31761 - Renewables in Electricity Markets

Renewable market participant strategies.

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Revenue calculation - Deterministic approach - Analysis: Forecast reliability & Net Revenue

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One-bid strategy - Analysis: Imbalance profitability

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Probabilistic approach

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1 Introduction

Most of energy producers, conventional or renewable, offer their generation through electricity markets. As wind is a variable and uncertain resource, wind power producers have to establish strategies for participating in these markets in order to maximize their possible revenue.
In this paper, three participation strategies are developed and compared for a single wind farm over the year 2017. The aim is to understand how a wind power operator can deal with revenues and opportunity costs. created by its generation deviations in a global electricity market.
For this, a wind farm of 160MW situated in Horns Rev in Western Denmark (DK1) has been chosen. The producer trades his energy through the Danish electricity market NordPool. The balancing market is ruled by a two-price settlement.

The wind farm electricity generation for each hour in 2017 is known, as well as deterministic forecasts and probability quantiles at several time before the concerned hour. Trading prices in the DK1 electricity market in both 2016 and 2017 have been extracted from the historical market data available on the NordPool website [1], as well as the wind global wind energy generation in DK1 in 2016.

First, the theory behind revenue calculations was established. Then three strategies have been developed: a strategy based on a single bid for each time unit, another one based on deterministic forecasts and a more sophisticated one based on a probabilistic approach. Finally, the annual revenue and energy trades have been calculated for the different strategies and compared to the ideal case where the wind producer offers the actual energy he produces.

Remark: The Danish electricity market NordPool [1] uses a time resolution of one hour. For the sake of simplicity, no difference were made between electrical power and energy in the calculation as they are made in MW and MWh during a time unit of one hour. Nevertheless, it should be noticed that the quantity bid during the day-ahead market is a power capacity in MW and that producers are rewarded for the energy they generates in MWh during each time unit.

2 Method : Revenue estimation

When an energy producer participates in an electricity market like the one studied in this paper, he will earn money both on the day-ahead market and on the balancing market. These revenues and the way to calculate them are introduced in this part.

2.1 Day-ahead Revenue

Before the gate closure of the day-ahead market - at noon the day before the actual generation - the producer will offer a power generation for the time unit t E_t^{DA}. After the market clearing, he will be asked to produce the scheduled power E_t^S. Only if his bidding price is lower or equal than the market clearing price will the producer be scheduled for the generation he had bid. For the wind producer considered in this paper, the bidding price is always equal to zero, so he will be scheduled when the clearing price is positive.
For each time unit, the producer will receive a revenue R_t^{DA} for his planned generation at the market clearing price λ_t^S:

$$R_t^{DA} = \lambda_t^S E_t^S \qquad \forall\, t \,\in\, T \tag{1}$$

Where :

$$E_t^S = \begin{cases} E_t^{DA}, & \text{if } \lambda_t^S \geq 0 \\ 0, & \text{if } \lambda_t^S < 0 \end{cases}$$

2.2 Balancing Market Revenue

The balancing market aims to compensate the global electric energy imbalance due to the difference between the electricity supply and demand. The indicator δP_t translates this imbalance. It is positive when the global generation is lower than the demand (i.e. when the market needs up-regulation), negative when it is higher than the demand (i.e. when the market needs down-regulation), and equal to zero when the market is perfectly balanced.
Each producer will then buy the electricity he is lacking compare to the day-ahead schedule of time unit t in the balancing market, or the other way around sell his energy surplus, at a price λ_t^B. This market is characterized by 2 prices: $\lambda_t^{\uparrow}$ - the price at which energy can be bought - and $\lambda_t^{\downarrow}$ - the price at which energy can be sold. The balancing price λ_t^B is equal to $\lambda_t^{\uparrow}$ when up-regulation is needed, $\lambda_t^{\downarrow}$ when down-regulation is needed and remains at the market clearing price when the energy flow is perfectly balanced :

$$\lambda_t^B = \begin{cases} \lambda_t^{\uparrow} & \text{if } \delta P_t < 0 \\ \lambda_t^{\downarrow} & \text{if } \delta P_t > 0 \\ \lambda_t^S & \text{if } \delta P_t = 0 \end{cases} \qquad \forall\, t \,\in\, T \tag{2}$$

In this case, δP_t was determined through the NordPool market data [1] such as, for each time unit:

$$\delta P_t \begin{cases} = 0 & \text{if } \lambda_t^{\uparrow} = \lambda_t^S = \lambda_t^{\downarrow} \\ = -1 & \text{if } (\lambda_t^{\uparrow} - \lambda_t^S) > (\lambda_t^S - \lambda_t^{\downarrow}) \\ = +1 & \text{otherwise} \end{cases} \qquad \forall\, t \,\in\, T \tag{3}$$

For wind energy producers, their imbalance ΔE_t corresponds to the difference between the generation bid and the generation actually measured in the farm E_t^{Wind} - when scheduled in the day-ahead market :

$$\Delta E_t = E_t^{Real} - E_t^S \qquad \forall\, t \,\in\, T \tag{4}$$

Where :

$$E_t^{Real} = \begin{cases} E_t^{Wind} & \text{if } \lambda_t^S \geq 0 \\ 0, & \text{if } \lambda_t^S < 0 \end{cases} \qquad \forall\, t \,\in\, T$$

Under the two-price settlement, producers are rewarded differently if their own imbalance increase or compensate the market global imbalance. They will buy or sell the electricity needed to meet their imbalance ΔE_t at the balancing price λ_t^B if they participate to the global imbalance, and at the market clearing price λ_t^S if they help balance the market through their own imbalance. This way, they will be penalized only if they increase the global imbalance. At the end of the balancing market, producers will earn - or spend - the balancing revenue R_t^B corresponding to the purchase or the sale of the energy they need at the adapted price (*Equation 5)*:

$$R_t^B = \begin{cases} \lambda_t^B \Delta E_t & \text{if } \delta P < 0 \text{ and } \Delta E_t < 0 \\ \lambda_t^S \Delta E_t & \text{if } \delta P < 0 \text{ and } \Delta E_t > 0 \\ \lambda_t^B \Delta E_t & \text{if } \delta P > 0 \text{ and } \Delta E_t > 0 \\ \lambda_t^S \Delta E_t & \text{if } \delta P > 0 \text{ and } \Delta E_t < 0 \\ 0 & \text{if } \Delta E_t = 0 \end{cases} \tag{5}$$

This revenue is negative if electricity is bought, and positive is electricity is sold.

2.3 Global Revenue

For each market time unit t, the producer will earn revenues R_t both from the day-ahead market and the balancing market:

$$R_t = R_t^{DA} + R_t^B \qquad \forall\, t \,\in\, T \tag{6}$$

The annual revenue is the sum of the revenue earned at each time unit of the year T:

$$AnnualRevenue = \sum_{t \,\in\, T} R_t \tag{7}$$

In this study, the time scale used is the year 2017 with the time resolution of the Danish electricity market Nordpool of one hour.

$$T = \{t_1, t_2, ..., t_{8760}\}$$

3 Bidding strategies

3.1 About 2017 market & wind power data

- In order to avoid computational problem and to have the same date system between market data and wind generation data, the time change moments, which occur on the 26th of March and the 29th of October, were modelled as usual days. The missing hour of March was artificially added as a empty hour - every prices and demand at zero - and one of the double hour of October was deleted, as they were very similar in terms of price.
- The data available for the wind farm studied showed hours when the wind power measurement and/or forecast were not defined (NA). When the measure of the actual energy generation were missing, it has been considered that the farm was stopped, for technical or meteorological reason. Thus, both measure and forecast data were set to zero.
  When only forecast data were missing, the undefined values were replaced by the forecast values found for time units with a similar generation. This choice was made in order to avoid a huge gap between the zero forecast and the actual production, and to keep reasonable forecast values.
- For each time unit of 2017, wind power forecasts were made the day before at 11:00 and 12:00 and the present day at 11:00 and 12:00. As the gate closure of the day-ahead market is happening at noon the day before the concerned time unit, it has been chosen to consider the most recent data available at this time: **forecasts made the day before at 12:00**. Indeed, it has been conceived that the forecasts were available a few minutes before the gate closure, making the new bid possible for the wind producer.

3.2 One-bid strategy

With this strategy, the wind producer will bid the same quantity on the day-ahead market for every time unit of the year. Thus, this quantity had to be determined before the 1st of January 2017. In order to choose the right quantity to bid, 2016 electricity market was used as a reference for 2017 estimation.

3.2.1 Generation in 2016

First of all, the power generation of the wind farm in 2016 had been estimated through a capacity factor c_t. For this, the global wind generation in DK1 was used from the electricity market data available on the NordPool website [1]. A global capacity factor for all the wind farms of the region has been calculated for each hour by taking the maximum wind generation in 2016 - 3401 MWh - as a reference level. These values have been considered as an approximation of the capacity factor of the wind farm considered in this study. With this hypothesis, the energy produced by the wind farm has been calculated for every hour in 2016:

$$E_t^{Wind} = 160 c_t \qquad \forall\, t \ \in \ T_{2016} \tag{8}$$

3.2.2 Revenue in 2016

Using the estimated hourly production, it was possible to calculate the annual revenue earned by the wind producer in 2016. The annual revenue was calculated for each bid quantity between 0 and 160 MW with a resolution of 1 MW:

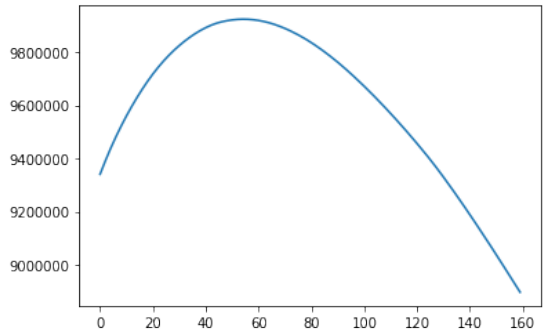

Figure 1: Revenue earned in 2016 for different single-bid quantities.

3.2.3 Single-bid for 2017

The maximum annual revenue is obtained for a bid of 54 MW. It is interesting to notice that the mean generation for a time unit was found to be 50 MWh with the hypothesis made for 2016. Moreover, the median generation is under 54 MWh too :

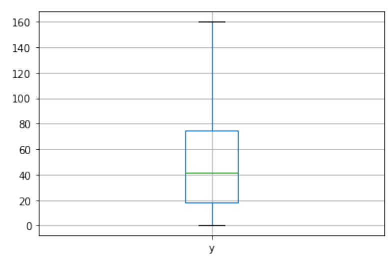

Figure 2: Power generation for a time unit in 2016.

This means that it was more interesting to bid higher than the real generation most of the time to get a higher revenue. This is explained by the balancing market behavior, which is studied in details in Part 4 of the report.

With regard to the calculation made for the 2016 market, a single-bid quantity of 54 MW has been chosen for this strategy :

$$E_t^{DA} = 54MW \qquad \forall\, t \;\in\; T \tag{9}$$

3.3 Deterministic wind forecast

This strategy is based on the deterministic forecast made at each time unit for the electrical energy generation. Here the producer only relies on the most recent estimation he had for the energy generation of its wind farm, and bid this quantity on the day-ahead market. As explained above, these values are available the day before at 12:00, just before the gate closure of the day-ahead market :

$$E_t^{DA} = E_t^{Fore,d-1,12} \qquad \forall\, t \;\in\; T \tag{10}$$

3.4 Probabilistic approach

For this last bidding strategy, the quantiles of the distribution function of the wind production for the upcoming days forecasts will be used.

3.4.1 Methodology

The layout of this bidding strategy is based on the observations and calculus made in *Zugno (2013)* [2]. The producer does not know up- and down-regulation prices; so he does not know in advance marginal gain and loss $\pi^+ = \lambda_S - \lambda^{\downarrow}$ and $\pi^- = \lambda^{\uparrow} - \lambda_S$ - also called up- and down-regulation costs or penalties. However, as described in *Zugno (2013)*, the optimal bid E_t^{DA} to be placed at time unit t is :

$$E_t^{DA} = F_{W_t}^{-1}\left(\frac{\hat{\pi}_t^+}{\tilde{\pi}_t^+ + \tilde{\pi}_t^-}\right) \tag{11}$$

where $\hat{\pi}_t^+$ and $\tilde{\pi}_t^-$ are respectively the expected values of π^+ and π^- for hour t and F_{W_t} is the cumulative distribution function of the wind power production W_t - which is here a stochastic variable.
This result means that the formula to place the optimal bid is the same as if we knew the marginal gain and loss but by replacing marginal gain or loss by their expected value based on previous observations.

To know if the producer can use this result, 3 assumptions need to be verified:

- The day-ahead price λ^S is not influenced by the bid chosen by the producer in the day-ahead market.
- The wind production E_t^{Wind} is not influenced by the bid chosen by the producer in the day-ahead market.
- The up- and down-regulation costs π^+ and π^- are independent of the imbalance of the producer.

The first and third assumptions are reasonable as the producer acts as a price-taker in the market - he does not produce enough to exercise any power on the market. As for the second assumption, curtailment is not considered as an option in the model studied here, which makes it valid.

3.4.2 Strategy applied

Based on the above calculus and observations, the third strategy can be formulated as follows. At the beginning of 2017, for every hour t of the day (between 0 and 23), the producer calculates a quotient $\hat{r_t}$

$$\hat{r_t} = \frac{\hat{\pi}_t^+}{\tilde{\pi}_t^+ + \tilde{\pi}_t^-}$$

with only the data that he knows yet, which are the one of 2016. Thus, he has 24 different $\hat{r_t}$. The average value $\hat{\pi}_t^+$ and $\hat{\pi}_t^-$ are calculated with 366 observed values in 2016 for every hour t (because 2016 has 366 days). So, bids placed on day 1 of 2017 are $E_t^{DA} = F_{W_t}^{-1}(\hat{r_t})\ \forall t \in [\![0, 23]\!]$ based on the result above. Then, each time that the producer has a new price data in 2017, he updates the average values $\hat{\pi}_t^+$ and $\hat{\pi}_t^-$ and then $\hat{r_t}$ by adding the new observation to the average. The new bid is $E_t^{DA} = F_{W_t}^{-1}(\hat{r_t})$ with $\hat{r_k}$ updated day to day.

4 Revenue estimation and strategy comparison

The following Figure (3) gathers the results of the revenue estimation of the wind producer in 2017, depending on the type of strategy used in the electricity market. The ideal strategy is used as a reference, where the producer is able to offer the quantity actually generated by his wind farm. The **performance ratio**, ratio between the revenue considered and the ideal one, gives an overview of the economic performance of the strategy. **Opportunity losses** relative to an imbalance represent the difference between the revenue earned and the revenue that would have been earned if this imbalance were known before bidding for the day-ahead market.

	Unit	Ideal	Single-Bid	Deterministic approach	Probabilistic approach
Annual Energy Contracted	MWh	7.08E+05	4.69E+05	7.31E+05	7.77E+05
Annual Energy actually Produced	MWh	7.08E+05	7.08E+05	7.08E+05	7.08E+05
Global Surplus	MWh	0.00E+00	3.30E+05	7.21E+04	5.51E+04
Global Shortage	MWh	0.00E+00	9.07E+04	9.51E+04	1.23E+05
Average up-regulation cost	€/MWh	0.0	39.48	34.78	34.37
Average down-regulation cost	€/MWh	0.0	23.06	26.25	26.62
Average electricity price	**€/MWh**	**27.83**	**25.86**	**27.03**	**27.03**
Opportunity loss due to Surplus	€	0.0	1071642.9	289078.0	221993.0
Opportunity loss due to Shortage	€	0.0	316580.5	275288.3	341391.8
Revenue from day-ahead market	€	19715411.4	14279355.0	20564379.2	21920113.9
Revenue from balancing market	€	0.0	4040434.0	-1413334.1	-2768087.3
Net Revenue	**€**	**19715411.4**	**18319790.0**	**19151045.1**	**19152026.6**
Part of imbalance (% of the prod.)	-	0%	59.5%	23.6%	25.2%
Performance ratio	**-**	**100%**	**92.921%**	**97.137%**	**97.142%**

Figure 3: Generation and revenue earned in 2017 for the different strategies.

4.1 Forecast reliability

Figure (3) shows that the strategy based on deterministic forecast is the most reliable in terms of estimation of the energy generation, as its "part of imbalance" ratio is the smallest with a global imbalance representing 23,6% of the production.
The relative error made between generation measured and bid on the day-ahead market are :

Single-Bid	Deterministic approach	Probabilistic approach
-3.82%	-1.86%	-2.31%

Figure 4: Mean relative error for the three strategies

This results confirms that the deterministic approach allows more accurate forecasts over the year, on average -1.86% of the real generation. The probabilistic approach allows close performances with a mean relative error of -2,31%. As expected, the single-bid strategy is less efficient with an mean annual error doubled, since its forecast resolution is per year and not per hour.
However, it is interesting to notice that the deterministic approach is not the most profitable strategy. The probabilistic approach implies higher imbalances and tends to bid at a higher quantity more often, as witnessed by its global shortage imbalance of 123 GWh over the year. Thus, the reliability of the generation estimation does not seem to be the key to the highest profitability of this strategy.

4.2 Net Revenue

From the economic point of view, the most efficient strategy is the probabilistic approach with a performance ratio of 97.142% as shown in Figure (3), slightly exceeding the performance of the deterministic approach of 97.137%. Here again, the single-bid strategy is less interesting, even if it ensures the producer to earn almost 93% of the maximum revenue. The following Figure (5) illustrates the economic "behaviour" of the three strategy during a representative period:

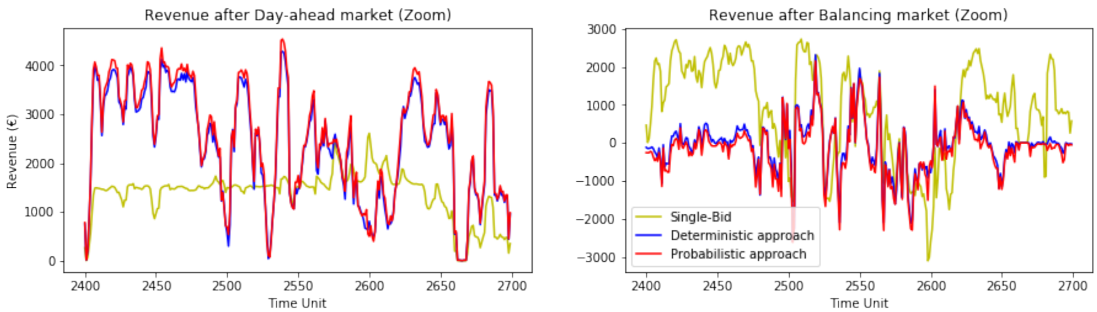

Figure 5: Economic behaviour of the three strategy on day-ahead and balancing market.

A clear difference can be seen between the single-bid strategy (yellow) and the two others. Indeed, its revenue after the day-ahead market is quite stable compare to the other, and most of the time lower since its bid is constant over the year. However, the balancing revenue reaches more extreme values since the error of forecast is higher on average. This observation is confirmed by the high global revenue earned with the single-bid strategy on the day-ahead market introduced in Figure (3) which is twice higher than the other, while its global revenue earned on day-ahead market is 6 M€ lower.
It is interesting to notice that deterministic and probabilistic approaches have similar behaviour and allow similar results. Nevertheless, it can be seen that the probabilistic strategy tends to earn more on the day-ahead market and to lose more on the balancing market.

	Mean Revenue (€)			Revenue difference between Deterministic & Probabilistic approach (€)	
	Single-Bid	Deterministic ap.	Probabilistic ap.	Mean	Median
Day-ahead market	1 630,1 €	2 347,5 €	2 502,3 €	156,4 €	268,0 €
Balancing Market	465,8 €	- 163,0 €	- 319,3 €	- 156,3 €	- 268,0 €
Net	2 112,7 €	2 208,9 €	2 209,0 €	0,1 €	9,1 €

Figure 6: Economic behaviour of the three strategy: Indicators.

These indicators confirm the fact that the third strategy allows to earn a higher net revenue on average - 0.1 € per time unit compared to the second strategy - even if it is more sensitive to the balancing market, with the highest mean costs - or negative revenue - in 2017 of -319.3 € per time unit. The probabilistic approach allows the producer to take more risk with its bids and to earn more money on the day-ahead market than with a more simple deterministic approach. In the end, the surplus earned during the day-ahead compensates the costs due to balancing requirements more efficiently than for the deterministic strategy.

4.3 Imbalance profitability

The third approach allows to take advantage of the expected values of the imbalance prices. It leads the producer to bid more energy on the day-ahead market compared to the deterministic approach, as highlighted by the higher revenue obtained on this market. Although this led to

a greater loss on the balancing market, the risk proved worthwhile, with a better performance ratio.
To understand how this improvement is reached, an overview of the system imbalance state is needed.

	No imbalance (δ P = 0)	Positive imbalance (δ P = 1)	Negative imbalance (δ P = -1)
Frequency	0.29	0.41	0.30
Average penalty (€/MWh)	0	7.76	8.44
Sum of penalties (€/MWh)	0	28030	22010

Table 1: System imbalance in 2017

Table 1 shows that the most frequent state of the system was a positive imbalance. Although the penalties induced by down-regulations were on average lower than the penalties induced by up-regulations, the sum of the penalties shows that down-regulation induced more penalization than up-regulation in 2017. From the point of view of the producer, this means that it was overall less penalizing to bid higher than the actual production than lower.

This behaviour of the system was taken into account in the probabilistic approach, which lead to bid at high quantiles most of the time:

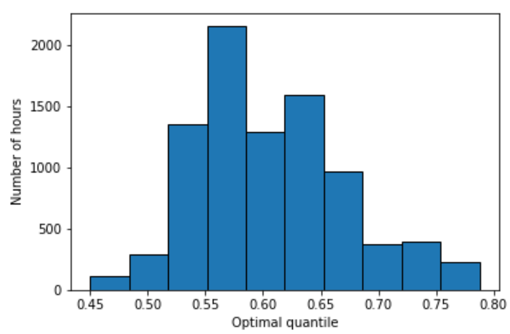

Figure 7: Optimal quantiles in 2017

By choosing to bid at these quantiles rather than to follow the forecast, the producer found himself with a higher global shortage and a lower global surplus. Figure 3 shows that the average up-regulation cost is higher in the probabilistic approach than in the deterministic one, while the average down-regulation cost is almost the same. In the probabilistic approach, the producer bought more energy on the balancing market, but at a lower price on average, because he had some knowledge on when this cost was equal to spot market price (i.e. when there was a positive system imbalance).
Compared to the deterministic strategy, the behaviour of the producer in the probabilistic strategy lead to a higher opportunity loss due to shortage of energy, and a lower opportunity loss due to surplus of energy. This is due to him choosing to be more often in a position of shortage of energy, which proved to be a winning strategy, as the total opportunity loss is lower.

5 Conclusion

Three bidding strategies have been built in this paper. They use more or less information to bid quantities on the day-ahead market, from a simple single-bid strategy which always bids the same amount, to a more complex probabilistic strategy which uses the forecast power generation distribution and corrects parameters day to day.

The analysis shows that the probabilistic strategy performs better than the deterministic one, which performs itself better than the single-bid strategy. The more information used, the more accurate the model is. If the single-bid strategy yields a lower revenue than the two others, the revenues produced by the deterministic and probabilistic strategies are very close to each other. Furthermore, the deterministic and probabilistic strategies achieve a revenue quite close to the ideal case, which makes them appear as quite competitive approaches. Nevertheless, they remain very reliant on the forecast accuracy.

Nomenclature

ΔE_t	Electricity imbalance of the producer at time unit t, MW
δP_t	Energy imbalance in the market at time unit t indicator
$\lambda_t^{\downarrow}$	Down-regulation price at time unit t, €$/MWh$
$\lambda_t^{\uparrow}$	Up-regulation price at time unit t, €$/MWh$
λ_t^{B}	Balancing market regulation price at time unit t, €$/MWh$
λ_t^{S}	day-ahead market price at time unit t, €$/MWh$
π^{+}	Marginal gain in balanced market, €$/MWh$
π^{-}	Marginal loss in balanced market, €$/MWh$
c_t	Wind farm capacity factor compare to its nominal capacity 160 MW.
E_t^{DA}	Power generation offered in the day-ahead market for time unit t, MW
$E_t^{Fore,d-1,12}$	Electricity generation estimated a day before at 12:00 for the time unit t, MWh
E_t^{Real}	Power really produced by the producer at time unit t (if scheduled), MW
E_t^{S}	Power generation scheduled after day-ahead market for time unit t, MW
E_t^{Wind}	Power available in the wind farm at time unit t, MW
R_t	Net Revenue earned in the energy market at time unit t, €
R_t^{B}	Revenue earned or lost after Balancing market at time unit t, €
R_t^{DA}	Revenue from the day-ahead market at time unit t, €

References

[1] NordPool historical market data for 2016 and 2017 :
www.nordpoolgroup.com

[2] M. Zugno, T. Jónsson, P. Pinson *Trading wind energy on the basis of probabilistic forecasts both of wind generation and of market quantities* Wiley Online Library, 2013

[3] Jupyter Notebook
https://jupyter.org/

6 Appendix

Every code used in order to determine the three bidding strategies and to calculate the different revenues have been uploaded with this paper, as Jupyter Notebook [3] files.

Each code corresponds to :

- **One-bid model** is the code used to determine the bid quantities for the one-bid strategy and to calculated its revenues.
- **Deterministic model** is the code used to calculate the revenues from the deterministic strategy.
- **Probabilistic model** is the code used to determine the bid quantities for the probabilistic strategy and to calculated its revenues.