The Impact of Wind Power on Day-ahead Electricity Prices in the Netherlands

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***Abstract*—A detailed analysis was conducted to assess to what extent availability of wind energy has influenced day-ahead electricity prices in the Netherlands over the past four years. With a meteorological model, time series of day-ahead wind forecasts were generated for the period 2006-2009, and these were compared with APX-ENDEX day-ahead market prices. Wind energy contributes to only 4% of electricity generation in the Netherlands, but was found to depress average day-ahead market prices by about 5%.**

With the help of the bid curves on the APX-ENDEX day-ahead market for 2009, a model was made to assess the impact of increasing levels of wind generation on power prices in the Netherlands. One of the main findings is that the future impact on prices will be less than in the past. With an increase of installed wind capacity from 2200 MW to 6000 MW, average day-ahead prices are expected to be depressed by an additional 6% in case no additional conventional generation is assumed. Taking into account existing government policy on wind and ongoing work on new conventional power plants, prices in 2016 will be only 3% lower due to wind.

I. INTRODUCTION

A. *Wind and Electricity Markets*

Electricity markets can be divided into four types, depending on the time until delivery. Most electricity in the Netherlands is traded on the forward market ENDEX for days, weeks, months or years ahead of delivery. About one fifth of the consumed electricity is traded on the APX day-ahead market or spot market. A relatively illiquid intra-day market for adjustments after closure of the day-ahead market is also organized by the APX-ENDEX group [1]. The TSO TenneT operates the market for regulating and reserve power or the 'balancing market', which takes place over 15-minute periods.

All these markets are to some extent affected by the increased share of wind generation. The variation in wind power output over time provides an opportunity to assess the impact of different amounts of wind generation on prices. Since in a forward market only the average level of wind generation can be taken into account, the impact of wind on forward markets cannot be assessed in this way. At the day-ahead time scale, the amount of wind power generation can be predicted with a higher level of reliability than at the time of the forward market.

From the point of view of wind forecasts it would be more optimal to postpone adjustments of production updates to a time closer to real-time. This does not fundamentally differ from the forecasts of demand which also improve closer to real-time. In the absence of wind, the day-ahead market primarily functions to balance updated demand forecasts with updates in availability of generators. An historic choice was made to have the day-ahead markets 12-36 hours before real-time, among others because it allows most decisions regarding production to be taken during office hours. Choosing a shorter time to real-time, a lower estimated error in the demand forecast would take place, but higher cost due to adjustments of generation closer to real time. It is therefore unclear if it would be beneficial to move the 12-36 hour period closer to real time. Most day-ahead markets therefore operate 12-36 hours before real time.

B. *Relation with other work*

Other studies focusing on the impact of wind on power prices also chose the spot market as the most relevant power market for wind [2, 3]. In the TradeWind study [2], the most detailed information is provided on the Danish market. To visualize the impact of wind on prices a division of the hours into different wind speed classes was made. This example was followed in our analysis. For the Danish study, actual wind power generation figures were used. For our analysis we prefer to use wind forecasts because at the closure of the day-ahead market only the wind forecasts are known.

Obersteiner and Redl [3] have analyzed the impact on the German and Austrian markets. They use forecasted wind generation, and modeled the impact of wind and other types of generation on the spot market price for base load power. Their analysis shows that both wind and CCGT technology influence base load prices on the spot market. Curiously the short run marginal cost of hard coal power did not substantially influence the base load spot price.

In our analysis we have limited ourselves on purpose to market information only plus the use of wind forecasts. This allows the use of the findings as being complementary to the outcomes of market models using marginal cost of the different generation technologies.

II. THE IMPACT OF WIND ON ELECTRICITY PRICES

A. *Determining the Amount of Wind Generation*

To obtain a time series of day-ahead expected wind power generation, a time series of wind speed forecasts have been made. In the past decade the volume of wind turbines installed in the Netherlands increased rapidly as is shown in Fig. 1, which is based on regular overviews of new wind farms as kept updated by Wind Service Holland [4]. Only in 2009 there was practically no growth compared to the previous year. With the HIRLAM weather model [5], predictions of the wind speed were made for the location Medemblik for periods between 12 and 36 hours in advance, and for a height of 50 meters. These wind speeds have been multiplied with a standard power-wind speed curve to obtain the wind generation output per MW of installed capacity. In the next step this was multiplied with the installed wind capacity in the Netherlands to obtain a time series of day-ahead forecasts of the output of all wind turbines in the Netherlands.

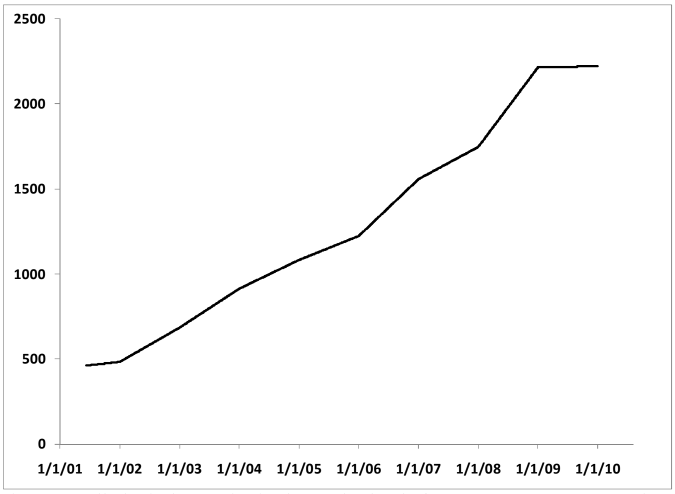

Fig.1. Installed wind capacity in the Netherlands from June 2001 to December 2009. Source: interpolation by ECN based on [4]

Over the period 2006-2009 the installed capacity of wind turbines in the Netherlands has increased with almost 50%. Table 1 shows the annual averages of the installed wind capacity and the average forecasted wind power generation. For the sake of comparison, also the volume of the APX day-ahead market is given. Incidentally, both wind generation and the day-ahead market volume are increasing at about the same rate. The average volume of wind generation is about one-fifth of the volume of the day-ahead market. This substantial share suggests that one can expect to observe an impact on prices.

TABLE 1
ANNUAL AVERAGES OF INSTALLED WIND GENERATION CAPACITY, FORECASTED WIND GENERATION AND APX VOLUME (MARKET CLEARING VOLUME) ALL IN MW FOR THE YEARS 2006-2009

	2006	2007	2008	2009	Average	
Installed wind capacity	1390	1651	1981	2218	1810	MW
Average forecasted wind generation	425	552	652	661	572	MW
Average APX volume	2196	2366	2826	3317	2676	MW

Sources: wind capacity: [4] wind generation forecasts: A. Brand, ECN; APX volume: APX-ENDEX.

B. *Day-ahead Prices for Different Categories of Wind Generation*

All hours of the year have been divided into four wind classes:

a) forecasted wind generation below 200 MWh per hour,
b) between 200-700 MWh per hour,
c) between 700-1200 MWh per hour, and
d) more than 1200 MWh per hour.

For each hour of the day, the average APX price is obtained for these four wind classes. As expected, higher wind output generally results in a lower average price. The largest impact (in absolute terms) is on the peak prices at around noon (see Fig. 2). At night, the effect is most regular: higher forecasted wind generation always leads to lower prices. In the late afternoon/early evening there are clearly other effects overshadowing a simple relation between wind and APX prices. As of yet, no plausible explanation has been found of this anomalous behaviour in the early evening peak.

Starting point in quantifying the impact of wind on electricity prices is to determine price levels at times when there is no wind generation. This is done in two different ways: firstly, by dividing all hours into different wind generation classes, and secondly by using regression analysis. APX prices during the hours in the lowest wind generation class (below 200 MWh per hour) can be interpreted as approximating the situation without any wind generation. Maximum wind generation in this class is about 11% of the installed wind capacity. During these hours the average wind generation is 4% of the installed capacity. Only 3% of the annual electricity produced by wind is generated in hours in which production is below 200 MWh per hour. These figures all suggest that the chosen interval from 0 to 200 MWh per hour is a good approximation of the situation without wind. Choosing a lower upper bound in hourly generation (below 200 MWh per hour) would reduce the number of hours in this category too much.

There is a disadvantage in this first approach of using the lowest wind generation category. Electricity demand is known to be higher at higher ambient temperature levels [6] and high temperatures are correlated with low wind speeds. Therefore an improved estimate of the hourly average APX prices in the absence of wind can be obtained from a regression analysis including temperature as one of the independent variables. Estimates of average hourly APX prices in the absence of wind power based on such a regression analysis are shown as the thick black curve in Fig. 2. This latter estimate of the day-ahead price in the absence of wind has been used in the remainder of the analysis.

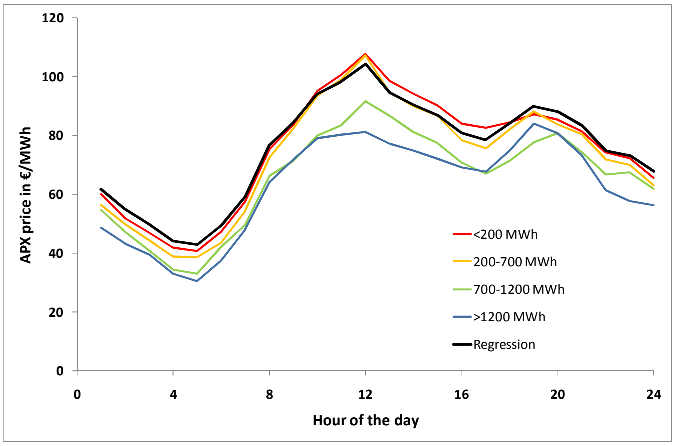

Fig. 2. Hourly average APX day-ahead prices in 2008 for different levels of forecasted wind generation (continuous curves) and for regression estimates for a situation with no wind (thick black curve).

C. *Summary of Impact on Average Price Levels*

There are three day-ahead price levels which are interesting for the analysis:

1) *Average day-ahead price* calculated by weighing hourly day-ahead prices with hourly day-ahead volumes. This price is relevant for all producers (and consumers of electricity. It contains the effects of wind generation as well as the impact of all other forms of generation.
2) *Wind energy price* calculated by weighing the hourly day-ahead prices with the volume of wind power generated. This price is primarily relevant for wind power developers because it provides the value of wind on the day-ahead market.
3) Day-ahead price in case the installed wind capacity does not generate electricity (*no-wind case*). This can be calculated in two alternative ways. First by weighing the hourly day-ahead prices with hourly day-ahead volumes, but only for those hours when the wind generation is below a certain limit (200 MWh per hour was chosen here). Another approach requires a regression analysis to find the day-ahead price at times the wind generation is exactly 0. These two methods provide price estimates for the annual averages which differ by about 1%. The regression approach is preferred in the rest of the analysis. This no-wind price level provides a starting point for quantifying the price depressing effect of wind power.

Summarizing the price impacts on four-year averages provides the following findings. Over the period 2006-2009 the average day-ahead electricity price in the Netherlands was found to be 53.04 €/MWh. Based on regression analysis findings, the average day-ahead price in the absence of wind generation was calculated to be 56.61 €/MWh. This implies that the wind has reduced average day-ahead prices by about 5%.

But this price depressing effect is even stronger when one focuses not on the general price level, but on the prices at times of wind generation. The value of electricity from wind on the day-ahead market was calculated by weighing the day-ahead market prices by the volume of hourly wind generation. These wind energy prices were about 6.5% below the average day-ahead prices and 11.5% below the calculated price in the absence of wind. This illustrates that even with a relatively modest contribution of wind generation (about 4% of total electricity generation in the Netherlands) the impact on electricity prices is already substantial.

Our findings regarding the impact of wind on average day-ahead prices are more or less in line with findings from other studies: TradeWind mentions an average of 6€/MWh reduction of spot prices in Spain in 2006, equivalent to 5% per 1000 MWh of wind. For Denmark, reduction percentages in day-ahead prices were observed of 14% in West Denmark and 5% in East Denmark in 2005 [2]. Obersteiner and Redl find for the German EEX a reduction in 2006 from 50.9 to 45.1 €/MWh [3].

III. A Simple Market Model to Assess the Impact of Wind on Electricity Prices

A. *Model Assumptions*

The analysis in the previous section was based on comparing wind generation forecasts with the actual prices realised on the APX day-ahead market, the so called Market Clearing Prices. Additional insights can be obtained from the information in the underlying bid curves. For each hour there is a curve of aggregated sales offers and a curve of aggregated purchase bids. At the point of intersection of the two curves one finds the market clearing price and volume. Please note that the purchase bids have no direct relation to the concept of electricity demand at that hour. Purchase bids often originate from electricity generation companies that formulate bids to buy electricity when the prices are too low to generate themselves. Furthermore, the day-ahead market is only one of a series of different markets, and not all electricity generation is traded on markets. Electricity demand therefore cannot be inferred from markets alone.

From APX-ENDEX BV we obtained for all 8760 hours of 2009 the bid curves, both ‘sales’ and ‘purchase’ curves, and the resulting Market Clearing Prices and Market Clearing Volumes. Wind appears to affect both ‘sales’ as well as the ‘purchase’ curves. The impact is not a simple shift of the whole curve by adding (part of) the additional wind generation as zero marginal cost power in the ‘sales’ curve, but turns out to be strongly dependent on the price level. The ‘sales’ curve is primarily affected at low price levels, and is almost unaffected at the maximum volume which take place at the highest price level of 3000 €/MWh. For the ‘purchase’ curve this is the other way around: it is practically unaffected at high price levels but shows most of the impact at low price levels at maximum volume.

One can simplify the analysis and ignore the detailed dependency of the ‘sales’ and ‘purchase’ curves on the price levels by focusing only on the total volume of sales offers and purchase bids. Fig. 3 shows for windy hours (forecasted>average wind generation) on working days in a single month (October 2009) how the total volume in purchase bids depends on the amount of forecasted wind generation. Because the forecasted wind generation is higher than the annual average one can expect an increase in expected volume of wind at the time of the day-ahead market. For every MWh of extra forecasted wind, the total volume of purchase bids was reduced by on average 0.225 MWh.

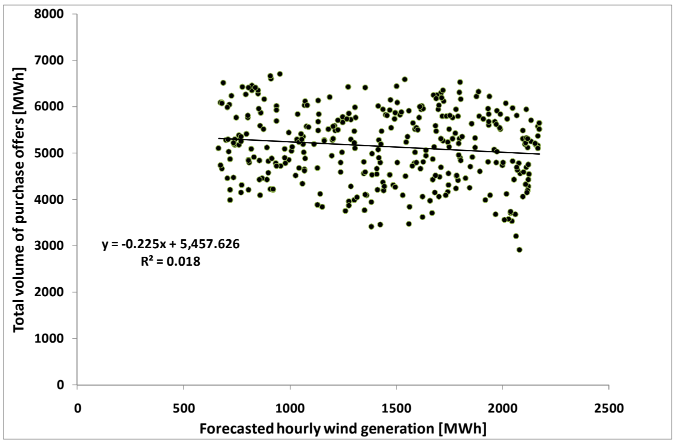

Fig. 3. Total volume of purchase bids in October 2009 for those hours in which the forecasted wind generation is higher than the annual wind generation.

When an extra amount of forecasted wind is affecting the volume of offers to sell or bids to purchase, the effect on the resulting market clearing price is independent on the division on either sales or purchases. An increase in volume of sales offers due to updated wind forecasts has precisely the same effect on prices as a similar decrease in the volume of purchase bids. In a similar way as shown in Fig. 3, sales offers were found to increase by 3.8% of every MWh extra forecasted wind. It is the combined effect which counts. For October 2009 a combined effect of 26.3% was found.

A simple model was built to assess the impact on day-ahead market prices of increasing volumes of wind generation. Additional wind is assumed to shift both 'purchase' and 'sales' curves separately with different percentages of the additional volume of wind generation. It is possible to scale-up 'sales' curves with additional conventional generation and 'purchase' curves with additional electricity demand growth. While it is acknowledged to be an oversimplification, it is expected to be an improvement compared to just extrapolating price impacts in previous years.

For the analysis described in the following section B only the installed wind capacity increases over the years, while electricity demand and the installed capacity of conventional generation remains constant. This is expanded in the next section D, in which also a growing electricity demand and increases in conventional generation are taken into account.

B. *Model Results with Constant Demand and Other Generation*

A single model run was conducted with a constant electricity demand over the years, and a constant level of non-wind generation, but with increasing levels of installed wind capacity in steps of 200 MW up to a level of 6000 MW. Since the impact on the price level of a shift in the purchase curve is equivalent to the impact of a shift in the sales curve, only one curve was assumed to be shifted in relation with increasing quantities of wind generation. The 'purchase' curve was assumed to be un-affected, while the 'sales' curve is assumed to shift with 30% of the additional wind generation. The rounded value of 30% was used and not the more precise value of 26% which was found for October 2009 to illustrate the expectation that this value is very much dependent on market conditions. The results of the simulations are presented in Fig. 4. It shows that the future impact of additional wind will be relatively smaller than in the past. An increase from the current level (end of 2009) of 2200 MW to 6000 MW will decrease the average APX price by almost 3 €/MWh, equivalent to 6% of electricity prices. The future impact is lower due to the reduced scarcity of electricity caused by the extra wind. This has a strong impact at small quantities of wind.

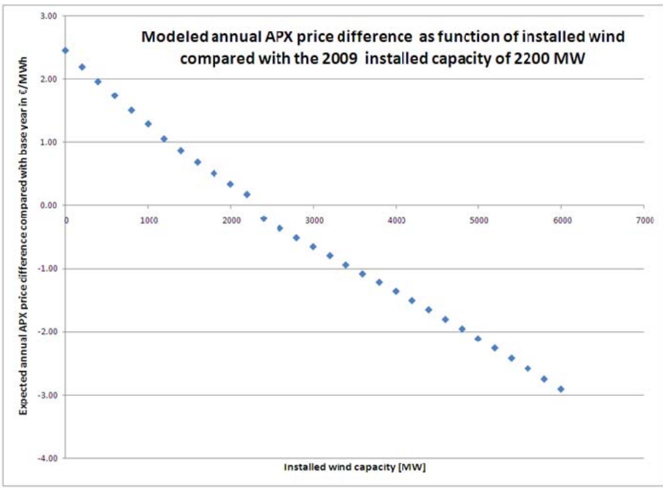

Fig. 4. Change in average annual APX price in €/MWh with different amounts of installed wind capacity in MW, assuming no change in conventional generation capacity, and compared with the 2009 price levels.

C. *Validation of Model with Constant Demand and Generation*

A simple validation of the model was performed by comparing the model-predicted increase in electricity prices at the level of 0 MW installed wind capacity (2.44 €/MWh, see Fig. 4) with the price increase found in 2009 based on actual prices. The regression-based estimate of the annual average APX price in 2009 in case of 'no wind' amounts to 42.11 €/MWh. The APX-volume weighted APX price was 39.63 €/MWh, resulting in a price difference of 2.48 €/MWh, which is very close to the model prediction of 2.44 €/MWh.

D. *Model Results with Changing Demand and Generation*

Electricity demand as observed by TenneT at the level of high voltage grids is assumed to increase from a level of 105 TWh in 2009, to 110 TWh in 2010 and growing with 4.5 TWh per year in the following years to account for the rapid growth in new generation power in the Netherlands. Purchase curves on the APX market are assumed to increase with the same growth percentage as the demand observed by TenneT.

Fig 5 shows the net cumulative generation capacity changes after 2009 based on the Reference Projections [7]. It includes decommissioning of 638 MW gas in 2013 and 600 MW gas in 2014.

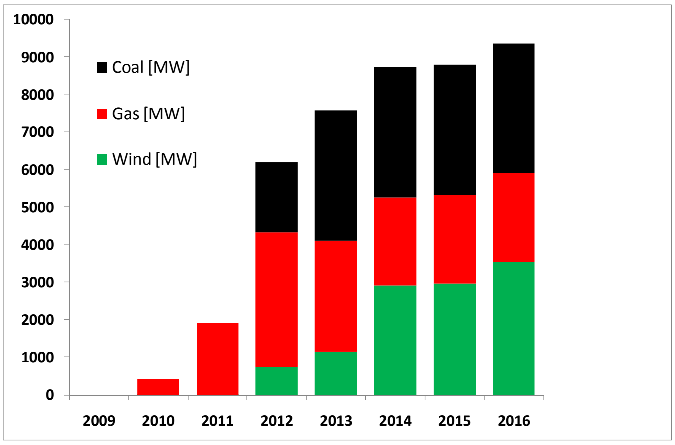

Fig. 5. Scenarios for cumulative installed generation capacity in MW over the period 2009-2016 under existing policy

Fig. 6 shows for each year in the period 2010-2016 the predicted effect on the day-ahead market prices of the increasing amounts of installed wind generation capacity and the changing amounts of conventional generation capacity as shown in Fig. 5. By taking into account demand increases and changes in conventional generation, the impact on prices is less than in the previous more academic case in which demand and conventional generation were assumed to be constant over the years. When the effects of a 30% electricity generation increase over the period 2009-2016 and an additional 5857 MW of conventional generation capacity are taken into account, prices in 2016 are predicted to decrease by 1.73 €/MWh due to the additional 3541 MW wind installed in the period 2009-2016. This is equivalent to a price depressing effect of only 3% of average day-ahead prices. As could be seen in figure 4 a similar increase in wind but without any changes in conventional generation leads to a much larger predicted price decrease of 2.73 €/MWh in 2016.

IV. Conclusion

A more or less straightforward statistical analysis has shown that over the past four years wind has had a substantial impact on day-ahead electricity prices in the Netherlands. Despite the relatively modest contribution of only 4% in electricity generation, average day-ahead prices were reduced by about 5%. A simple day-ahead model, which includes assumptions about future changes in conventional generation shows that in future the price-depressing effect of wind will continue to take place but at a slower rate than in the past.

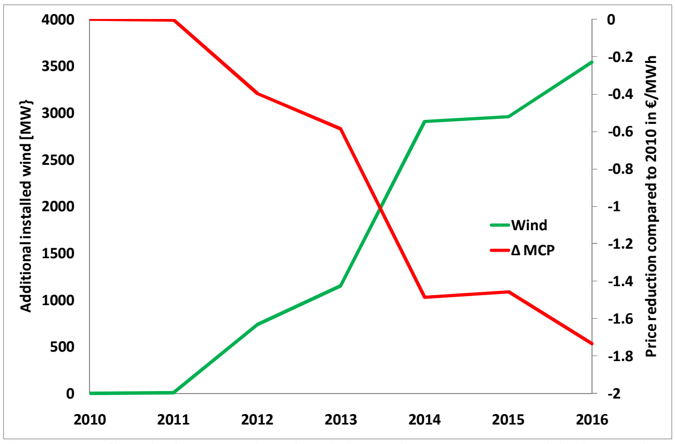

Fig. 6. Predicted decrease in electricity prices (ΔMCP) with increasing installed wind capacity compared to 2010 levels, including the effects of changes in conventional generation.

Acknowledgment

This work has been funded in 2010 by the Netherlands Ministry of Economic Affairs (recently renamed into Economic Affairs, Agriculture and Innovation). It is part of research to improve understanding of the impact of increased intermittency on electricity generation.

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