Instituto Complutense de Análisis Económico

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Francisco Javier Eransus

Instituto Complutense de Análisis Económico (ICAE)

Facultad de Ciencias Económicas y Empresariales,

Universidad Complutense de Madrid.

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JEL Classification C22, C44.

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Introduction

The Spanish electricity system is based on a sequence of markets where retailers and power generators trade the energy to consume each hour. Most energy is exchanged in the day-ahead market, while the expectations of market participants on consumption and production are updated in the intraday markets. Finally, the actual levels of consumption and production will differ from those previously planned and the System Operator (SO) will use the short term mechanisms it has available to guarantee the real-time balance between energy generation and load, with the implied adjustment costs being transferred to market participants. Each Program Bidding Unit (PBU)[1] pay or is paid by the amount of energy it has actually bought or sold regardless of the amount planned, but it is also charged with the cost of its imbalances. In the Spanish case, the imbalances regulation scheme is asymmetric, with the PBU not being charged if the sign of its imbalance is contrary to that of the imbalance system as a whole. For instance, if the system needed more energy than that actually produced and the PBU generation (consumption) was more (less) than the energy traded in the markets, the PBU will not pay for its imbalance. But if both imbalance signs are the same, the system will charge the PBU by the product of its deviation times the market cost of its imbalances.

The PBUs most affected by imbalance costs are power renewable generators, especially wind PBUs. For obvious reasons, the accuracy of wind power forecasting tools is limited even in the short term and so the imbalances of these PBUs are usually large [see [1], [2] and [3] for a revision of such forecasting tools]. In Spain, the hourly imbalance average for a representative 50 MW wind farm is around 35% of its power production. The imbalances also reduce revenues for power generators other than wind farms and for consumption PBUs, although the effect is not as serious as for wind farms.

Obviously, the most effective way to reduce imbalance costs of a power plant or a retailer is to take advantage of the portfolio effect. This happens especially for wind farms, see [4]. The forecasting error drops drastically if a set of them makes a joint bid as a single PBU, because the individual prediction errors usually have low correlation. In fact, the Spanish power regulation allows the business activity of companies we will refer to as Renewable Power Generators Representative (RPGR), that try to get together different actors to make a joint bid. The imbalance of this type of wind PBUs is around 10%-15% of production.

Adjusting the bid in the intraday markets to reflect the updated predictions is other obvious way to reduce imbalances. But in that case the potential differences between the day-ahead and intraday market prices should be taken into account [see [4], [15] and [16]]. Updating predictions using the intraday markets and the portfolio effect are the two natural ways to reduce the cost of PBU imbalances by decreasing their size.

However, it is obvious that there is another way to reduce the cost of PBU imbalances, which is to directly derive optimal bidding strategies designed to minimize imbalance costs. This decision-making problem has been widely dealt with in the literature, usually for the case of wind power generators [see [14], [5] and [6]].

This paper is part of this literature too. For a risk neutral and price taker PBU operating just in the day ahead market or in the intraday markets, the PBU optimal bidding for minimizing its imbalance costs under an asymmetric imbalances system, as in Spain, will be a function of the expected imbalance costs, the probability distribution function of the energy to be consumed or produced by the PBU and the probability distribution function of system imbalances. In theory, the result applies not only for wind PBUs but also for other renewable sources of energy generation, as well as for some consumption PBUs.

Strategies for splitting the generation or consumption between the day-ahead and the intraday markets are not considered here, so their prices are irrelevant for our analysis. Some literature on optimal strategies when day ahead as well as intraday markets are both used to design the bid can be found in [17], [18] and [19], among others.

We test our optimal bidding strategy for Spanish power markets in an empirical exercise with actual data. For the whole 2014 we compare the hourly bids obtained under our method for a theoretical wind power PBU against bids based on the last point forecast available each hour. We propose simple methodologies to estimate the three arguments included in the optimal bidding function. Our results show that the use of the suggested bidding strategy provides significant economic savings. These results are themselves the most relevant contribution of the paper. Most studies concerning optimal short term wind power trading are based on unrealistic assumptions such as the perfect foresight of imbalance market costs. Our proposal can be easily applied in practice to the Spanish current power markets, so it should be very valuable for those electricity market participants for which imbalance costs play a key role in their business, as RPGR.

The paper is structured as follows. The first section presents the statistical formulation of the problem and the derivation of the optimal bidding function. The empirical exercise is the content of the second section, including a very brief description of the methodologies used for estimating the arguments of the optimal bid function. Main conclusions are available in the last section.

1 The optimal bidding strategy

Let $u_t = e_t - e_t^P$ be the hourly imbalance of a generation PBU (denoted in what follows by GPBU), with e_t and e_t^P being the amount of energy actually generated and planned for that hour, respectively. In the case of a consumption PBU (denoted as CPBU), $u_t = e_t^P - e_t$, with e_t being the amount of energy actually consumed that hour. We denote the hourly system imbalance by s_t , being the sum of the imbalances u_t of all PBUs. So if $s_t > 0$, the system as a whole overgenerated (or underconsumed) energy relative to the level planned, forcing the SO to use its short-term mechanisms to keep the real-time balance between load and supply. The energy added or subtracted to balance the system has a market hourly price and the part of it that may be paid by the PBUs is denoted by c_t (it is the absolute difference between the day-ahead price and the imbalances price).

PBU imbalances are penalized in the Spanish power system as follows:

	$u_t > 0$	$u_t < 0$
$s_t > 0$	$c_t\|u_t\|$	0
$s_t < 0$	0	$c_t\|u_t\|$

So the cost to GPBU of hourly imbalances (denoted by CT_t) is a function of the bid e_t^P and the random variables c_t, e_t and s_t. Under risk neutrality, the optimal bid e_t^P calculated in $t-k$ will be the one minimizing the mathematical expectation of CT_t in $t-k$ restricted to $e_t^P > 0$. Assuming that e_t is stochastically independent of s_t and c_t, it is easy to find the solution of the mathematical optimization problem.

The optimal bid $[e_t^P]^*$ will be a function of: a) $F_{e,t-k}(.)$, the probability distribution function of e_t, conditional on the information set available at $t-k$. The larger its variance is, the more extreme will be $[e_t^P]^*$; b) $F_{s,t-k}(0)$, the probability that the system imbalance will be negative, conditional on the information set available at $t-k$. The relation between $[e_t^P]^*$ and $F_{s,t-k}(0)$ is negative; c) the ratio of $E_{t-k}(c_t|s_t<0)$ to $E_{t-k}(c_t|s_t>0)$, which are denoting the mathematical expectation at time $t-k$ of the market cost of imbalances at t when system imbalances are negative and positive, respectively. The relation between $[e_t^P]^*$ and $\frac{E_{t-k}(c_t|s_t<0)}{E_{t-k}(c_t|s_t>0)}$ is negative as well.

For a CPBU is fairly easy to find an analogous result, but in that case the relation between the optimal bid and $F_{s,t-k}(0)$ and $\frac{E_{t-k}(c_t|s_t<0)}{E_{t-k}(c_t|s_t>0)}$ are both positive.

The assumption of independence between e_t and the pair s_t, c_t plays a key role for achieving these results. It is very reasonable for both renewable GPBUs and CPBUs. The correlation between the system load and s_t is low enough[2] that the independence assumption can be considered as a reasonably good approximation. On the contrary, the largest CPBUs should not be considered as price takers, so our line of reasoning would not be valid for them.

2 Empirical exercises

We want to evaluate the economic effect of applying in practice the optimal bidding strategies in Spanish power markets. To do so, we will apply the optimal bid for a hypothetical wind PBU throughout 2014 and we will compare the imbalances costs with those that the PBU would obtain with bids based just on the best available energy forecasts. We will use actual data for the market costs of imbalances.

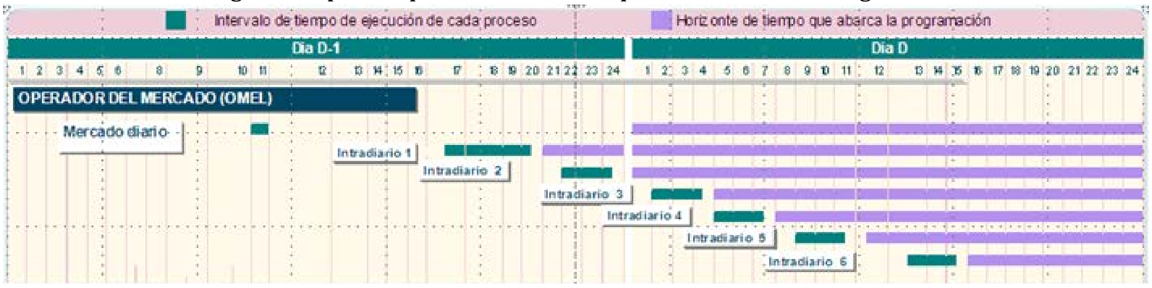
In this paper we will propose simple methods to estimate every hour the parameters of the optimal bid, $F_{s,t-k}(0)$, $\frac{E_{t-k}(c_t|s_t<0)}{E_{t-k}(c_t|s_t>0)}$ and $F_{e,t-k}(.)$. These methods use just the information actually available when the bid must be submitted to the market, so they truly can be applied in practice and the results should be representative of the real benefit that a wind power PBU could get using the bidding strategy.

2.1 The time sequence of the Spanish power markets

Before describing the exercise, it is necessary to understand the sequence of the Spanish power markets and their corresponding scheduling horizons. This information is summarized in Figure 1. The day-ahead market (DAM) is organized each day at 12:30 and the participants must submit the bids to cover their production or consumption of energy over the 24 hours of the next day. From then on, there are six intraday markets (IM 1 to IM 6) that allow the participants to update forecasts of consumption or generation. Their programming horizons are shown in the Figure 1.

[2] The linear correlation coefficient between the Spanish system load and the absolute value of system imbalances is about 0.15.

Figure 1. Spanish power markets sequence and scheduling horizons.



2.2 Design of the exercises

We will consider two types of participation in the power markets. In Design 1, we assume that the PBU is bidding just in the DAM, without updating their forecasts using the IM. Such PBU will need to have forecasts of the power generation and estimations of the variables involved in the optimal bidding strategy with a time horizon between 13 and 36 hours. In Design 2 we will consider the opposite situation: the PBU does not bid in the DAM and it bids all its power generation in the IM, updating the power generation forecasts as often as possible. This PBU will bid six times, according to the next scheme (see Figure 1):

- The PBU bids for hours 1 to 4 in the IM 2 organized the day before. Forecasts with a time horizon 1 to 4 hours are needed.
- The PBU bids for hours 5 to 7 in the IM 3. Forecasts with a time horizon of 1 to 3 hours are needed.
- The PBU bids for hours 8 to 11 in the IM 4. Forecasts with a time horizon of 1 to 4 hours are needed.
- The PBU bids for hours 12 to 15 in the IM 5. Forecasts with a time horizon of 1 to 4 hours are needed.
- The PBU bids for hours 16 to 20 in the IM 6. Forecasts with a time horizon of 1 to 5 hours are needed.
- The PBU bids for hours 21 to 24 in the IM 1. Forecasts with a time horizon of 1 to 4 hours are needed.

Obviously, the imbalances will be much smaller in this case than in Design 1.

We will make bids every day during 2014 for the 24 hours of the next day under both designs. We will consider two bids, the last available PBU power generation forecast and the optimal bid applied under the methods we will propose in the next section. We will denote them by FB (Forecast Bid) and OB (Optimal Bid), respectively. Because the information we need is not public for an actual PBU of the Spanish system, we will consider the total installed wind power in Spain as a unique PBU (about 22,000 MW). The SO publishes hourly forecasts of the total Spanish wind generation each hour for the next 48 hours. The FB in $t-k$ for time t will be the last SO forecast for time t available in $t-k$.

All data used for this exercise (system imbalances, market costs of imbalances, forecasts and actual data of the total wind generation) are available in web of the information system of the Spanish TSO (http://www.esios.ree.es/web-publica/).

2.3 Methodologies to estimate the optimal bid

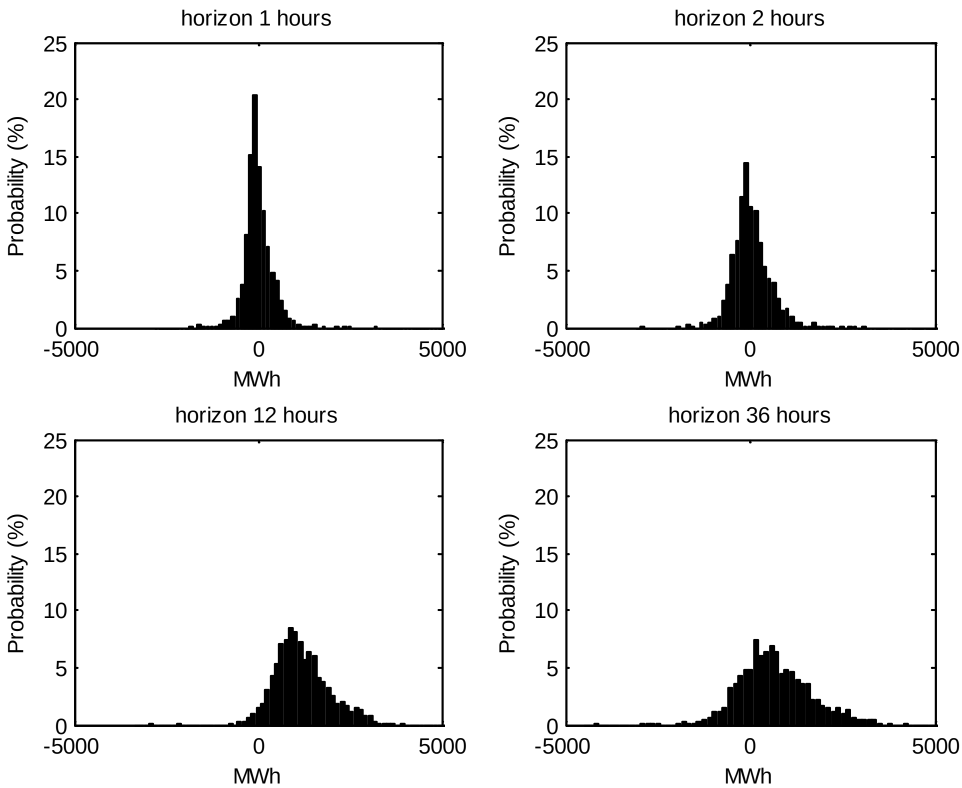
As an estimate of the probability distribution $F_{e,t-k}(.)$ we will add to the wind power generation OS forecast for t available in $t-k$ the empirical distribution of historical k-period ahead forecasting errors.

We use the sample of forecasting errors between 2010 and 2013. Some forecasting error distributions are shown in Figure 2. As it can be seen from the figure, the SO forecasts turn out to be biased, generally underpredicting the total power generation of the system so, in practice, they should be adjusted to center $F_{e,t-k}(.)$ appropriately. However, we will not do that adjustment in our simulation exercises to avoid conditioning the conclusions on the comparison between FB and OB.

Our approach can be applied to estimate the probability distribution function of the energy for non-wind GPBUs or even in the case of CPBUs.

More complex methods to estimate $F_{e,t-k}(.)$ could be used, probably leading to significant decreases in wind PBU imbalance costs under our suggested bidding strategy. Kernel Density estimators are used in [9], [10] and [11], while spline quantile regression and a Beta distribution is applied in [12] and [13], respectively.

Figure 2. Probability distributions of the SO wind power generation forecasting errors



Having good estimates of $\frac{E_{t-k}(c_t|s_t<0)}{E_{t-k}(c_t|s_t>0)}$ would require a very complex model. A method for predicting the costs of market imbalances is developed in [7], by separately forecasting DAM prices, imbalance prices and the sign of the system imbalance. We will follow a naïve approach, estimating this ratio of conditional expectations through the ratio between the historical average of the market cost for negative and positive imbalances over the same hour and month indicated by t. This way we take into account the hourly and monthly seasonality that these costs exhibit. To compute these averages we use a sample from 2012 to 2013.

The most sophisticated computation for the exercise is performed for estimating $F_{s,t-k}(0)$. The statistical features of the system imbalance suggest that a multiplicative SARIMA model with both 168 and 24 seasonal orders is appropriate for forecasting the series s_t. The model is run each 24 hours with the last data of s_t. The estimation of $F_{s,t-k}(0)$ will be achieved from the empirical distribution of the k time horizon historical forecasting errors but centered at the SARIMA forecast for t calculated in $t-k$. The forecasting errors are from previous SARIMA model forecasts. Particularly, we have used the data of system imbalances from 2009 to 2012 as a sample to build the SARIMA model and we have applied this model to predict the series every hour in 2013, letting us having the empirical forecasting errors probability distributions for each of our relevant time horizons.

The capability of the SARIMA model to predict correctly the sign of the system imbalance in 2014 is shown in Table 1. As it is expected, the forecasting accuracy of the model drops with the horizon but not drastically. Positive imbalances are more difficult to forecast than negative ones but fortunately they happen not as often as the negatives (about 35% of the hours). Averaging the results for the 36 horizons, the actual system imbalance sign was the expected by the model in the 66% of the hours, but the model performance was quite better for the very short horizons.

Table 1. Success Rate (%) of system imbalance SARIMA forecasts

Horizon (k)	Positive imbalance	Negative imbalance	Both
1	74%	93%	87%
2	69%	84%	78%
1–4	62%	83%	**76%**
13–36	40%	77%	**65%**
1–36	**45%**	**77%**	**66%**

Evidence about the accuracy of the approach we have used to estimate $F_{s,t-k}(0)$ is shown in Table 2. For instance, in 89% of those hours for which we estimated a probability higher than 90% that the full system imbalance would have a particular sign (either $\hat{F}_{s,t-k}(0) < 0{,}1$ or $\hat{F}_{s,t-k}(0) > 0{,}9$), the imbalance really had the expected sign. The results in Table 2 suggest that the method works reasonably good. Theoretically, the Wold's descomposition can be used for an analytical estimation of $F_{s,t-k}(0)$. However, the results turn out to be much worse than with our empirical method, possibly because of the non-normality of the innovations.

Table 2. Success Rates of system imbalance SARIMA forecast depending on the estimated probability $\boldsymbol{\hat{F}_{s,t-k}(0)}$

Probability Interval	50%–60%	60%–70%	70%–80%	80%–90%	90%–100%
% Successfull forecast (1)	53%	62%	68%	80%	89%

(1) % of hours such that the model predicted correctly the system imbalance sign when the estimated probability $\boldsymbol{\hat{F}_{s,t-k}}$ was inside the interval in the row above.

Alternative methodologies could also be applied for predicting the sign of the system imbalance, like logistic regression, Bayes classifiers and Support Vector Machines [see [6], [7] and [20]].

2.4 Results

The most important results achieved in our empirical simulation exercises can be seen in Table 3. Both exercises suggest a significant reduction in the costs of PBU imbalances by using the optimal bidding strategy under those methodologies we proposed in the previous section, compared to that based on the available PBU power generation point forecasts. However, there are important differences between exercises. Savings are around 7% in Design 1, while rising to 26% for Design 2. For a Spanish PBU representing around the 10% of the total installed wind power of the system (there are several PBUs in Spain with power not less than this), the yearly savings could be 10% × 8,760 × 510 € = 446,760 € if bidding just in the DM and 10% × 8,760 × 953 € = 834,828 € if bidding just in the IM. In practice both types of markets are used for bidding and savings would be between these two.

The effectiveness of the optimal bidding strategy is related to the time horizon, so savings are much more significant in the case of Design 2. This is even clearer in Table 4, which displays the savings obtained in Design 2 by time horizon. The shorter the time horizon, the larger are the savings. The reason is that if the time horizon is short, the forecasts as well as the estimation of $F_{s,t-k}(0)$ are accurate enough so that the strategy works well, getting many hours with a zero cost of PBU imbalances. The FB bid also obtains better results for shorter horizons, although this is essentially due to a reduction in the size of imbalances size, rather than to a significant increase in the number of hours with zero cost. This observation suggests that under more accurate PBU generation forecasts the optimal strategy bidding gains would be even larger. In practice forecasts for a particular wind GPBU are usually better than for the whole wind power system, so these results are most likely an underestimation of the potential benefit from bidding by OB rather than by FB.

Table 3. Main results of the empirical exercises for the optimal bidding strategy

	Design 1			Design 2		
	FB [(1)]	OB [(2)]	Saving [(6)]	FB [(1)]	OB [(2)]	Saving [(6)]
Hours (%) with zero cost [(3)]	40%	47%		41%	65%	
PBU hourly average cost (€) [(4)]	7.451	6.941	**7%**	3.717	2.764	**26%**
PBU imbalance / forecast [(5)]	11%	15%		6%	15%	

[(1)] Bid $(t-k,t)$= forecast for the PBU wind power generation in t available in $t-k$;
[(2)] Bid $(t-k,t)$= estimation in $t-k$ of the optimal bid (2) for t;
[(3)] % of hours such that the PBU imbalance cost was zero (the PBU imbalance sign was the opposite of the system's one);
[(4)] Average hourly PBU imbalance costs;
[(5)] Sum of absolute PBU imbalances over the analyzed period / sum of the power generation;
[(6)] Reduction (%) of PBU imbalance costs under OB strategy compared to the reduction under the FB strategy.

Table 4. Savings by time horizon. Design 2

Horizon ($\boldsymbol{k}$)	Hours with zero cost		PBU average cost (€)		Savings (%)
	FB	OB	FB	OB	
1 hours	44%	78%	1.886	1.150	39%
2 hours	41%	66%	3.263	2.300	30%
3 hours	40%	59%	4.234	3.110	27%
4 hours	39%	55%	5.134	4.125	20%
5 hours	37%	50%	7.243	6.340	13%

To clarify the way the OB works we show in Table 5 the relevant information about two particular hours in the Design 1 simulation exercise. First of all, we analyze the bids for hour 1 of January 2, 2014, which were submitted to the DM at 12:00 of the day before ($k=13$). The available OS forecast and hence the

FB was 11,466 MWh. However, our methodology estimates a probability of 81% that the system imbalance is positive. Taking into account this figure, as well as the wind generation variability and the estimation of market costs of imbalances, the OB turns out to be 12,880 MWh, 1,414 MWh over the prediction, as an attempt to make the PBU imbalance to be negative. The actual PBU generation was finally 12,816 MWh. Under the OB the PBU would have had a zero cost, because its imbalance sign would be the opposite of the system's one. On the contrary, under the FB, the PBU would have paid 6,925 €. The other sample refers to the bids for the hour 2 of January 4, 2014, which were submitted to the DM at 12:00 of the day before ($k = 14$). The available OS forecast was 10,595 MWh. Our method estimates a probability of 55% that the system imbalance would be positive, thereby with high uncertainty on its realized sign, making the OB to be 10,973 MWh, very similar to the prediction. The system imbalance turned out to be positive, as we predicted, but the actual wind generation was much larger than the forecast and the PBU imbalance was positive as well, even under OB. However, the PBU imbalance would have been smaller under the OB than under the FB, with the PBU having to pay 4,670 € in the first case and 7,833 € in the second one.

3 Conclusions

The paper shows evidence about the benefits from applying an optimal bidding strategy for minimizing the imbalances costs of PBUs (Program Bidding Unit) in the Spanish power market. The optimal bid is a function of the expected market costs of imbalances, the probability distribution of the energy to be produced or consumed by the PBU and the probability distribution of system imbalances. We have suggested simple methodologies for estimating these parameters, so it would be easy to implement in practice just following the information provided in the paper. Our empirical exercises focused on wind PBUs, considering the total installed wind power of the Spanish system as a single PBU. We found that, compared to bid simply the PBU point energy forecast, the savings from using the suggested bidding strategy might range from 7% to 26%, depending on the markets where the PBU bids. For standard Spanish wind PBUs, it would amount to annual savings above 500,000 €. The results would need to be adapted to actual PBUs, but we suspect that true savings would still be higher. Improving the accuracy of the estimated parameters can enlarge very significantly the economic benefits of the optimal bidding, which remains as an obvious next step for future research.

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