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Gone with the wind? — Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply

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ABSTRACT

The increased wind energy supplied to many electricity markets around the world has to be balanced by reliably ramping units or other complementary measures when wind conditions are low. At the same time wind energy impacts both, the utilization of thermal power plants and the market prices. While the market prices tend to decrease, the impact on the utilization of different plant types is at the outset unclear. To analyze the incentives to invest in thermal power plants under increased wind energy supply, we develop a computational model which includes ramping restrictions and costs and apply it to the German case. We find that due to current wind supply the market prices are reduced by more than five percent, and the incentives to invest in natural gas fired units are largely reduced. An increased wind supply erodes their attractiveness further. Consequently, a gap between the need for and the incentive to provide flexibility can be expected.

1. Introduction

Today, wind power provides a comparatively cheap source of renewable and almost carbon free electricity in many countries. Modest costs per output produced establish a comparative advantage of wind power over most other renewable energy applications. With fossil prices on the rise, wind power may also be competitive with conventional sources like gas and coal fired power plants. However, in most countries wind power production is not subject to market pricing but to governmentally predetermined tariffs like the German feed-in tariff for renewable energies (FIT). The FIT establishes a guaranteed price for every supplied renewable energy production unit, to be purchased and paid by the established power market participants, and allowed to be passed through to consumers.

Given such support, wind power has experienced a fast development in the last decade in many countries,–especially in Denmark, Germany, and Spain, the US, and China–, and is expected to grow further in the next years. For instance, Lemming et al. (2007) project the current annual 25% increase in installed wind power to continue until 2015 reaching a global electricity market penetration of 25% by the midst of the century. Other sources project similar figures. For Europe, Eurelectric (2007) calculates with 190 GW of wind power capacity installed in the EU 27 by 2030 in its baseline scenario. In the case of Germany, according to BDEW (2008) almost 40 TWh of wind energy has been produced in 2007, corresponding to about 23 GW installed. Furthermore, Nitsch (2008) projects a production increase of more than 45 TWh to almost 88 TWh by the year 2020, and a market share of wind power in Germany of circa 15%.

This development may give rise to problems of reliability of the overall electricity supply because wind power output fluctuates, in part stochastically, with day to day meteorological conditions and falls close to zero several times of the year. Therefore, wind power adds to the problem of power plant commitment, and, second it reshapes the profile of the residual load profile. The problem of stochastic power demand and unit commitment constitutes a problem that has been addressed by Takriti et al. (1996) and Carpentier et al. (1996) with a stochastic optimization approach, while Tuohy et al. (2009) account in a similar framework for the additional uncertainty induced by stochastic wind generation. They study a test electricity system and find that stochastic optimization reduces expected system costs by around 0.25% and suggest more frequent system planning to facilitate the use of more up to date wind forecasts.

However, we model the impact of wind power integration on electricity wholesale prices when forecasts are perfect, which is driven by the fact that in most systems electric power can neither be stored economically nor the demand side can be sufficiently managed, e.g. by real time pricing and metering or by increased trade in electricity. Thus,

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particularly in the short run the more flexible thermal power plant sector has to provide sufficient ramping capacity to cope with hours of weak wind output. In this framework, we address the question whether the electricity market will provide incentives to commission appropriate capacities. Two effects of increased wind power are apparent: On the one hand, the erosion of prices received by market based thermal power plants. On the other hand, the ambiguous effect of wind power on the utilization of thermal power plants. While the demand left for thermal power plants is clearly reduced by the introduction of wind power, the profile of the residual load is changed by wind power generation such that more flexible units like gas turbines might experience an increase of utilization.

The price effect of the introduction of wind power has attracted some attention in the contemporary literature. Rathmann (2007) analyzes the support for renewable energy supply by using a numerical model with varying assumptions on the cost structure which are based on historic fuel price and emission market price data. He shows that renewable energy support can reduce electricity wholesale prices for certain parameter values. Bode and Groscurth (2006) use a similar model of the German power sector with exogenous emission pricing and find a negative price effect for some consumers which are partially exempted from the burden of the renewable energy supply (RES) support. Traber and Kemfert (2009) apply an oligopolistic market model and include an endogenous emission price determination. They find significant feedbacks of the emission market since the promotion of renewable energy slackens the emission market price signals. Hence, two effects of renewable energy support dampen electricity producer prices: a substitution effect which reduces the demand for conventional emission intensive sources and an emission price effect which reduces conventional production costs. Furthermore, they investigate the consumer side of the market[1] and find that the price dampening effect of the emission price reduction is overcompensated by the price increasing burden related to the support of RES. However, a criticism directed to these models is that they do not account for start-up and ramping peculiarities which is discussed as an important topic when analyzing the impacts of fluctuating RES.[2]

Unfortunately, start-up costs increase the effort to model cost minimization on the producer side. They add a fixed cost component which is independent of the subsequent utilization of started-up power plants and lead to non-convexities of the marginal production costs of a single plant. The problem is also known as unit commitment problem which is often analyzed as integer programming (IP) or mixed integer programming (MIP) problem. For a thorough description of this type of model see Hogan and Ring (2003). A major disadvantage of IP models is, however, their computational effort. In addition, solvability for large systems is not guaranteed. Alternatively, one can use linear programming (LP) models. These models can be computed much easier but they have to sacrifice some accuracy, since they are not able to cope with non convexities arising from decreased part load efficiencies. For a recent example see Kuntz and Müsgens (2007).

Some studies analyze the German market in particular. Assessing market power on the German power market, Weigt and Hirschhausen (2008) account for the costs induced by start-up processes with a model that combines two optimization stages. First, a MIP is used to solve the unit commitment problem, and, second, an optimization with fixed binary plant status variables taken from the first step is used to find the actual dispatch, i.e. production of electricity. They find significant deviations from the historic market outcomes, amounting on average to mark-ups of eleven percent in baseload, and to almost thirty percent in peak load periods. In the field of the analysis of effects of wind power support on market prices Sensfuß et al. (2008) use a so-called agent based simulation platform which also accounts for start-up costs. They find price reducing effects of about 0.7 euro cent due to 52.2 TWh renewable energy supply for Germany in 2006.

In the models with start-up costs mentioned above, conventional electricity production will be completely crowded out by any RES since they are in principle load fulfillment models. However, with a comparatively high fraction of heavy industry consumers with high electricity cost shares as well as options to reduce consumption, and, given the rather close connections to adjacent markets in the European neighborhood, some elasticity of demand has to be accounted for. A notable example is provided by Müsgens (2006) who uses a linear model (LP), includes international trade in electricity and finds significant exertion of market power on the German market in peak load hours. However, to our knowledge the models applied so far are not able to account for market power and start-up effects at the same time.

With the present paper, we try to fill this gap in the literature and present a simple model that incorporates a convex representation of start-up costs, i.e. we abstract from decreasing average costs of single units after start up which is justifiable by the large plant portfolios that lead to a minor relevance of part load operation of single plants. The setting allows us to model the electricity system in a market framework with elastic supply and demand. The model is formulated as a mixed complementary program (MCP) and termed ELECTRICITY SUPPLY AND DEMAND MATCH under EMISSION TRADING and RENEWABLE ENERGY (ESYMMETRY). We apply the model to the German wholesale electricity market where conventional electricity suppliers encounter no transmission constraints and subtract the exogenously given wind supply from market demand. Demand elasticities are used to calibrate the model to replicate the spot prices of the energy exchange in Leipzig. Since we do not model international electricity trade explicitly, the calibrated demand elasticities reflect potential effects from adjacent markets.

Together with the wholesale market price effects of the wind power supply, we study the incentive to invest in thermal power plants. Similar to other approaches to investigate electricity markets, e.g. Lise et al. (2006), Bushnell et al. (2008), Traber and Kemfert (2009), the model can assess different market behavior of important electricity suppliers: On the one hand, price taking perfect competitive behavior of all market participants, and, on the other hand, Cournot quantity setting behavior of large firms under competition of a price taking aggregate of fringe firms.

In the following Section 2 we describe the mathematical model. In Section 3 we introduce the technologies available to conventional power producers in Germany, and demonstrate the calibration of the model. Section 4 reports results in regard to prices, emissions, electricity production mix, and the incentives of firms to invest in new thermal power plants. Finally, Section 5 summarizes the results and concludes.

2. Model

The representative firm i maximizes profits from plant operation, i.e. revenues net of production costs, regarding fixed costs as sunk. In each period t of the limited[3] time horizon T, the firm's revenues are the product of its production of electricity in all plants, $q^{i,t}$, and the market price, determined by the inverse demand, $P^t(Q^t)$, and the aggregate production Q^t of all firms.

[1] In the present paper we focus on the supply side of the market, and therefore ignore effects induced by the support mechanism on the consumer side.

[2] The importance of the flexibility of thermal power plants for the integration of wind power has been pointed out by several studies. See for instance DENA (2005) or Oswald et al. (2008).

[3] The optimization is applied to a single week. Thus, discounting may be neglected.

We regard a set of conventional production technologies N and denote a single technology as n. The costs associated with the production of $q^{i,t,n}$ in technology n of firm i are assumed to be decomposable into a part that applies independently from the load profile to all produced units, and a part which depends only on ramping processes, i.e. the load gradient. Denoting the maximum available capacity $\overline{q}^{t,n}$, the load gradient can be defined as:

$$l^{i,t,n} \equiv \begin{cases} \dfrac{q^{i,t,n} - q^{i,t-1,n}}{\overline{q}^{i,n}} & \text{if } q^{i,t,n} > q^{i,t-1,n} \\ 0 & \text{otherwise} \end{cases} \quad \forall t \in T, \forall i \in I, \forall n \in N. \tag{1}$$

The two parts of the costs are denoted as variable costs, $C^{i,t,n}(q^{i,t,n})$, and ramping costs, $R^{i,t,n}(l^{i,t,n})$, respectively. The ramping costs of a period t grow with the load gradient. Therefore, any load increase in one period will weakly decrease the start-up costs to reach a given load in the following period due to a reduced necessary load gradient. More precisely, the ramping costs of firm i in period t and technology n, $R^{i,t,n}$, are assumed to be linear in the load gradient: $R^{i,t,n}(l^{i,t,n}) = R^n l^{i,t,n}$, where R^n denotes marginal ramping costs. The variable costs are linear in output and, hence, can be written as: $C^{i,t,n}(q^{i,t,n}) = C^n q^{i,t,n}$.

In addition, the load gradient of every firm and technology is restricted to her maximum load increase, $\overline{l}^{i,n}$, which is the product of the maximum load gradient $\overline{l}^n$ of each technology and the according maximum available capacity of each firm. The maximum available capacity, $\overline{q}^{i,n}$, is in turn the product of installed capacity $q^{cap,i,n}$ and availability a^n and gives rise to the second technology specific restriction of each firm.

The inequality-restricted profit optimization problem of firm i can be expressed as:

$$\begin{aligned} \max_{qi} L^i &= \sum_{t=1}^{T} P^t(Q^t)q^{i,t} - \sum_{t=1}^{T}\sum_{n=1}^{N} C^n q^{i,t,n} - \sum_{t=1}^{T}\sum_{n=1}^{N} R^n l^{i,t,n}, \\ &\text{s.t.} \\ &\overline{l}^{i,n} \geq l^{i,t,n}, \forall t \in T, \forall n \in N, \text{and} \\ &\overline{q}^{i,n} \geq q^{i,t,n}, \forall t \in T, \forall n \in N, \end{aligned} \tag{2}$$

with q^i denoting the time profile of production of firms i. The central first order condition with regard to production in technology n of oligopolistic firm i in period t in a Nash-equilibrium can be written as:

$$\frac{\partial L}{\partial q^{i,t,n}} = P'^t(Q^t)q^{i,t} + P^t(Q^t) - C^n - R^n \frac{\partial l^{i,t,n}}{\partial q^{i,t,n}} - \lambda^{i,t,n} - R^n \frac{\partial l^{i,t+1,n}}{\partial q^{i,t,n}} + \lambda^{i,t+1,n} - \kappa^{i,t,n} \leq 0, \tag{3}$$

where $\lambda^{i,t,n}$ and $\kappa^{i,t,n}$ denote the shadow prices of the load gradient restriction and the capacity restriction. Furthermore, the first derivative of the inverse demand is denoted as $P'^t(Q)$.

Small firms regard the price as independent of their output decision, and, thus, their first order condition boils down to

$$\frac{\partial L}{\partial q^{i,t,n}} = P^t(Q^t) - C^n - R^n \frac{\partial l^{i,t,n}}{\partial q^{i,t,n}} - \lambda^{i,t,n} - R^n \frac{\partial l^{i,t+1,n}}{\partial q^{i,t,n}} + \lambda^{i,t+1,n} - \kappa^{i,t,n} \leq 0. \tag{4}$$

The optimality conditions (4) and (3) say that if a firm produces with a certain technology, it equates marginal revenues with marginal costs. The difference between the two types of firms is captured by the mark-up $-P'^t(Q^t)q^{i,t}$, which is deducted from the price to calculate marginal revenues in case of oligopolistic firms. In contrast, the marginal costs are represented in the same way for both types of firms. They include marginal variable costs, marginal current period ramping costs, the shadow prices of current period ramping and capacity restrictions, and the reduction of costs associated with ramping in the following period due to an output increase in the current period. Our linear representation of ramping costs implies that firms would either fully ramp up a technology to the possible extent or would choose not to ramp up if the marginal revenues were independent of output. However, a partial ramp up of relative expensive technologies can occur due to the effects of production on marginal revenues.

Most important information for our results is provided by the shadow prices of the capacity constraints, as they reflect the incentive to increase the installed capacity of a technology. If we furthermore subtract investment costs from the average shadow price, we get the incentive to invest for each technology. Note that these incentives depend on the market behavior of a firm: a large strategic firm has a smaller incentive to invest since it expects a price that includes a mark-up in addition to full cost recovery.

In the following section, the technology parameters will be introduced, and we discuss which of the two behavioral assumptions is more appropriate by comparing with historic spot prices from the European Energy Exchange (EEX) in Leipzig.

3. Cost functions, data and calibration

The time and firm invariant constant marginal costs of technology n are

$$C^n = \frac{p^n + \sigma e^n}{\eta^n} + oc^n, \forall n \in N, \tag{5}$$

where σ denotes the emissions price, and p^n, e^n, η^n and oc^n denote the fuel price, the fuel emission, the degree of efficiency, and the variable operation and maintenance costs of technology n respectively.

The ramping costs $R^{i,t,n}$ are, by contrast, not only depending on the used technology, but on the period t and the firm i since they are related to time- and firm-specific load gradients. However, the marginal ramping costs of a given technology n are constant and the same for all firms. The logic behind this assumption is that marginal costs of ramping can be approximated by a smooth increasing function due to the huge power plant portfolios of the considered firms, although marginal cost function decrease with its actual load up to the capacity limit for each single plant. We decompose the marginal ramping costs into the ramping fuel requirement, rf^n, and increased depreciation due to ramping, d^n, as follows:

$$R^n = rf^n(p^n + \sigma e^n) + d^n, \forall n \in N. \tag{6}$$

Table 1
Technology parameters.

	Fuel price	Fuel emission	Efficiency	o&m costs	Ramping fuel	Ramping depreciation	Maximum load gradient	Availability
	p [cent/kWh]	e [kg/kWh]	η [%]	oc [cent/kWh]	rf [kWh/kW]	d [cent/kW]	$\bar{l}$ [%/h]	a [%]
HYD	0.00	0.00	1.00	0.26	0.0	0.00	100	0.75
NUC L	0.21	0.00	0.34	0.04	16.7	0.17	4	0.86
NUC S	0.21	0.00	0.32	0.10	16.7	0.17	4	0.86
BC New	0.45	0.40	0.43	0.26	6.2	0.30	8	0.85
BC Old	0.45	0.40	0.34	0.26	6.2	0.10	8	0.85
HC New	0.72	0.34	0.43	0.20	6.2	0.50	14	0.82
HC Old	0.72	0.34	0.34	0.20	6.2	0.15	14	0.82
NG CC	2.17	0.20	0.58	0.13	3.5	1.00	50	0.86
NG ST	2.17	0.20	0.40	0.15	4.0	1.00	50	0.86
NG GT	2.17	0.20	0.35	0.15	1.1	1.00	100	0.86
O ST	1.72	0.28	0.38	0.15	4.0	0.50	50	0.84
O GT	1.72	0.28	0.33	0.15	1.1	0.50	100	0.84

The main technologies of conventional producers are hydro (HYD), large and small nuclear (NUCL L, NUCL S), old and new brown coal (BC Old, BC New), old and new hard coal (HC Old, HC New), natural gas combined cycle (NG CC), natural gas steam and gas turbines (NG ST, NG GT), and heavy oil steam and gas turbines (O ST, O GT). An overview of the technology specific inputs mainly based on own estimates is given in Table 1.

Parameters in regard to ramping costs reflect the costs of the start-up processes of power plants and are based on DENA (2005). They include all costs associated with increased start-up depreciation due to increased forced outage rates, additional maintenance, and loss of life expectancy.[4] Since the estimates for depreciation apply to new installed power plants, we introduce a discount of these values in regard to old coal fired power plants which are older than forty years on average. We assume the potential economic depreciation to be smaller for old plants since their economic values are comparatively low. Our figures are, however, in the range of those used in the literature on the German market, e.g. (Müsgens, 2006; Weigt and Hirschhausen, 2008).

To estimate expected available production capacities, we have to weight net installed capacities with expected availabilities which are reported in terms of annual averages in the last column of Table 1. There are important seasonal impacts on the expected availabilities of power plants. For instance, revisions of power plants in central Europe are most often scheduled in the summer month, and, thus, more generation capacity is available in winter and spring. Also, availability of hydro power units is generally depending on precipitation which is typically low in summer. For the simulation of four seasons[5], we weight the annual availabilities with 6/7 to represent summer and autumn, and with 8/7 for winter and spring.

Furthermore, for the representation of the supply side, we utilize plant data of the four major electricity producers–EnBW, E.ON, RWE, Vattenfall–while minor producers are aggregated to a set of fringe firms as reported in Table 2. The representation of control over plants is based on a multiplicative calculation of ownership up to five layers. For example, in case of two ownership layers, the control over an indirectly owned plant is represented by the product of the large firm's share in a partially dependent company times the ownership share of the dependent company. Alternatively, full control over plants could have been assigned to those companies owning the majority of shares, which would map the under representation of minority shareholders in decision making more accurately. The advantage of our procedure is its adequate representation of generated profits.

The model is applied to simulate a single week. To study a complete year from November 2007 until October 2008, we calculate four weeks which had a wind yield that was close to the seasonal average wind production in the respective period. The winter 2007 - 2008 is represented by the week from 3rd of February until 9th of February 2008, spring 2008 by the week from 28th of March until 3rd of April 2008, summer 2008 by the week from 28th of June until 3rd of July 2008, and autumn 2008 by the week from 8th until 14th of September 2008. The emission permit prices for these weeks complete the input for the supply side. They are taken from the download section of EEX and have been 0.025, 22, 27.5 and 23 euro per ton of CO_2 for the chosen weeks in winter, spring, summer and autumn respectively.

The demand side is represented by periodic iso-elastic demand which can be written as $D^t(P^t) = D_0^t\left(\frac{P_0^t}{P^t}\right)^{-\varepsilon}$, where ε denotes the price elasticity, and D_0^t and P_0^t reference values of demand and price. Their values are the realized periodic market demands from the download section of the UCTE[6] net of wind supply, and seasonal hourly average EEX prices respectively. Following the strategy of Green and Newbery (1992), we try to fit the model as close as possible to historic spot market values. Therefore, the model is calibrated by the choice of the periodic demand elasticity. We apply either constant elasticities over all periods or periodic elasticities that are inversely related to the seasonal average hourly EEX prices. The latter assumption is based on the economic logic that possibilities to substitute supply, e.g. by demand reduction of industrial consumers or increased imports, should be more scarce in peak load hours and more abundant in weak load hours.

Table 3 documents the calibration procedure for the selected spring-week in terms of the coefficients of correlation, the average difference of EEX-spot-price to model price, and the mean of the absolute deviation of model prices and EEX prices. The first four rows list the respective results for constant demand elasticities between 0.6 and 0.9, while the last four rows show the results for hourly elasticities of demand that are four- to sevenfold the inverse of the seasonal average hourly EEX prices. When we compare the model accuracy under the assumption of oligopolistic

[4] Costs induced by part load inefficiencies and efficiency decreases due to component degradation which depends in particular on the operation history of single plants are not accounted for in our approach. Some sources report significantly higher start up costs for single plants, e.g. Denny and O'Malley (2009), which, however, frequently might not be fully priced in by the electricity suppliers as pointed out by Lefton et al. (1997). We are confident that our parameter values do not underestimate the assumptions of the German companies since the study DENA (2005) was conducted by, amongst others, the largest companies on the market RWE and E.ON. These companies have no reason to understate their cost assessment because they are frequently suspect of pricing above costs.

[5] The seasonal disaggregation is chosen in line with DENA (2005): winter from November until February, spring from March until April, summer from May until August, and autumn from September until October.

[6] Union for the co-ordination of transmission of electricity, www.ucte.org/resources/dataportal/.

Table 2
Installed net electric capacities of the German electricity sector.

q^{cap}	Net MW installed				
	EnBW	E.ON	RWE	Vattenfall	Fringe
HYD	427	1507	638	0	893
NUC L	3286	7639	3536	904	906
NUC S	733	0	0	514	51
BC New	404	974	1074	3639	217
BC Old	0	346	7544	3664	192
HC New	495	2585	1288	1194	2157
HC Old	2179	7348	3165	473	3979
NG CC	357	417	939	760	2598
NG ST	260	2384	1416	423	1877
NG GT	427	1070	627	920	2073
O ST	328	1476	19	259	287
O GT	112	7	2	387	254

competition to that of perfect competition, we find that the former achieves better performance in terms of the difference and deviation from the historic EEX-prices while the latter achieves a better coefficient of correlation.

However, the assumption of perfect competition generates prices that are at average around 13% lower than the EEX prices, while assuming oligopolistic competition yield price simulations that at average hit the EEX-price history. Since both behavioral assumptions yield acceptable *Rs* of above 0.9, imperfect competition seems to be more adequate to model the German market with our cost assumptions, and is therefore assumed in the following.

Comparing the setting with constant elasticities to the setting with hourly elasticities we find rather modest differences in regard to *R* and the average difference from the historic EEX-prices, but the average deviation of model results is significantly decreased to around eleven percent. These best values achieved are based on periodic elasticities that are the inverse of the seasonal average hourly EEX prices in Euro cent per kWh multiplied by a scaling factor of five, and are highlighted bold in Table 3. This assumption yields elasticities around one, i.e. elastic demand in the base load hours and inelastic demand in peak load hours. Fig. 1 below highlights the outcome of the calibration in regard to plant dispatch and prices respectively.

The same calibration procedure has been applied to the representative weeks in winter, summer, and autumn 2008. We found that hourly elasticities with scaling factors of 7 for winter, 8 for spring, and 5 for the summer achieves best values to replicate the history of EEX prices.

4. Results

We develop our results by the use of four scenarios. First, the model is calibrated to the baseline scenario *Real Wind* (RW) which replicates the current wind output and its volatility. Second, scenario *Constant Wind* (CW) assumes that the same total periodic

Table 3
Coefficients of correlation, difference of EEX-spot-price to model price, and mean deviation of model price to EEX prices.

	Oligopolistic competition			Perfect competition		
	R	Difference	Deviation	R	Difference	Deviation
Elasticity						
0.6	0.933	−6.9%	13.7%	0.933	14.2%	18.9%
0.7	0.932	−2.7%	13.1%	0.937	13.2%	17.9%
0.8	0.929	−0.1%	13.2%	0.937	12.5%	17.1%
0.9	0.929	1.4%	13.1%	0.936	11.9%	16.5%
Scaling factor of elasticity						
4	0.934	−7.5%	11.3%	0.935	15.1%	19.3%
5	0.933	0.0%	11.2%	0.939	14.2%	18.4%
6	0.932	3.3%	12.2%	0.940	12.7%	16.9%
7	0.933	4.7%	12.6%	0.938	11.7%	16.0%

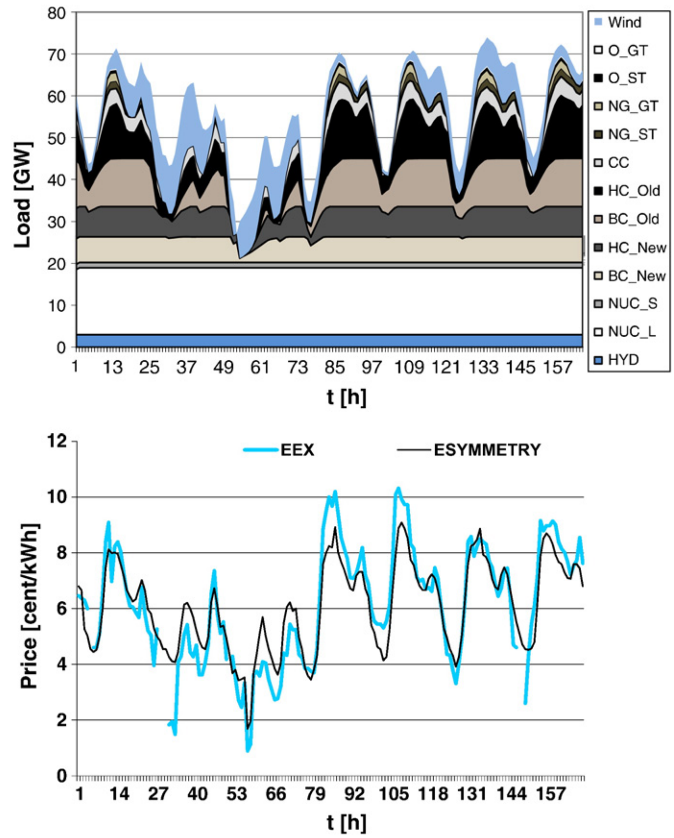

Fig. 1. Plant dispatch (top), and EEX and model prices (below) in the representative spring week.

amount of wind output is smoothed across the respective week and delivered hourly with its average periodic output. It is chosen to demonstrate the effects that are induced by the fluctuation of current wind energy output. Thirdly, we calculate the counterfactual *No Wind* (NW) where no wind energy is supplied and all load is matched by conventional power units. Finally, we calculate the scenario *Advanced Wind* (AW) that assumes the same wind output volatility as *Real Wind*, but wind power output doubles in order to calculate the impact of the projected wind energy supply increase.

Table 4 reports the results with regard to the volume weighted average price level, the emissions and the supply of wind and conventional power, where the results for the representative weeks are transformed by the seasonal volume weights to get annual values. The baseline scenario *Real Wind* yields an average price level of 6.9 cent, emissions of 344 million tons of CO_2[7], and a total supply to German consumers of 510 TWh. Wind power supplies account for 42.5 TWh or more than eight percent of total supply. Furthermore, we show the changes that are induced by the current wind supply of the scenarios *Constant Wind* and *Real Wind* compared to the scenario *No Wind*, and the change expected to be induced by the increased wind supply of scenario *Advanced Wind* compared to scenario *Real Wind*.

If we first consider the changes induced by the scenario *Real Wind* compared to *No Wind* documented in the center column of the bloc on the right of Table 4, we find that the price level is reduced by 0.37 euro cent or more than five percent. In addition, the emissions decreased by 13,6 million tons of CO_2 while the supply increased by 27.3 TWh. The supply effect comprises of the additional wind power supply of 42.5 TWh and the reduction of conventional power plants by 15.2 TWh. In other words, only a little more than one third of

[7] The calculated emissions of the electricity sector appear to be rather high when compared to other sources, e.g. Nitsch (2008), since we include the emissions related to combined heat and power production.

Table 4
Prices emissions and supply in the scenarios together with induced changes.

	Scenario				Change		
	NW	CW	RW	AW	CW vs. NW	RW vs. NW	AW vs. RW
Price level [cent/kWh]	7.27	6.86	6.90	6.57	−0.41	−0.37	−0.33
CO2 [MT]	357.1	344.0	343.6	326.4	−13.1	−13.6	−17.1
Supply [TWh] of which	482.3	509.6	509.5	532.4	27.4	27.3	22.9
- Wind	0.0	42.5	42.5	85.0	42.5	42.5	42.5
- Conventional	482.3	467.1	467.0	447.4	−15.1	−15.2	−19.6

Table 5
Incentives to invest in new brown coal (BC), hard coal (HC), natural gas combined cycle (CC) and natural gas turbine (NGGT) power plants for the different market actors, and relative change induced by scenario *Advanced Wind* compared to *No Wind*.

BC	HC	CC	NG	GT
EnBW				
NW	1.5	1.4	1.0	0.2
RW	1.2	1.1	0.7	0.1
AW	1.1	0.9	0.6	0.0
rel. Change	−30%	−33%	−41%	−85%
E.ON				
NW	0.6	0.4	0.1	0.0
RW	0.3	0.2	0.0	0.0
AW	0.0	0.0	0.0	0.0
Rel. change	−100%	−100%	−100%	not def.
RWE				
NW	0.7	0.5	0.1	0.0
RW	0.4	0.3	0.0	0.0
AW	0.1	0.0	0.0	0.0
Rel. change	−79%	−99%	−100%	not def.
Vattenfall				
NW	1.3	1.2	0.7	0.0
RW	1.0	0.9	0.5	0.0
AW	0.7	0.6	0.2	0.0
Rel. change	−47%	−52%	−68%	−100%
Fringe				
NW	2.7	2.6	2.1	0.8
RW	2.4	2.2	1.7	0.6
AW	2.0	1.9	1.5	0.4
Rel. change	−25%	−26%	−29%	−45%

wind power supply has led to a crowding out of conventional resources.[8] As a consequence the saved emissions are comparatively small: each kilo Watt hour has reduced emissions at average by only 320 g of CO_2 while the average emission of the conventional production is more than 670 g of CO_2. If we take the FIT for wind power of currently 9 cent as implied in BDEW (2008) and the market price for electricity as cost indicators, the according marginal abatement costs of wind power are almost 66 euro per ton of CO_2.

Nonetheless, the emission reductions of *Real Wind* are higher than those that would have been caused by a constant supply of wind power. The first column of the bloc on the right hand side of the table shows the induced change by the *Constant Wind* scenario. In this setting the price reduction and the supply increase would have been more pronounced, and consequently, the emission reduction would have been smaller. The intuition behind this result is that the increased ramping drives prices more than emissions. Combined, both effects increase the marginal abatement costs of wind power to more than 69 euro per ton of CO_2. The comparison of the *Real Wind* scenario with the *Constant Wind* scenario, however, reveals only a comparatively small importance of the effects due to the fluctuation of wind.

The last column of Table 4 shows the changes due to the doubling of wind power, i.e. the *Advanced Wind* scenario, in comparison with the *Real Wind* scenario. It emerges that the price level decreases by another third of a cent, and that the emission are additionally reduced by more than 17 million tons of CO_2. At the same time supply is almost 23 TWh higher while the crowding out of conventional supply is 19.6 TWh. Thus, compared to the changes induced by the current wind power supply, the advanced wind power supply yields an higher crowding out of conventional supply and a significantly enhanced emission reduction per supply, i.e. 400 g of CO_2 per kilo watt hour. Thus, the according marginal abatement costs of wind power at current support tariff is reduced to 60 euro per ton of CO_2. This finding can be explained by a successively higher crowding out of coal fired plants as more wind power is supplied.

In the remainder of the paper we analyze the question whether the market expectations will provide the signals for investments in power plants that are needed to provide sufficient ramping capacities for the fluctuating wind power supplies. Therefore, we compute the incentive to invest as the difference between the average shadow price of the capacity restriction and the investment costs per output of the different technologies. In line with EWI/EEFA (2008), we adopt investment costs of 1.5, 1.3, 0.7, and 0.2 euro cent per kilo watt hour for new brown coal, new hard coal, natural gas fired combined cycle and simple gas turbines respectively. In Table 5 we report the incentives to invest for those technologies that are relevant for the German market[9] and their relative change induced by *Advanced Wind* compared to *No Wind*. In a perfect competitive market the incentives to invest at given prices are equal to the ones reported for fringe firms in the lower rows of Table 5. We find that for all technologies the incentives to invest decrease with the development of wind supply. Notably, the flexible gas turbines lose half of their attractiveness relative to the *No Wind* scenario and are always dominated by hard coal and brown coal as well as combined cycle gas turbine investments. Combined cycle gas turbines experience a reduction of incentive to invest by almost thirty percent, while coal based units experience a reduction of only about one fourth. Thus, for firms which act perfect competitively, investments in more flexible natural gas based units are not only dominated by coal fired base load units, but lose competitiveness with the development of wind power.

Decreasing load factors, i.e. the impacts on actual utilization of power plants are driving these findings. Although the absolute reduction of the load factors of peak load plants and of the mid- and baseload units are comparable, the relative changes of utilization of peaking plants like gas turbines are much more pronounced since they operate less than a third of the time of baseload units, e.g. coal fired power plants, in either scenario. Comparing *Advanced Wind* with *No Wind*, we find reductions of utilization of natural gas fired gas turbines by almost forty percent and of combined cycle units of fourteen percent, while the utilization of new hard and brown coal plants is reduced only by about four and two percent respectively. Hence, wind power will increase the gap between the incentives to invest in flexible units and the need of these units. These findings suggest that the competitive market is not likely to cope with the wind energy increase unless additional measures are introduced.

Including the incentives of oligopolistic firms in the analysis does not improve the picture, since incentives to invest are the weaker the larger the firm. In the advanced wind scenario the incentive to invest in natural gas fired gas turbines completely vanishes for the four dominant players. Combined cycle gas turbines also significantly lose attractiveness—although to a lesser extend compared to simple gas turbines. The two largest companies E.ON and RWE have no incentive to invest in

[8] The support of renewable energy by the German FIT has an additional effect on the demand side due to increased consumer prices. These effects are not considered here. For a detailed analysis of impact on consumer prices see Traber and Kemfert (2009).

[9] Large scale hydro power is not a relevant investment since suitable sites are completely developed. In addition, nuclear is not an option due to the political decision on the phase out of nuclear energy in Germany.

combined cycle gas turbines already in the current *Real Wind* situation, and the advanced wind supply does not improve that incentive. For the two smaller strategic companies, Vattenfall and EnBW, combined cycle gas turbines might still be an option, but compared to the scenario without wind energy supply their incentive to invest in this technology has been reduced by 68 and 41% respectively, bringing it down to almost zero for Vattenfall. Thus, the prospects for new gas fired units look bleak, especially when the commission of coal fired units is viable. These findings are at least partially supported by the current empirical evidence. Out of roughly 11 GW thermal power plant capacity that is planned to go online in Germany until 2012 less than fourteen percent are natural gas fired units.[10]

5. Summary and discussion

We developed the electricity market model ESYMMETRY which applies different behavioral assumptions in regard to supply of firms and includes start up costs of thermal power plants. It turns out that a representation of the large electricity companies as Cournot quantity setters is more appropriate under our cost assumptions, and that hourly elasticities around one yield the closest results compared to the price history at the EEX.

We find that the current wind supply of 42.5 TWh from Winter 2007 until autumn 2008 reduced the emissions of the sector by 13.6 million tons of CO_2. Moreover, the reduction of the spot market price of 0.37 euro cent per kilo Watt crowded out about a third of a conventional production unit per unit of wind power. Consequently, the implied marginal abatement costs are more than 66 euro per ton of CO_2. To assess the impact of the fluctuating character of the wind supply we additionally calculate a scenario in which the wind energy is assumed to be supplied constantly over time. We find that the real fluctuating wind supply is more effective in terms of emission reduction and less effective with regard to price reduction. Due to reduced crowding out of conventional production, the marginal abatement costs of a constant wind supply would increase to 69 euro per ton of CO_2.

In addition, we shed some light on the impact of an increased wind supply. We find that the price dampening effect per unit of wind energy supplied is likely to decrease while the emissions will be reduced more effectively. It turns out that the doubling of the wind supply will reduce emissions by more than 17 million tons of CO_2 and prices by only one third of a cent. Hence, the marginal abatement costs would decrease to about 60 euro per ton of CO_2 at current support tariff. This improvement of the effectiveness of the support policy is caused by a successive displacement of base load coal units with their relatively high carbon intensity. However, given the marginal abatement costs implied by the European emission trading system of currently around 15 euro per ton of CO_2, the promotion of wind power by the FIT is still an expensive option to reduce emissions in the power sector.

Another central insight is gained in regard to the ability of the market to cope with the increased intermittent supply of wind power. We find that the incentives to invest in flexible power plants, e.g. natural gas fired gas turbines and combined cycle units, which are able to cope with strong fluctuations, seem to be not sufficient. Rather, the attractiveness of these units is greatly reduced by the development of wind supply, since their load factors are over proportionally reduced. In particular, large strategic power supply firms do not have any incentive to invest in natural gas units. These findings call for a more market based approach to wind energy pricing.[11] If wind energy suppliers had to provide reliability as the market demands it, they would have an incentive to back up their units by complementary measures in order to avoid high costs of alternative procurement in hours of weak wind output. In addition to own investment in flexible units, these measures could include demand side management, interruptible supply contracts, the acquisition of facilities for power storage or the extension of the grid infrastructure to facilitate increased trade in electricity.

The results in regard to price and emission effects of the wind energy supply which are obtained in our study are well below the effects calculated by other investigations which abstract from elastic electricity demand, e.g. Rathmann (2007), Sensfuß et al. (2008). However, even when compared to the results found in Traber and Kemfert (2009), who use a elasticity of demand of about 0.5, the market price and conventional production reductions obtained in the present paper are modest. One reason for the differences is that total production costs are higher when including start-up effects and thus the elasticities obtained by the calibration are higher, i.e. around one. The burden of the support system induced on final consumers might be another reason for the deviations. Therefore, the inclusion of the renewable support system could be a fruitful extension of the model.

The investigation of the economics of balancing measures is generally expected to gain further importance. Not only fluctuating wind power is contributing to the problem of reliability, but also other fluctuating supplies, e.g. from solar power. In addition, carbon capture and storage (CCS) will probably decrease the flexibility of coal fired units. While in a carbon constrained world RES and CCS have to accompany each other, their combination opens up questions in terms of reliability left for future research.

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[10] See for instance the summary of planned power plant projects in: Kurzanalyse Kraftwerksplanung 2020, German Energy Agency (DENA), retrievable under http://www.dena.de/.

[11] For a discussion of the appropriate design of electricity market pricing see Gribik et al. (2007).

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