Optimal Wind Farm Bids under Different Balancing Market Arrangements

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***Abstract*— If a wind power producer must pay the costs of imbalances, the question arises of what is the optimal bid, given the market rules and the statistical properties of the wind forecasts and the imbalance prices. In this paper we derive optimal wind power bids for two sets of market rules, reflecting previous and new rules in the Nordic power system. The optimal bids are based on the evaluation of a large number of scenarios for the realizations of the wind forecasts and the balancing market prices respectively. Scenario aggregation is used to limit the total number of scenarios. The wind forecast errors are described by a traditional ARMA model. The balancing market prices are described by a model that uses time series and statistical models of the volumes and prices on the balancing market. The optimal bid in the so-called 1-price system will normally be to either bid zero or maximum production. In the alternative 2-price system, the optimal bid will be close to expected production. For the particular case study in this paper, the optimal bid for the 1-price system gives an improvement in total revenues of 2.5 %, while there is no observable improvement for the 2-price system. As such, the new system does give incentives to wind power producers to bid "correctly". However, the total revenues for the wind park are reduced with 2 % in the 2-price system, compared with the 1-price system.**

Keywords-wind power, forecast, optimal bid, balancing markets, settlement rules

I. INTRODUCTION

Although wind forecasting methods are continuously improving, it is not possible to forecast wind speed exactly, even with a short time horizon. In many power markets, the day ahead market clears around noon the day before operation. This means that wind forecasts with a time horizon of at least 12 to 36 hours must be used when the spot market bids are submitted, resulting in considerable uncertainty, e.g. [1]. This uncertainty results in deviations between the spot market bids for each hour and actual production. Because there must be a continuous balance between generation and demand in the power system, these deviations must be balanced out in real time, which is the task of the System Operator.

Many power systems today use balancing markets for the purpose of balancing in real time, cf. [2], Appendix 1. From the viewpoint of the System Operator, it is important that the total imbalances are as small as possible, because it is difficult and expensive to have sufficient balancing resources. Therefore most market systems are based on incentives to so called Balance Responsible Parties to make sure that they stick to their submitted plans as far as possible. Usually this is accomplished by the fact that the costs for being in imbalance are potentially high.

For wind power it is obviously a disadvantage to face high costs for imbalances, because it is "non-dispatchable". E.g. in Germany this is solved by paying the so-called feed-in tariff for all wind power, while giving the System Operators the task to balance all deviations from plan[3]. On the other hand in Norway and Sweden, (large) wind producers have the same responsibility for their own imbalances as any other power producer. In such cases, the question arises what is the optimal bid for the wind producers, given the statistical properties of the expected wind production and the prices in the balancing markets, as well as the particular market design.

The Nordic market has used a common merit order list for system balancing since 2002. This list is based on bids from producers for up- or downward adjustment of production. Also some large consumers offer reduction of demand. The common merit order list is used for the whole Nordic area, which means that the cheapest object of the list is used for regulation, unless this causes congestion. Recently further harmonization of the balancing market rules has been agreed [4]. Among others this has resulted in changes in the settlement rules, which potentially have an impact on both the revenues and the optimal bid strategies of wind power producers.

The goal of this paper is to derive the optimal bidding strategy for a wind power producer, i.e. the bidding strategy that maximizes his total revenues, given the market design and the statistical properties of the wind forecast and the balancing market prices. The results of the optimal strategy will be

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compared for the two relevant settlement rules, and they will also be compared with the standard bid, which is equal to the expected value of the forecast.

In the following we will first outline the present balance settlement system in the Nordic countries, specifically focusing on the differences between the so-called 1-price and 2-price settlement systems. In the following sections we will explain how we calculate the wind forecast (Section III) and the balance price forecast (Section IV). Subsequently we discuss the determination of the optimal bids for each settlement system. In section VI we show the results of a case study, while Section VII draws the conclusions. The work described here is based on [5].

II. BALANCING SETTLEMENT IN THE NORDIC SYSTEM

Until September 2009, the Nordic countries had different rules for balance settlement. In Norway, a 1-price system was used, where all imbalances were settled according to the balance price. The balance price is determined on the basis of the highest activated balancing market bid in the actual hour. The other countries had variants of a 2-price system, where deviations are paid the less favorable of the balance price and the spot price [4].

The rationale for the 2-price system is to give producers a stronger incentive to comply with their plans, providing better information and reducing the burden of balancing on the System Operator. On the other hand, the 1-price system is more "efficient" in the sense that it sends the same marginal price signal to all market parties.

If wind production forecast deviations and balancing market price deviations are symmetrically distributed, it is straightforward to show that a producer who bids expected production will have zero regulation costs in the long run with the 1-price system. In practice there will be asymmetries in both balancing market prices and wind forecast errors, resulting in a positive cost. However, the real costs of deviations from schedule will be relatively small under this system in Norway because of the relative low balancing prices in general, which are a result of the high share of hydro production. On the other hand, the 2-price system is generally seen as unfavorable for wind power producers because production cannot be perfectly planned.

The present common Nordic system [1] uses two balances, one for production and one for consumption and trade (which for convenience is called the consumption balance):

Production balance =
actual production – planned production

Consumption balance =
planned production + actual trade + actual consumption

Consumption and sales have a negative sign, production and purchase a positive sign and purchase and sales are defined from the Balance Responsible Party's (BRP) point of view. Negative imbalance implies that the TSO sells balance power to the BRP (i.e. the BRP buys balance power from the TSO) and vice versa.

While the consumption balance is priced in accordance with the 1-price system, a 2-price system applies to the production balance. The difference between the price systems is illustrated in the table below, where the "BM prices" are the marginal prices for up- and down-regulation.

TABLE I. BALANCING MARKET PRICE SYSTEMS

	BRP Imbalance	System balance: negative (up regulation)	System balance: positive (down regulation)
1-price system	negative	p_{BMup}	p_{BMdown}
	positive	p_{BMup}	p_{BMdown}
2-price system	negative	p_{BMup}	p_{spot}
	positive	p_{spot}	p_{BMdown}

In the 1-price system an imbalance in the same direction as the system imbalance is punished, while an imbalance that supports the system is rewarded correspondingly. Over time the costs and revenues of imbalances to a large extent level out in Norway. In the 2-price system, imbalances in the same direction as the system imbalance are treated in the same way as in the 1-price system, but imbalances that support the system are not rewarded.

III. WIND FORECAST ERROR MODEL

The wind speed forecast error model is a traditional ARMA(1,1) model of the form [6], [7]:

$$\Delta V(t) = \alpha \Delta V(t-1) + \beta Z(t-1) + Z(t)$$
$$\Delta V(0) = 0, Z(0) = 0$$

where $\Delta V(t)$ is the deviation from forecast in hour t, and $Z(t)$ is a normally distributed variable with expected value 0 and standard deviation σ_Z. A wind speed scenario is calculated as the sum of the wind speed forecast and the wind speed forecast error scenario, and converted to wind power using the relevant power curve for a wind turbine of wind farm.

To calculate the parameters α, β and σ_Z for the actual site, it is necessary to have sufficient data for wind speed or wind farm production as well as forecast deviations. If these data are not available, it is possible to use general parameters based on the sophistication of the weather forecast, the general shaping of the terrain around the wind farm and the average wind speed [6].

The model is used to create a large number of wind speed and resulting wind power scenarios. The number of scenarios is subsequently reduced as discussed in Section V.

IV. BALANCING MARKET PRICE MODEL

The balancing market price model exists of two parts, a long term linear model that describes the relation between prices and volumes, and a short term SARIMA (Seasonal Auto Regressive Integrated Moving Average) model to calculate a forecast of the difference between the balancing market price and the spot price for the next 48 hours. This model is documented in [8]. The modeling steps are as follows: the

SARIMA model is first used to create a forecast of the price difference Δp_r between the balance price and the spot price for the next 48 hours, based on the data for the preceding week. This price difference is used to determine the regulation state in the balancing market, cf. Figure 1.

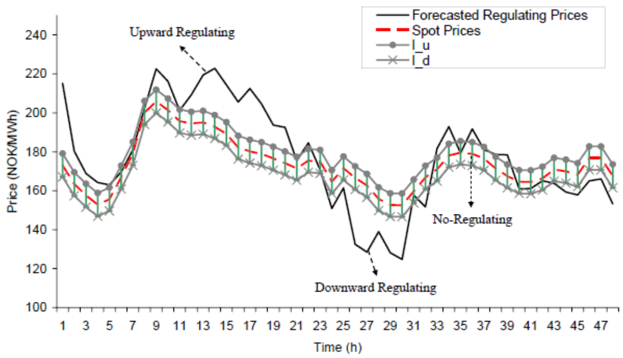

Figure 1: Regulation state determination

If Δp_r is within a certain band based, no regulation is assumed. Outside the band, a positive Δp_r indicates upward regulation and a negative Δp_r downward regulation.

A long term statistical model is used to describe the relation between regulation volumes and prices. For each state (upward, downward and no regulation), the model exists of a deterministic part based on linear regression and a stochastic error term using an extreme value distribution [8]. By sampling volumes with this model, resulting balancing market prices can be calculated. In [8], the regulation state was treated as deterministic. In the present work the model is enhanced with a probability distribution modeling the uncertainty of the regulation state, where the standard deviation is based on the mean squared forecast error of the SARIMA model [5]. Based on this probability distribution we can sample any number of regulation states.

The model we used is based on data for the year 2007. It can be argued that the statistical properties of the prices may change as a result from the changes in settlement rules. Although this may be the case, there are insufficient data available with the present settlement rules, which only were finally implemented in September 2009.

V. Bid Optimization

The procedures in the previous 2 sections are used to generate large numbers of scenarios for wind power forecast deviation and balancing market prices respectively. The number of scenarios is subsequently reduced using scenario aggregation [11]. The expected revenue for the wind farm owner for a particular hour under the 1-price system is given by:

$$
\begin{aligned}
REV = {} & P_{bid} \cdot p_{spot} \\
& + py_{y=1} \cdot \sum_{i \in S_o \cap S_u} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot P_{BM,j} \cdot pj_j \right] \\
& + py_{y=2} \cdot \sum_{i \in S_o \cap S_u} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot P_{BM,j} \cdot pj_j \right] \\
& + py_{y=0} \cdot \sum_{S_o \cap S_u} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot p_{spot} \cdot pj_j \right]
\end{aligned}
$$

where P_{bid} is the bid volume, p_{spot} the spot price and $py_{y=\chi}$ the probability for regulation state χ (1 up, 2 down and zero no regulation). The index i indicates the realized wind power scenario, P_i the corresponding wind power and p_i the probability of the scenario. S_o is the set of scenarios with overproduction ($P_i > P_{bid}$), and S_u the set of scenarios with underproduction. The index j indicates the balancing market price scenario and pj_j its probability and $P_{BM,j}$ the balancing market price. For the 2-price system, the expected revenue is given by

$$
\begin{aligned}
REV = {} & P_{bid} \cdot p_{spot} \\
& + py_{y=1} \cdot \left\{ \sum_{i \in S_o} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot p_{spot} \cdot pj_j \right] \right. \\
& \qquad \left. - \sum_{i \in S_u} \sum_{j=1}^{m} \left[\left(P_{bid} - P_i \right) \cdot p_i \cdot P_{BM,j} \cdot pj_j \right] \right\} \\
& + py_{y=2} \cdot \left\{ \sum_{i \in S_o} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot P_{BM,j} \cdot pj_j \right] \right. \\
& \qquad \left. - \sum_{i \in S_u} \sum_{j=1}^{m} \left[\left(P_{bid} - P_i \right) \cdot p_i \cdot p_{spot} \cdot pj_j \right] \right\} \\
& + py_{y=0} \cdot \sum_{S_o \cap S_u} \sum_{j=1}^{m} \left[\left(P_i - P_{bid} \right) \cdot p_i \cdot p_{spot} \cdot pj_j \right]
\end{aligned}
$$

In each case, the optimal bids are found by a straightforward enumeration of all possibilities, using a step size depending on the size of the wind farm.

VI. Results

The model was tested for a wind farm on the coast of Central Norway, with an installed capacity of 57 MW. Wind data were available for the period 15 May 2008 to 24 February 2009. Data for some days were missing, resulting in a total number of 271 days with data. Because the wind farm was commissioned only recently, insufficient production data were available, and estimates of α, β and σ_Z were based on general characteristics described in [6] and the relevant data for the wind farm, resulting in the values $\alpha = 0.98$, $\beta = -0.81$ and $\sigma_Z = 1.75$.

Using the procedures described in Sections III and IV, we generated 100 wind forecast scenarios and 100 balancing market price scenarios. Using scenario aggregation, these were subsequently reduced to 10 scenarios each, giving a total of 100 scenarios. Because Norway so far only has a limited installation of wind power, it can fairly be assumed that there is little or no correlation between balancing market prices and deviations between forecasted and actual wind.

We will first focus on the optimal bids. These are shown for a typical day in Figure 2 and Figure 3 respectively.

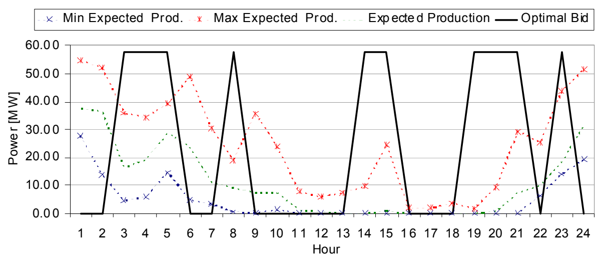

Figure 2: Optimal bids for 7 October 2008, 1-price system

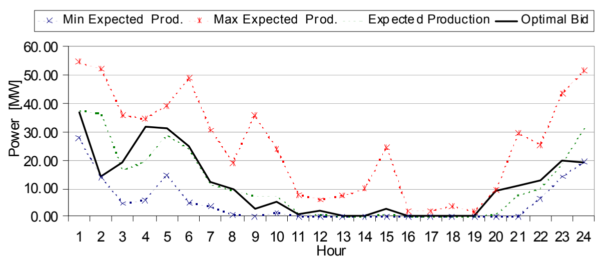

Figure 3: Optimal bids for 7 October 2008, 2-price system

The figures show minimum, maximum and expected production respectively, as well as the optimal bid. The default bid is equal to the expected production.

For the 1-price system we see the typical behavior that the optimal bid is either zero or equal to maximum production. The reason is that if the probability for upward regulation is higher than the probability for downward regulation, it is optimal to bid zero, regardless the actual wind forecast. In this case one will get paid the upward regulation price for all production. Correspondingly, if the probability for downward regulation is higher than the probability for upward regulation, it is optimal to bid maximum production. Some comments to this conclusion must be made: Firstly, this bidding behavior is not allowed according to the market rules in the Nordic system and it would probably quickly be revealed by the System Operator. Today, based on the rules of Nordpool electricity exchange, the wind power producer is obliged to bid expected production for the next day. However, producers could bid less extreme, e.g. by bidding the lowest expected production in the case of expected upward regulation and the highest expected production in the case of expected downward regulation. Secondly, the method requires that the regulation state can be forecasted with some certainty, which is possible according to the price model we use. Thirdly it is required that there is no correlation between the deviation between actual wind forecast and prices. This will not be the case in countries with high penetration of wind power. Especially if many producers would try this strategy, there would occur a high correlation, which would defeat the strategy. Finally the strategy would result in a higher volatility of the daily revenues. However, as subsequent results will show, the impact on longer term volatility is negligible.

With the 2-price system, the optimal bid may be either higher or lower than the expected value, but is normally close to it. The actual value will depend on the skewness of the distribution of the balancing market prices and the wind speeds respectively. To illustrate the dependency on the balancing market prices, we simulated the optimal bid for a particular hour for all relevant wind speeds for three different balancing market price forecasts as given in the following table:

TABLE II. BALANCING MARKET PRICE SCENARIOS

	Probability		
	Upward regulation	Downward regulation	No regulation
UP07	0.70	0.20	0.10
DOWN07	0.20	0.70	0.10
45-45	0.45	0.45	0.10

In the forecasts UP07 and DOWN07, the probabilities are heavily skewed towards upward and downward regulation respectively, while the 45-45 forecast is symmetrical with respect to the probabilities of the regulation directions. The expected balancing market price for downward regulation (given that there is downward regulation) in this particular case is 22.4 NOK/MWh lower than the spot price, while the corresponding value for upward regulation is 10.8 NOK/MWh higher than the spot price[1]. The results of are shown in Figure 4 below.

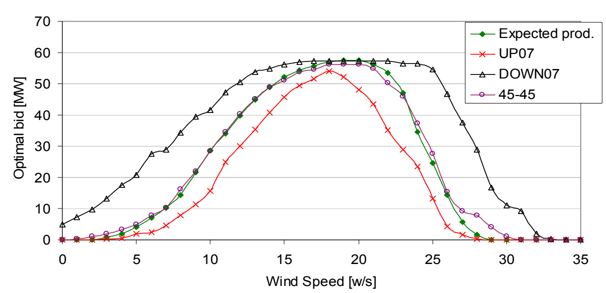

Figure 4: Optimal bids with different balacing market price forecasts

The Forecast curve shows the production of the wind park for wind speeds between zero and 35 m/s. At expected wind speeds above 22 m/s the wind speed for more and more of the specific turbines in the park are exposed to wind speeds above the cutoff speed and have to stop, resulting in a steeply declining production of the park.

[1] 1 NOK = 0.119 Euro, December 2009

For the DOWN07 forecast, the optimal bid is significantly above the expected production. Because of the high probability of downward regulation, it is optimal to have a low probability of producing more than bid. If there is downward regulation in reality and the wind park produces according to the forecast, the wind park owner gets paid the spot price for the bid, and has to pay the spot price for his imbalance, cf. TABLE I. , i.e. he receives the spot price for his whole production. Correspondingly, the optimal bid for UP07 is below the expected production. The optimal bid for the 45-45 scenario is somewhat above the expected production because of the expected values of the differences between the spot price and the up- and downward regulation prices respectively. This is also the reason why the difference between the DOWN07 optimal bid and the spot price is greater than the corresponding difference between the spot price and the UP07 optimal bid.

These results show that the tendency for the optimal bid under the 2-price system is the same as under the 1-price system, i.e. it is optimal to bid more than expected production when the probability for downward regulation is highest, and less than expected production when the probability for upward regulation is highest. However, the effect is much less, and will only be significant with highly skewed probability distributions. As we will show next, this is normally not the case for the period we analyzed.

We now look at the whole period for which we have data, i.e. 271 days or 6504 hours. The average spot price in Southern Norway in this period was 407.1 NOK/MWh, and the average wind park production was 16.9 MW (29.6 % of the installed capacity). TABLE III. below shows the average net hourly total revenues (spot + balancing market) of the wind park for the 1- and 2-price systems respectively, where the default bid is equal to the expected wind production.

TABLE III. AVERAGE HOURLY REVENUES [NOK]

	Simulated results			Actual results		
	Default bid	Optimal bid	Diff	Default bid	Optimal bid	Diff
1-price	6779	7136	357	6246	6405	159
2-price	6716	6733	17	6112	6095	-17
Diff	67	403	-	134	310	-

We make a distinction between the simulated results and the actual results. The first are based on the average values obtained by simulating the 100 scenarios, the second by simulating the wind speeds and balance prices on the actual day. The simulated results are better than the actual results, which may be caused by the scenario aggregation, i.e. the fact that 10 x 10 scenarios do not fully describe the statistical properties of the wind and price probability distributions.

From TABLE III. we can draw some interesting conclusions. Firstly, for the 1-price system the simulated effect of bidding optimally versus expected production is 159 NOK/hour with actual wind and prices, which would amount to 1.4 million NOK/year, an improvement of approximately 2.5 % of the expected wind park revenues. For the 2-price system, although the optimal bid is different from the expected value, this does not increase the wind park expected revenues. Using the actual values, there is even a very small, insignificant decrease in revenues. This shows that the 2-price system does not incentivize producers to bid different from expected production, which was one of the motivations behind the system.

Secondly, if the default bid is used, the average revenues for the wind park owner are 134 NOK/hour or 2 % lower for the 2-price system than for the 1-price system, using actual data. Although 2 % does not sound much, it still amounts to 1.2 million NOK/year for this relatively small wind park, making the objections to the 2-price system from wind producers understandable. Using optimal bids, the difference between the 1-price and 2-price systems is much higher, reflecting the much greater advantage of optimal bidding in the 1-price system. In this case, the difference is approximately 5 % using actual data. However, it must be emphasized that this kind of optimal bids are against the system rules, and that they would not be viable in a system with much wind power as discussed above.

Thirdly, we look at the average price obtained by the wind park and the implicit imbalance cost for wind. If it obtained the spot price for all production, the average price would have been 403.3 NOK/MWh. This is slightly lower than the average price for the period, because there was obviously some more production when prices were below the average. This is the price a producer would get if he could forecast his production with 100 % certainty. TABLE IV. below shows the average prices obtained under various assumptions, and the resulting imbalance cost.

TABLE IV. AVERAGE OBTAINED PRICE AND IMBALANCE COST [NOK/MWH]

	1-price system		1-price system	
	Av. price	Imb. cost	Av. price	Imb. cost
Default bid	369.1	24.9	361.1	42.2
Optimal bid	378.4	34.2	360.1	43.2

Finally some words on the volatility of the wind park revenues, depending on the bid strategy. Because the optimal strategy deviates from bidding expected production, it is natural to expect that this strategy increases the volatility of the revenues, which may be undesirable. We therefore calculated the variance of the hourly revenues based on the 100 simulated scenarios. TABLE V. below shows the calculated volatility on an hourly, daily and weekly basis respectively.

TABLE V. REVENUE VOLATILITY, STANDARD DEVIATION IN %

	Default bid			Optimal bid		
	hourly	daily	weekly	hourly	daily	weekly
1-price	32.1	9.7	3.5	36.0	9.7	3.5
2-price	32.5	9.9	3.6	32.4	9.9	3.6

It should be noted that we assume the spot price is known in these calculations, so that the real uncertainty is higher, especially with a weekly time horizon. However, we only focus on the volatility caused by the uncertainty in the wind forecast and the balancing market price. We have here also assumed that the hourly values are independent. This is not completely correct because of the properties of the SARIMA model, but we believe this effect is very small.

The table shows that we do observe the effect of higher volatility of the revenues with the optimal bid for the 1-price system. However, this difference between the bid strategies vanishes when periods of a day or longer are considered, which means that this it not a problem in reality. For the 2-price system there is no difference in volatility.

VII. CONCLUSIONS

This paper considers the optimal bids for a wind park in the Nordic power market, and compares the settlement rules for imbalances that were in use until recently (the "1-price model") and the new common Nordic rules ("the 2-price model). Balancing market price forecasts are based on the forecast of the regulation state, using a SARIMA model, and a forecast of the price given the regulation state, using a linear model. An ARMA(1,1) model is used for the error in the wind forecast.

The optimal bid for the 1-price model is either to bid zero or the maximum wind park production, depending on the forecast of the system state. It should be noted that this is not allowed according to the rules in the Norwegian market. For the 2-price model, the optimal bid is normally rather close to the expected production, but there is some deviation based on the skewness of the balancing market price and wind forecast error deviation distributions.

A case study was done for a 57 MW wind park in Central Norway showed for the period 15 May 2008 to 24 February 2009. Using actual wind and price data, there was an increase in revenues of 2.5 % for the optimal bid compared with a default bid equal to expected production for the 1-price system. For the 2-price system there was no observable increase. This shows that the 2-price system gives incentives to wind producers to bid more correctly than under the 1-price system.

It is also observed that the total revenues of the wind park for the actual case are reduced with 2 % with the 2-price system, assuming default bids in both cases.

Further work will focus on the situation in other markets, and especially the case of high wind penetration, which can introduce a correlation between the deviation between wind forecast and actual wind and the balancing market prices.

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