOWN} \geq 0$$

3.3 Data

The model comprises the region of Germany on a detailed level and the neighboring countries Denmark (West), the Netherlands, Belgium, France,

Switzerland, Austria, the Czech Republic, and Poland on an aggregated level. Data for the year 2008 is used as input.
Generation is divided into twelve plant types: hydro (run-of-river and reservoir), nuclear, lignite, coal, gas and oil steam, combined cycle gas and oil turbine, open cycle gas and oil turbine, and pump storage plants. National power plant capacities are based on VGE (2008) and include existing power plants with a capacity above 100 MW. The development of the German power plant fleet until 2020 assumes decommissioning of existing power plants based on technical lifetimes (50Hertz Transmission et al., 2010) and proposed power plant investments till 2018 (BDEW, 2009). Marginal costs of power plants are based on fuel and CO_2 certificate price for 2008.
Wind generation is accounted with marginal costs of zero, thus the node-specific demand will be lowered by corresponding nodal wind generation. In 2008, generation capacities of installed wind turbines sum to 27 GW and is expected to increase to 37 GW onshore and 14 GW offshore in 2020 (50Hertz Transmission et al., 2010). Wind generation capacities in Germany are distributed among all system nodes according to published data on regional wind capacities by national transmission system operators. Wind generation of neighboring countries is aggregated.
Demand values for 2008 represent the average hourly demand as published by ENTSO-E. In 2020, demand is expected to decrease by 8% in Germany (50Hertz Transmission et al., 2010). Within Germany, nodal demand is determined by taking the regional population and gross domestic product into account. Further information can be found in Leuthold et al. (2010).
The underlying physical grid for Germany is based on the European high-voltage grid ENTSO-E. The neighboring countries of Germany are represented on an aggregated level. Hence, national congestion in those countries is neglected. The transmission network is depicted in Figure 2. The development of the physical transmission grid until 2020 is based on ENTSO-E (2010).
Transactional restrictions in the spot market model between countries are based on the net transfer capacity (NTC) published by ENTSO-E. The indicative NTC values for Summer 2008 are used and considered constant until 2020.
To analyse the impact of different demand and wind levels on congestion management costs nine scenarios are specified. Demand is defined relative

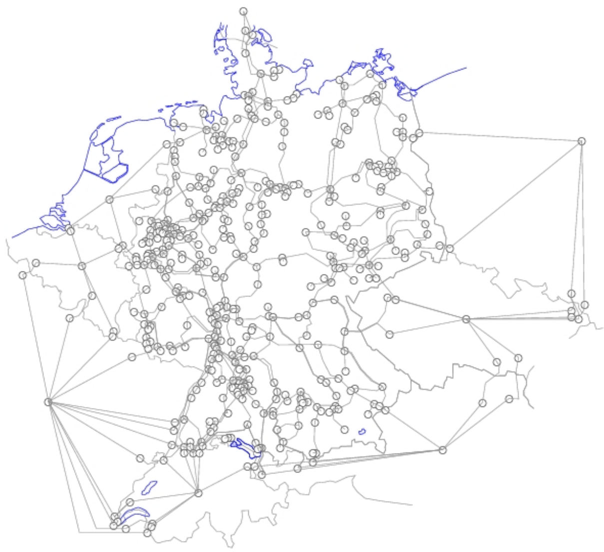


Figure 2: Transmission network

to average hourly demand and classified into three scenarios representing low (85%), medium (100%), and high (115%) demand levels. Wind generation is defined by three different scenarios and varied between low (20% of installed capacity), medium (40% of installed capacity), and high (60% of installed capacity) wind penetration.

4 Results and Discussion

4.1 Results and Comparison

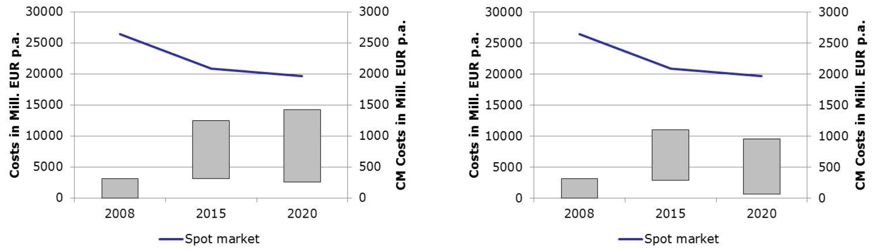
We conduct nine different load and wind scenarios which are simulated for the years 2008, 2015, and 2020. Proposed power plant investments, expected wind capacities, electrical load, and proposed network extensions for Germany are adjusted for the 2015 and 2020 optimizations. Data related to neighboring countries are not changed. Yearly or total costs represent the costs for consumers[4] and are the weighted costs of the presented scenarios. The weights are based on hourly demand and wind values by the ENTSO-E and national TSOs.

[4] Costs for consumers are defined as the product of demand and market price (dual variable on Eq. 6).

Total yearly costs for consumer in Germany are 26 billion EUR in 2008 (Figure 3). In 2015 and 2020 total yearly costs decrease to 21 and 20 billion EUR. The decrease of the total costs is caused firstly by the increase of wind capacity from 23.9 GW in 2008 to 37 GW in 2020. Secondly, load decreases by 8% and thirdly, significant generation investments in relatively cheap hard coal power plants are planned. All three factors impact the total costs and lead to a decrease of generation costs by roughly 26%.
However, the spot market model does not take physical transmission constraints into account and hence, dispatch is characterized by the national merit order cost curve of available fossil and renewable generation. In order to match the dispatch determined in the spot market model with transmission limitations of the physical transmission network, additional actions have to be undertaken by national TSOs to ensure secure operation of the transmission network. In our modeling approach two different congestion management methods are implemented.
Firstly, re-dispatching of power plants in order to ease national physical network congestion is considered. Power plants in regions with excess generation[5] have to decrease their output to reduce congestion in the transmission network. On the other hand, the reduced generation output in the surplus region has to be compensated by an increase of generation output in the deficit region to ensure equality of demand and supply.
Secondly, the re-dispatching of power plants is extended by the option to optimize network topology in order to manage loadflows. The physical transmission network is characterized by substations and transmission lines connecting different substations. Within substations, transformers and switches are the main components and enable the TSO to optimize loadflows in the network through switching actions. In order to reflect the technical flexibility of the TSO, switching of transmission lines is considered as a congestion management option. The mathematical representation in our approach is rather simplified as transmission lines can only be switched on or off and further switching options within a substation are neglected.
In both congestion management methods the increase and decrease of generation is associated with costs which are interpreted as congestion management costs. As network topology optimization does not cause direct costs

[5]This means, generation which cannot be physically exported due to physical network congestion.

to the TSO, the second congestion management method (network topology optimization and re-dispatching of power plants) can be interpreted as a lower bound on congestion management costs. On the other hand, the management of congestion using only re-dispatching of power plants is interpreted as an upper bound on congestion management costs. The costs of considered congestion management methods are displayed in Figure 3 for the considered years and for the different network expansion cases.



(a) Without network extension (b) With network extension

Figure 3: Total spot market (line, left axis) and congestion management costs[6] (bars, right axis)

It can be seen in Figure 3 that the option to re-dispatch power plants results in additional dispatch costs as power plants which are dispatched in the spot market model have to be re-dispatched due to network congestion. On the other hand, network topology optimization reduces the need for power plant dispatch adjustments significantly. For 2008, congestion management costs range between 0 and 314 million EUR per year (c. 1.2% of total spot market costs). If no network expansion is considered, congestion management costs increase to 1426 million EUR per year (c. 7.2% of total spot market costs) in the maximum in 2020 (Figure 3(a)). The significant increase in congestion management costs can be explained by the location of new renewable and fossil generation in northern Germany. In combination with the regional distribution of demand this leads to a significant physical flow from northern to southern Germany and thus increases the need for congestion management. Through optimization of network topology congestion management costs are reduced to 254 million EUR per year in 2020 (c. 1.3% of total spot market costs). Hence, switching of transmission lines leads to a reduction of

[6]The upper (lower) end of the bar represents the upper (lower) bound on yearly congestion management costs.

congestion management costs but cannot ease all network congestion as it is the case in 2008 and (costly) re-dispatching of power plants is still needed to ensure secure network operation.

The overall picture does not change if network extension is introduced in the model (Figure 3(b)). Costs of the spot market remain unchanged as physical network constraints are not considered. However, congestion management costs are reduced through planned network extension stated in ENTSO-E (2010). In 2020, yearly congestion management costs are reduced and range between 61 million EUR (c. 0.3% of total spot market costs) and 948 million EUR (c. 4.8% of total spot market costs). Compared to the case without network extension (Figure 3(a)), the need for re-dispatching power plants decreases as the physical network from northern to southern Germany is strengthen. However, re-dispatching of power plants is still needed and network congestion cannot be eased solely by topology optimization. Furthermore, congestion management costs are on a higher level compared to 2008.

Comparing the different demand and wind generation scenarios gives further insights about their impact on congestion management costs and thus the need for re-dispatching power plants. Congestion management costs in all considered years strongly depend on wind generation level and highest congestion management costs can be observed in scenarios with high wind penetration and high demand. Compared to the cost results for 2008, the dependency of costs in 2020 on wind generation is similar but the absolute values of congestion management costs are higher due to more installed wind capacity in northern Germany.

Especially the upper bound on congestion management costs, which only includes re-dispatching of power plants as a congestion management method, is affected by wind generation rather than by demand. If network topology optimization is additionally introduced as a congestion management option, the cost impact of wind generation reduces and the demand level becomes more important. Thus the lower bound on congestion management increases with higher levels of the demand as flexibility of network topology optimization is reduced due to higher utilization of the network.

If proposed network extensions are considered, the congestion management costs are positively affected and decrease in all considered demand and wind scenarios (Figure 3(b)). Especially in scenarios with high wind generation significant reductions can be observed leading to the overall reduction of congestion management costs compared to the case without network extensions.

4.2 Discussion

Comparing the spot market and congestion management cost results between the considered years indicates the relevance of internal congestion management given higher shares of wind generation. Whereas in 2008 congestion can be eased by network topology optimization, re-dispatching of power plants becomes important in the following years and increases the congestion management costs especially in hours with high wind generation (Table 2). Therefore, congestion management and the design of an appropriate congestion management regime becomes important in the future.

Furthermore, proposed extension of the german high voltage transmission network can partly reduce the increase of congestion management costs (Table 2). Especially in scenarios with high wind generation congestion is reduced and thus the need for costly re-dispatch of power plants decreased. Hence, proposed network extension improves the integration of renewable generation and reduces congestion management costs, although the network extensions are not able to fully eliminate the need for congestion management.

Finally, we compare our results with the case of an implicit allocation of transmission capacity within the spot market. In this optimal dispatch approach, generation of power plants is optimized taking all physical network constraints into account and the resulting costs can be seen as the minimum generation costs including congestion management costs. Optimization of network topology can be included, but is neglected here. Comparing the costs of the approach between the years indicates a significant reduction in total generation costs similar to the costs of the spot market (Table 2). However, as the original spot market model takes only limitations on international transfers into account, additional costs occur in order to ease physical network congestion. Comparing futurecosts of the optimal dispatch with the spot market costs and the estimations for congestion management cost shows the advantage of an integrated determination of generation dispatch and network utilization. Especially in 2015 and 2020 significant cost saving can be achieved by an integrated congestion management. Furthermore, total costs in the optimal dispatch case increase if the proposed network extensions are considered. This gives indications that transmission expansion is mainly driven by congestion management costs.

in million EUR/a	**2008**	**2015**		**2020**	
Network Extension		*No*	*Yes*	*No*	*Yes*
Optimal dispatch	26,947	20,722	21,764	19,650	20,119
Spot market	26,406	20,873		19,668	
CM Costs					
Lower bound	0	308	285	254	61
Upper bound	314	1,243	1,100	1,426	948

Table 2: Comparison of total costs and congestion management costs

The model bears shortcomings with respect to consideration of security constraints of the physical transmission network as the N-1 security criterion is not considered in the optimization. Furthermore, transmission switching is roughly modeled as only complete transmission lines can be switched on or off. Technical flexibility resulting from switching of individual circuits esp. in substations, as well as other technical options are not considered. Regarding the input data, only data for Germany is adjusted between considered years. Therefore, the impact of adjusted generation and demand in neighboring countries is not taken into account. The spot market model is rather simple as only one hour is optimized. A better representation of the current market regime can be achieved by a 24h spot market model including unit commitment of power plants. Finally, the current dataset has to be updated to the current status of information esp. the shutdown of nuclear power plants.

5 Conclusions

This paper investigates the impact of physical network constraints on spot market results and total costs. Therefore, an approach is described which replicates the current market regime in Germany consisting of a spot market and a congestion management model. Re-dispatching of power plants and optimization of network topology are considered as congestion alleviation methods. The results indicate the necessity for an integrated national congestion management as net transfer capacities are not able to represent national network congestion and congestion management costs tend to

increase especially in high wind scenarios in the future. Comparing the different congestion management methods, optimization of network topology has to be considered as it shows significant benefits in managing network congestion. However, N-1 secure operation of the physical network has to be ensured which reduces the benefits of topology optimization.
Based on the presented results the yearly costs of congestion management can vary between 0 and 314 million EUR in 2008. In 2020, minimum congestion management costs increase to 254 million EUR and 1426 million EUR in the maximum. Congestion management costs can be further decreased to 61 million EUR in the minimum through proposed network extension. However, network extension cannot fully eliminate possible congestion and thus congestion management becomes more important in the future especially if the share of renewable wind generation increases. Based on the presented results, the need for improving the current congestion management regime arises in order to manage expected congestion and resulting congestion management costs in Germany given higher share of intermittent renewable generation.

Acknowledgments

Friedrich Kunz acknowledges support of the RWE fellowship program (RWE Studienförderung).

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