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Optimal electricity market for wind power

H. Holttinen*

VTT Processes, Energy Production, P.O. Box 1601, FIN-02044 VTT Espoo, Finland

Abstract

This paper is about electricity market operation when looking from the wind power producers' point of view. The focus in on market time horizons: how many hours there is between the closing and delivering the bids. The case is for the Nordic countries, the Nordpool electricity market and the Danish wind power production. Real data from year 2001 was used to study the benefits of a more flexible market to wind power producer. As a result of reduced regulating market costs from better hourly predictions to the market, wind power producer would gain up to 8% more if the time between market bids and delivery was shortened from the day ahead Elspot market (hourly bids by noon for 12–36 h ahead). An after sales market where surplus or deficit production could be traded 2 h before delivery could benefit the producer almost as much, gaining 7%.

Keywords: Wind power; Electricity market; Forecasting; Regulation market

1. Introduction

Nordpool is the largest electricity market in Europe with longest history, since the beginning of the 1990s. It is operating in the Nordic countries: Norway, Sweden, Finland and Denmark. In the spot market, hourly production can be traded. The market is cleared at noon, for the bids for the 24 h the following day, 12–36 h ahead. For Sweden and Finland, there exists also an after-sales market Elbas, which closes 1 h before delivery, with continuous trade.

Wind power is traded at the Nordpool electricity market already today, by the Danish companies. In the future, large-scale wind power production will be reality in many countries. The use of wind power as a renewable energy source is one of the means of achieving the greenhouse gas emission targets set in Kyoto agreement. Ways to push more wind into the electricity system, and the markets, would promote the use of renewables.

To realise the optimal market for wind power, this paper presents a case study based on 1 year wind and price data from Denmark. First the regulation needs of wind power is discussed. The current wind power forecast method is described and the forecast errors analysed. To quantify the benefits of operating in a shorter forecast horizon, the market calculation is made for different prediction horizons. To quantify the benefits of operating in a larger area for wind power production, the calculations are made by using simultaneous wind power data from the western and eastern parts of Denmark.

2. Regulation needs of wind power and market operation

The electricity production system provides a total amount of electricity, at each instant, corresponding to a varying load from the electricity consumption. The failure to keep the electricity system up has high and costly consequences, thus the reliability of the system has to be kept at a very high level. For the fast load variations, and unforeseen problems with production capacity, there are reserves at the system operator's disposal. The cost of reserves depends on what kind of production is used for regulation: hydropower being the cheapest option and gas turbines the most expensive one. Regulation power is nearly always at a higher cost than the bulk power available at the market. This is because it is used at short intervals only, and has to be kept ready so that continuous production by that

*Tel.: +358-40-518-7955; fax: +358-9-460-493.
E-mail address: hannele.holttinen@vtt.fi (H. Holttinen).

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capacity cannot be sold to the electricity spot market. Paying extra for regulation is also one incentive for the market actors to maintain their power balance.

Wind energy is renewable, mostly distributed generation characterised by large variations in the production. The intermittency of the wind power production, as well as the difficulties in predicting the production a day ahead, can cause difficulties for wind power producers acting in the market. If a substantial share of electricity comes from an intermittent power production with large variations, this will also increase the amount of regulation power needed in the system. This is because the system operator has to prepare for unforeseen large variations in the production, in addition to load swings and outages of production capacity. Information from a well working forecasting method for wind power would ease this problem, and is needed as soon as wind power variations are becoming as large as the variations of load. The costs of increased regulation will be passed on to the consumers by prices of system services, and the production capacity providing for this extra regulation will gain.

Traditionally, looking at system operation, wind power forecasts have a value to the system. Day-ahead forecasts help the scheduling of conventional units: planning the start-ups and shut-downs of slow starting units in an optimised way, keeping the units running at best possible efficiency, saves fuel and thus operational costs of the power plants. Forecasts 1–2 h ahead help keeping up the optimal amount of regulating capacity at the system operators' use. Keeping too little reserves risks the adequacy of power, which is crucial in power systems. Keeping too much reserve makes running the system expensive. Simulations of system operation with different levels of wind power prediction errors show that minimising prediction error increases the benefits by the wind plant measured as fuel savings from the conventional units. However, both the system in question (production mix and load variations) and the properties of wind power production (correlation with load) have a strong effect on the results of how much benefit the improved predictions bring about (Milligan et al., 1995). Simulations of the England–Wales system show that the prediction errors begin to affect the system fossil fuel costs when the wind power penetration is about 8% (of yearly energy, 13% of the capacity installed). At large wind power penetrations (20–30% of energy), wind production forecasts can increase the savings in total fuel costs by 13–35% (Watson et al., 1999). For the hydro-dominated Swedish system, the decrease of efficiency in the hydro system due to the uncertainty (forecast errors) of wind power production has been simulated. Wind power would need to be produced 1% more to compensate for the losses of hydro power production, when wind power production is 4% of yearly electricity consumption in Sweden (Söder, 1994).

Today, as we are acting at liberalised electricity markets, the unit commitment and scheduling is done to a large extent by the market: supply and demand bid to the market, which is settled at the most cost-effective way for each hour, day ahead. Also regulating power can be sold and bought at a market, closing an hour before, or even during the operating hour. The system operators still have duties, because keeping up the system needs the balance to hold at every instant, so the ancillary services provided by the system operators include the allocation and operation reserves. In this situation, there is still value in wind power forecasts. All the producers with wind power in their generation mix, bidding to the market, need a forecast to base their bids on. With a forecast, they can count their wind power capacity when making a bid, selling all possible production. Forecast errors result in supplying a different amount of energy than the bid, and this will be penalised—buying power from the regulating market results in extra costs and thus reduced net income for the operator. The market design in this respect, that is how much the deviations of original bids to the market are penalised, can have a considerable effect on the wind power producer. The Dutch system of rewarding over-production with only 16 Euro/MWh and penalising power not delivered with 120 Euro/MWh will result in dropping the net income of a wind power producer to less than half, if 25% of the production is badly predicted (Hutting and Clejne, 1999). In a Danish study (Nielsen et al., 1999) the deviations of wind power production due to mispredictions will impose a 1.3–2.7 Euro/MWh extra cost from settling the deviations at balancing market. Market design can also change the bidding strategy from simply minimising the error in energy (Bathurst et al., 2002; Nielsen and Ravn, 2003).

For the system operator, the situation has not changed when it comes to the duty of keeping the system running despite all load and production swings, and optimising the use of reserves. When there is a considerable amount of wind power in the area, accurate knowledge of wind power production still helps to reduce the reserves needed for unforeseeable swings in production. With electricity markets, also the regulation power can be traded at the market, so also the regulation power available at neighbouring countries can be used.

There will always be prediction errors for the load as well. The load forecasts are typically more accurate, with long experience and more predictable diurnal and seasonal patterns. This is why the operation in electricity markets will be more difficult for wind power producers than for other actors. The form of an electricity market that would enable wind power producers acting in the market in an optimal, cost effective way, is one of the questions in this paper.

3. Description of the electricity system in Denmark

West and East part of Denmark are separate two areas, not connected by transmission lines, and part of separate electricity systems, Central Europe's UCTE (West part) and Scandinavian Nordel (East part). They both have transmission lines to Germany and Sweden, and in addition West Denmark to Norway (Fig. 1). In this paper, the main focus is on the Western part, where the largest part of the wind power production resides in Denmark. In Denmark, the independent system operators Eltra (western Denmark) and Elkraft System (eastern Denmark) are responsible for the prioritised production, which is most of the wind power plants in the area and small combined heat and power plants (CHP).

Eltra is the balance responsible market player for 80% of the installed wind power in Denmark. The prioritised production accounted for about half of 2001 total demand (20.9 TWh) for the area: wind power 3.4 TWh (16%) and local CHP 6.8 TWh. The total installed wind capacity is already larger than the off-peak load level, also in wintertime (Table 1) (Hilger, 2002). At times, wind power production is close to the total consumption in the area. In 2002, wind power production has reached instantaneous penetration of 100% during 1 h, which is unique in the world. Eltra bids a part of wind energy production in the daily spot market, thus avoiding the rescheduling of other production units in the area.

In the Eastern part of Denmark, Elkraft System is balance responsible for approximately 20% of the installed wind power in Denmark. The prioritised production accounted for about 25% of 2001 total demand for the area, wind energy about 6%. The total installed wind capacity relative to demand is approximately half of off-peak load levels.

Table 1
Capacity at Eltra area (western Denmark) in 2001

	Capacity (MW)
Central CHP	3200
Local CHP	1520
Wind power	1930
Interconnection to Norway	1000
Interconnection to Sweden	630
Interconnection to Germany	1200
Peak demand	3700

Fig. 1. The area and transmission lines of Denmark: the western part is the Jutland peninsula and island Fyn, the largest islands on the eastern part are Zealand and Lolland. (*Source*: Hilger, 2002).

4. Forecasting wind power production

4.1. Wind power prediction tool WPPT

Wind Power Prediction Tool (WPPT) has been developed in collaboration with Eltra/Elsam and Informatics and Mathematical Modelling (IMM) at the Technical University of Denmark (DTU). The development work for the first version was initiated in 1992. In 2001, the example year used in this paper, the version WPPT 2 was used. The next version was to be implemented in 2003.

The model is based on statistical time series modelling taking as input the weather forecast for wind as well as the on-line measurements of wind power production for selected reference wind farms. The model produces power production estimates for the reference wind farms, each representing a sub-area, and up-scales the production estimates for the sub-areas. Finally, the total prediction for the area is the sum of the predictions for sub-areas (Nielsen and Madsen, 2000). The predictions are made for 39 h ahead and updated half hourly.

The on-line measurements have negligible weight on prediction horizons of more than 12–18 h. The wind speed forecasts from the national weather service are obtained 4 times a day. The resolution for the HIRLAM model is 17 km, and the forecast wind speed will be interpolated between the grid points for each of the 14 reference wind farms. The WPPT model is correcting the meteorological wind speed estimates for their tendency of producing larger wind speed values for longer time horizons as well as their lack of taking into account site specific diurnal variation.

4.2. Forecast errors

Taking the year 2001 as an example, the predictions were compared to the actual production in Eltra area (western Denmark). The data comprised wind power predictions as made by WPPT model during operation in 2001, and actual, measured wind power production of Eltra area. One August week of missing predictions was excluded from the data. To see how much the prediction error increases with increasing forecast horizon, the predicted wind power production at different prediction horizons were compared to the actual production.

The correlation of predicted wind power production and actual wind power production keeps at a quite high level during the whole of the prediction horizon, above 0.90 for the first 12 h and above 0.80 for up to 30 h ahead (Nielsen and Madsen, 2000). Correlation tells us of the ability of the predictions to follow the ups and downs of the wind production.

When forecasting 6 h ahead, the error for the installed capacity of about 1900 MW wind power was between ± 100 MW for 61% of time. Large errors (more than 500 MW) occurred during nearly 1% of time. When forecasting 36 h ahead, the errors were relatively small (inside ± 100 MW) 37% of time and large errors (outside ± 500 MW) occurred during 7% of time. The mean error of the predictions is near zero, but there is a slight bias to the positive error side (predicted wind power more than realised).

In Fig. 2 the total error during the whole year has been calculated for different prediction horizons. It is presented as % of total realised production. For comparison, persistence assumes that the production will be the same at $t+k$ hours as at t hours. For short time horizons, up till 3 h, the persistence gives good

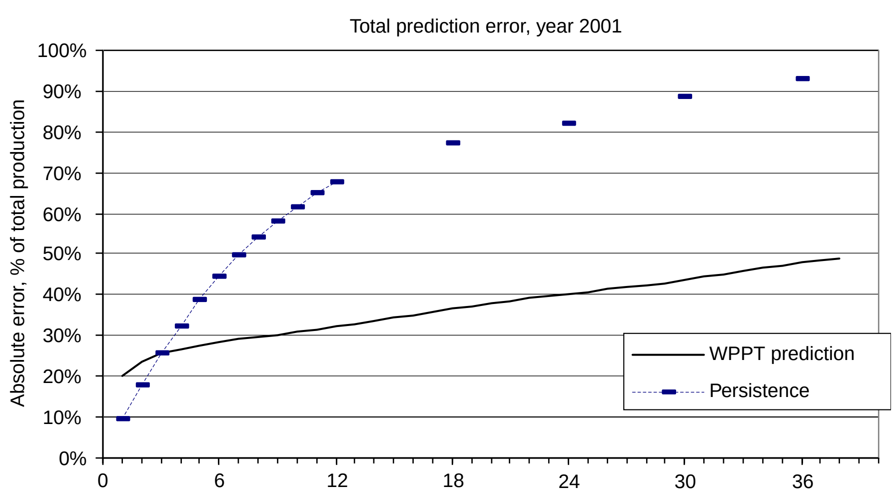

Fig. 2. The total absolute prediction error (sum) during 1 year for different prediction horizons, as percentage of the total realised production in 2001.

results, even better than the WPPT. This is partly because there is no access on-line to the whole production of the area and in the WPPT model of year 2001 the up-scaling the production was not up-to-date.

The proportion of energy that will be known x hours before can be seen from Fig. 2, showing the total absolute error from predictions x hours ahead, divided by total production. Assuming the same level of production ahead as presently (persistence), 90% of energy will be known 1 h before. From the WPPT model, 70% of the energy will be known 9 h before, 60% of energy will be known 24 h before and only 50% of energy will be known 36 h before. The forecast errors here are larger than usually presented, which is due to calculating in total energy instead of % of installed capacity. For Nordpool electricity market (prediction horizon 13–37 h ahead), the mean absolute error (MAE) is 8–9% of installed capacity. However, for market operation this results in 38% of yearly production mispredicted.

The forecast horizon is here taken from the constantly updated values of WPPT, however, the longer predictions are based on weather forecasts, which are only updated 4 times daily. It takes about 3 h for the new forecast to come out in the WPPT output. The actual forecast horizon is thus 3–9 h longer than stated here.

Fig. 2 reveals the difficulty of acting at the market: even though the overall shape of the production curve can be predicted, the exact hourly value of wind power production is difficult to forecast 7–38 h ahead. This results in 30–50% of the total energy being forecasted wrongly. It has to be noted, however, that this is not the latest state-of-the-art of the forecasting models, improvements are expected in the future.

4.3. Improvements to the wind power forecasts in the future

Wind power forecasting day ahead is still new and the models are constantly subject to improvements (e.g. Landberg, 1994; Giebel et al., 2003). The variations of wind power production in northern European latitudes occur due to weather systems passing the area, causing high winds, which calm down again. Forecasting wind power production relies on forecasted wind speeds in the area. The largest error component in the wind power production forecasts is the input from the weather forecast models. Meteorological institute weather service forecasts for wind speed and direction are not very accurate—partly because so far exact values at space and time have not been crucial for other applications. An accuracy of ± 2 m/s and ± 3 h has been enough. For wind energy, however, this results in large errors in a day-ahead hourly market.

There are currently several projects running aiming at improvements both for the weather forecasts and the statistical model part. Running the weather forecast models with several input values (ensemble forecasting) should give information on the uncertainty of the wind speed forecast, and also help choose the right wind speed forecast as a basis for wind power predictions. The next version of WPPT will improve the on-line data and up-scaling (Nielsen et al., 2002). The reference wind parks selected in 1996 are no longer representative for the sub-areas. Wind power capacity of 600 MW in western Denmark at the end of 1996 is now more than 2000 MW at the end of 2002, and the average size of the turbines has increased dramatically. Taking into account wind direction dependency has been observed to improve the forecasts for most of the sites (Nielsen, 1999).

Getting better knowledge of on-line wind power production in the area will improve both the short-term forecasts and the up-scaling and estimation procedures of the statistical prediction model. Getting better accuracy for weather forecasts for wind, as well as other improvements described above, will improve the medium and long-term (12–36 h) forecasts. It is difficult to state the future accuracy, but the improvements could be of the order of 20–50% of the accuracy today.

Load forecasts have been studied for decades. However, it will not be possible to get to the same level of accuracy with wind power predictions as the load predictions are. Electricity consumption behaves with predictable diurnal and seasonal patterns, when looking at larger areas, with errors in the order of about 1.5–3% of peak load, corresponding to an error of about 3–5% of total energy, when forecasting day ahead.

4.4. Reduction of prediction error in a larger area

There is also value in making the forecasts for a larger area—when the weather fronts pass over the area, forecasting the time some hours wrong for one site does not always mean it is wrong for the whole area. Wind power prediction errors cancel out to some extent when the area is larger (Focken et al., 2001). Making a production forecast to only one wind park results in more errors than making the forecast to tens or hundreds of wind parks covering a larger area. The same applies for load forecasting: predicting one load produces large errors compared to predicting the load in a larger area with hundreds of individual loads.

For system operation, the knowledge of wind power forecasts can be derived either by making a prediction for wind power production in the whole system area, or by aggregating the information of all the wind power bids in the market, so basically there is no difference in the information. However, for a producer owning only one wind park, there will be a considerable difference in income relying on forecasts for only that site compared with a joint operation in the markets with several wind parks distributed over a larger area.

For the effect of prediction errors smoothing out in a larger area, the data was analysed to see the errors separately compared with the possibility of operating wind power in co-operation between West and East part of Denmark.

In western Denmark, the wind parks have as a largest distance North–South less than 300 km and East–West less than 200 km (Fig. 1). In the eastern part of Denmark, the wind parks are spread over area of 200 km (N–S) by 100 km (E–W) (excluding the Bornholm island). Together, the distance between wind parks can be 300 km in East–West direction. The installed wind power capacity in 2001 was about 550 MW in the East compared with nearly 2000 MW in the West.

Simultaneous prediction and production data were available from the system operators in Denmark, Elkraft and Eltra. Comparative data was available for updates 4 times a day, that is why the comparison is here made on Nordpool market predictions, for 12–36 h ahead. Four days (in February and September) were removed from the data because of missing prediction data in Elkraft data. With the missing 1 week of Eltra data this results in 8440 h of comparable data for the year 2001.

The tool used for wind power prediction in Elkraft System was developed in-house. The key elements are essentially the same as already described for WPPT, i.e., the bases are the weather forecasts for wind and on-line measurements of wind farms.

The initial total prediction errors in a 12–36 h market were 1.28 TWh for Eltra (West) and 0.33 TWh for Elkraft (East). For 35% of the time, the prediction error was to opposite directions in the West and East. This results in the total prediction error for the whole area being 1.47 TWh instead of 1.61 TWh just adding up the two (a 9% reduction in the prediction error).

If there were twice as much wind power as today in Elkraft area, a 12% reduction would happen, and if Elkraft's production were the same as Eltra's, a 14% reduction would happen in the prediction error when combining the two areas instead of calculating them separately. In both these calculations a simple up scaling was performed. The development in reduction (9–12–14%) reflects that the reduction will be relatively larger if the wind power capacities in the two areas are closer to being identical.

5. Wind power acting on day ahead electricity market

5.1. Case study Eltra at Nordpool Elspot market

The market calculation is here made assuming different times between the bids and the delivery. Hourly data for year 2001 was used for

- wind power production: actual, measured production of Eltra area in West Denmark,
- wind power predictions: as made by Eltra/WPPT model during operation in 2001,
- market prices: Nordpool ELSPOT area price for West Denmark, Odense and
- prices for regulation market in western Denmark: for up- and down-regulation.

During the example year 2001, there was 1 week with faulty operation of the WPPT, due to missing weather forecasts. So the time period studied here is 2.1–16.8 and 25.8–31.12. The Nordpool prices during the time are presented in Table 2 and Fig. 3.

The predicted time series for Nordpool was calculated from the 11 o'clock prediction the previous day for hours 0:00–24:00 next day, that is 13–37 h ahead predictions updated once a day. The bids for the market have to be given until 12:00 the previous day, so 1 h was given for the operator to make the bid to the market. Actually the forecast horizon is longer, as the forecasts are mainly based on weather forecasts, and they are calculated based on input values from 6 o'clock. Taking several hours to run the weather forecast model at DMI, the results will be available for WPPT model at about 9 o'clock.

The predicted time series for a more flexible market (6–12 h ahead) were calculated as 7–13 h ahead predictions updated four times a day to produce the forecasts for the next day: from the predictions at 17:00 (→ 00:00–05:00), 23:00 (→ 06:00–11:00), 5:00 (→ 12:00–17:00) and 11:00 (→ 18:00–23:00) hours. Example of 1 month for the predicted wind power production calculated in two ways, together with the measured production, can be seen in Fig. 4.

A third calculation was made for a constantly operating market for hourly production, with bids closing 1 h before. As 1 h was again left for the operator to make the bids, this meant using the information 2 h before for the wind power prediction. The best prediction type here is the persistence, using the realised wind

Table 2
Market price level for area Denmark west during example year 2001 (7.45 DKK/Euro)

2.1–16.8, 25.8–31.12, 2001	Nordpool ELSPOT	Regulation down	Regulation up
Average price Eur/MWh	23.7	12.3	30.2
Min price Eur/MWh	0.9	−0.7	8.0
Max price Eur/MWh	268.8	40.9	214.7

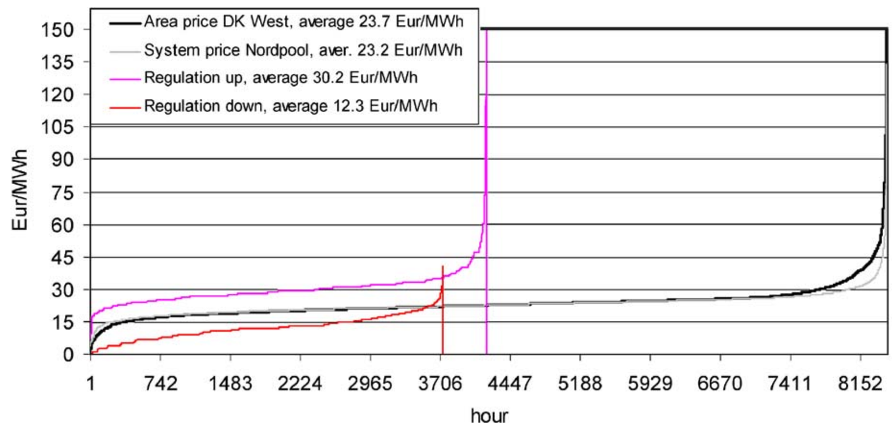

Fig. 3. Market price data from Denmark West, year 2001, as duration curves. Regulation price exists only for either up or down for each hour. There are 135 h that the up-regulation price is above 46 Eur/MWh, maximum price is 214.7 Eur/MWh. The West Denmark area price is 140 h above 46 Eur/MWh, maximum 268.7 Eur/MWh (system price 55 h and 238.4 Eur/MWh, respectively).

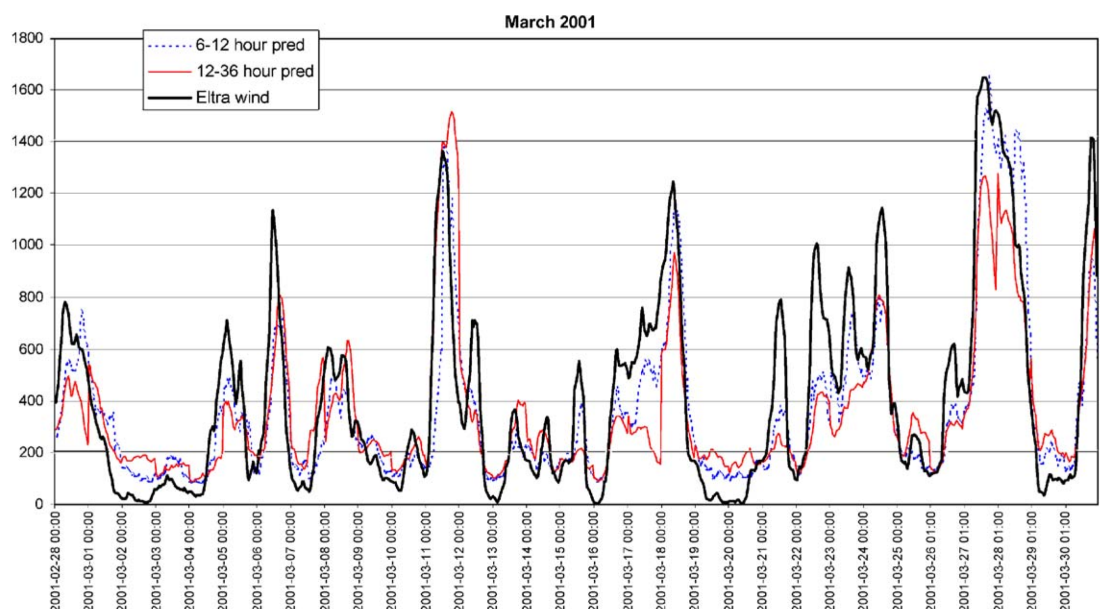

Fig. 4. Example of the predictions made to the Nordpool market (12–36 h) and to a more flexible market (6–12 h) compared to the realised production (Eltra wind), during 1 month.

power production 2 h before as the estimate for current hour. This is not something available today, as the measured information for thousands of wind turbines is not on-line. It is however used here to show what could be achieved in the future. Actually, WPPT improves the 2 h forecast already notably, so with either good on-line measurements or good, representative reference wind farms and up scaling in the future, the 2–3 h-ahead prediction can also improve in the future.

The income from the market and the cost of regulation were calculated in the following way. Income I for the hour i is the predicted power $\hat{P}_i$ times Nordpool area price for West Denmark p_{spot}:

$$I_i = \hat{P}_i p_{\mathrm{spot}}. \tag{1}$$

Cost c for the hour i is prediction error times regulation price p_{reg}. When wind power producer produces less than what has been bid to the market, the missing part will have to be purchased at up-regulation price, which is higher than the spot price received from the market. When wind power production is higher than the bid to the market, the surplus production is sold at down-regulation price, which is lower than the spot price, resulting in a negative cost in formula (2). Down-regulation price can be negative, resulting in a cost instead of just lower income than if the prediction had been correct:

$$c_i = (\hat{P}_i - P_i) p_{\mathrm{reg}}. \tag{2}$$

In Denmark, the so-called two-price model in the settlement of imbalances is used. This means that regulation price exists only for either up or down at each hour, depending on the direction of the system imbalance. Only when imbalances according to wind power prediction errors increase system imbalances, the regulation prices apply. When wind power prediction errors are in the opposite direction—i.e. "help the system to balance"—imbalances are priced at Nordpool spot price (Fig. 5). The imbalance of wind power was to the same direction as system imbalance about 70% of time in 2001. For the remaining 30% of time, when wind power imbalance is actually helping the system balance, the spot price is used for the imbalance, resulting in wind power being paid according to realised production. Finally, the net income is the income subtracted by costs, for the whole time period:

$$I_{\mathrm{TOTAL}} = \sum_i I_i - c_i. \tag{3}$$

The results are presented in Table 3.

If there were no forecast errors, the average price from Nordpool (area West Denmark) for wind power would be 22.9 Eur/MWh (average area price 23.7 Eur/MWh). Wind power seems to be influencing the area price, as there is more difference in the price for wind power compared with average area prices than there is for the system price of Nordpool (average 23.2 Eur/MWh, wind power 23.0 Eur/MWh).

For Nordpool 12–36 h market, prediction error for the year totals 0.68 TWh predicted too high and 0.67 TWh too low. This means that 39% of the total yearly energy was predicted wrong. Taking into account that during some hours (about 30% of time) the imbalance caused by wind power was to opposite direction than system imbalance, and wind power income was calculated for the realised production, this results in 31% of wind power production to be balanced at the regulation market. For a 6–12 h market, prediction error for the year totals 0.52 TWh predicted too high and 0.53 TWh too low. This means that 30% of the total yearly energy would have been predicted wrong, and 21% of the production had to be balanced at the regulation market. For a constantly operating hourly market, using persistence from 2 h before as the bid for wind power, 18% of the energy would be mispredicted, and 10% of the production would have to be balanced at the regulation market.

A more flexible market, allowing the bids for wind power to be updated 6–12 h before, would reduce the regulation costs by 30% and increase the net income by 4% from 20.1 to 20.9 Eur/MWh. An hourly operation, using persistence estimation from 2 h before, would reduce the regulation costs for nearly 70% and increase the net income by 8% to 21.8 Eur/MWh.

Because of the regulation costs and varying prices in the market, there are some hours that the net income of wind power producer would be negative, that is, the regulation costs exceed the spot income. For Nordpool market (12–36 h), about 8% of the time there is no net income but costs. For a more flexible market (6–12 h) this reduces to 6% of the time. Hourly operation would nearly end negative cash flow situations (only 0.3% of the time). All the negative net income situations in 2001 occurred due to high prices of up-regulation. In theory, in situations where negative income would arise with negative down-regulation prices, wind power could limit the production of some of the farms.

Table 3
Income and costs for wind power producer in western Denmark, with and without forecasts, calculated from 2001 data

2.1.–16.8, 25.8–31.12, 2001	Realised production	13–37 h forecasts	7–13 h forecasts	2–3 h persistence
Total (sum) TWh	3.35	3.36	3.34	3.35
Min, MW	0	48	49	0
Max, MW	1731	1899	1899	1731
Average, MW	392	394	391	392
Prediction error, up/down as % of total 3.35 TWh		20%/19%	15%/15%	9%/9%
Income Nordpool Elspot, average Eur/MWh	22.9	22.9	22.9	22.8
Income Nordpool Elspot, predicted and realised production[a]				
average Eur/MWh		22.4	22.4	22.5
Regulation: up/down				
% of time		40%/29%	37%/27%	28%/25%
% of energy		15%/16%	10%/11%	5%/5%
Average price Eur/MWh		30.1/13.8	30.6/13.3	29.4/13.4
Regulation costs				
Eur/MWh regulated		5.9	5.2	3.8
Eur/MWh produced		2.3	1.5	0.7
Net income Nordpool				
Average Eur/MWh	22.9	20.1	20.9	21.8

[a] This takes into account the 30% of time when no regulation market price exists for wind power, as the imbalance is to opposite direction of system imbalance. During those hours the income is calculated from the realised production, not the predicted one.

5.2. Case study—Eltra using after sales market like Elbas

If an after sales tool was at a wind power producer's disposal, the correction of prediction errors could for a large part be traded at markets, instead of paying penalties for it. Elbas is a market like that, operating currently in Finland and Sweden. The trade closes 1 h before delivery. This enables the wind power producer to look at the production level 1–2 h before, when the production level is already known more accurately than 13–37 h before, and trade the over- or under-predicted amount at Elbas. Taking the price series from Elbas market for year 2001, it was estimated how much the wind power producer would gain in this way.

There is for every hour a range of prices available from Elbas, because the market is continuous and you can trade for each hour's production constantly up to 1 h before, as long as there is a buyer taking your offer to sell and vice versa. The minimum price was used for the situations when wind power would need to sell the surplus production, and the maximum price was used when more power was needed to fulfil the bid made for wind power production. There was a price at Elbas for 92% of the time (Fig. 6), for the remaining 8% of the time of the year 2001, all the error in prediction was corrected at regulation market, in the same way as in the previous Section 5.1.

The Swedish area price for Elbas represents what the Danish price would be, except for cases of bottlenecks of transmission capacity between the areas. In bottleneck cases the areas have a different price. In 2001, this was about 25% of the time. The direction of bottleneck is also relevant: if the bottleneck is to transmission towards Sweden and there is overproduction of wind power that needs to be sold to Sweden, it is a bottleneck that matters in this calculation. The same applies for bottlenecks that are for transmission towards West Denmark. Taking the direction of the bottlenecks into account, leaves us with 13% of time when there has been a bottleneck the Swedish Elbas price data for Denmark has been used. For these hours the assumption that similar prices would exist in Denmark if they had the same after sales market has been made.

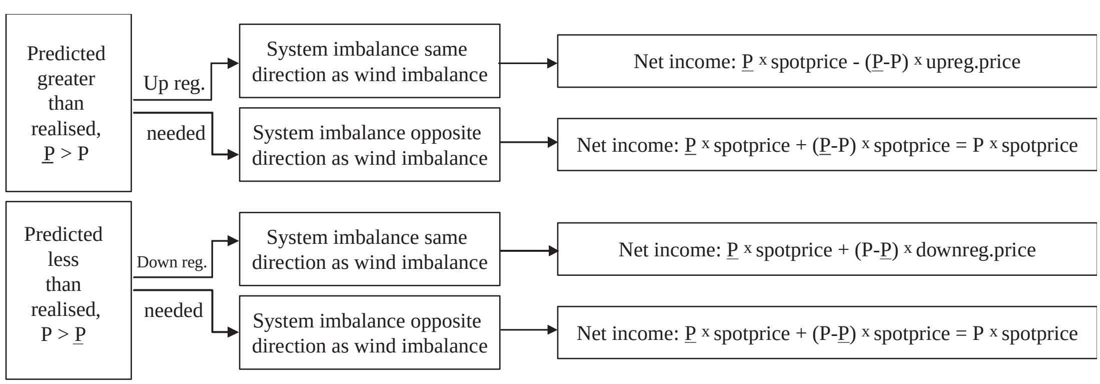

Fig. 5. Selling wind power in the Nordpool market with West Denmark regulation market.

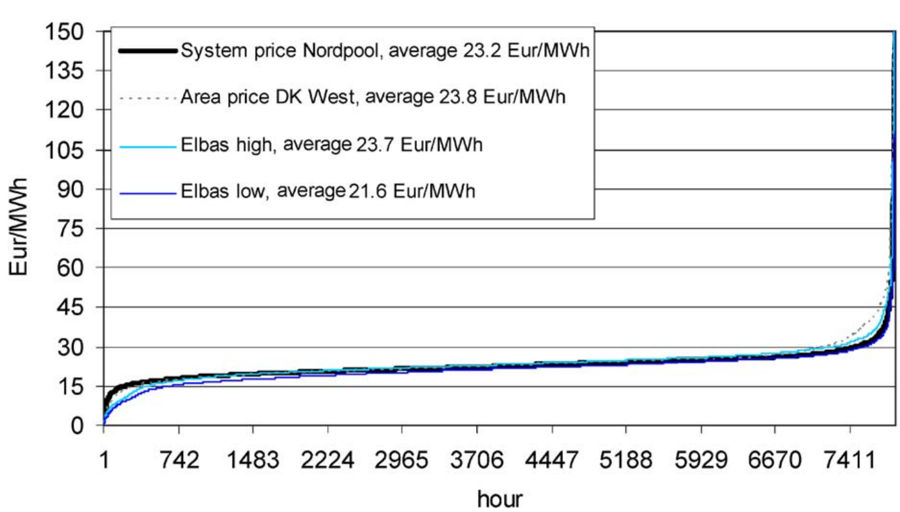

Fig. 6. Prices at Elbas market in 2001, compared with Nordpool system prices and the area price for Denmark West, as duration curves for the hours for which Elbas price exists (7858 h). The maximum price at Elbas was 241 Eur/MWh, and the price was above 46 Eur/MWh 79 h for the highest realised and 43 h for the lowest realised price.

Now the same calculation as for previous chapter is done, where the wind power producer first gets an income from Nordpool Elspot for the bids according to 13–37 h ahead prediction at the Odense area price. This results in the same original income for the producer of 22.9 Eur/MWh, for the total 3.3 TWh predicted to be produced during the year.

With the predictions 2–3 h ahead, like in the previous section, the producer trades the difference of the original bid and the now more accurate prediction in Elbas market. For each hour there will be either a cost (from buying the missing production, at the highest realised Elbas price) or income (from selling the surplus production, at the lowest realised Elbas price). From 2001 data, there was slightly more buying than selling, so that the net cost was 1.6 Eur/MWh (cost per trading amount 1.2 TWh, for the total wind power production the cost is 0.6 Eur/MWh).

For regulating market, only 0.4 TWh needed to be adjusted, coming from the amount each hour that differed from 2–3 h-ahead prediction. This 0.4 TWh includes also some hours of larger prediction errors, from the 12–36 h prediction, for the 8% of time with no Elbas price. Regulating market costs were 3.9 Eur/MWh regulated or 0.7 Eur/MWh total produced. The net income is Elspot income—net cost from Elbas—regulating market cost, 22.9–0.6–0.8 Eur/MWh, and results in 21.5 Eur/MWh total produced for 2001.

This result shows that with an after sales tool, the net income for a wind power producer can be close to what it would be if the market was designed to be a short and flexible one (21.5 Eur/MWh compared with 1–2 h market calculation 21.8 Eur/MWh in Table 3). The result here for wind power at Elbas market assumes that the price level of the after sales market stays most of the time near the day-ahead spot market prices. This means that wind power is not influencing the after sales market price, at least not more than the here assumed lowest-price-for-selling and highest-price-for-buying.

6. Conclusions and discussion

Wind power production, on an hourly level for 1–2 days ahead, is more difficult to predict than other production forms, or the load. The overall shape of the production curve can be predicted using weather forecasts and time series analysis. However, the high peaks of wind power production are difficult to predict at hourly levels for both the exact amount and the exact occurrence in time. For the prediction models in use in Denmark in 2001, the errors amounted to 30–50% of the total energy being forecasted wrong, when forecasting the exact hourly value of wind power production 7–38 h ahead. It has to be noted, however, that this is not the latest state-of-the-art of the forecasting models, improvements are expected in the future.

Combining the predictions for East and West Denmark would result in a reduction of prediction error. For 35% of the time, the prediction errors for a 12–36 h ahead market are to opposite directions. The prediction error of the combined two areas would be 9% less than simply summing up their separate prediction errors. The prediction error would decrease more if the wind power capacity would be more identical in the two areas—by simple up-scaling of the production in the East to the same level as in the West—a 14% reduction in error would be achieved.

The predictions were analysed together with the electricity market prices for Denmark, using actual data from year 2001. The income for wind power in West Denmark, not taking the prediction errors into account, would have resulted in 22.9 Eur/MWh (average spot price for the area 23.7 Eur/MWh). When bidding the forecasted production to the market, the income for wind power producer is 22.4 Eur/MWh taking into account the hours (nearly 30% of time) when spot price applies for the realised production, not the predicted one. In the two-price model in the settlement of imbalances, there is regulation market price for the imbalance only when the imbalance is to the same direction as the system (net) imbalance. Costs from the regulation market for the prediction errors for 12–36 h ahead market were 2.3 Eur/MWh total wind power production, resulting in net income of 20.1 Eur/MWh. A cost of 2.6 Eur/MWh for the payment of real time imbalance of power has been reported from West Denmark for year 2000, so this calculation is well in line (Eriksen et al., 2002).

A more flexible market, allowing the bids for wind power to be updated 4 times daily, with predictions of 6–12 h ahead, would reduce the regulation costs for 30% and increase the net income by 4%. Hourly operation, using persistence estimation from 2 h before, would reduce the regulation costs for 70% and increase the net income by 8%. Using an after sales tool like Elbas for trading the estimated surplus or missing production 2 h before delivery would reduce the regulation costs by 70% and increase the net income by 7%.

The results are based on year 2001 data of West Denmark, where wind power penetration is considerable and can be seen to influence the prices. The assumption has been made, that the same price level would apply when shortening the time between bids and delivery, not taking into account the implications of a shorter market to other production forms and actors. For Elbas after sales prices, no impact of wind power production or bottlenecks to the price level has been assumed. If the price level at regulating market was higher in penalising the imbalances, the benefit for a flexible market, or after-sales tool, could be greater. On the other hand, acting at flexible markets could also bring about extra trading costs.

For a wind power producer, selling his production at a market, there is a clear benefit for trading as close to the delivery as possible, because this reduces the prediction errors and thus extra costs from regulating. Also forecasting for a larger area also improves the forecasts and reduces the error. With an after sales market, the situation can also be improved for the producer.

Market design can have a strong influence on new, renewable, intermittent production forms like wind power. For the power system, all imbalances do not need to be balanced one-by-one, only the net imbalance. In a large system this results in considerable benefit, when most of the individual imbalances counteract one another. This should be reflected by the regulating market as well. For example the two-price model in the settlement of imbalances in use in Denmark only penalises the ones having their imbalance in the same direction as the system (net) imbalance. However, it does not take into account that only part of this imbalance needs to be corrected (the net imbalance), as in the market the ones having their imbalance to the opposite direction help the system. For example in Norway, the ones having their imbalance to the opposite direction than the system actually gain. As the imbalance for wind power is about the same to both direction, this results in almost no extra regulation costs for wind power in Norway (Gustafsson, 2002). In California the imbalance for wind power is calculated as the average over a month, which also results in near zero imbalance costs for wind power (Caldwell, 2002).

With the current day-ahead market, an after sales tool like Elbas for trading the mispredicted amounts of wind power would help the wind power producers. However, looking from the power system point of view, it is not necessary to trade some amounts of wind power production back and forth, especially in a case where several individual wind power producers would try to reach the bid production amounts this way. The rules for the market have been set for producers that can influence their production amounts. For them, penalising imbalances is the economic incentive for everyone to make the effort in keeping the balance, thus helping the system operators. For production form like wind power, it may however result in unoptimal operation in the market for the individual producers. This might also be one incentive for forming larger wind power producers' pools taking the benefits for reduction of forecasting errors in larger geographical areas.

There is no technical barrier in making the electricity market more flexible that is, shortening the time between the clearing of the market and the delivery. This can be done by introducing new products to the market, as well. With more flexible mechanisms than what is in use today, there is the possibility to ease the integration of wind power to the system. A well working after sales market could help both wind power producers and the system operator, in reducing the amount and cost of wind power at the regulating market. However, looking from the power system point of view, only the net imbalance has to be dealt with, so unnecessary trading back and forth for individual producers is not the optimal solution.

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