Improving Congestion Management: How to Facilitate the Integration of Renewable Generation in Germany

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In this paper the German congestion management regime is analyzed and future congestion management costs are assessed given a higher share of intermittent renewable generation. In this context, cost-based re-dispatching 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. This uniform pricing model is compared to a nodal pricing regime. The results show that currently congestion can mainly be managed by re-dispatching power plants and optimizing the network topology. However, congestion management costs tend to increase significantly in future years if the developments of transmission as well as generation infrastructure diverge. It is concluded that there is a need for improving the current congestion management regime to achieve an efficient long-term development of the German electricity system.

Keywords: Electricity, Congestion management, Network modeling, Germany

http://dx.doi.org/10.5547/01956574.34.4.4

1. INTRODUCTION

Several European countries have implemented special support schemes for renewable energy sources in electricity generation in order to achieve the RES-E targets set by the European commission and 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.

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Renewable electricity generation especially wind generation is characterized by high capital and low operational costs. Hence, wind generation is placed in the beginning of the merit order and is thus 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 load 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 the 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 uniform pricing 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 results of the uniform pricing model are compared to an implicit allocation of national transmission within the spot market known as nodal or locational pricing.

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 models and the underlying dataset are described in Section 3. The results are presented and discussed in Section 4. Section 5 presents the conclusions.

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. Therefore, congestion management is aimed at obtaining a cost optimal power dispatch while accounting for those constraints

(Kumar, Srivastava, and Singh, 2005). Congestion management mechanisms can be classified into transmission capacity allocation and congestion alleviation methods (Androcec and Wangensteen, 2006; Krause, 2006).

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 (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 de Vries and Hakvoort (2002).

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 power flow 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 congestion alleviation methods (de Vries, 2001; Krause, 2006). Re-dispatching of power plants means, that the dispatch of power plants determined in the spot market has to be adjusted by the network operator if congestion occurs in real-time operations of the physical transmission network. Therefore, dispatch of specific power plants is decreased and increased in order to alleviate congestion through an adjustment of power flows within the network. The selection of generators as well as the financial compensation depends on the applied method. In a cost-based re-dispatching regime, selection of generation adjustment is done by the network operator considering costs. Constrained-off generators receive the difference between their generation costs and the spot market price, constrained-on generators get paid their fuel costs (Wawer, 2007). If a market-based re-dispatching regime is applied, the selection of generators as well as the prices for generation increase and decrease are determined using a separate balancing market (Dijk and Willems, 2011). The paid prices for generation adjustments further depend on the pricing rules of the balancing market.

2.2 Application of Congestion Management

The optimal usage of existing transmission capacity is ensured through the implementation of nodal prices (or locational marginal pricing) as physical constraints and the scarcity of transmission capacity are reflected in resulting nodal prices (Hogan, 1992). The general concept of nodal pricing on electricity markets is based on Schweppe et al. (1988). Within this concept, transmission capacity and the usage of the transmission network is determined during the energy market clearing process. Hence, nodal pricing can be seen as a fully coordinated implicit auction (Brunekreeft, Neuhoff, and Newbery, 2005). Nodal pricing is currently applied e.g. in the electricity market of Pennsylvania-New Jersey-Maryland (PJM).

In Europe, nodal pricing is not applied as most countries are characterized by a decentralized electricity market. Instead of nodal pricing, uniform pricing schemes are used in most European countries and constraints on national (or intra-zonal) transmission lines are not taken into account during the market clearing process. Therefore, congestion alleviation methods are required if the network operator is faced with congestion on national transmission lines. Cost- or market-based re-dispatching is widely used in European countries. On the other hand, international or cross-border transmission capacity, reflected by the net transfer capacity (NTC), is allocated using market-based capacity allocation methods.

However, some European countries extended the uniform to a zonal pricing regime and introduced implicit auctions for national transmission capacities. E.g. in Norway currently five different zones are defined and the transmission capacity between zones is implicitly allocated in the Nord Pool market procedure (market splitting). Price differences between zones reflect congestion on inter-zonal transmission lines. Bjørndal and Jörnsten (2001) describe the concept of zonal pricing in Norway and study the optimal definition of price zones. Especially the definition of zones requires complex analysis (Bjørndal and Jörnsten, 2001) and furthermore, inter-zonal transmission capacity cannot be defined uniquely (Ehrenmann and Smeers, 2005). Therefore, intra-zonal congestion cannot be fully avoided by the market splitting procedure and additional congestion alleviation methods are necessary (Bjørndal, Jörnsten, and Pignon, 2003).

2.3 Congestion Management 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 German 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 an 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 participants are not obliged to trade at the power exchange and can also trade bilaterally 'over the counter'. 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 15 minutes 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 power flow 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[2] 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 development of costs for congestion management (cost-based re-dispatching of power plants) is displayed in Table 1. In relation to national consumption re-dispatching costs amount 0.09 EUR per MWh consumption in the maximum in 2008. In comparison to an average electricity spot market price of 65 EUR per MWh in 2008, congestion management costs represent only a small fraction. According to Deutscher Bundestag (2010), costs for congestion man-

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 Netherlands. Cross-border capacities on remaining borders (Poland, Czech Republic) are allocated through explicit auctions.

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

Table 1: Re-dispatching Costs and Consumption in Germany, Cost Values in Million EUR per Year and Consumption in TWh (Source: Deutscher Bundestag, 2010)

	2007	2008	2009
Re-dispatching costs	30	45	25
Consumption	527	526	496

agement are significantly 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.

3. MODEL FORMULATION

The 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, Weigt, and von Hirschhausen, 2010). The basic model formulation is adjusted in order to represent the German market procedure consisting of a spot market and the congestion management by national transmission system operators. The general assumptions of the model are that firstly a competitive behavior of market participants is assumed and secondly an independent system operator optimizes the system variables for the entire regional scope of the model. The model optimizes a representative hour, thus intertemporal aspects are neglected.

3.1 The Uniform Pricing Model

3.1.1 The Spot Market Model[3]

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

3. The following format is used in the mathematical notation: variables are denoted by capital letters, whereas parameters are in small letters. Subscripts represent indices.

system node n representing substations of the physical transmission network. The minimization of total generation costs (equation (1)) is subject to the market clearing constraint, the individual power plant capacity restrictions, and the restriction of international trade. The market clearing constraint (equation (2)) ensures the equality of load q_n, renewable generation $g_n^{wind} + g_n^{solar}$, 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 generation (g_n^{wind} and g_n^{solar}) 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 (equation (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 (equation (4)). Thus international transfer is limited whereas transfers between national nodes are unlimited. Generally the spot market model determines a least-cost power plant dispatch based on the national merit-order curve which means that cheapest power plants are used to serve national loads. International transfers allow the utilization of generation in neighboring countries up to the available transfer capacity. As trade within a country is not restricted a uniform price for each considered country can be determined. To do so, the marginal or dual variable on the energy balance (equation (2)) is interpreted as spot market price $price^{DA}$ reflecting the marginal costs of the residual power plant. The final linear problem is optimized for one hour.

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

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

$$G_p \le g_p^{max} \tag{3}$$

$$\sum_{n \in c} \sum_{nn \in cc} TF_{n,nn} \le ntc_{c,cc} \tag{4}$$

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

3.1.2 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 (equation (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 decreased generation pays their saved fuel costs mc_p to the TSO. However, decreased generation receives the spot market price and is thus 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 (equation (6)) and the generation capacity restriction (equation (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 power flow approach is used to reflect technical restrictions of the transmission network. Given the technical network characteristics ($b_{n,nn}$ and $h_{l,n}$), the power flow on physical transmission lines LF_l (equation (9) and (10)) as well as the physical net input at each system node NI_n (equation (8)) are determined by the load angle Δ_n. Physical transmission limits are represented by p_l^{max} (equation (11)). Flexibility of the network topology is considered as a congestion management method and reflected by the binary variable $ONLINE_l$ in the model following Fisher, O'Neill, and Ferris (2008). The scalar m used in equation (9) and (10) is a large number. If a line is switched off ($ONLINE_l = 0$) the transmission capacity is set to zero according to equation (11). Additionally, equation (9) and (10) result in a large positive and negative number representing the upper and lower limitation on load angle differences $\sum_n h_{l,n}\Delta_n$. Otherwise if a transmission line is online ($ONLINE_l = 1$), equation (9) and (10) collapse to an equality constraint $\mathrm{LF_l} = \sum_n h_{l,n}\Delta_n$ and determine the power flow on transmission lines. The introduction of two separate equations for the power flow is necessary to put no restriction on load angle differences.[4] Optimization of network topology goes in hand with reliability issues as switching lines may reduce the N-1 security meaning that the system may not be able to withstand the outage of single transmission equipment. Hedman et al. (2008) present an approach to incorporate reliability constraints in a network topology optimization problem. However, the solution

4. If equations (9) and (10) are replaced by the equality constraint for the power flow $\mathrm{LF_l} = \sum_n h_{l,n}\Delta_n$ the power flow on line l will be zero if a line is switched off due to the reduction of transmission capacity. More importantly the load angle difference between nodes connected by line l will be zero, too. This would result in zero exchanges between both nodes, which is not necessarily the case as power flows are just re-routed with in the transmission network if a line is switched off.

time of the network topology problem increases substantially, if security constraints according to Hedman et al. (2008) are introduced. To approximate reliability requirements in the presented model transmission capacity of lines is downgraded by 20% (Leuthold, Weigt, and von Hirschhausen, 2010). The presented congestion management model is solved in a two-step procedure to differentiate between congestion costs resulting from congestion on international and national transmission lines. Firstly, only international transmission lines are considered and congestion management costs are determined. Afterwards, national transmission lines are added and re-dispatching costs for relieving national congestion are determined. As the net transfer capacities used in the spot market model are assumed to be fixed and thus do not necessarily reflect resulting congestion situation, the separation is useful. National congestion can be managed by re-dispatching power plants and optimizing network topology. If only re-dispatching of power plants is considered,[5] congestion management costs are interpreted as an upper bound. The lower bound on congestion management costs is achieved if both methods (re-dispatching and network topology optimization) are incorporated as topology optimization is available at no direct costs. In this case the mixed integer problem is solved in the relaxed version to reduce computation time.[6] The final linear mixed integer problem is optimized for one hour given the results of the spot market model.

$$\min_{G_p^{UP}, G_p^{DOWN}} \sum_p mc_p G_p^{UP} - mc_p G_p^{DOWN} \tag{5}$$

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

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

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

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

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

5. In this case the binary variable $ONLINE_l$ is fixed to one for all transmission lines.

6. Solving the network topology optimization to an optimal integer solution increases computation time substantially (see e.g. Fisher, O'Neill, and Ferris, 2008). As the analysis focuses on general results rather than detailed impacts on network topology, the relaxed solution of the integer problem provides sufficient information.

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

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

$$ONLINE_l = \{0,1\}$$

3.2 The Nodal Pricing Model

The nodal pricing model now includes physical network characteristics and optimizes the power dispatch G_p by minimizing total generation cost $\sum_p mc_p G_p$ (equation (12)) subject to physical network restrictions. The previously described uniform pricing spot market model takes only transfer limitations on international exchanges into account and congestion in the physical national transmission network is solved afterwards using the congestion management model. In the nodal pricing model, physical load flows of the entire transmission network and occurring congestion are considered while optimizing the generation dispatch of individual power plants. Thus, the generation dispatch of power plants does not necessarily follow the national merit-order curve (compared to the uniform pricing model) as physical load flows and their restrictions may require more costly plants to be online in case of congestion.

Again, the nodal energy balance (equation (13)) has to ensure the equality of nodal generation including renewable generation from solar and wind capacities (g_n^{wind} and g_n^{solar}), nodal load q_n, and net input or withdrawal from the transmission grid NI_n. To account for physical characteristics of transmitting electricity, a DC power flow approach is used to determine the load flows LF_l on individual transmission lines l (equation (16)). The maximum capacity of transmission lines limits the absolute physical exchanges between system nodes (equation (17)). The final linear problem is optimized for one hour assuming an independent system operator.

$$\min_{G_p} \sum_p mc_p G_p \tag{12}$$

$$q_n - g_n^{wind} - g_n^{solar} = \sum_p G_p + NI_n \tag{13}$$

$$G_p \leq g_p^{max} \tag{14}$$

$$NI_n = \sum_{nn} b_{n,nn} \Delta_{nn} \tag{15}$$

$$LF_l = \sum_n h_{l,n} \Delta_n \tag{16}$$

$$|LF_l| \leq p_l^{max} \qquad (17)$$

$$G_p \geq 0$$

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.

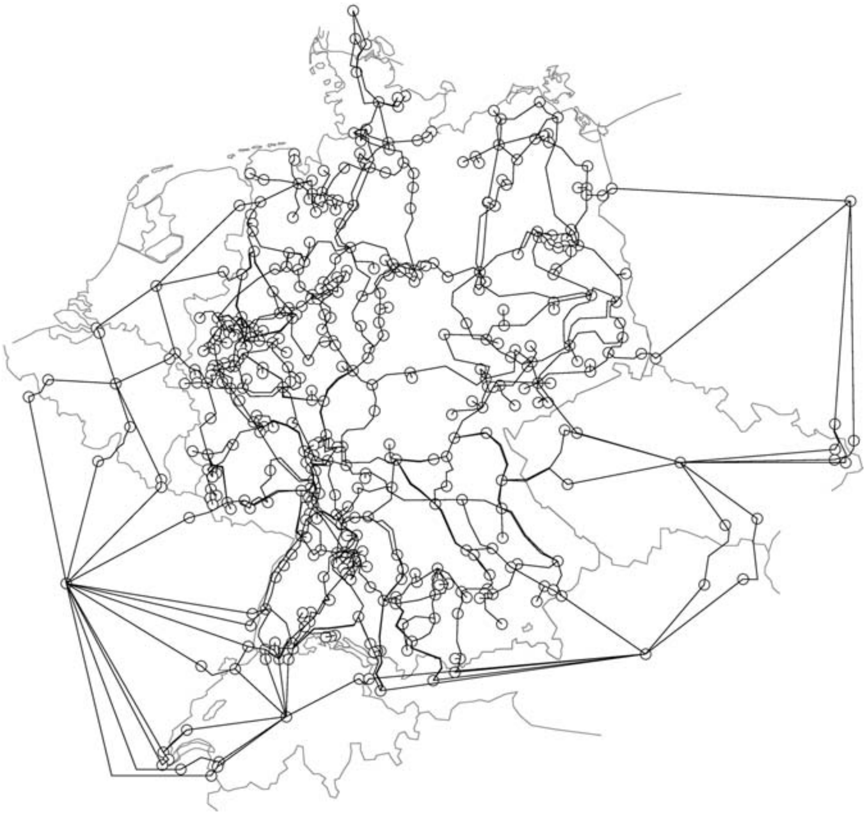
Generation is divided into twelve plant types: hydro (run-of-river and reservoir), nuclear, lignite, coal, gas and oil steam, combined cycle gas and oil turbine, open cycle gas and oil turbine, and pump storage plants. National power plant capacities are based on VGE (2008) and include existing power 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, 2011). The phase-out of 12.3 GW out of 20.5 GW nuclear generation capacities in Germany till 2022 is taken into account. The shutdown of eight nuclear plants in 2011 as well as the stepwise phase-out of remaining nuclear capacities till 2022 is based on Deutscher Bundestag (2011). Marginal costs of power plants are based on fuel and CO_2 certificate price for 2008.

Renewable electricity generation comprises wind as well as solar generation and is accounted with marginal costs of zero. Thus the node-specific load will be lowered by corresponding nodal renewable generation. In 2008, generation capacities of installed wind turbines sum to 27 GW and are expected to increase to 37 GW onshore and 14 GW offshore in 2020 (50Hertz Transmission et al., 2010). However, only 4.3 GW offshore wind capacity are currently planned to be commissioned until 2020 (BDEW, 2011). On the other hand, solar electricity generation capacities increased substantially during the last years. Installed solar generation capacity in 2008 is 5.3 GW. Following Nitsch et al. (2010), installed capacity raises to 38.4 GW in 2015 and 51.8 GW in 2020. Renewable generation capacities in Germany are distributed among all system nodes according to data on regional renewable capacities published by national transmission system operators. Renewable generation capacity of neighboring countries is aggregated.

Load values for 2008 represent the average hourly consumption as published by ENTSO-E. In 2020, load is expected to decrease by 8% in Germany (50Hertz Transmission et al., 2010). Within Germany, nodal load is determined by taking the regional population and gross domestic product into account. Further information can be found in Leuthold, Weigt and von Hirschhausen (2010).

The underlying physical grid for Germany is based on the European high-voltage grid considering voltage levels of 220 kV and 380 kV. Neighboring countries of Germany are represented on an aggregated level. Hence, national

Figure 1: High Voltage Electricity Transmission Network in Germany



congestion in those countries is neglected. The transmission network is depicted in Figure 1. Transactional restrictions used in the spot market model between countries are based on the net transfer capacity (NTC) published by the European Network of Transmission System Operator for Electricity (ENTSO-E). The indicative NTC values for summer 2008 are used and considered constant until 2020. The development of the physical transmission grid until 2020 is based on the Ten-Year Network Development Plan published by the ENTSO-E (ENTSO-E, 2010). Based on this report, network extensions of a total length of 1,946 km are added to the existing transmission grid until 2020, of which 504 km are upgrades of existing transmission lines and remaining 1,442 km are new overhead lines. 974 km of network extensions are considered to be realized before 2015. The network extensions comprise both regional network extension projects with only a few kilometers length as well as interregional ones mainly from northern to southern Germany. Main purpose of planned network extensions is the integration of renewable energy sources in the northern part of the country in the existing transmission network. Additionally, ensuring security of supply, reduction of re-dispatching costs, as well as connection of thermal generation capacities are listed as expected benefits of planned network extensions.

To analyze the impact of different load, wind, and solar levels on congestion management costs 27 representative hours are specified as scenarios based on data for 2008. Load is defined relative to average hourly load and classified into three scenarios representing low (85%), medium (100%), and high (115%) load 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 generation. Solar generation is divided into a low (0% of installed capacity), medium (10% of installed capacity), and high (20% of installed capacity) generation scenario. Models are optimized for each hourly scenario separately, thus representing a static optimization neglecting intertemporal aspects.[7] Defined scenarios are weighted to achieve annual results. Scenario weights are based on hourly load and renewable generation data for 2008 published by ENTSO-E and national transmission system operators.

4. RESULTS AND DISCUSSION

The analysis comprises 27 different scenarios which are simulated for the years 2008, 2015, and 2020. Proposed power plant investments, expected wind and solar generation capacities, electrical load, and proposed network extensions for Germany are adjusted for the 2015 and 2020 optimizations. Data related to neighboring countries as well as generation costs are not changed. Yearly or total costs represent the costs for consumers[8] and are the weighted costs of the presented scenarios. In the following analysis firstly cost and price results of the uniform and nodal pricing regime are presented using the models described previously. Afterwards, results of both pricing regimes are compared and discussed.

4.1 Uniform Pricing

Total yearly costs for consumer in Germany are 25.0 billion EUR in 2008 (Figure 2) representing the product of market price and national load of the spot market model. In 2015 and 2020 total yearly costs decrease to 22.3 and 21.3 billion EUR. The decrease of the total costs is caused firstly by the increase of renewable generation capacity. Wind capacity is expected to rise from 23.9 GW

7. The incorporation of intertemporal aspects (e.g. ramping or minimum-on/-off time constraints) in combination with the optimization of the network topology increases the computation time of the described model substantially and are therefore neglected.

8. Costs for consumers represent short-run marginal costs and are defined as the product of load and market price (dual variable on equation (2)). Additional costs such as capital costs of transmission and generation equipment as well as taxes are not considered in this analysis.

in 2008 to 37 GW onshore and 4.3 GW offshore in 2020. Additionally, solar generation capacity changes from 5.3 GW in 2008 to 51.8 GW in 2020. As renewable generation is accounted with marginal costs of zero, load is reduced and thus cost for consumers decrease.[9] 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 spot market costs by roughly 17%. Among the impacting factors, renewable generation has the strongest impact causing a reduction of consumer costs of c. 9%. Comparing renewable generation, wind generation accounts for a reduction of 37 million EUR per 1000 MW installed capacity, whereas solar generation reduces consumer costs for 11 million EUR per 1000 MW installed capacity. The difference between both technologies results from the utilization of installed renewable generation. As wind generation shows on average higher utilization factors, generation and thus cost reduction potential is higher compared to solar generation in Germany. As spot market model does not take physical transmission constraints into account and the dispatch is characterized by the national merit order cost curve of available fossil and renewable generation. Thus, the impacts of renewable generation on costs represent the merit order effect of additional renewable generation as market prices decline by increased generation from renewable sources (see e.g. Sensfuß et al., 2008).

However, the spot market model does not take physical transmission constraints into account as only international transfers are limited by the net transfer capacity. 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 this modeling approach two different congestion management methods are implemented.

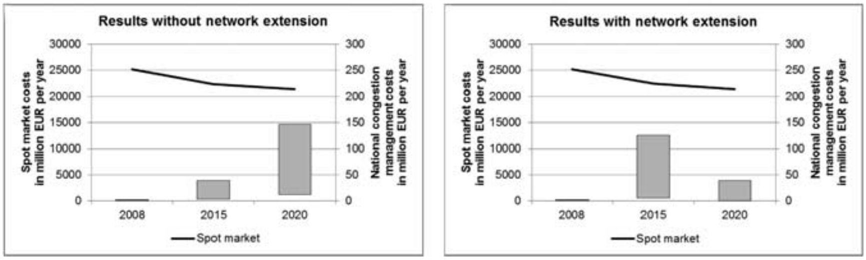
Firstly, re-dispatching of power plants in order to ease national physical network congestion is considered. Power plants in regions with excess generation[10] have to decrease their output to reduce congestion in the transmission network. On the other hand, the reduced generation output in the surplus region has to be compensated by an increase of generation output in the deficit region to ensure equality of load and supply. In the modeling approach all power plants are allowed to be re-dispatched in order to retrieve limits on congestion management costs. Technical or administrative restrictions which may limit the adjustment of generation output are not taken into account.

Secondly, the re-dispatching of power plants is extended by the option to optimize network topology in order to manage power flows. The physical

9. The analysis is restricted to short-run marginal costs of the spot market. Additional costs beside the explicit costs of the spot market resulting for instance from the promotion of renewable energies are thus neglected.

10. This means, generation which cannot be physically exported due to physical network congestion

Figure 2: Spot Market (line, left axis) and National Congestion Management Costs (bars, right axis) without and with Network Extension, Million EUR per Year



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 power flows 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 the presented 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 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. Additionally, international and national congestion management costs are differentiated. The national costs of considered congestion management methods are displayed in Figure 2 and listed in Table 2 for the considered years and for the different network expansion cases. The line represents consumer cost and the bars reflect the range between the lower and the upper bound of national congestion costs.

It can be seen in Figure 2 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 national network congestion. On the other hand, network topology optimization reduces the need for power plant dispatch adjustments as network topology optimization does not cause direct costs to the TSO.

For 2008, national congestion management costs range between 0 and 1.7 million EUR per year. Comparing calculated costs with experienced costs (see Table 1) the calculations confirm the relatively low need for congestion management. Differences between experienced and calculated re-dispatching costs can

Table 2: Results of the Uniform Pricing Regime, Cost Values in Million EUR per Year and Prices in EUR per MWh

	2008	2020 No network extension	2020 Network extension
Spot market costs	24,983	21,322	21,322
International congestion management costs	178	2	4
National congestion management costs	0–1.7	12–147	0–40
Max spot market and congestion management costs[a]	**25,162**	**21,471**	**21,366**
Avg. spot market price	47.90	44.70	44.70

[a] Costs of the uniform pricing regime represent spot market costs, international and the upper bound of national congestion management costs.

be explained by the fact that currently the TSO cannot decide over all available generation units and is limited to pre-contracted re-dispatching capacities. If no network expansion is considered, congestion management costs increase to 147 million EUR per year (c. 0.7% of total spot market costs) in the maximum in 2020 (Figure 2, left side). 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 load this leads to a significant physical flow from northern to southern Germany and thus increases the need for congestion management. Among renewable sources, wind generation shows the strongest impact on re-dispatching costs resulting in 1.7 million EUR per 1000 MW installed capacity. On the other hand, additional solar generation decreases re-dispatching costs by –0.3 million EUR per 1000 MW installed capacity. As solar generation is mainly located in southern Germany and closer to load centers, the specific impact on re-dispatching costs is negative. Through optimization of network topology congestion management costs are reduced to 12.0 million EUR per year in 2020 (c. 0.1% of total spot market costs). Hence, switching of transmission lines leads to a reduction of 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. Costs for international congestion management are 178 million EUR in 2008 and decline to only 2.4 million EUR in 2020. The costs for international congestion management strongly depend on the definition of the net transfer capacity which limits international transfers. Whereas in 2008, the net transfer capacity used in the spot market model allows more international transactions as physically possible. Thus additional re-dispatch is required to ease network congestion. In future years, the opposite occurs and more trades are possible from a physical perspective and hence costs for international re-dispatch are reduced. In reality, TSOs would adjust the net transfer capacity between countries during the hours and years taking impacts on international congestion management costs into account.

The overall picture does change if network extension is introduced in the model (Figure 2, right side). Costs of the spot market remain unchanged as physical network constraints are not considered. However, national 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 0 million EUR and 39.6 million EUR (c. 0.2% of total spot market costs). Compared to the case without network extension (Figure 2, left side), the need for re-dispatching power plants decreases significantly as the physical network from northern to southern Germany is strengthen. This is especially true in 2020 as interregional transmission lines are expected to come online. However in 2015, congestion management costs show a steep increase which is mainly caused by a heterogeneous development of generation and transmission capacity. At selected locations within the transmission network, generation capacity is expected to come online, but existing transmission capacity is not sufficient to transport the additional generation resulting in higher re-dispatching costs for these plants. In 2020, additional transmission capacity is available at these locations and hence congestion management costs decrease. It is likely that both developments are coordinated to some extent especially if a new power plant is commissioned. Regarding the impact of renewable sources on congestion management costs, additional wind as well as solar generation show a specific impact of 1.7 and −0.04 million EUR per 1000 MW installed capacity, respectively. The impact is comparable to the case without network extension. Costs for international congestion management decrease to 4 million EUR in 2020 considering network extensions.

4.2 Nodal Pricing

In a second step, it is assumed that the German market implements a nodal pricing regime meaning that national as well as international transmission lines are taken into account in the optimization of the power plant dispatch. In the nodal pricing regime, an independent system operator is assumed which optimizes the entire electricity system subject to physical network constraints. The physical characteristic of transporting electrical energy is reflected by a DC power flow approach. In contrast to the uniform pricing, only a spot market is considered and a separate congestion management regime is not required as physical network constraints are already accounted in the spot market.

Comparing the spot market costs defined as product of nodal price and nodal load, the results are generally comparable to the uniform pricing. In 2008, spot market costs amount 25.6 billion EUR and decrease 15% to 21.8 billion EUR per year in 2020 neglecting transmission expansion (Table 3). If network expansion is taken into account, spot market costs are affected as congestion

Table 3: Results of the Nodal Pricing Regime, Cost Values in Million EUR per Year and Prices in EUR per MWh

	2008	2020 No network extension	2020 Network extension
Spot market costs	25,626	21,751	21,805
Avg. nodal price	49.14	45.60	45.71

Table 4: Comparison of Cost and Benefit Results for Uniform and Nodal Pricing Regime for the Entire Model Region, Cost and Benefit Values in Million EUR per Year

	Uniform Pricing		Nodal Pricing	
	2008	**2020 Network extension**	**2008**	**2020 Network extension**
Consumer costs	77,928	72,281	77,193	71,419
Generation costs	30,677	28,603	30,676	28,573
Generation benefits	45,374	41,532	44,937	41,163
Congestion benefits	2,056	2,191	1,581	1,683
Congestion costs	180	44		

situation and hence the dispatch of power plants changes. Therefore, costs decrease to 21.8 billion EUR per year compared to 2008.

Comparing both network extension cases indicates that spot market costs slightly increase by 0.2% with additional transmission capacity. This is surprising, but a result of regional differentiated prices. In the case without network extension, nodes in the northern part of the country benefit from low cost wind generation. Due to network congestion, nodal prices reflect the low generation costs of wind. In case of network expansion local network congestion is relieved and prices in the northern part of Germany increase. Hence, additional transmission lines increase the transmission capacity between nodes especially in the northern part, but do not lead to a significant reduction of spot market costs.

4.3 Discussion

Comparing the spot market and congestion management cost results between the considered years with the nodal pricing results indicates the impact of internal congestion management given higher shares of wind generation and the development of the thermal power plant fleet. Table 4 depicts the cost and surplus results of both pricing regimes for 2008 and 2020. The results comprise all countries considered in the modeling approach. The consumer costs are equivalent to spot market costs and reflect the product of price and demand of the corresponding spot market. Generation costs comprise the cost of the final generation dispatch valued with marginal costs. Generation benefits are defined as the product of spot market price and generation quantity. The benefit of congestion describes the congestion rent of implicit auctioning of net transfer capacity in the uniform pricing and of transmission capacity in the nodal pricing, respectively. Congestion costs are the previously described international and national congestion management costs occurring in the uniform pricing model. In the following short-term as well as long-term economic implications of both pricing regimes are discussed.[12]

In the short-term perspective, pricing regimes are expected to show comparable overall cost results, but the distribution of costs among the market players may vary. Using a stylized two-node electricity system, de Vries and Hakvoort (2002) and Frontier Economics and Consentec (2004) analyze various congestion management regimes and their impact on cost and revenues of market participants. They conclude that in the short-run all congestion methods achieve an efficient dispatch, but the distribution of costs and surpluses differs. Consumers and generators profit when using congestion alleviation methods (e.g. re-dispatch or counter-trading) as the TSO rather pays congestion costs than receives congestion revenues. If capacity allocation methods (e.g. implicit auctioning) are applied, de Vries and Hakvoort (2002) found opposite effects as prices are regionally differentiated depending on congestion situation. Thus, overall consumer cost increases while generation surplus decreases. The TSO benefits as he faces congestion revenues rather than congestion costs. Ding and Fuller (2005) analyze distributional effects using a realistic dataset for the Italian transmission system. However, provided analyses concentrate on a comparison of individual congestion management regimes and do not take into account the interaction of different congestion methods. In this analysis, the uniform pricing regime comprises the capacity allocation of international capacities as well as the congestion alleviation of national congestion in a second step. As can be seen in Table 4 the previously mentioned aspects on overall efficiency and distributional effects are comparable, but not identical. Due to the interaction of two congestion management regimes deteriorating effects can be observed. Interpreting generation cost as an efficiency measure, the uniform pricing shows higher generation cost as only national generation in Germany is allowed to be re-dispatched to ease national congestion. In 2008, the effect is rather marginal whereas in 2020 generation costs increase to 30 million EUR per year reflecting 0.1% of generation costs. Thus the limitation of available capacities for re-dispatch causes a loss of efficiency. On the other

11. Beside the economic implication additional aspects exist which may reduce economic advantages. See e.g. Knops, de Vries, and Hakvoort (2001) for an evaluation of congestion management regimes with respect to institutional and legal aspects. Concerning the implementation of nodal pricing in Europe, Neuhoff et al. (2011) lists additional aspects which are relevant when changing the current market design towards nodal pricing.

hand, consumers do not necessarily profit from the application of congestion alleviation methods. Due to characteristics of the uniform pricing spot market model, prices and thus consumer cost are higher than in nodal pricing. Hence, consumer rent[13] is distributed to the TSO who receives congestion rents through the allocation of international transfer capacity. A participation of demand within the re-dispatch procedure would redistribute rent from the TSO to consumer. However, the effect on consumers as well as other market participants varies between considered countries. E.g. consumer in Germany profit from the uniform pricing regime as costs are lower compared to nodal pricing.

In the long-run perspective, investment incentives provided by pricing regimes become relevant. Following de Vries and Hakvort (2002) congestion alleviation gives the TSO economic incentives to extend the network in order to reduce costs for alleviating congestion. Comparing the savings of congestion management costs through network extension of 107 million EUR per year with annualized investment costs of 183 million EUR per year[14], show that both are in a comparable range. However, transmission extensions provide additional benefits such as increased security of supply which are not explicitly considered in this approach. Hence, annualized investment costs are higher than direct savings in congestion management costs. On the other hand, consumers and generators do not receive economic signals about congestion when using congestion alleviation methods. Furthermore, Ding and Fuller (2005) show that a uniform pricing regime with congestion alleviation gives even perverse incentives for generation expansion. Contrary to congestion alleviation methods, capacity allocation methods provide generators as well as consumers with economic signals on network congestion through regionally differentiated prices while the TSO receives no or negative incentives. Thus it is impossible to give all market participants economically efficient signals in a long-run perspective. This raises the question which market participant should receive congestion signals. de Vries and Hakvort (2002) conclude that giving economic signals to consumers and generators should be preferred as it may be easier to influence the network planning process of regulated TSOs. As the results have shown, congestion management costs depend on a homogenous development of generation and transmission infrastructure and tend to increase significantly if both developments diverge. Economic signals on congestion given to generators and consumers can at least to some extent achieve a homogenous development, but investment in generation may also depend on other locational specific factors (e.g. fuel costs). On the other hand, if no economic signals are provided through differentiated prices, extension of transmission infrastructure is of special importance and has to anticipate the development of thermal and renewable generation, and demand. With respect to

12. Assuming an arbitrary demand function, consumer rent can be determined by subtracting consumer costs from the integral of the specified demand function.

13. Annualized investment costs are based on investment costs of 800,000 EUR/km (L'Abbate and Migliavacca, 2010) and an annuity factor of 11.75% (Leuthold et al., 2009).

Germany, the Federal Network Agency (Bundesnetzagentur, BNetzA) stated in their network monitoring report (BNetzA, 2011) that 49 out of 151 transmission expansion projects are delayed caused by missing administrative approvals due to diverse reasons (e.g. public resistance, uncertainty about renewable capacity extension). Especially in the context of renewable generation and the expected capacity development (17 GW wind and 46 GW solar capacities till 2020) the relevance of an appropriate development of both transmission as well as conventional generation infrastructure is important to achieve a secure, economically efficient, and environmentally friendly electricity system.

The modeling approach bears shortcomings with respect to consideration of security constraints of the physical transmission network as the N-1 security criterion is considered in an approximated way. 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 load in neighboring countries is not taken into account. The spot market and the congestion management model are rather simple as only one hour is optimized. A better representation of the current market regime and intertemporal optimization aspects can be achieved by a 24h spot market model including unit commitment of power plants.

5. CONCLUSIONS

This paper firstly investigates the impact of physical network constraints on spot market and congestion management costs. Therefore, an approach is described which replicates the current uniform pricing 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. Secondly, uniform pricing results are compared to a nodal or locational pricing regime as an integrated congestion management regime.

The results indicate that both investigated pricing regimes achieve comparable overall results in the short-term perspective, but both regimes differ in the distribution of costs. However, as international capacity is allocated within the spot market and national congestion is eased through congestion alleviation in the uniform pricing model, differences to theoretical analyses occur. More importantly, pricing regimes provide different incentives to market participants to adjust their long-term investment behavior. The uniform pricing regime provides incentives to the TSO to appropriately extend network infrastructure, whereas generators and consumers receive economic signals through locational differentiated prices in the nodal pricing regime. This raises the question, which market participant should receive long-term signals, either the TSO or generators/ consumers. The analysis for the German electricity system shows that a homogeneous development of transmission as well as generation infrastructure is required to reduce congestion management costs otherwise management costs increase significantly. However, German TSOs are currently in charge to appropriately extend the network to expected generation and consumption developments. Given the expected capacity expansion of renewable energy sources and the current delays of transmission expansion projects, it is concluded that long-term economic signals should be given to market participants rather than TSOs to achieve a homogeneous development.

Based on the presented analysis, 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 shares of renewable generation and the development of the conventional power plant fleet.

ACKNOWLEDGMENTS

Earlier versions of this paper were presented at the Young Energy Economists and Engineers Seminar (YEEES) in Dresden 2011 and the IDEI conference “The Economics of Energy Markets” Toulouse 2011. The author acknowledges Christian von Hirschhausen, Dominik Möst, Hannes Weigt, and three anonymous referees for their constructive comments. Friedrich Kunz acknowledges support of the RWE fellowship program (RWE Studienförderung).

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