# Effective Pricing of Wind Power

## *Uncertainties in Wind Production Often Priced at Too Low Levels*

This article describes the pricing and hedging of wind power contracts. It demonstrates that substantial discounts relative to baseload power prices are reasonable to cover the negative wind-price correlation and to cover the difficulty of hedging price risks.

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In this article, we outline a sound approach to the assessment of wind power projects, based on a careful analysis of project returns. In particular, we describe a number of hedge mechanisms and highlight some common pitfalls in structuring wind power purchase agreement (PPA) deals.

Wind power is one of the most viable options to meet renewable energy targets. The attractiveness to investors depends on investment costs, expected future power price and (heavily) on the subsidy regime. But with the steady increase of wind production, the ability to secure future cashflows and to manage the risks becomes a key issue as well.

### *Wind Power Investments*

Among the various options for renewable energy, wind power production has shown the most steady growth rates. According to various sources, installed capacity grew worldwide by 20-40 % in each of the last 10 years. With about 180 TWh annual production per year, wind is now responsible for around 1 % of global electricity generation. Wind turbines are now primarily located in Western Europe (around 60 %), with the largest share in Germany and Spain. However, capacity is expanding rapidly elsewhere as well. For example, the US attracted the largest investments in 2006 and 2007, while Asian wind power also benefits from the general search for energy (see WorldPower 2007, Hays and Attwood).

Both policymakers and market players forecast continued growth in the next 5-10 years, attracting investments of €15-20 billion annually. As an example, in the EU, of all new capacity in the last five years, one third was wind power. And the EU's 2020 target of 20 % green power consumption is unimaginable without a steep wind power production increase – with wind being currently the most economical renewable energy source that does not eat away at worldwide food crops.

Nevertheless, growth rates have slowed down slightly in the last few years. Whereas incentive schemes have at times been extremely generous, rates of return are now more in line with actual capital costs. Moreover, efficiency improvements and economies of scale no longer always outweigh construction cost increases. As a result, investors have to take a more critical look at the financial prospects and risks in investment projects.

Total investment costs for onshore wind turbines are currently reaching €1,500 per kW installed capacity, up from less than half this amount about three years ago. Offshore investments are around twice that amount. A typical investment may have a required gross yield of 10 % return over a 20 year economic lifetime, roughly corresponding with an (undiscounted) pay-back period of 9 years. A quick calculation shows that this investment alone requires an annual income of €175,000/MW per year. Assuming 2,500 full load hours per year, sales prices should exceed €70/MWh. This calculation excludes the impact of operational expenses and subsidies, which also influence the required sales price.

Current baseload prices (February 15th 2008) for German power deliveries in the next four years are at a level of €60-64/MWh, so high wind power project returns are not self evident. Even worse, receiving an average baseload price is not very likely, as a result of both the price and volume risks discussed in this article.

### *Price & Wind Patterns*

Selling all the produced power at uncertain spot prices is definitely not a way to get new projects financed. Instead, selling off a large share of the expected power production in advance is necessary in order to attract any debt financing and to provide enough security for equity investors. Long-term PPAs are concluded between wind turbine investors and third parties – such as distribution companies and power traders – such that cashflow uncertainty is transferred to the third party. Notwithstanding this, some market player will eventually take on the risks of volume and price uncertainty and will want to be compensated for it, which will be reflected in the PPA contract terms.

PPAs are tailor-made contracts that cover for the inability to hedge the major price risks in the market. First, power production is rather unpredictable and certainly non-constant, so hedging with tradable block contracts (months, quarters, calendars) always leaves a lot of the actual production volume exposed to market price movements.

> ... installed capacity [wind] grew worldwide by 20-40 % in each of the last ten years

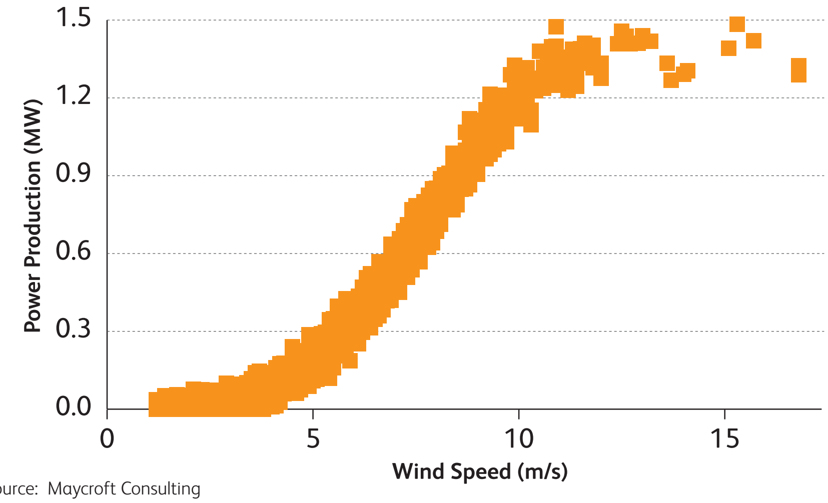
Second, even on the most liquid power markets, tradable contracts do not exist for more than four to six calendars ahead. Exposure beyond that period can hardly be hedged.

A 'full-service' PPA contract allows the wind turbine owner to sell off all production at a fixed price for the next 10-20 years. Understandably, the price for this service is at a large discount to current forward prices. A 'medium-service' PPA contract can reduce this discount. For example, it may be agreed that before the beginning of each year a hypothetical company *Windmill* may 'click' a price (perhaps the EEX calendar price of that day, minus a pre-determined premium) it receives from the off-taker for the power produced the next year. Because this structure leaves the long-term price risk with the wind turbine owner, the discount will be smaller.

### *Discount on Market Prices*

In any contract structure, the price for wind power will contain an adjustment relative to the market price. This is due to a variety of factors:

**FIGURE 1: WIND PRODUCTION PATTERN**




Source: Maycroft Consulting

1. Wind production has seasonal and daily patterns that either create a premium or discount.
2. Wind production is rather unpredictable, so causes imbalance costs.
3. Wind production is negatively correlated with market prices.

The first discount, in particular, is very location and market specific. Wind production depends on location (off-shore/coast/in-land), surface type and altitude, and no general wind production profile can be provided. Wind is typically stronger in winter and this works out positively for average sales prices in many markets. However, especially at higher altitudes, a daytime wind 'gap' may be observed. Such a wind gap can lead to a relatively large reduction in average power production, because power production is exponentially related to wind speed for the most common wind speed range of 3-8 m/s.

The second discount, related to imbalance costs, may be reduced through accurate forecasts. Moreover, better forecasts help to improve effectiveness of hedges. A good forecasting method incorporates a number of predictable patterns, including the seasonal and daily average shapes. Another feature is that wind speeds have shown a steady decline over the past 20-30 years at many locations in Europe. And finally, wind speed levels are clustered, meaning that we observe extended windy or calm periods (days, hours), and also extended periods where wind is very variable or very stable.

To understand the drivers of this second 'discount component', we use data from an arbitrary German windmill. Figure 1 shows production data in 15 minute intervals for a period covering one week in 2007. The forecasts were made one day in advance and used for daily communication ('Fahrplan') to the grid operator. They are compared with actual production. We observe deviations of 20-30 % between forecasted and actual production per 15 minutes. Even an aggregation by day still yields an average forecast error of 17 %. These numbers are not due to poor forecasting ability and are very common. The costs that the resulting imbalances create depend on the way imbalance costs are 'penalised'. The design of the imbalance market varies country by country, but imbalance is generally costly. In the Belgian market, for example, any imbalance leads to a cost of at least 10 % of the Belpex day-ahead price and can increase to over 50 % of the Belpex price when the wind turbine imbalance is in the same direction as the market's imbalance. In general, the larger the share of wind power in the supply mix, the more often a turbine's imbalance will be correlated with the market, and the larger will be the imbalance costs for individual turbine owners. With continuous wind capacity extensions, this is increasingly becoming an issue and should be appropriately priced into longer-term contracts.

A good forecasting method incorporates a number of predictable patterns

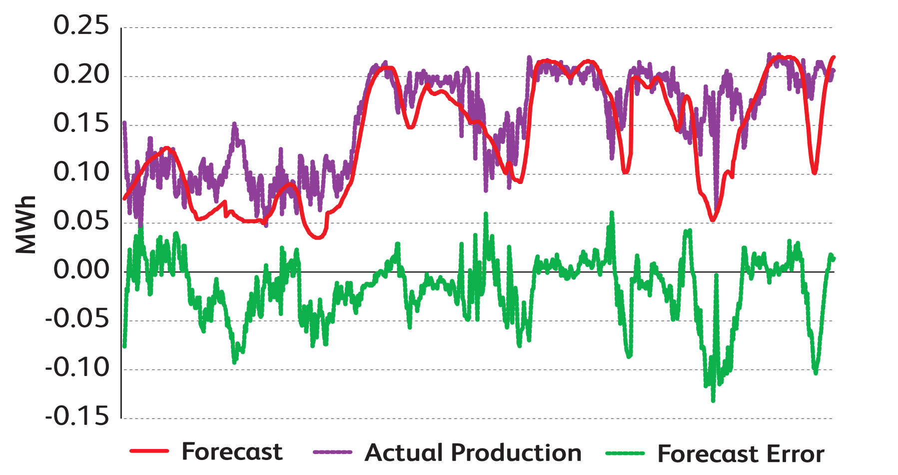
The relationship between wind power production and day-ahead market prices – the basis for the third discount – has been documented by several macro-level studies. A large study on the Danish market analysed how wind turbines influence the electricity price on the common Nordic spot market, and quantified the economic impact. It compared actual market prices in 2005 with the hypothetical situation if wind turbines did not exist. It concluded that electricity cost savings on the Nord Pool and the value of the exported wind power to Germany had a total value of over €250m, which exceeded the total amount of government subsidies. Whereas this is a gain to consumers, an individual turbine owner faces the situation of adversely selected production: The turbine produces more on days and hours when market prices are relatively low. This mechanism is similar to that of the imbalance discount.

## *Power Price & Wind Simulations*

Forecasting wind over several planning horizons helps to reduce imbalance costs and set up more effective hedges. However, as the 15 minute data demonstrated, even over short horizons, forecasts are almost certainly wrong. A proper assessment of average and potential turbine revenues therefore requires the evaluation of hundreds of potential scenarios of wind speed, power production and market prices, preferably through Monte Carlo simulation. Maycroft has conducted various studies involving the joint simulation of wind speed, power production and spot and forward market prices, which has lead to the development of its *Wind Power Pricing Model*. Typical questions addressed by the model are:

1. How much power will be produced on average per month or year and within what range?
2. What will be the average spot price at which the power can be sold?
3. What is the distribution of revenues generated by the mill when power is

**Figure 2: One Week of Wind Power Production**




Source: Maycroft Consulting

sold at spot prices?

4. What is an effective hedging strategy and how does it affect the distribution of revenues?
5. What is the distribution of Net Present Value and internal rate of return for the windmill under various hedging strategies?

Key to successful Monte Carlo simulations is to make realistic assumptions about the various dynamics, correlations and market fundamentals. The first building block for a windmill is a simulation model for wind power, taking into account the correlation with power spot prices. Elements that should be incorporated are the various levels of seasonality, the non-normality of wind speed levels and the serial autocorrelation (trends) in the wind speed over time. In Figure 3 we plotted the correlation between wind speed and power spot day-ahead price for the Dutch market. We used daily average price and wind data for an inland location and display a moving average correlation of one year. This type of correlation is incorporated in any wind-power simulation model. Correlation between wind and power price has almost always been negative and has a downward sloping trend. This trend is obviously caused by the increase in wind power generation capacity.

The second building block is a power spot price simulation model. The non-storability of power, combined with inelasticity in demand, causes spot prices to be very volatile and spiky. This is especially prevalent in power markets with no or limited hydropower capacity, such as Germany, France and The Netherlands. Maycroft uses stochastic jump and regime-switch models to capture this behaviour in power spot prices, (described in De Jong, *Studies in Non-linear Dynamics and Econometrics*, 2006). According to our experience, more basic mean-reverting models can give a biased picture of both expected turbine revenues and the distribution of turbine revenues. For example, an inappropriate incorporation of the short-lived spike behaviour tends to over-estimate the 'usual' volatility and therefore actually over-estimates risk.

The third building block is a simulation model for power forward prices. Joint power market price simulations of spot and forward are then created by linking the spot prices to the short-term forward price simulations. For evaluations of investments in fuel-fired power stations, we advocate the use of co-integration. Co-integration, as implemented in the *Fundamental Energy Market Simulation Model,* captures the fact that power peak and off-peak prices tend to move in line with marginal production costs. Since marginal production costs are primarily driven by coal, gas and $CO_2$ prices, the model incorporates fundamental relationships between power and these commodities.

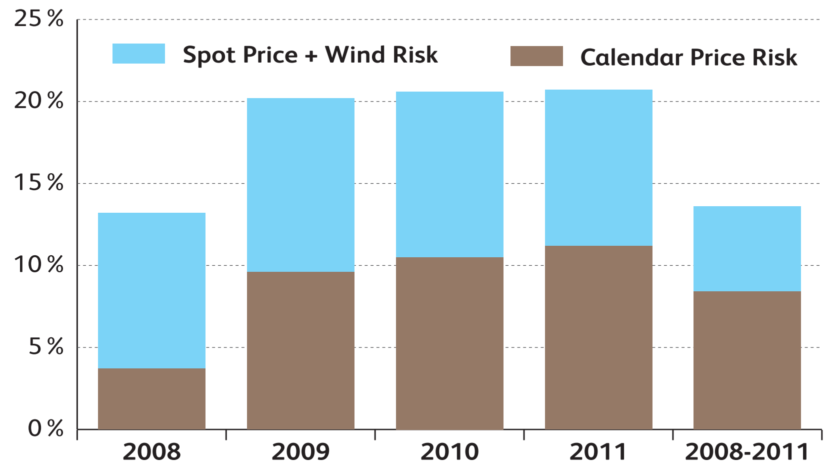
> Correlation between wind and power price has almost always been negative

Based on current and expected future production details per country, the user can 'steer' power prices in a specific direction. Although for longer-term power-fuel applications co-integration is indispensable, for turbine evaluations Maycroft's *Trading Energy Simulation Model* is most appropriate. The latter achieves a somewhat closer match between the simulated and actual correlations of market traded products. It is therefore extremely useful to evaluate hedging strategies and portfolio risks.

**Figure 3: Correlation Price – Wind**


Source: Maycroft Consulting

**Figure 4: Turbine Market Price**




Source: Maycroft Consulting

## *Hedge Effectiveness*

Using the simulation approach, we present results for a hypothetical windmill project. The turbine has a capacity of 1.5 MW and an average annual production of 3,680 MWh (28 % load). We assume it is December 2007 and turbine production starts on January 1st 2008. We evaluate potential revenues in the first four years, 2008-2012, and compare two basic hedging strategies:

1. Selling all power on the spot market.
2. Selling four years ahead on the forward market.

Note that in practice a combination of forward contracts may be used whereby, for example, 50 % is sold a long time ahead and hedges are further put in place over time using shorter maturities. We focus on market price risk, so ignore technical and imbalance risk. Furthermore, we assume that power spot prices are on average equal to forward prices for the same delivery period.

With forward prices trading at a level of €60.70/MWh, the analysis shows that a discount of almost €6/MWh is required to compensate for the negative correlation between wind production and spot prices. The weighted average spot price of €54.80/MWh leads to annual revenues of around €200,000. We consider this discount to be a conservative estimate, as we did not incorporate the trend of increasing (negative) correlation that may be expected for the future.

With hedging, the consequences of unexpected drops in the power price can be limited. Without any hedge, especially when analysing spot revenues in the later calendars, income is uncertain due to potential price changes. The power price risk increases, therefore, from a low €2/MWh in 2008 to almost €7/MWh in 2011. However, a considerable proportion of the forward price risk can be hedged by selling the power ahead in the forward market. Note that revenues in individual years may be volatile, but that the average revenues over multiple years are more stable.

Combining price risk and production spot price correlation risk leads to an increase in the standard deviation of average annual revenues from 13.2 % in 2008 to 20.7 % in 2011. All this is summarised in the Figure 4.

In practice, a hedge scheme may be more sophisticated than just using calendars at one specific point in time – for example using monthly forward contracts. The monthly hedge has the advantage of incorporating expected monthly production patterns, but since monthly forecasts are generally rather poor, the benefits to a calendar hedge are somewhat limited. Most importantly, although the analysis demonstrates that a forward market hedge reduces exposure to market price movements, a considerable proportion of the market risk remains. Spot price risk is at a level of 50-70 % for the four individual years and 35-40 % for their average.

> ... these risks are easily overlooked and wind power priced too optimistically

On top of this, calendar forward prices are generally available for, at most, four to six years ahead, so the remaining production years are totally exposed to market price movements. A so-called ‘roll-over’ hedge may take away part of this longer-term price risk though. For example, one may sell forward larger volumes in the 2011 contract in order to hedge expected production in the years 2012 and beyond, and then each year roll the position to the new longest maturity. Such a roll-over strategy can reduce mark-to-market exposure but is not very common as it may also induce large margin calls on the exchange where the hedge is executed.

## *Pricing Components*

Wind power contracts typically contain discounts relative to the market forward prices. This derives from the difficulty in forecasting wind production and the variability in wind production, the correlation with market prices (imbalance and day-ahead). In the case presented, the correlation between day-ahead prices and wind production was already responsible for a discount of €6/MWh. A typical discount for imbalance costs has about the same magnitude, leading to an expected revenue shortfall of €12/MWh – without even taking into account the effects of the continuous increase of wind production on spot power prices.

The analysis also demonstrates that a considerable proportion of the price risks, both short-term and long-term, are unhedgeable and should be incorporated in additional discounts. It is our experience that these risks are easily overlooked and wind power priced too optimistically. ■

**Cyriel de Jong** and **Hans van Dijken** work at Maycroft Consulting, an independent consultancy firm offering specialised advice on trading and risk management in energy markets. Maycroft advise energy companies, end-users, exchanges, governments, regulators and financial institutions.

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