Influence of market rules on the economic value of wind power: an Austrian case study

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Abstract: Currently, wind power faces heterogeneous conditions for market integration throughout Europe, given both differing wind power and power system characteristics as well as according regulatory frameworks. This paper discusses marketing options and assesses the influence of market rules on the economic value of wind power for an Austrian case study. Special emphasis is thereby put on options for short-term wind power forecasting and trade. Results indicate that market integration can be improved considerably by implementing continuous day-ahead markets in Central European Countries as a first step. Under such framework conditions also simple forecast approaches provide a significant added value.

Keywords: wind power; electricity market; forecasting; support mechanisms.

References to this paper should be made as follows: Obersteiner, C. and von Bremen, L. (2009) 'Influence of market rules on the economic value of wind power: an Austrian case study', *Int. J. Environment and Pollution,* Vol. 39, Nos. 1/2, pp.112–127.

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Lueder von Bremen has been working at ISET in offshore wind power predictions and pan-European variability of wind power since March 2008. He studied meteorology at the University of Kiel (Germany). He did his PhD

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1 Introduction

The volatile characteristics of wind power influence power system operation in two ways (see Weber, 2006):

- the variability of wind power affects the unit commitment of other (conventional) power plants in terms of lower full load hours and additional start-ups and shut-downs
- the limited predictability affects requirements for power reserves and increases the amount of energy needed for balancing the system.

While costs related to the variability of wind power are determined by wind power and power system characteristics only, imbalance costs related to the limited predictability also depend on the regulatory framework for market integration of wind power.[1] Therefore, market rules determine limits (barriers) for the integration of wind power from an economic viewpoint.

The objective of this paper is to assess the impact of framework conditions for marketing wind power on its economic value based on empirical analyses of an Austrian case study. Therefore, the market value[2] of wind power is evaluated for available marketing options within the Central European electricity market and different scenarios for short-term wind power forecasting. These scenarios reflect both the status quo as well as improved conditions with respect to the forecast horizon and variations of the spatial distribution of wind sites. Assessed imbalance costs are compared with empirical data available for other European countries. Finally, recommendations for an efficient market integration of wind power are derived with respect to the Central European electricity market.

2 Regulatory framework for the market integration of wind power

2.1 Support schemes and concepts for market integration in Europe

In order to meet the targets for electricity from Renewable Energy Sources (RES-E) defined within Directive 2001/77/EC (European Commission, 2001), in recent years a variety of support schemes has been implemented in the Member States of the European Union (EU). Literature on RES-E support schemes typically distinguishes between price and quantity driven support instruments (see, e.g. Haas et al., 2004).

Currently the most prominent price driven instrument is the so called Feed-In Tariff (FIT). Under such a scheme, RES-E is remunerated at defined tariffs (prices) which are typically guaranteed for a defined period of 10–20 years.[3] Such a scheme is – at least

from the perspective of a RES-E generator – totally uncoupled from wholesale power markets as tariffs are not related to the power price. Therefore, as shown by Markard and Petersen (2006), FIT also attracts investors from non-energy sectors and private initiatives. More market oriented is the Feed-In Premium (FIP) system that provides a bonus (premium) additional to the market price for any produced MWh RES-E.

The most prominent representative of quantity based support schemes is a quota obligation combined with Tradable Green Certificates (TGC). In this case, the share (quantity) of RES-E that has to be purchased by obliged market actors during a defined period (usually 1 year) is set by government. In practise, retailers approve that their consumers have fulfilled the quota by presenting a corresponding amount of certificates for purchased RES-E. In order to introduce more flexibility in such a system, these certificates may be traded among power market actors. The RES-E generator gains revenues from selling power and green certificates either bilaterally or on corresponding markets. Both prices for power and green certificates vary according to supply and demand. In theory, the price of so-called Tradable Green Certificates (TGC) should reflect the difference between the long-run marginal cost of the marginal RES-E technology and the corresponding market value.

According to Held et al. (2006), FIT are the most commonly used support scheme for RES-E in EU Member States, as this scheme historically proved to be effective (in terms of increase in RES-E generation) as well as economically efficient (i.e. cost per supported MWh RES-E are comparatively low).

The way wind power (RES-E) is integrated in power markets mostly depends on the applied support instrument as illustrated in Table 1 for selected EU Member States.

In TGC or FIP systems, wind power is traded on wholesale power markets or bilaterally and thereby treated in a similar manner as conventional electricity. In general, this implies that wind power is programme responsible, i.e. trading (generation) schedules have to be notified a day-ahead to the system operator and deviations from these schedules are accounted for as imbalances and settled ex post with imbalance prices. In such schemes, the support instrument has to not only close the gap between long-run marginal cost and revenues from selling wind power, but also allow for a remuneration of imbalance cost. The central actor for market integration of wind power is the Programme Responsible Party (PRP), which might be a utility or a power trading company. Obviously, there is a financial incentive for the wind power operator and the PRP to minimise imbalance cost. The PRP might use several marketing options in order to maximise the value of wind power, while the wind power generator may even support the PRP, e.g. in forecasting the wind power generation day-ahead.

However, in FIT schemes, programme responsibility is usually transferred to a third party. In most FIT systems, the Transmission System Operator (TSO) is obliged to purchase wind power at the guaranteed tariff and to allocate corresponding volumes to PRPs according to their end user demand. This allocation may be realised in the form of a long-term power product (e.g. monthly or quarterly band) or on a daily basis in the form of the forecasted wind power profile as shown by Hiroux and Maupas (2006). In the first case, the TSO trades differences between the allocated power band and day-ahead wind power forecasts on the day-ahead market or even bilaterally, while in the second case, PRPs have to consider the wind power profile in their day-ahead trading activity. Alternatively, the TSO might be obliged to bid short-term wind power forecasts on the day-ahead market. In either case, the TSO is charged for imbalances and socialises corresponding cost in the form of system charges. Obviously, the TSO is the central

player with respect to market integration in such a scheme. The TSO forecasts wind power and also manages financial transactions, but has no direct financial incentive to maximise the economic value of wind power. Therefore, under such configurations the TSO needs to be incentivised (i.e. regulated) accordingly.

Table 1 Main support schemes and corresponding framework conditions for the market integration of RES-E in selected European countries (Status, 2007)

Country	*Main support schemes*	*Support period wind (yrs)*	*Configuration for market integration*
Austria	FIT	10–13	Third party is programme responsible; allocation of wind power to PRPs based on daily profiles, imbalance cost socialised via grid tariff
Denmark	FIP and tender schemes for wind off-shore	10; 20	TSO is responsible for part of wind power generation; TSO bids day-ahead forecast on day-ahead market, After support period wind power is programme responsible, producers receive a grant to (partly) offset imbalance cost
Estonia	FIT, purchase obligation	12	DSO is charged for wind power imbalances, cost socialised via grid tariff
Finland	Tax exemption combined with investment incentives		Wind power is programme responsible
France	FIT	15	Main utility (EdF) responsible for balancing wind power, cost are passed on to consumers
Germany	FIT	20	TSOs are programme responsible, allocation to PRPs in form of quarterly band, imbalance cost socialised via grid tariff
Greece	FIT combined with investment incentives	12–20	Power market is organised as obligatory pool; cost for imbalances socialised
Netherlands	FIP	10	Wind power is programme responsible
Spain	FIT/FIP	Life time	Major part of wind generation marketed by PRPs, no market based balancing mechanism
Sweden	Quota obligation system/TGC		Wind power is programme responsible
UK	Quota obligation system/TGC		Wind power is programme responsible

Source: Energy Economics Group

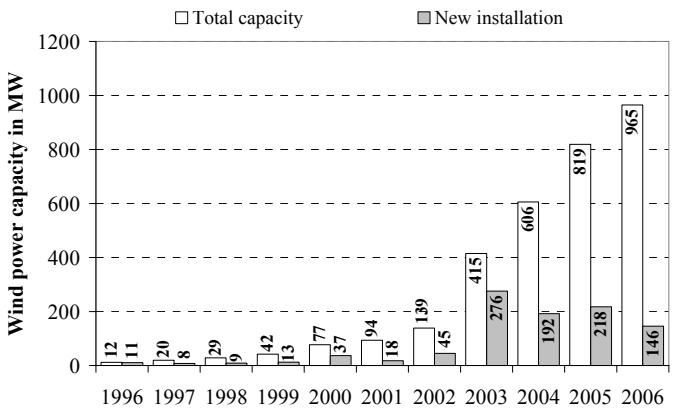
What are the implications of described market integration configurations in a mid-term perspective? In schemes where wind power is programme responsible, involved actors face no major structural changes after the period of support. However, in FIT schemes producers take over the responsibility for marketing wind power, which might constitute a challenge for actors who are not experienced in this business. In both cases, finally, the market value of wind power determines if turbines may be operated economically after the support period.

In practice, we can also see combinations of the two described settings. In Spain, for example, wind power producers can choose between a remuneration based on a FIT and a FIP in addition to the pool price, which is currently set at 50% of the FIT. Historically, we can observe that the share of wind power sold on the pool highly depends on expectations of pool price developments; in 2005 the share increased from 20% up to 93%. Under the FIP scheme, wind power producers have to bear imbalance cost (5.5 €/MW h in 2005) and cost for forecasting and administration (1.3 €/MW h in 2005). The Spanish scheme has triggered not only the appearance of new actors like market agents and forecast providers, but also the introduction of an hour-ahead market that supports the market integration of wind power. Another promising approach applied in Spain is the obligation of wind power producers >10 MW to forecast their output day-ahead also within the FIT scheme. Deviations above 20% are penalised. Such regulatory incentives may smooth the transition from FIT to conventional marketing after the period of support (see AEE, 2007).

2.2 Regulatory framework for marketing of wind power in Austria

Since 2003, the Ökostromgesetz (Renewable Energy Act) forms the legal basis for RES-E support in Austria. It defines a FIT scheme on national level that remunerates wind power at a tariff of 78 €/MWh during a period of 13 years. This framework has led to a considerable increase in wind power from 139 MW at the end of 2002 to 965 MW at the end of 2006 (see Figure 1).

Figure 1 Development of wind power in Austria from 1996 to 2006. Numbers refer to end of the corresponding year



Source: IG Windkraft

An amendment of the Renewable Energy Act which became effective from October 2006 implied minor changes with respect to tariffs and support duration and a cap on additional annual expenditures for support. It also foresees institutional changes like the implementation of a settlement centre – the so called Ökostromabwicklungsstelle (OeMAG) – which handles several financial transactions related to support of RES-E and is therefore also financially responsible for imbalances (see E-Control, 2002 and E-Control, 2006).

Market integration is based on a single PRP – the so-called Eco Balance Group (EBG) – operated by OeMAG, which collects all supported RES-E. OeMAG forecasts RES-E generation and allocates the forecasted profile to retailers (conventional PRPs) based on their end user demand on a daily basis.

After the support period, wind power may still be marketed via the EBG at a quarterly defined price, which is oriented at futures notations at the European Energy Exchange (EEX) minus average expenditures for imbalances due to wind power in the EBG in the previous year. Alternatively, wind power producers may trade wind power themselves and therefore constitute own PRPs or sell wind power to power traders, i.e. existing PRPs.

The historical development of wind power together with the support period determines the volume of wind power that has to be traded outside the support scheme in the short to medium term. As wind turbines installed before 2003 received guaranteed tariffs for 10 years only, selected wind power producers already face this situation.

2.3 Framework conditions for marketing wind power on wholesale electricity markets

In Central European power markets, wind power may be traded bilaterally or on one of the established power markets like the EEX in Germany, the main power exchange in this region, or the Energy Exchange Austria (EXAA). Both provide futures, forward and day-ahead trade for a variety of power products. Since September 2006, EEX also operates an intra-day market. Unlike, e.g., the Scandinavian power exchange (Nord Pool), these power exchanges do not offer trade on weekends and public holidays, which is a crucial constraint from the perspective of wind power as will be shown in this paper.

This constraint implies that for weekends and public holidays, forecast horizons exceed the day-ahead time frame, which lowers forecast accuracy and therefore implies higher imbalances and related costs.

According to the Austrian balancing mechanism, cost for secondary (energy related cost only) and tertiary control are allocated to PRP based on their imbalance. Imbalances are settled on a monthly basis, with the imbalance clearing price on a 15 min timescale for each Control Area (wind generation is located in the Control Area of Verbund Austrian Power Grid (APG)).

3 Methodology and Data

The market value of wind power is determined for different samples of 22 wind sites in Austria. Empirical analyses are carried out for the period of 1 year (from 07/2005 to 06/2006) using historical wind power data with a time resolution of 15 min.

3.1 Analysed marketing options

Strategies for trading wind power on liberalised power markets are primarily driven by the need to mitigate risks imposed by the volatility of short-term power market prices and by cost for imbalances. The risk of volatile day-ahead prices can be hedged perfectly with futures contracts if power generation is perfectly predictable (like e.g. thermal power). Wind power generators, however, face a quantity risk as the production is likely to

deviate from the contracted position on the futures market.[4] The generator may close open positions on the day-ahead market based on short-term forecasts and thereby faces the price risk at least for the volume of deviation. Depending on the balancing mechanism (one price vs. two price system) it may be optimal to close positions according to short-term forecasts or to stay strategically long. In any case, the possibility of short-term trade – be it on a day-ahead or intra-day basis – is important to lower the risk of imbalance cost. To sum up, an adequate marketing strategy for wind power should comprise a combined trade on power markets with different timescales.

In order to provide a broad picture, various trading options are analysed. Trade on intra-day markets is not considered as there is no data available for the analysed period. In all cases, deviations from trading schedules are settled ex post with imbalance prices determined according to the clearing procedure of the Austrian balancing mechanism. Historical EEX spot (day-ahead) and futures prices as well as imbalance prices for the balancing zone of Verbund APG are used to assess the market value of wind power. The analysed marketing options are briefly described in the following:

- *No trade*: the whole wind generation is interpreted as imbalance power and therefore settled with imbalance prices. This is rather a theoretical option as it is not inline with the market rules.
- *Trade on long-term market*: the average wind generation is traded in the form of quarterly base load futures. Prices are averages of corresponding EEX-futures settled in the previous trading quarter. Deviations between actual and average power are settled with imbalance prices. In practice, seasonal wind power variations are predictable to a limited extent only. However, it is assumed that the quarterly average wind power generation is known ex ante, i.e. the long-term quantity risk is neglected.
- *Combined trade on futures and spot market (with perfect vs. real wind power forecasts)*: the average wind generation is sold in the form of quarterly base load futures (compare with previous option); deviations between short-term forecasts and mean power are traded on the spot market; deviations between actual and forecasted wind power are settled with imbalance prices. By trading short-term forecasts on the spot market, imbalances and corresponding cost are reduced as short-term forecasts show higher accuracies than quarterly wind generation estimates.
- *Trade on spot market (with perfect vs. real wind power forecasts)*: wind power forecasts are traded on the spot market; deviations between actual and forecasted wind power are settled with imbalance prices. The sole trade on the spot market imposes high price risks due to the volatility of spot market prices and will therefore not be applied in practice.
- *Eco balance group*: wind power is sold via the EBG at defined conditions. The price is determined by a ‘quarterly market price’ defined according to the Renewable Energy Act minus imbalance cost for wind power in the EBG in the previous year. This option is considered as the reference case, as it reflects conditions for marketing during the support period.

3.2 Modelling wind power forecasts

Reference wind power forecasts are calculated using a forecast tool developed by Siemens PSE. Forecasts base on historical (day-ahead) wind speed forecasts from the Austrian Central Institute for Meteorology and Geodynamics (ZAMG).[5] The meteorological model applied at ZAMG provides numerical weather data on an hourly basis with a horizontal resolution of 10 × 10 km. Forecasts are performed on the level of wind parks, i.e. for each wind park weather forecasts of the nearest node (grid point) are used. Due to the lack of wind speed forecasts for time horizons >48 h, forecasts exceeding the 1-day time horizon are reproduced by the corresponding forecast of the previous day. Wind speeds are transformed into wind power data using a piecewise linear transformation matrix which is calculated offline based on a pivot analyses of historical wind power measurements and wind speed forecasts.

A forecast tool developed at the Center for Wind Energy Research (ForWind) located at the University of Oldenburg is applied as well in order to provide a benchmark for today's state of the art wind power forecasting. This tool uses a newly developed approach that is based on the principal component regression. The component analysis is applied to squared wind speed maps, multiplied with the normalised spatial distribution of wind power capacities of the analysed wind farm arrangement (ξ). Wind speed maps are based on 00 UTC wind forecasts of the European Centre for Medium-Range Weather Forecasts (ECMWF), which are available with a geographical resolution of 110 × 66 km and a time resolution of 3 h. The forecasting model consists of the following steps, starting from the wind power weighted squared wind speed ξ:

- principle component analysis of forecasted ξ using all forecasts (all lead times) of the last 90 days
- computation of principle components c_j corresponding to ξ
- multivariate linear regression analysis between the first six c_j and the (historic) wind power feed-in of all considered wind parks (85 MW capacity) and storing of regression coefficients
- calculation of ξ^p from ECMWF forecast
- computation of principle components c^p_j that correspond to predicted ξ^p
- application of stored regression coefficients with c^p_j to estimate the total wind power feed-in (indexed as Cluster 85).

The regression coefficients are recalculated every 15 days, i.e. the principle component analysis is performed only every 15 days. The consideration of the last 90 days into the principle component analysis guarantees that seasonal changes in the wind field distribution are taken into account. For a detailed description of the applied method see von Bremen et al. (2007).

3.3 Pooling of wind sites

Using the Siemens PSE model, investigations are carried out for different arrangements of wind sites (pooling) in order to assess the dependency of forecast accuracy and corresponding imbalance cost on the cumulated installed capacity. Capacities of pooled wind sites range from 7.5 to 85 MW. Key data of the analysed arrangements are summarised in Table 2.

Table 2 Key data of analysed wind site arrangements in Austria

Key parameters	*Cluster 7.5*	*Cluster 12.5*	*Cluster 30*	*Cluster 85*
Number of aggregated wind sites (n)	7	13	16	22
Installed capacity (MW)	7.5	12.4	29.0	85.9
Installed capacity per site (MW)	1.1	1.0	1.8	3.9
Generation in analysed period (MWh)	10,375	17,421	44,767	152,230
Full load hours (h/yr)	1,388	1,408	1,544	1,771

4 Results

4.1 Wind power forecast accuracy

In the literature, different measures are used to describe the accuracy of wind power forecasts. In this paper, the Mean Absolute Error normalised (NMAE) by mean wind power is used because it directly indicates the share of imbalances on total wind generation.

$$\text{NMAE} = \frac{\frac{1}{N}\sum_{t=1}^{N} | P_{\text{forecast}}(t) - P_{\text{measure}}(t) |}{\frac{1}{N}\sum_{t=1}^{N} P_{\text{measure}}(t)} \tag{1}$$

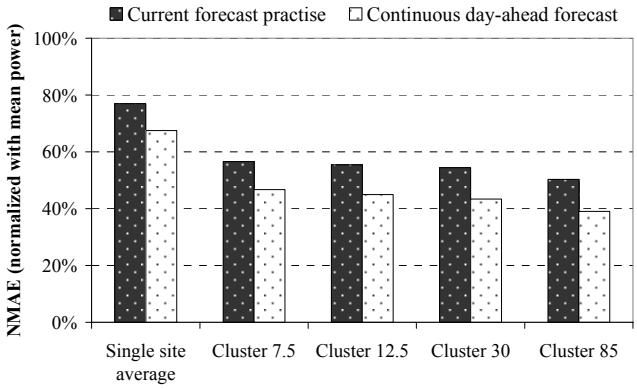
NMAE indicates the mean absolute error normalised by mean wind power. Forecasted $P_{\text{forecast}}(t)$ and measured wind generation $P_{\text{measure}}(t)$ define the forecast error in each time step t. The number of time intervals N is determined by the time step t (15 min) and the analysed period, which is 1 year.

Results show that the forecast error decreases significantly for a sample of few spatially dispersed sites compared to a single site forecast. The NMAE for a single site forecast ranges from 68% to 90% (average 77%) and decreases for the arrangement of seven sites (cluster 7.5) to 57%. The improvement of the forecast accuracy through further pooling is moderate because analysed arrangements of wind sites show a comparable spatial distribution.

It is a well-known fact that pooling (aggregating) of spatially distributed wind farms reduces the short-term wind power forecast error through spatial smoothing of uncorrelated errors in the Numerical Weather Prediction (see, e.g. Focken et al. (2002)). In this paper, the effect of wind farm pooling is analysed not only in terms of wind power forecast error but also in terms of related imbalance cost.

A considerable decrease of the forecast error in the range of 20% can be realised by applying continuous day-ahead forecasts instead of the current forecast practice (Figure 2). However, this implies the existence of a continuous day-ahead market and a coordinated adoption of market rules with respect to the timing for delivery of power schedules.

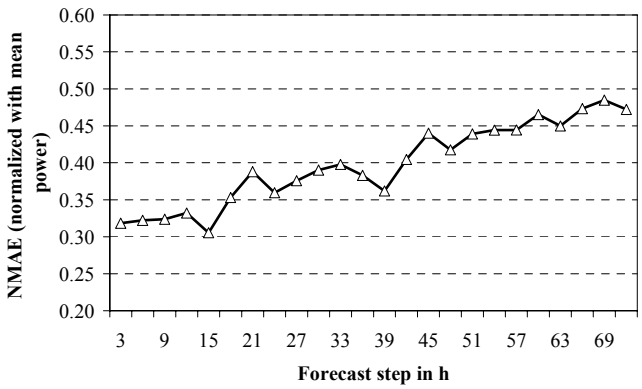
Figure 2 Mean absolute percentage error of wind power forecasts for different arrangements of 22 Austrian wind sites



Sources: IG Windkraft, ZAMG, Siemens PSE forecasts, own calculations

With 39%, the NMAE of the ForWind model is the same as for the day-ahead forecast of all 22 wind farms using the above-mentioned pooling approach. However, it should be mentioned that wind speed forecasts used for the ForWind model (ECMWF) are less accurate than those used for the Siemens PSE model (ZAMG). The evaluation of the NMAE shows a continuous decrease in forecast skill with increasing forecast time (see Figure 3), which demonstrates the potential to reduce imbalances through shorter gate closures.

Figure 3 NMAE (normalised with mean power) against forecast time for cluster 85 MW calculated with ForWind's forecast model with wind forecasts from ECMWF based on the 00 UTC forecast run for the analysed period



With 50%, the NMAE for cluster 85 (Figure 2) is in the range of the day-ahead forecast error of the *EBG*, which represents the total Austrian wind power generation. According to Schönbauer (2006), the NMAE for this portfolio has decreased from 52.5% in 2003 to 45.8% in 2005. Installed wind power capacities in the corresponding years are 168 and 698 MW, respectively.

When applying the ForWind forecast model on total German wind power generation for the year 2006, a NMAE (day-ahead) of 18.9% can be reached based on 00 UTC ECMWF weather forecasts.[1] This number reflects the current forecast quality of commercial forecast providers in Germany. The main reason for the difference in forecast accuracy is the wider geographical spread of wind farms in Germany. Other influencing parameters are the accuracy and geographical as well as time resolution of numerical weather predictions and the local orography, which is more complex in Austria.

4.2 Imbalance cost

Imbalance costs are calculated by assessing deviations between forecasted and actual wind power – i.e. the imbalance – with imbalance clearing prices published for the Austrian control area of Verbund APG for every quarter of an hour on a monthly basis.

As a reference, these costs are assessed for the case of a sole long-term trade i.e. without any short-term forecasting (compare with trading option 2 in Chapter 3). Results of the reference case are compared with both short-term forecast scenarios (see Table 3).

Table 3 Imbalance cost for analysed arrangements of wind sites under different forecast scenarios (07/2005–06/2006)

Imbalance cost (€/MWh (wind))	*Reference case*	*Current short-term forecast practice*	*Continuous day-ahead forecast*
Cluster 7.5	10.3	8.9	4.9
Cluster 12.5	10.4	8.4	4.3
Cluster 30	13.2	9.3	5.1
Cluster 85	12.5	8.1	4.6

Source: APCS, Siemens PSE forecasts

The results show that imbalance cost range from 10 to 13 €/MWh (wind generation) for the reference case. This is about 20–25% of the average EEX base price in the analysed period. Imbalance cost can be reduced by introducing short-term forecasts by 1.4–4.4 €/MWh (15–35%) and by more than half (5.4–8 €/MWh) by applying continuous day-ahead forecasts. Cluster 12.5 bears comparatively high cost, which might be explained by an unfavourable correlation between imbalances and imbalance prices. In the following, results of the Austrian case study are compared with corresponding numbers for two Danish wind power portfolios and results of literature.

Imbalance costs are lower in Denmark even if system characteristics are comparable, as both systems have access to hydro power and wind sites are geographically concentrated. For a portfolio of around 500 MW managed by Vindenergi Danmark, costs range from 0.8 to 2.9 €/MWh (wind generation) in the period from 2003 to 2006. Comparable numbers for Denmark are calculated by Holttinen (2005) and Morthorst (2003) for the years 2001 and 2002, respectively.

Holttinen et al. (2006) assess balancing cost for different forecast scenarios and wind farm arrangements in Finland. Numbers are based on imbalance prices for 2004 and range from 0.6 to 1.5 €/MWh (wind generation). Kleinschmidt et al. (2006) calculate imbalance cost for a 100 MW onshore wind farm in The Netherlands for the years 2004 and 2005 between 5.6 and 8.8 €/MWh (wind generation).

Why do imbalance costs vary considerably among different countries? In principle, imbalance costs are determined by the amount of imbalance (i.e. the forecast error) and

the imbalance price seen by a specific portfolio. Core parameters determining the forecast accuracy are the forecast horizon and the spatial distribution of wind sites as shown in this paper. Imbalance prices are related to the level of wholesale electricity prices and depend on the power system characteristic, the design of the balancing mechanism and, for a specific portfolio, the correlation between portfolio imbalances and the corresponding system imbalances. These parameters obviously differ for the mentioned systems, which might explain the huge bandwidth of imbalance cost.

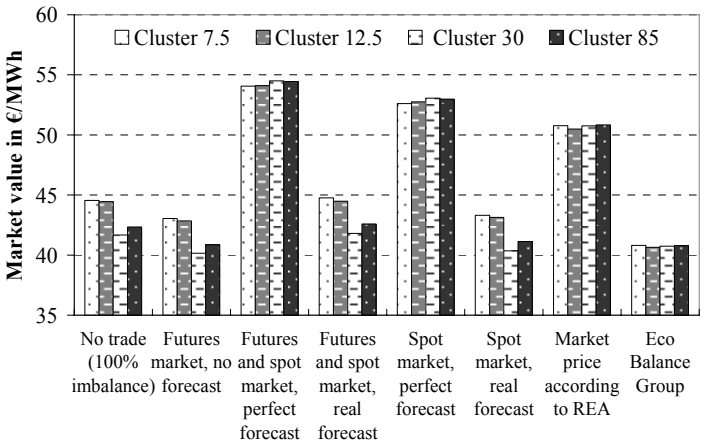
4.3 The market value of wind power

It is important to note that the applied approach does not allow for the identification of a 'most promising trading option' under the existing regulatory framework as such. Such an analysis would go beyond the scope of this paper. However, the results illustrate the bandwidth of the market value of wind power under different framework conditions related to a certain period of consideration.

For marketing options that do not reflect imbalance cost, analysed arrangements of wind farms show comparable market values. This concerns the two cases with perfect short-term forecasting and marketing via the EBG. Deviations between clusters for all other marketing options reflect differences in imbalance cost as already indicated in the last paragraph.

The highest revenue results from a combined trade on the futures and spot market; the market value is lowest when wind power is traded via the EBG (see Figure 4). The settlement of the measured power with EEX spot market prices, which represents trade on the spot market with perfect forecasts, results in a market value of 52 €/MWh. This equals the average base price in the considered period.

Figure 4 Market value of wind power for different arrangements of wind farms and marketing options

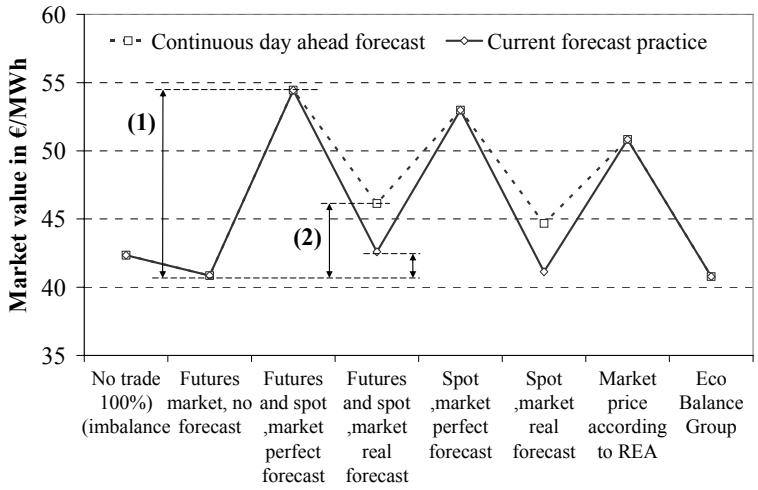


Sources: EEX, APCS, Siemens PSE forecasts

The comparison of different marketing options again illustrates the influence of the forecast accuracy on the market value of wind. The additional value of a hypothetical perfect forecast (1) ranges from 11 to 14 €/MWh for the considered arrangements.

The use of real forecasts (2) increases the market value depending on the underlying regulatory framework between 1.6 and 5.7 €/MWh as shown exemplarily for Cluster 85 in Figure 5.

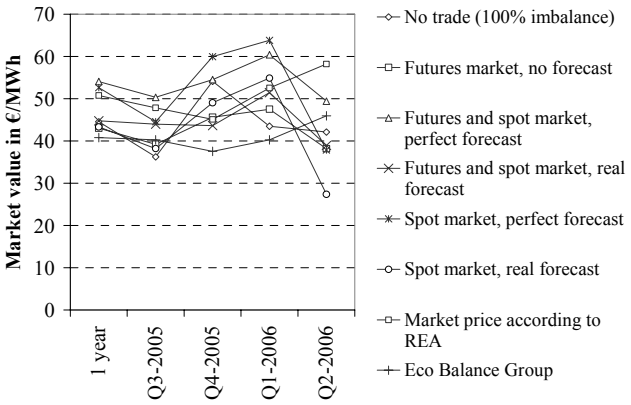
Figure 5 Market value of wind power for different marketing options. Assumptions: 22 wind sites (85 MW), 07/2005–06/2006



Sources: EEX, APCS, Siemens PSE forecasts

Quarterly analyses illustrate the sensitivity of the market value of wind power and the varying ranking of different marketing options. The results therefore have to be interpreted against the background of the analysed period. Deviations between futures and spot market prices indicate the influence of the trading strategy on the market value (see Figure 6).

Figure 6 Quarterly market value of wind power for different marketing options. Assumptions: 22 wind sites (85 MW), current forecast practice, 07/2005–06/2006



Sources: EEX, APCS, Siemens PSE forecasts

5 Conclusions

This paper analyses the impact of framework conditions for marketing on the economic value of wind power within an Austrian case study.

Results show that the availability of short-term power markets and corresponding market rules with respect to the timing of schedule delivery are crucial requirements for an efficient market integration of wind power. The comparison of the current forecast practice with continuous day-ahead forecasts illustrates how forecast errors are translated into imbalance cost and further into the market value of wind power.

The introduction of a continuous day-ahead trade on Central European power exchanges would not only lower imbalances of wind power but also lower overall cost for balancing the system and therefore affect imbalance clearing prices. This implies that the potential for reducing imbalance cost is even higher than assessed in this paper when interpreting the impact of improved framework conditions for the entire Austrian wind power portfolio. Yet it is difficult to quantify this additional effect as it depends on the liquidity of the day-ahead market on weekends and public holidays.

The assessment of the market value for different trading options underlines the potential added value of short-term wind power forecasting. However, this potential can be utilised to a limited extent only under current framework conditions. Instead, continuous day-ahead forecasts increase the market value of wind power considerably even if simple forecast algorithms are applied.

The comparison of imbalance cost in different European countries illustrates that wind power is faced with heterogeneous framework conditions with respect to market integration. The most relevant regulatory aspects in this respect are the gate closure of short-term power markets and the design of the balancing markets and imbalance clearing mechanisms.

Due to the effect of pooling, wind power forecast accuracy is mainly determined by the spatial distribution of wind sites and to a lesser extent by the total capacity of a (forecasted) wind portfolio. Therefore, an optimised marketing of wind power can also be realised within small-scale structures. Moderate levels of aggregation of wind farms principally open the door for new market players in this business.

Acknowledgements

The authors gratefully acknowledge Erich Fuchs from Siemens PSE for providing wind power forecasts and useful advice. IG Windkraft, oekostrom AG and ZAMG are thanked for providing wind generation and weather forecast data for the analysed wind sites. The authors thank Lukas Weißensteiner, Christian Redl, Sam C. Syvertsen and four anonymous referees for helpful comments. These analyses have been carried out within the research programme ‘Energy systems of tomorrow’ – an initiative of the Austrian Federal Ministry for Traffic, Innovation and Technology (BMVIT). The programme ‘Energy systems of tomorrow’ is financed by technology funds of the Austrian Federal Government upon the recommendation of the council for research and technology.

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Notes

1 As possibilities to store electricity are limited, the operator of a power system – the so-called System Operator (SO) – has to ensure that supply equals demand in every instant. In order to balance net deviations from contracted positions of market actors, the SO activates the so-called power reserves in real time. A balancing mechanism allocates cost for balancing the system (i.e. cost for keeping and operating power reserves) to market actors (some parts may also be socialised). Therefore, they have to submit schedules which reflect trading positions based on forecasted supply and demand to the SO with a defined lead time before physical delivery – the so-called gate closure. After physical delivery deviations between realised and submitted schedules – so-called imbalances – are settled with imbalance prices. In this context, imbalance cost indicates cost associated with the settlement of imbalances from a market actor's point of view.

2 The term *market value* in the context of this paper indicates the sum of net revenues from trading wind power on power markets and possible imbalance cost.

3 Further price driven instruments used to promote RES-E are investment subsidies and tax incentives.

4 Given the considerable seasonal volatility of wind power generation, trading of monthly base futures seems to be adequate.

5 Weather model runs are performed two times a day: at 12 a.m. (00 UTC) and 12 p.m. (12 UTC). As the spot market at EEX closes at 12 p.m. only weather data of the 00 UTC model can be used for day-ahead forecasts. The lead time of day-ahead (weather) forecasts consequently ranges from 24 to 48 h.

6 This number bases on forecasts performed in von Bremen et al. (2007).