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1. Introduction

Over the last twenty years, electricity markets in industrialized countries have become more and more deregulated. One main element in this endeavor was to separate the natural monopoly of electricity transportation from the production and trading side, the latter becoming subject to competition. It was expected that market forces would make the system more efficient and drive prices down. Today, most generation companies are privatized and power exchanges have been established where different products are traded in spot and futures markets. However, to create a well-designed market for electricity that sets the right incentives and leads to an optimal outcome in terms of social welfare is not a trivial task. A prominent failure is the California Electricity Crisis, where a poorly implemented market design was an important factor which led to catastrophic developments (Joskow, 2001). David Freeman, chairman of the California Power Authorities, correctly stated the problem: "Any system that can be gamed, will be gamed, and at the worst possible time" (US Senate 2002, p. 84).

Although the German electricity market is already well-established, it has not evolved in a favorable way in all aspects and it is facing two serious challenges that could become a hazard to its future development. First, prices are still high and several studies suggest that the strategic market behavior of the four biggest electricity generators in the German market (RWE, E.ON, Vattenfall Europe and EnBW) is the reason for this observation (e.g. Hirschhausen et al., 2007). Second, the responsible German regulatory authority expects major congestion in the electricity transmission grid due to structural changes on the production side (Bundesnetzagentur, 2008, p. 36). This congestion in turn would put a limit to free trade and cause suboptimal dispatch of generators increasing overall production costs. Although both issues are well known and their individual effects are frequently discussed, little research has been conducted on how the combined effects of both factors might affect the German market. Some studies analyzing these issues for other regions, though, come to the conclusion that congestion in the grid and strategic market behavior strongly influence each other (e.g. Harvey and Hogan, 2000; Johnsen et al., 1999).

This paper presents an agent-based simulation model of the German electricity market that takes both effects into account: the strategic behavior of market participants as well as the limitations that congestion in the grid might impose on market outcome. Also, a representation of high wind power production is included into the model since this is a special characteristic of the German electricity market. This model is then used to analyze whether it is adequate to look at the described issues separately, as is the case in the current discussion on the German electricity market, or if there is a possible interdependence that requires a joint approach for a realistic appraisal of the market situation.

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The rest of the paper is structured as follows: Section 2 describes the basic concepts of the physical and the market side of electricity trading. It explains the delivery of electricity though the grid and introduces the basic types of congestion management. Section 3 explains the model and refers to the underlying implementation by Sun and Tesfatsion (2007a, 2007b). Section 4 shows the simulation results and analyzes the different effects of congestion, strategic market behavior and high wind generation on prices, and social welfare. Finally, Section 5 concludes and gives an outlook on future research.

2. Congestion management and the situation in Germany

Free trade in electricity requires a reliable electricity grid that allows the distribution of electricity from any given generator to any consumer (load). However, depending on the location of the generators and loads in the grid, and the delivery contracts between them, the power flowing through a certain power line might exceed the line's capacity. In this case the line is said to be congested and unrestricted electricity trade is no longer feasible.

In the past, congestion within Germany has been less of a problem. However, many studies predict that due to an increase in power production from wind energy in the north of Germany, the grid will soon face congestion problems on a regular basis (see e.g. Deutsche Energie-Agentur, 2005; Weigt, 2006; EnBW Transportnetze AG et al., 2008). Further stress to the grid is very likely, since old conventional power plants are being shut down and new ones are being built in places distant from the main loads. In addition, increasing international trade potentially increases transits through the German grid. All German transmission system operators (TSOs) are currently planning new grid extensions in order to prevent situations of instability.[1] Yet, as the authorization and construction process takes about ten years on average in Germany (Bundesnetzagentur, 2008, p. 9), more frequent congestion situations are likely on a medium term.

In the case of congestion, the TSO has to make sure that the flow through the congested line is not increased any further. Several congestion management methods have been developed for coordinating generation in the presence of congested lines, such as re-dispatching, zonal pricing (also known as market coupling or market splitting) or nodal pricing (see Stoft (2002) and Etso (2006) for a detailed description of congestion management methods).

The possible congestion management methods influence the way generators bid into the market and can possibly enhance their potential market power. Johnsen et al. (1999) for example show empirically that congestion can lead to the exercise of market power in their study on the Norwegian electricity market, where zonal pricing is applied. Ding and Fuller (2005) evaluate strategic incentives under different congestion management schemes and compare economic welfare effects and the distribution of economic surplus under nodal pricing with zonal and uniform pricing mechanisms and find that in some cases, where nodal pricing is not applied, price changes for generators constrained by congestion vary in a way that would lead to severe perverse incentives. Harvey and Hogan (2000) demonstrate in a game theoretical analysis that nodal pricing (and similarly inter-zonal pricing) is always at least as cost-efficient as zonal pricing and results in better incentives for load, generation, and grid investment. Brunekreeft et al. (2005) argue that nodal pricing is only optimal on a short-term basis, since it does not include long-term investment costs and other costs of the grid and its operation. As a solution to this problem, they propose long-term financial transmission rights issued by the TSO, which are used to hedge against the risk of changing nodal prices and allow the TSO to make credible long-term strategy commitments about the grid structure.

Several approaches have been made to model and simulate the German electricity market in order to derive quantitative results for policy advice. The Argonne National Laboratory at the University of Chicago has established the *Electricity Market Complex Adaptive System* (EMCAS),[2] which they used to model the European energy market and to simulate the market clearance and the exertion of market power on the European Energy Exchange (EEX) (Wang et al., 2008). This simulation study relies on a simplified network topology of the European power grid in which Germany and Austria together constitute one node. Hence, it does not study the implications of different grid developments on locational prices within the German network, but only overall national prices.

When dealing with congestion, potential market power should be taken into account for three reasons. First, since strategic behavior influences market outcomes it also influences the resulting flows and congestions. Second, congestion might change the generators' ability to exercise market power. Third, the choice of a congestion management method has major effects on the market, and possible loopholes can put the entire system at risk.[3] For these reasons, the model presented here considers the joint effect of both congestion and strategic behavior by market participants.

3. The model

The methodology of agent-based modeling is establishing more and more in electricity market modeling. The main advantage of this methodology in relation to the research questions studied here is that it offers a way of simulating strategic interaction of players in a straightforward way. The agents only have partial knowledge about their own generating costs, and can learn to optimize their bidding strategies based on the experience they gain from market trading. Simultaneously, unlike with game theoretic analyses, agent-based simulation offers the flexibility to define a large range of scenarios, thus allowing for its application to the study of real-world market topologies. Weidlich and Veit (2008a) give an elaborate overview of the state-of-the-art of agent-based modeling applied in this field. While some models are applied to the case of Germany (e.g. Weidlich and Veit, 2008b, 2008c), and others integrate the transmission grid underlying the power system (e.g. Sun et al., 2007), the implications of different grid situations on the German electricity market have not been studied with agent-based simulation so far.

The model developed in the present paper is based on the AMES (agent-based modeling of electricity systems) Wholesale Power Market Test Bed, version 1.31, by Sun et al. (2007). It models a DC approximation of an AC power grid with nodal pricing and adaptive generator agents. In their simulations of a five-node test case, the authors of the AMES model show that their simulated generators learn to substantially increase prices through strategic bidding behavior and that congestion in the grid influences the market outcome. The AMES market package has been chosen because it provides a workable simulation platform

[1] The latest updates on grid extensions can be found on the TSOs' web pages.

[2] Compare www.dis.anl.gov/projects/emcas.html (visited 03/26/2009).

[3] For example, McCullough (2002) describes in detail how Enron tricked the Californian re-dispatch mechanism to generate large profits during the California Electricity Crisis.

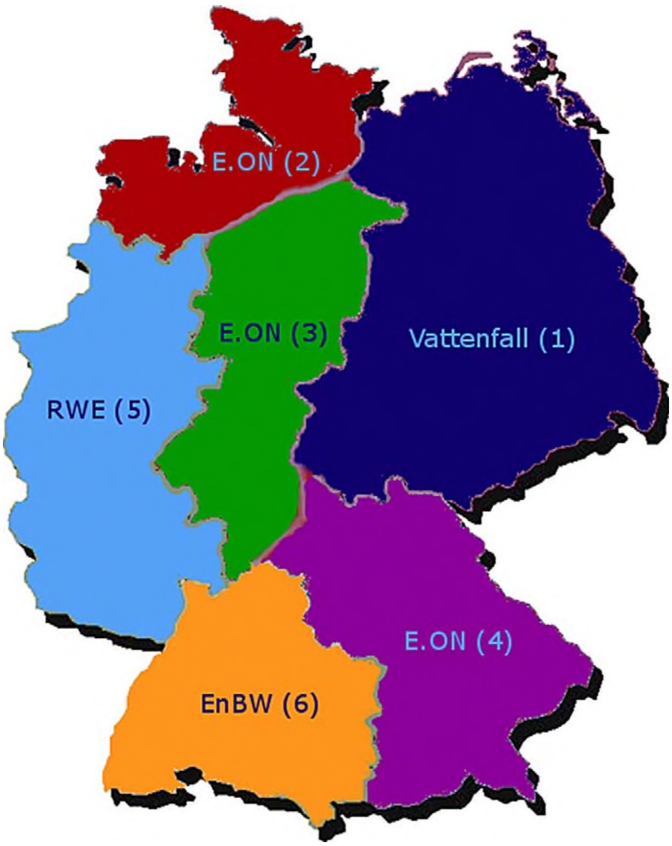

Fig. 1. Zones in the German high-voltage grid (analogous to the zones in the 2005 grid study by the German Energy Agency (Deutsche Energie-Agentur, 2005, Abb. 7-1).

that has proven its ability to create functioning agent-based electricity market simulations, and because the open source code allows changing the program in order to adapt it to the German case. The extensions and adaptations that were coded in order to represent the German market are explained where needed.

3.1. *Congestion management and grid representation*

Although not in place at the moment, zonal pricing is discussed as a congestion management mechanism for Germany at least since the regulatory authorities proposed it as a solution to future grid congestions in 2006 (Bundesnetzagentur, 2006). Therefore, this mechanism is also assumed for the presented model. For this mechanism to make efficient use of the grid capacity, it is necessary that regularly congested lines do not lie within the different pricing zones, but serve as interconnectors between them, since only re-dispatching can be used within zones (Etso, 2001). The same zonal division of the grid as in the 2005 grid study by the German Energy Agency (Deutsche Energie-Agentur, 2005) is used. This leads to the definition of six different zones, which are also illustrated in Fig. 4: Vattenfall (1), E.ON 2 (2), E.ON 3 (3), E.ON 4 (4), RWE (5), and EnBW (6). (Fig. 1)

Another assumption for the German high-voltage grid model is that there is unlimited intra-zonal transmission capacity, so intra-zonal congestion does not occur. This assumption allows condensing each zone to one representative node in the grid.[4] The grids of all countries directly connected to Germany have also been included into the model as condensed individual country nodes, but any further interconnections between these countries are omitted. Multiple electric circuits mounted onto the same tower are joined together to resemble one single line, while lines that cross the zonal borders at different points are modeled separately. In some cases, it was therefore necessary to introduce auxiliary nodes as by definition of the AMES grid representation, there can be only one line directly connecting two nodes. In cases where auxiliary nodes are necessary, they were chosen to represent real physical locations in the high-voltage grid and therefore add more detail to the model. The lines connecting nodes of the same zone were given very high capacity limits and very low reactance, allowing power to flow freely within zones. Power lines interconnecting different zones have been modeled as realistically as possible.

The grid model is based on the 2007 European high-voltage grid map by the *Union for the Co-ordination of Transmission of Electricity* (UCTE, 2007). The map contains all power lines with 220 kV or higher voltage, including information about the mounted circuits. Furthermore, it also shows 110 kV interconnectors and the locations of power plants and substations in the grid. The thermal limit of power lines can vary depending on the specific cable used and the number of cables in a bundle that form a circuit. In this study, a thermal limit of 1500 MVA is assumed for 380 kV circuits and a limit of 700 MVA for 220 kV.[5] If more than one circuit is mounted to one tower, their capacity is summed up to form a single line. Since the model of Sun and Tesfatsion (2007a) allows to omit reactive power,[6] the MVA values are taken as MW.

In order to analyze the isolated effect of congestion on the German market, a reference case is defined in which congestion does not occur. This is achieved by assigning the same values as used for the intra-zonal lines to all lines in the grid. This setting eliminates all potential grid constraints, allowing free trade across all zones.

3.2. *Generator agents*

3.2.1. *Agent behavior*

As will be explained below, each conventional power plant in our model is run by an individual agent i that each round chooses its strategic bid from its action domain AD_i. Each agent can choose from 16 (M) individual offer curves that allow it to ask for up to four times its true marginal costs. Agents are capable of learning from past experience through a modified version of the Erev and Roth (1998) reinforcement learning algorithm that was shown to be especially suitable for electricity market simulations by Nicolaisen et al. (2001). The algorithm is non-deterministic and was designed to mimic human learning behavior in games.

The algorithm assigns a propensity q_{im} to all strategies which are updated each round t depending on the agent's experience ($Profit_{im'}$) with the choosen bid m'.

$$q_{im}(t+1) = [1-r]\cdot q_{im}(t) + R_{im}(t)$$

$$R_{im}(t) = \begin{cases} [1-\varepsilon]\cdot Profit_{im'} & \text{if } m = m' \\ \dfrac{\varepsilon}{[M-1]}\cdot q_{im}(t) & \text{if } m \neq m' \end{cases}$$

Similar to Erev and Roth ε is the experimentation parameter and r the recency parameter which gave us the best learning results at

[4] One of the drawbacks is that issues such as transmission losses cannot be resembled and therefore no attempt has been made to model them. Sun and Tesfatsion (2007a) suggest that a possibility to include transmission losses in their model is to give every line an individual penalty parameter π.

[5] In accordance with Müller (2001), a capacity limit of 600 MW is assumed for both of the two submarine cables, i.e. the Baltic Cable connecting Germany and Sweden and the Kontek Cable connecting Germany and Denmark.

[6] To allow a good DC approximation of an AC power grid, the AMES Market package automatically minimizes voltage angle differences.

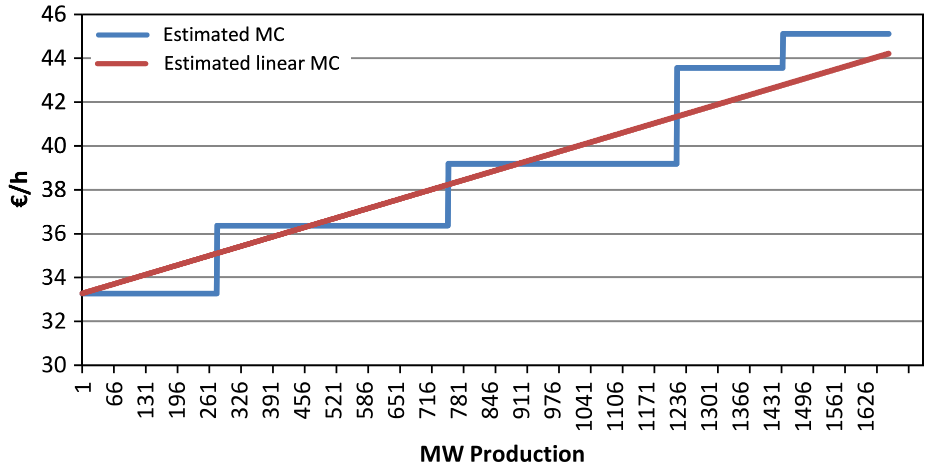

Fig. 2. Estimated marginal costs parameters of an exemplary (hard coal) power plant.

0.97 and 0.07, respectively. The calculated propensities are then used to derive probabilities $p_{im}(t)$ at which the agents randomly choose their bids.

$$p_{im}(t) = \frac{e^{q_{im}(t)/c}}{\sum_{j=1}^{M} e^{q_{ij}(t)/c}}$$

C is a cooling parameter and influences the speed of convergence towards a preferred strategy. We found 1000 to be a good value. In addition we set all initial propensities to 6000.

Using this algorithm the agents learn how to best strategically behave in any given market situation. The partially random behavior especially in the beginning of learning helps them to experiment while the market does not get stuck in any particular equilibrium as it might with a deterministic approach. So when we talk of strategic behavior we refer to the agents learning what the best action is for them to choose, rather then submitting their true marginal cost as an offer. Strategic behavior can lead to a strong falsification of market prices if the market runs into a one-sided peak situation (Hurlbut et al., 2004). The authors show how strategic bidding is affecting the market prices so severely that bankruptcy of multiple market participants is the result. Hence, enabling agents to bid strategically is a core capability to incorporate into the model in order to use it to evaluate the efficiency of market mechanisms.

All bids are collected by the TSO who dispatches the power plants in merit order subject to transmission capacity constraints. Prices in each zone are set by the last marginal MW that is dispatched.

3.2.2. Conventional power plants

Based on the power plant data base of the Federal Environment Agency (Umweltbundesamt, 2006), and the UCTE Map (UCTE, 2007), all German power plant locations with a total generation capacity of more than 100 MW and a connection to the high-voltage grid are represented in the model. At each power plant location there can be multiple block units. The block units are independent power plants that can differ by age and technology. As described below, all block units in one location have been aggregated to form a single plant which is run by a single agent.

Each of these (aggregated) plants is defined by its technology parameters (mainly variable cost functions) and the node in the grid where it is located. The lower production capacity limit for each plant is set to zero, and the upper limit is set to the sum of upper capacities of the block units an agent can dispose of. The zip codes from the power plant data base (Umweltbundesamt, 2006) have been used to allocate the plants to the grid.

Production technology is further reflected in the plants' individual marginal cost (MC) functions. The MCs are assumed to be fuel costs including, if applicable, costs for CO_2 emission certificates. This data is taken from Schlesinger et al. (2007, Table 7.1–2). Since energy efficiency varies by plant type and technological state, individual energy efficiency coefficients are calculated for each of the block units, based on the year of construction and the plant type of the units as in Schröter (2004).

Using fuel costs and the individual energy efficiency coefficients, marginal costs for each block unit are calculated.[7] Assuming that block units are dispatched in merit order within power plants, an MC function that takes the form of a step function is created for every power plant. As a requirement of the AMES simulator these step functions are transformed into linear MC functions through linear interpolation between the total variable costs for production at the upper and the lower capacity limit (see Fig. 2 for an illustration of this calculation for one of the power plants included in the model).

To capture the effect of plant outages and plant maintenance, the available generator capacity for the day-ahead market is reduced to some extent. Based on past availability data (VDN, 2006), the assumed average availability of conventional and hydroelectric power plants is 92%, which is subtracted proportionally of each plant's maximum production capacity. To account for capacity which is reserved for delivering balancing power and has already been sold on the balancing power market, the maximum production capacity of all plants that meet the requirements to provide balancing power are proportionally reduced further. Based on data published by the German TSOs, the maximum production capacity of all gas, oil, and coal-fired stations as well as all hydroelectric plants is reduced by another 12% in the model.[8]

3.2.3. Hydroelectric power plants

Hydroelectric power plants that have storage capacity usually need more extensive modeling than conventional power plants, because they carry out complex inter-temporal optimization. As described in Johnsen et al. (1999), the decision whether to

[7] Marginal costs for nuclear power plants are assumed to be 5 €/MWh including costs for final storage as given in Vattenfall AB (2006, p. 18).

[8] While the plants' maximum capacity levels set in the model are reduced, all other calculations based on maximum production capacity are still conducted with the original values of maximum capacity.

generate or to increase the storage level is based on opportunity costs ("water value"), which depends among other factors on the amount of water in the storage, the storage capacity, and the expected development of the electricity prices. In our current version of the model, however we focus on short periods of specific peak load market situations in which we assume that the water values and levels stay constant. Since pumped storage plants usually generate at peak hours, we set the basic water value to $MC_i^{hydro} = 43.19$ €/MWh, which corresponds to the marginal costs of an old hard coal-fired power plant run at peak-load times. Agents operating these plants can then adjust their reported supply offers to the specific market situation through reinforcement learning.

3.2.4. Wind power generation

Wind power generation depends only on the wind situation and is not subject to any decision process. For each of the scenarios in the presented model, either a situation of high or of low wind power generation is assumed. Therefore, the minimum and maximum capacity for each wind power generating agent is fixed for each scenario, with $Cap_i^U = Cap_t^L + 1$[9] which ensures that the simulated TSO has to dispatch the wind generator. This represents the TSO's legal obligation in Germany to accept all generated wind power. All wind power producing agents are modeled as non-learning agents who always report their true marginal costs, which are set equal to the lawfully fixed feed-in tariff (here: $MC_i^{wind} = 90$ €/MWh). As a simplification, all wind generation capacity in a given zone is represented by one single agent.

For the low wind scenarios, wind power generation is set to the average level of wind production that E.ON Netz GmbH, Vattenfall Europe Transmission GmbH, and RWE Transportnetz Strom GmbH reported for their control area on December 13, 2007 between 8 am and 8 pm. For the high wind scenario, wind power generation is increased to the highest levels reported for each zone in December 2007, which in reality did not occur exactly at the same time. The wind generation scenarios are summarized in Table 1.

3.3. The loads

One load serving entity (LSE) is attached to the main node of each zone, including those of the neighboring countries. These LSEs represent the accumulated demand for electricity in that region of the grid. However, as only the high-voltage grid is modeled and electricity production in lower-voltage levels of the grid is not modeled explicitly, the LSEs represent the vertical load[10] in the high-voltage grid, and not the total electricity consumption in an area. The data underlying the LSE's demand is the vertical load of Thursday, December 13, 2007, which is available for each of the four German control areas on each of the TSOs' websites.[11]

As the data was only available for the TSO's control areas, which do not fully match the assumed pricings zones, further calculations were necessary for distributing the loads accordingly. Weigt (2006) uses local GDP data for regionally differentiating electricity use. In the present model, we proceed similarly. A linear correlation between local GDP values (Eurostat, 2006) and electricity demand is assumed to calculate weights for the different zones (or zonal parts) within a given control region.

Table 1
Wind power generation for the low and high wind scenarios.

Wind scenarios	Vattenfall (1)	E.ON 2 (2)	RWE (5)
Low wind (MW)	347	83	174
High wind (MW)	7657	7256	3304

Based on (E.ON Netz GmbH, 2008b; RWE Transportnetz Strom GmbH, 2007b; Vattenfall Europe Transmission GmbH, 2008a); wind generation in the other three defined zones is negligible.

3.4. Interconnected foreign markets

Germany exchanges electricity with all its neighboring countries, except for Belgium, which has no direct connection to the German high-voltage grid. In the model, each of these countries is represented through a central country node and, if necessary, auxiliary nodes representing real locations in the foreign grids.[12] All interconnections to Germany are modeled according to the specification in the UCTE Map (UCTE, 2007), while the same assumptions are made as for the German grid. However, interconnections between two neighboring countries are omitted.

From the German perspective, the only aspect that matters about the neighboring electricity markets is how much power can be imported from or exported to the foreign grids. Under the assumption of zonal pricing, this is determined by (i) the maximum transport capacity for export to this country, (ii) the maximum transport capacity for import from this country, and (iii) the price of electricity in the foreign market. Values used for maximum transmission capacities at each border are taken from Etso (2007) for winter working days in 2007/2008. These values can differ by the direction of transport, as not only the capacity of the interconnectors is taken into account, but also the grid in the hinterland. As market coupling is assumed between all countries, the transmission capacity is always completely utilized in the direction from the low to the high price country. Prices in the neighboring countries are assumed to be the average peak-time prices in the day-ahead markets for December 13, 2007. Except for the Netherlands, these prices were available at the websites of the corresponding power exchanges.[13] Setting a fixed exogenous price for the market of a neighboring country requires the assumption that the foreign market is sufficiently large compared to the trade volume with Germany, so that the trade does not influence the prices or behavior in the foreign market. Alternatively, if the real prices of the simulated trading day are available, one could also assume that all interactions between the countries are already reflected in the prices. Whatever view one takes, for the

[9] The difference of 1 MW between upper and lower capacity ensures that formal requirements of the model implementation are met.

[10] The vertical load in the high-voltage grid is the amount of electricity that flows from the high-voltage grid into the lower grid levels. In rare cases, such as high wind generation, the direction of this flow might be reversed.

[11] (E.ON Netz GmbH, 2008a; EnBW Transportnetze AG, 2007; RWE Transportnetz Strom GmbH, 2007a; Vattenfall Europe Transmission GmbH, 2008b). The given data has been averaged for EEX peak time (8 am to 8 pm).

[12] Luxembourg is an exception, because it has no major power production facility on its soil except for one 1100 MW hydroelectric power plant (UCTE, 2007; International Energy Agency, 2005, p. 72). However, this plant is not a part of Luxembourg's high-voltage grid, and is only connected to the German grid. In the model, this plant is therefore given its own auxiliary node, and is modeled as all other hydroelectric plants, but without the ability to learn. The main node of Luxemburg carries only Luxembourg's vertical load. Using relative GDP values based on Eurostat (2006) the Luxembourgian load is estimated to be equal to a fraction of the load in zone 5 (RWE). Hence, unlike the other foreign markets, Luxembourg is fully integrated into the model.

[13] Energy Exchange Austria, 2008; Nord Pool Spot AS, 2008; Operátor trhu s elektřinou, 2008; Powernext, 2008; Towarowa Gielda Energii, 2008. For the Netherlands, a price of 80 €/MWh was assumed. According to information provided by an APX expert, the actual peak price for the Netherlands on December 13, 2007 was 122.18 €/MWh. However, since both prices were above the resulting German prices, the direction of flows was not affected.

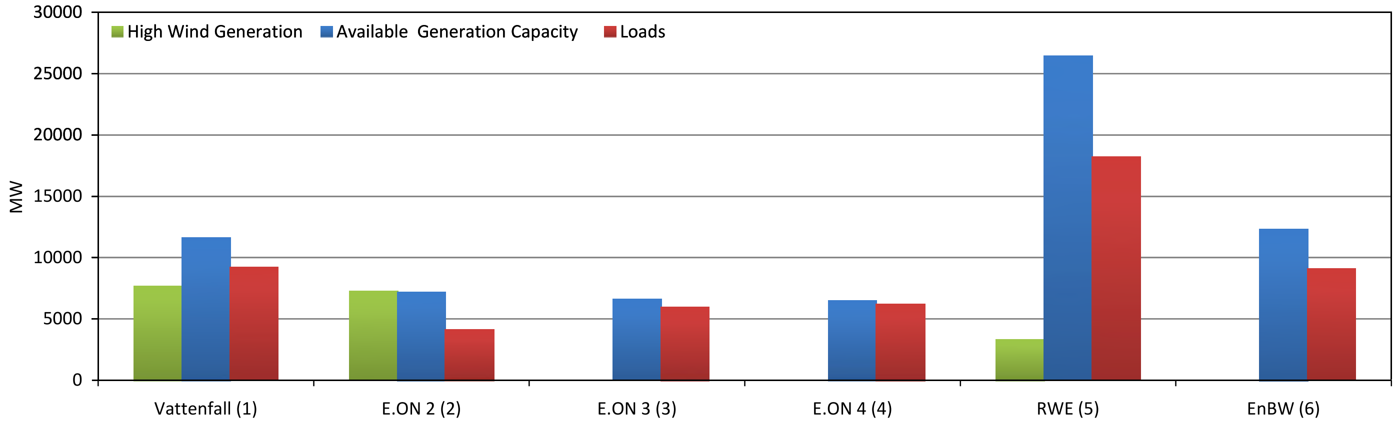

Fig. 3. Loads, available generation capacity and wind power generation under high wind for each German zone.

Table 2
Overview of the eight simulated German market scenarios.

Low wind		High wind	
Perfect competition and congestion	Strategic behavior and congestion	Perfect competition and congestion	Strategic behavior and congestion
Perfect competition and no congestion	Strategic behavior and no congestion	Perfect competition and no congestion	Strategic behavior and no congestion

direction and the amount of German electricity flows only the sign of the price difference is important, not the total price difference.

To achieve a realistic representation of imports and exports, each of the main nodes of a country is equipped with a load and a non-learning generator agent that together represent only that part of the foreign market that is affected through trade with Germany. The load is set equal to the maximum amount of electricity that is allowed for import from Germany. The generator's lower production limit is set to zero, the upper production limit is set equal to the sum of the country's simulated load and the maximum transmission capacity for export to Germany. This setup ensures that only the allowed quantities are traded. As long as German prices are lower, the foreign load is served only through imports from Germany. When the German prices are higher than the price of a given country, then the generator in this country will serve the domestic load and export the rest of its capacity to Germany.

4. Numerical results

4.1. Parameter values and scenarios

Several tests have been conducted in order to find a set of learning parameter values that avoid a premature convergence to one action, while at the same time ensuring that the market reaches equilibrium at the end of the simulation. The resulting learning parameters are roughly similar to those of Sun and Tesfatsion (2007b).[14]

[14] Experimentation parameter: $e = 0.97$, recency parameter: $r = 0.07$, cooling parameter: $C = 1000$, initial propensities: $q0 = 6000$ (as the scale of agents' profits in the German market simulation differs from that in Sun and Tesfatsion's markets, it is rather a coincidence that the value for $q0$ and C fit both models), action domain parameters: RIMaxL = RIMaxU = 0.75 (i.e. price markups of up to 400% of true marginal costs are possible), M1 and M2 = 4 (as compared to Sun and Tesfatsion (2007b), the agents' action domain size M is reduced from 100 to 16 possible actions in order to reduce the noise in the market and allow for a better convergence, as the simulated market of the present model is much larger than in Sun and Tesfatsion (2007b)).

The day-ahead market in the AMES market package simulates single trading days with hourly market clearing. However, as no constraints that make inter-temporal optimization necessary (ramping constraints, startup and shutdown costs and storage capacity in the case of pumped storage hydroelectric plants) are considered in the present model, we rather model single specific market situations with different hourly load levels. In the following, results from simulations with a typical winter week-day peak load situation are presented and discussed.

In all simulated scenarios, a high load level is assumed, since congestion and strategic behavior seem most problematic under high load. Generators are identical across scenarios. Fig. 3 depicts how vertical loads, windpower generation capacity and available conventional production capacity are distributed among the defined zones. From this we created eight scenarios which result from a combination of the following three factors (see also Table 2):

1. no congestion in the grid vs. congestion,
2. low wind generation vs. high wind generation, and
3. perfect competition (all generators bid true marginal costs) vs. strategic behavior.

The reference case of perfect competition is automatically calculated by the AMES market package before the first trading day of every simulation run. The result can then be compared to the market outcome with strategic behavior. Hence, only four different data sets are necessary. As opposed to the "no congestion" scenario in which the parameters for the grid are chosen in a way that no congestion constraints occur in the grid, the so called "congestion" scenario actually resembles the real German grid and allows for congestion to occur. Even though the occurrence of congestion was not preset in the system the simulated "congestion" scenario turned out to have at least some congested lines in equilibrium. Each of the scenarios was run 20 times for 3000 simulated peak-time hours, using different initial random number seeds for each run. Results were averaged across runs.

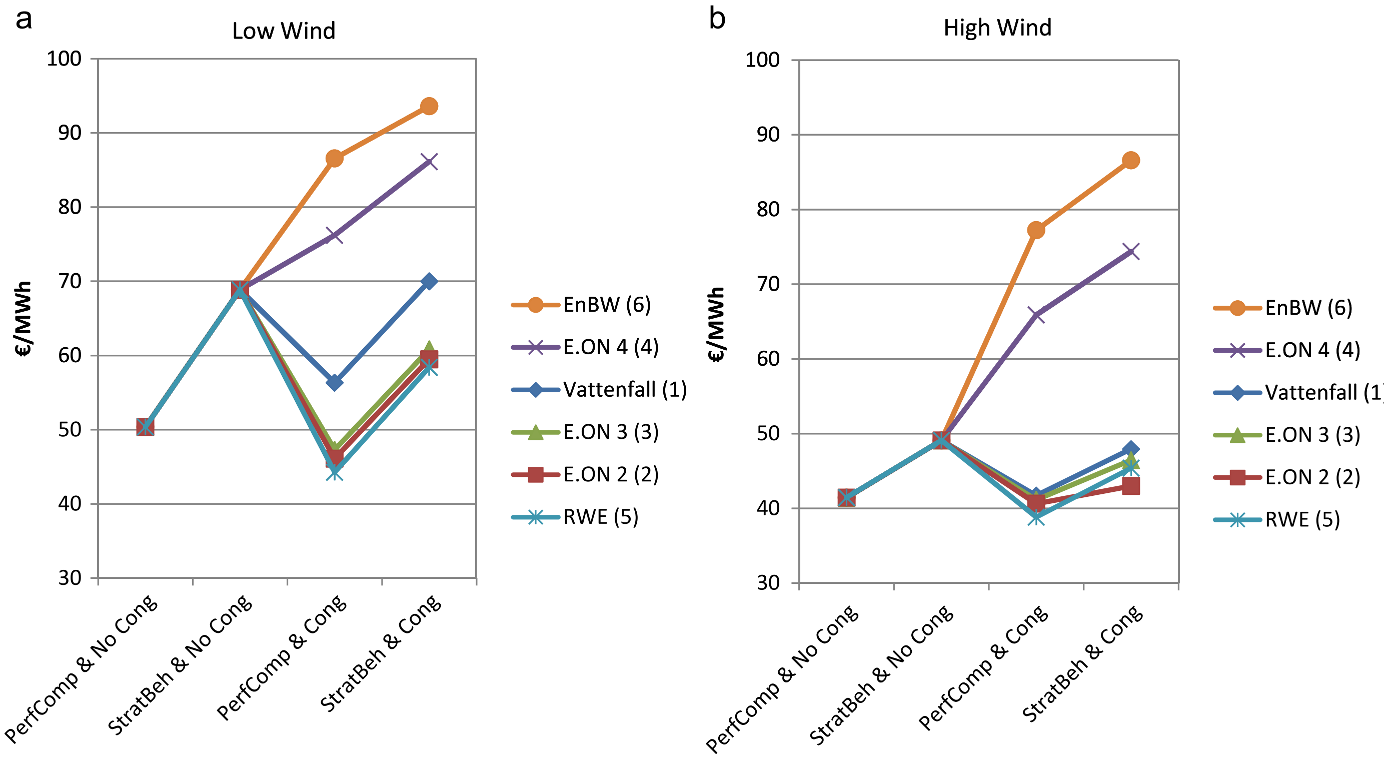

Fig. 4. Average zonal prices.

4.2. Zonal prices

The average zonal prices for each of the eight different scenarios are displayed in Fig. 4. Prices under low wind generation are displayed on the left side, and those under high wind generation are shown on the right side. Without congestion, prices are equal in all zones. With congestion, prices in southern regions strongly increase.

Before discussing the various effects on the prices, the outcome is compared to that of the real German electricity market. The scenario that best describes the current situation at the European Energy Exchange and its resulting price is the scenario under strategic behavior and no congestion. Under low wind, the average price in this scenario was 68.87 €/MWh. Since a high load situation based on December values was modeled, the simulated prices should be in the range of EEX December peak prices, available from EEX's website (European Energy Exchange AG, 2008). Compared to an actual EEX Phelix Peak price on Thursday, December 13, 2007 of 113.02 €/MWh, the simulated prices appear rather low. However, just one week before on Thursday, December 6, 2007, the Phelix Peak price was 66.37 €/MWh and for December 2006 the working day peak prices averaged to 61.80 €/MWh.[15] Therefore, considering the fact that the model is a simplification of the real market and many factors that influence daily market outcomes such as the real plant availability were approximated, the simulated outcome seems within a realistic price range.

There are three ceteris paribus effects that can be examined. The first effect shows how prices change when congestion occurs as compared to the scenario with perfect competition and no congestion. In Fig. 4 it can be seen that – as expected from theory – congestion leads to different zonal prices, while a situation with no congestion leads to one uniform price. Further, congestion increases the prices in the south of Germany and decreases the prices in other regions.

The graphs also show that there is a strong interdependence between these three variables. The percentage price increases from strategic behavior vary between 36.7% and 5.8% depending on the zone and the market environment. If market power of the supplier's side is measured in percentage price increase caused by strategic biding behavior, two main observations can be made. First, high wind generation reduces overall market power. Second, though not in line with some expectations from the literature, market power in Germany decreases under congestion. It can thus be concluded that the largest part of a price increase through congestion can be explained by the market structure itself, because more expensive generating units have to be operated in zones which cannot import cheaper electricity from other zones, as the lines linking to these zones do not offer enough capacity. The additional percentage price increase that stems from strategic behavior is smaller as in cases without congestion. However, it should also be noted that the price increases are regarded here in absolute terms, so the same absolute price increase in the scenario without congestion results into higher percentage increases as in the congestion case in which the basic price level is already higher. Due to the spatial location of wind power feed-in, the ability of generators to exert market power under congestion differs across zones, which results in the effect that, in absolute terms and under high wind conditions, generators gain market power in some zones and loose it in other zones.

Furthermore, wind power best suppresses prices when there is no congestion in the grid. Under congestion, only the prices in the Vattenfall (1) zone are lowered even further. In addition, the percentage decrease in prices through wind is stronger under strategic behavior than under perfect competition, except for the southern zones (E.ON 4 (4) and EnBW (6)) when the grid is congested. (Figs. 5–7)

[15] Own calculation based on market prices for December 2006 of the European Energy Exchange AG (2008): Monday to Friday; without the holiday week between Christmas and New Year's Day, were prices were even lower.

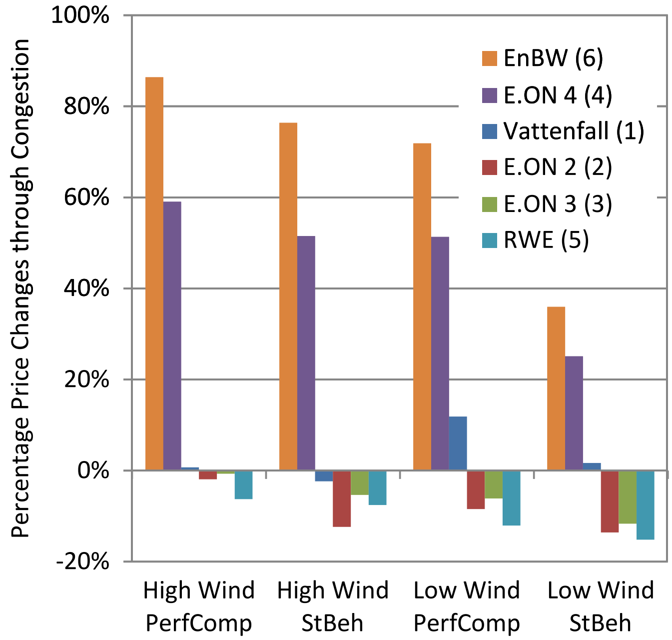

Fig. 5. Percentage price changes through congestion.

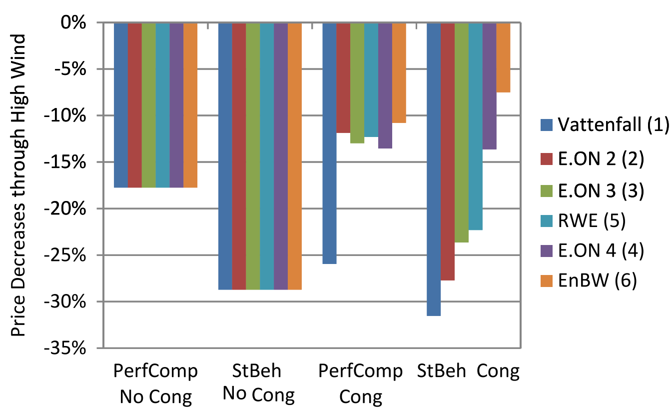

Fig. 6. Percentage price decreases through high wind generation.

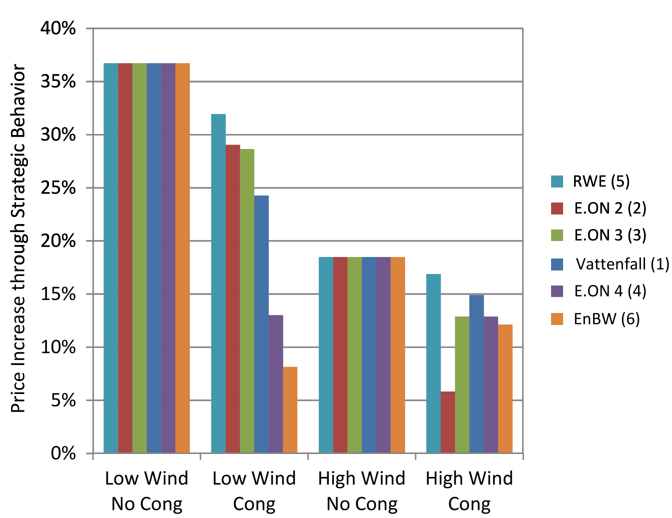

Fig. 7. Percentage price increases through strategic behavior.

The simulation results also show that the joint effect caused by the two factors of strategic behavior and congestion cannot be simply inferred from multiplying the two isolated ceterus paribus effects, because both factors are interdependent. Fig. 8 shows the deviation between the joint modeling of strategic behavior and congestion on the one hand, and an independent consideration of these effects on the one hand. If the effect of congestion and strategic behavior is estimated through simply multiplying the isolated percentage price changes of both factors, the joint effect is overestimated by 1.4% and 26.4% as compared to the case in which the factors are jointly modeled. This is here referred to as price prediction error. Fig. 8 shows that there is not only a prediction error in every scenario considered in this analysis, but the errors also vary greatly depending on location and wind situation. This suggests that only a model that combines the market side of electricity trading with the physical side can really capture the joint effects of congestion and strategic behavior on market prices in an adequate way.

Tables 3 and 4 give some more information about the price statistics resulting from the 20 simulation runs of each scenario.

4.3. Total generation costs

Usually, social welfare, defined as the sum of producers' and consumers' surplus, is among the most important indicators for evaluating markets. In an electricity market with assumed inelastic demand, social welfare is maximized when total production cost is minimized. Therefore, the actual system-wide costs for generation are analyzed for the presented eight scenarios. Generation costs are displayed in Fig. 9 and range from 1.9 million to 2.9 million € per hour. The strongest increase in total production costs is due to high wind power production. The assumed feed-in tariff of 90 €/MWh for wind power generation is well above the generation costs of conventional power plants.

Apart from costs for wind power, congestion and strategic behavior both increase system-wide costs. In the case of strategic behavior, the reduction of social welfare is not due to higher market prices, since additional profit on the generators side is also part of social welfare, but because generators' true marginal costs are obscured so that generator dispatch is not in the true merit order. Congestion, on the other hand, hinders the transport of efficiently produced electricity and hence leads to a socially suboptimal dispatch as well.

Fig. 10 shows the percentage increases in total production costs if one moves away from the ideal case of perfect competition and no congestion. The ceteris paribus effects show that congestion and strategic behavior both increase costs (or reduce social welfare) by about the same amount. In general, both effects are smaller under high wind generation, not only percentagewise but also in absolute terms. Wind power can apparently lower the negative effects that congestion and strategic behavior have on social welfare. It serves a part of the load and thereby reduces the residual load that is served by the conventional power plants. Since the residual load is lower, it can be served without having to use some of the less efficient power plants with high marginal costs. Even with congestion and strategic behavior, this effect should reduce the residual production costs. Following this line of reasoning, one would also expect that in scenarios with lower loads, economic costs of congestion and strategic behavior would decrease in the same manner. (Figs. 11 and 12)

Furthermore, it should be noted that under both high and low wind generation, the joint negative effect of strategic behavior and congestion on social welfare is stronger than what would be expected from extrapolating the isolated effects. However, especially in the case of high wind, this effect is relatively small,

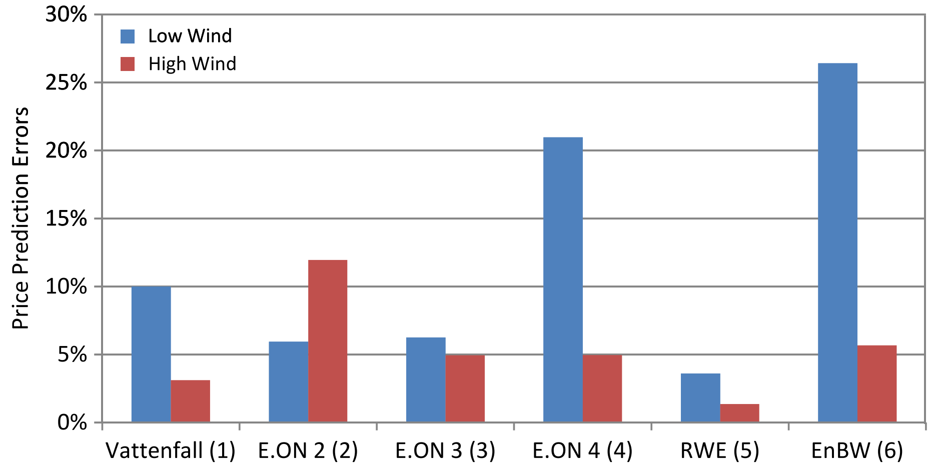

Fig. 8. Percentage errors of multiplying the individual effects of congestion and market power vs. modeling them jointly.

Table 3
Low wind zonal price statistics: average (standard deviation), max, min; $N = 20$.

Zone/Scenario	PerfComp and No Cong	StratBeh and No Cong	PerfComp and Cong	StratBeh and Cong
Vattenfall	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	56.34 (0), 56.34, 56.34	70.01 (3.29), 76.54, 64.51
E.ON 2	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	46.11 (0), 46.11, 46.11	59.5 (3.61), 68.32, 55.04
E.ON 3	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	47.29 (0), 47.29, 47.29	60.84 (3.56), 69.41, 56.42
E.ON 4	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	76.22 (0), 76.22, 76.22	86.14 (2.3), 91.71, 82.84
RWE	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	44.28 (0), 44.28, 44.28	58.42 (3.72), 67.57, 53.81
EnBW	50.38 (0), 50.38, 50.38	68.87 (6.13), 80.01, 58.5	86.57 (0), 86.57, 86.57	93.61 (1.79), 97.96, 91.36

Table 4
High wind zonal price statistics: average (standard deviation), max, min; $N = 20$.

Zone/Scenario	PerfComp and No Cong	StratBeh and No Cong	PerfComp and Cong	StratBeh and Cong
Vattenfall	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	41.72 (0), 41.72, 41.72	47.93 (3.29), 54.71, 43.62
E.ON 2	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	40.64 (0), 40.64, 40.64	43.01 (2.55), 48.04, 39.25
E.ON 3	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	41.15 (0), 41.15, 41.15	46.45 (1.67), 51.09, 44.03
E.ON 4	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	65.9 (0), 65.9, 65.9	74.38 (1.43), 77.9, 72.16
RWE	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	38.83 (0), 38.83, 38.83	45.38 (2.07), 50.3, 42.17
EnBW	41.44 (0), 41.44, 41.44	49.1 (2.05), 51.91, 45.03	77.23 (0), 77.23, 77.23	86.59 (0.91), 88.69, 85.22

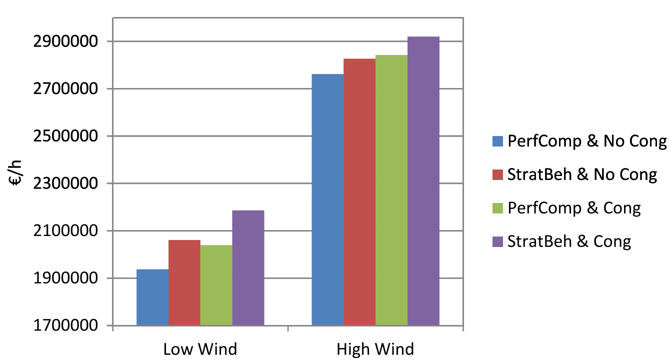

Fig. 9. System-wide total cost of generation per hour.

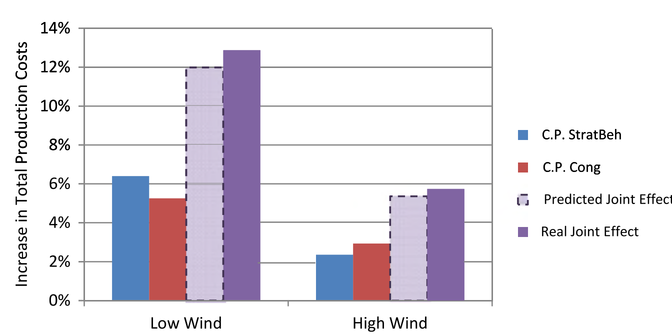

Fig. 10. Percentage increases of total cost of production through congestion and strategic behavior.

so that further tests would have to confirm that these results are truly systematic and not due to variations in the data.

5. Conclusion

The increasing trades amongst the European electricity markets and a shift in location of electricity generation challenge the old grid infrastructure. Intra-German congestion is already on the rise, which creates the need for further adaptations of the current market design. As congestion may influence the potential for market participants to bid strategically, the agent-based simulation model of the German electricity market presented in this paper captures the effects of both congestion and strategic market behavior. It can thus be used to analyze how both factors affect market outcomes. The model includes a detailed

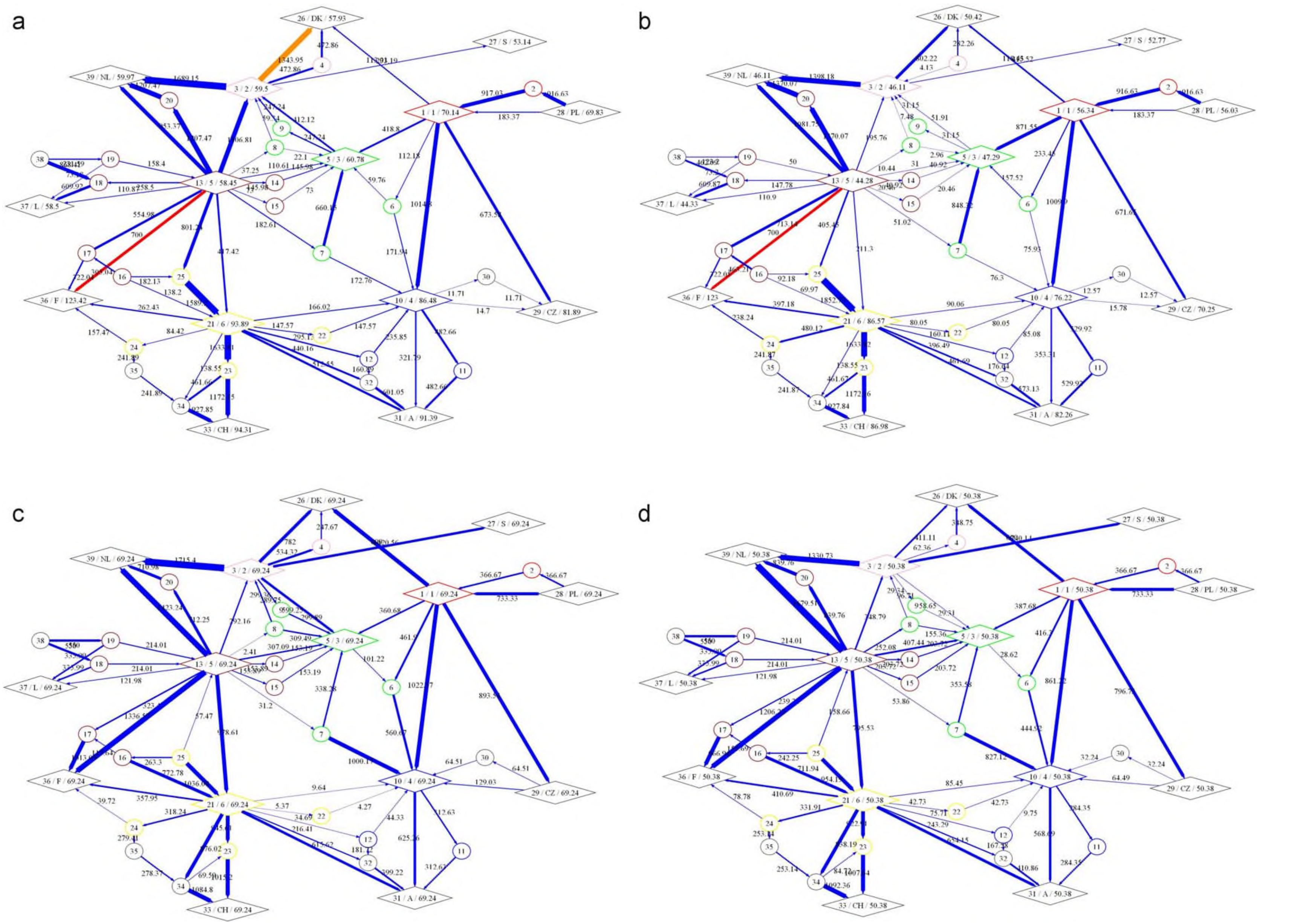

Fig. 11. Transmission situation for different scenarios with low wind generation. (a) Low wind, strategic behavior, congestion; (b) Low wind, perfect competition, congestion; (c) Low wind, strategic behavior, no congestion; (d) Low wind, perfect competition, no congestion.

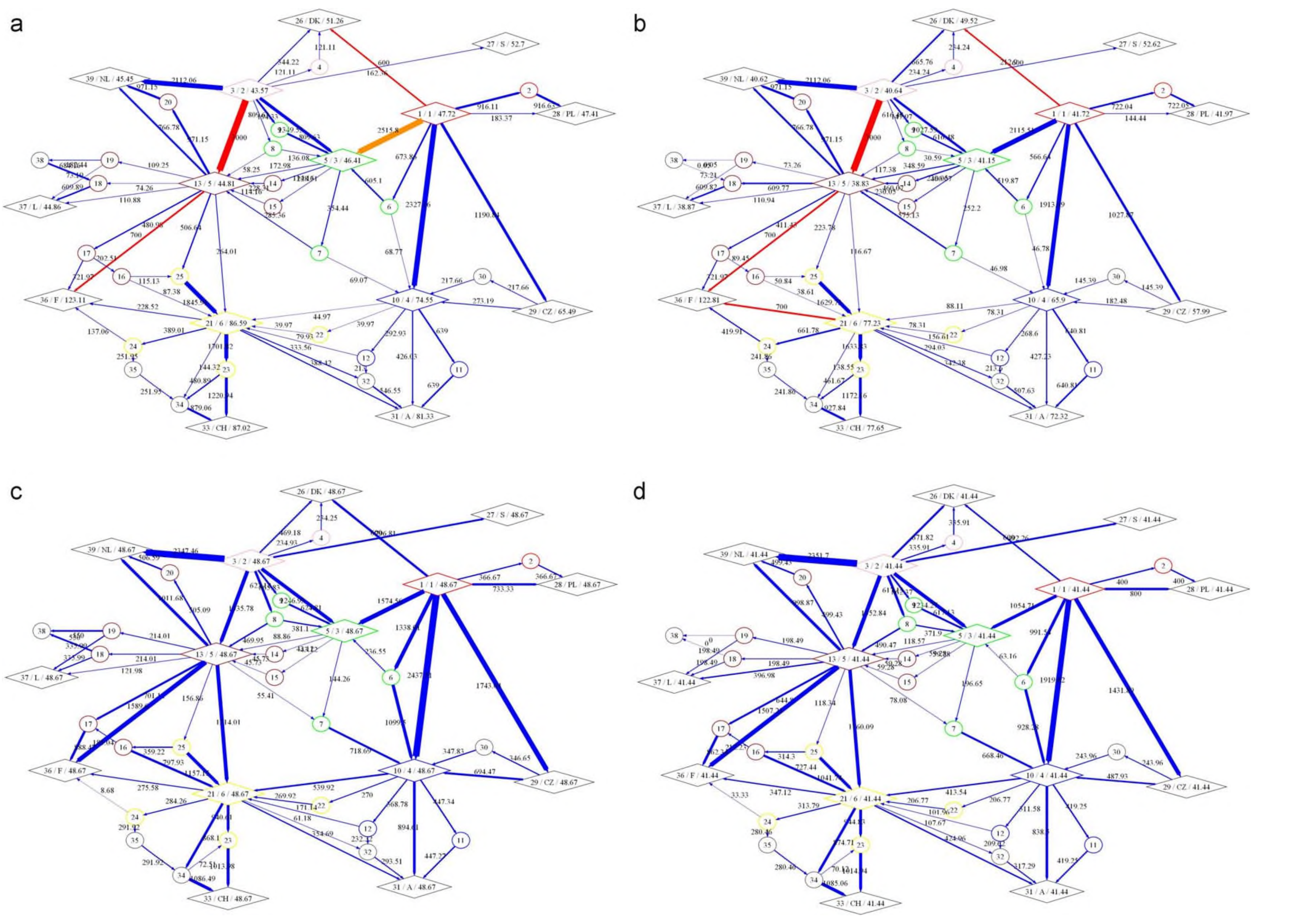

Fig. 12. Transmission situation for different scenarios with high wind generation. (a) High wind, strategic behavior, congestion; (b) High wind, perfect competition, congestion; (c) High wind, strategic behavior, no congestion; (d) High wind, perfect competition, no congestion.

representation of all major power plants in the German power system, and a simplified representation of the German high-voltage grid with a zonal pricing mechanism.

Simulation results show that under zonal pricing congestion strongly increases electricity prices in the south of Germany and decreases prices in other areas. Furthermore, strategic behavior helps agents increase market prices in every case. However, congestion and high wind generation reduce the effect of strategic behavior. Unfortunately, this is not the case when it comes to the assessment of social welfare. While the reduction of social welfare through the isolated effects of congestion and strategic behavior is about the same, the joint damage is even higher than one would expect. High wind power generation reduces this negative effect, but it is itself so costly that social welfare decreases even further.

The results also show that there is a great interdependence between the effects of strategic behavior in the market and congestion in the German grid. Therefore, it can be concluded that modeling only isolated effects is not a suitable method to make predictions about the German market in which both strategic behavior and congestion are now inherent.

Future research should extend the model of the German market to other market situations and test some scenarios on how the German market could develop over the next years. In our work, we exemplified how the stronger utilization of wind power and the occurrence of strategic bids affect the market volatility. However, this has only been shown along our given input data. In order to show the robustness of the effects, additional validation runs und inclusion of further datasets of the model has to be conducted. To enhance the performance of the model, the learning algorithm should be further adapted to improve learning outcomes, and agents should be enabled to maximize the joint profit with other agents who belong to the same company. In addition, it should be analyzed more closely how congestion and strategic behavior influence each other in the German market, and whether other factors, such as the absolute level of prices, influence this interdependence. We discussed that the fact whether a utility operates mainly in a high wind zone or not affects the market power. The effect which became visible in our work is that there is a correlation between the wind dependency of the utility and its market power in wind and no-wind situations.

Appendix

The following two figures visualize the model of German high-voltage grid and the countries that are interconnected with it, for selected simulation runs of various scenarios. The notation applied is summarized in the following.

Nodes: Rhombi: main nodes, 〈node number/zone/price〉; circles: auxiliary nodes (same price as the main node they belong to); colors: Vattenfall (1), E.ON 2 (2); pink; E.ON 3 (3) green; E.ON 4 (4), RWE, EnBW.

Power lines: arrowhead points in the direction of the power flow, thickness represents relative amount of power transmitted through the line, which is proportional to its flow; colors: blue: no congestion, orange: more than 80% of the capacity is used, red: congestion.

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