Abstract

Led by energy and environmental policies the EU power sector is undergoing vast changes to achieve a market driven and sustainable future. Market based price discovery and different renewable support schemes are seen as key solutions in achieving the desired future production mix. Most liquid power markets use marginal cost based price discovery where the price is set by marginal costs of the last producer needed to cover all load, usually a fossil fuel power plant. At the same time the majority of new investments are made with significant help from government support schemes in renewable production capacities, which have very low marginal costs. The increasing share of renewable production will thus impact price levels in day-ahead markets. This paper analyses the potential impact of more renewable electricity production on price discovery in the NordPool Spot market, which already has a high share of renewable electricity traded. Results show that ceteris paribus NordPool Spot is likely to have very high price volatility in the future and alternative revenue sources are required for new investments.

Keywords: Electricity price; marginal cost; NordPool; renewable energy

Introduction

The European Union’s 20-20-20 targets commit member countries to 20% renewable energy use by year 2020 with expectations for renewable electricity share as high as 60%. Even larger ambitions are being considered for 2050 with almost 100% of electricity used in the European Union coming from non-CO₂ emitting sources (European Commission, 2012). Increasing oil prices further encourage use of renewable energy. This topic is equally intensively discussed in Northern Europe, which has one of the world’s most integrated international electricity markets – the NordPool – where all electricity trading between Norway, Denmark, Sweden, Finland, Estonia and Lithuania takes place. Latvia is expected to join NordPool in June 2013.

According to economic theory, in perfect competition market price is equal to the marginal costs of producers. The purpose of marginal cost pricing in electricity markets is to differentiate consumption by time of use and geographical area so costs could be conveyed to consumers in a fair way. Consumers on the other hand could make an informed decision about their consumption level in order to economize it (Malik and Al-Zubeidi, 2006). This is also the underlying logic for trading at NordPool. The sale price is determined by the marginal cost of all producers and the bidding price of the most expensive auction winning unit at each point.
in time sets the sale price for any given time (Nielsen et al. 2011). As the marginal costs are higher for fossil fuel based power plants (owing to fuel and CO₂ emission costs), volumes produced by such plants will eventually determine the overall price level in the region.

Such a scheme works well as long as there is some predictability in the system. However if fossil fuelled plants are increasingly replaced by renewable sources of energy the system price is likely to decrease: wind, solar and hydro power plants have no fuel or emission costs and depending on the technology used some of those plants could also be subsidised. This means that if all consumption could be covered by renewable production with low marginal costs, the price of electricity on the day-ahead market would drop. This would reduce revenues for power producers and could make it unattractive for new investors to set up new production capacity in the region. Whereas literature exists on the topic of integrating more renewable capacity to electricity markets, to the authors’ knowledge broader public discussion on this issue in Northern Europe is yet to take off.

This article is set up as follows. First, relevant literature is reviewed to indicate the most appropriate costing methodology for electricity markets, showing why and how marginal costs are the best choice. Second, marginal costs of various production technologies are presented, providing a comparative overview of generators used to feed electricity to the NordPool power exchange. A presentation of the NordPool setup and what-if analysis on future price trends follows. The authors introduce calculations for future electricity price development assuming 10GW and 20GW of new renewable energy production (as per publicly discussed renewable energy targets), acknowledging the effect on marginal cost as well as savings from fuel and CO₂ emissions. Presentation of key takeaways concludes the analysis.

**Literature review: explanation of marginal cost pricing for electricity**

Due to its role as a pivotal component of modern life and development the cost of electricity needs to address production and transmission costs as well as meet social and political objectives at the same time (Malik and Al-Zubeidi, 2006). Even without these supplementary objectives achievement of the core component – economic efficiency in production and transmission – is a challenge: production costs of electricity vary with changes in electricity demand and time.

Friedman (2011) argues that real-life electricity prices are almost never equal to the marginal costs of providing it. Referring to United States electricity markets he demonstrates that electricity sales rates are usually set at average cost. This means that actual marginal cost during peak periods has been higher and during off-peak periods below the average. Accordingly, several high marginal cost power plants have been built with the aim of operating only during peak periods, with substantial unused capacity during the off-peak. This results in overconsumption of electricity during peaks and under-consumption during off-peak periods. Consequently according to Friedman’s (2011) calculations the average U.S. residential consumer faces a price for off-peak electricity that is 331% above its actual marginal cost.

The idea that market pricing cannot be based on marginal costs is also found in Jakubiak (2004), as he argues that market entry is well above zero and hard to calculate into marginal costs (especially since it is not instantaneous); and because markets operate on an hourly or
sub-hourly basis whereas production decisions are often made on a multi-hour basis (Jaku- 
biak, 2004).

Hartley and Moran (2000) offer an explanation to Friedman’s (2011) findings: in a compe-
titive auction market prices are always set so that the market clears, with both demand and 
supply adjusting. As demand has low price elasticity, all adjustment in the short term is on 
the supply side. In the long term the relationship between prices and production costs will 
depend on the level of demand and the way costs vary with output. If a producer exhibits 
increasing returns to expanding output, average costs will fall as output expands and marginal 
costs will be smaller than average costs. If there are decreasing returns to scale, average costs 
will rise as output expands and marginal costs will exceed average costs. Therefore, behav-
ior of average costs as output expands has a critical influence on whether electricity prices 
in an auction market are likely to be sufficient to cover the costs of production or vice versa 
(Hartley and Moran, 2000).

Malik and Al-Zubeidi (2006) further explain that the difference between short and long term 
pricing lies in consideration of investments: in the short-run all capital equipment is fixed so 
marginal costs include the cost of producing an additional unit of electricity with existing 
capacity. In the long term investments can be made to alter capacity and equipment. In that 
case the marginal cost is defined as the difference in present value of the future stream of 
costs associated with producing an additional unit of electricity. Hence costs must be related 
to the economic value of future resources required to meet increased consumption (Malik 
and Al-Zubeidi, 2006). Hartley and Moran (2000) also conclude that all future costs must be 
reflected; otherwise the market would be signalling that there is excessive supply and some 
capacity will exit or new capacity will be deferred until market growth exhausts the over-
capacity. This helps explain some of the findings from Friedman (2011): if price is higher 
than marginal costs it does not necessarily mean the existence of market power; or owe to the 
specifics of the electricity market, as also happens in other capital intensive industries such as 
air transport and offices (Hartley and Moran, 2000).

![Diagram](image-url)  
**Figure 1.** Bid placement alternatives for power producers (authors’ drawing)
Yet it can easily be proven that it is optimal for power producers to always bid at their short-run marginal production cost level (see Figure 1). The electricity sales market consists of several bidders, each with a different cost base. As market price is set by the most costly auction winning unit, all of the producers get the same price, even though they offer to sell at different prices.

If a producer makes a bid \( BP_j \) higher than its short-run marginal costs \( SRMC \) and the market clearing price \( MCP_j \) is between these two values, the bid will not be accepted and the producer will lose the right to sell electricity to the market. The producer would otherwise have earned the difference between the market price and its short-run marginal costs: \( \pi_j = q^* x (MCP_j - SRMC) \) where \( q^* \) is the amount of electricity that could have been produced. If the producer makes a bid \( BP_j \) which is lower than \( SRMC \) and the market clearing price \( MCP_j \) is also lower, then the producer will be forced to sell below its marginal costs and make a loss: \( -\pi_j = q^* x (SRMC - MCP_j) \). Therefore it is optimal for producers to always bid at a price that is equal to marginal costs. This is the basis for considerations further in this article.

Nielsen et al. (2011) have reached the same conclusion: as the eventual selling price is the same for all bidders, producers will prefer to bid close to their own short term marginal costs and have the highest possible chance of winning the auction, while also hoping to win more expensive bids. Indeed, electricity trading in open markets is a rather short-run process: auction markets set prices on an almost continuous basis to balance supply and demand. Although electricity futures and forward contracts can also be traded for e.g. 5 years ahead, they do not adequately consider changes in capacity, therefore reflecting the short run marginal costs of supply and not the longer run costs associated with ensuring a continuing supply of capital to the industry (Hartley and Moran, 2000).

**Prior findings on marginal costs of electricity production**

NordPool is divided into the Elspot and Elbas markets, where the former is the day-ahead market and the latter is an intraday balancing market. This paper focuses on price formation in the day-ahead market (Elspot) as most of the trading takes place there. Buyers and sellers on the Elspot market place bids before noon the day before the physical transaction takes place (Nielsen et al., 2011). Demand for electricity is primarily dependent on temperature, length of the day from sunrise to sunset, and the level of industrial production (Hjalmarsson, 2000). As the sale price is the same for all producers on the NordPool spot power exchange, the economically most efficient production units will earn the most, and units with the highest bidding price will earn just enough to cover their short run marginal costs.

Producers with the lowest short term marginal costs are owners of wind turbines, hydro plants and nuclear plants. For a nuclear power plant the short run marginal cost includes fuel and operating and maintenance (O&M) costs, approximately at 10 EUR/MWh (Roques et al., 2006). For hydro power plants the direct hydropower operation costs are negligible. Indirect costs are the opportunity costs of releasing water, as water could be stored and used for future generation. Opportunity costs are therefore equal to the expected future value of electricity produced (Faria and Fletten, 2011). The short-run marginal costs of power production in wind parks consist primarily of O&M costs, approximately at 5 EUR/MWh (Reuters, 2012). These
sources are followed by combined heat and power (CHP) units, condensing power plants, coal, biomass, gas and oil fired generators. Actual costs vary depending on exact location, country regulations (especially regarding CO₂ quotas and/or other taxes, subsidies) but the short run marginal cost for a conventional coal fired power plant (which is used as a comparison for renewable generation technologies in this article) currently equals approximately 40 EUR/MWh with an efficiency rate of 40% (Reuters, 2012). This covers fuel cost, emission costs and O&M costs.

David Milborrow (2011) has performed an overview of both capital cost estimates as well as operational costs for various production technologies, comparing results globally and also providing a discounted year 2020 estimate. This allows for calculation of long-run marginal costs, where producers have to consider all future costs including divestment and new investments. Long-run marginal costs can be split into two components: capacity and energy cost. The former is the cost of a generating unit that in an optimal system would be added to accommodate increased peak period demands – i.e. to sustain demand indefinitely. The latter consists of generation, transmission and distribution costs including fuel and variable operating costs of the machine with the highest running cost of operation at that hour (Majumdar et al., 1997). Findings from Milborrow’s work are presented in Figure 2 below. As his calculations excluded hydropower and biomass, these have been added from external sources without projections for year 2020.

![Figure 2](image)

**Figure 2.** Indicative long-run marginal costs of various technologies in 2010 and 2020 (discounted) in the UK. Authors’ drawing based on Milborrow (2011), EUBIA (2012) and EREC (2012)

It is visible from Figure 2 that the lowest long-term marginal costs are in fact in hydropower based technology; and other renewable technologies (in addition to gas turbines) follow suit. Considering future cost developments especially in CO₂ emission quotas and fuel, it can be estimated that hydropower would remain the cheapest source of power; followed by onshore wind. No projections are available for biomass, but its price is likely to decrease rather than increase, making it similarly attractive to onshore wind power. Milborrow (2011) indicates that there is also a reasonable consistency in the literature on the costs of coal and gas plants,
using fuel price guidance and a carbon price of around 35 euro per tonne. He admits that there are difficulties in coming up with plausible values for nuclear, as most construction data from recent years are usually from outside Europe and North America – hence financing institutions would also likely require a “risk premium”, which raises the cost of capital (Milborrow, 2011).

Milborrow’s long-run marginal cost estimations confirm the trends in short-run marginal costs (which determine daily pricing in NordPool), i.e. that renewable technologies have lower marginal costs than conventional technologies used today. Given the argument that net electricity prices will in fact be lower because of low marginal costs of renewable technologies offsetting the cost of subsidies to promote them (de Miera et al., 2008) – and environmental concerns for a cleaner future – it is clear that increase of renewable technologies in the production mix is inevitable. Owing to this article’s aim it is therefore valid to analyse to what extent renewable producers have already influenced NordPool pricing and how likely it is to change in the future.

**Functionality of electricity trading at NordPool**

The latest information available for 2011 shows that electricity generated from renewable energy sources amounted to 20.4% of the EU-27’s gross electricity consumption (Eurostat, 2013). In Norway more than total (103.6%) and in Sweden more than half (56.4%) of all electricity consumed was generated primarily from hydropower and biomass (Eurostat, 2012a). In 2010 59% of total electricity consumption in the Nordic and Baltic countries (Denmark, Estonia, Finland, Latvia, Lithuania, Norway, Sweden) was covered from renewable sources as of 2009 (Eurostat, 2012b, 2012c). The remaining 148TWh of demand were produced from nuclear and fossil fuels, roughly 50% from each (NordPool, 2011).

![Figure 3. NordPool Spot bid curves in hours 05:00-06:00 on seven consecutive days leading up to 27.04.2011 and 07.10.2011 respectively (S-shaped vertical lines) together with set system price (shown as black dots), short run marginal costs of coal-fired power plant (solid horizontal line) and reservoir levels in hydro power plants (dotted horizontal line). Authors’ drawings based on NordPool Spot and Reuters data.](image-url)
Given the high amounts of hydropower installed in the area (48% of total net electricity production in 2010 as per Eurostat 2012c) the reservoir levels of hydropower plants play an important role in today’s price setting. Low hydro reservoir levels increase the opportunity cost of using water for power production, which in turn increases hydropower’s marginal costs. High hydro reservoir levels on the contrary reduce the opportunity costs and hence lower the bid curves and market prices as shown on Figure 3. In the left hand graph (at end-April) the hydro reservoirs are less full than in the right hand graph (at end-October). The sales price (shown as black dots) at the same consumption levels (indicated as S-curved vertical lines for 7 consecutive days) is therefore much closer to the short run marginal cost levels of coal-fired power plants (49 EUR/MWh) on the left-hand graph, dropping significantly to around 10 EUR/MWh in the right hand graph as hydro plants have full reservoirs and need to produce power in order to avoid spilling water.

Decreasing sale price of electricity as a result of more renewable generation has also been measured by Sensfuß et al. (2008) in Germany; Nielsen et al. (2011) prove using historical data that the Danish electricity price has similarly been impacted by the amount of wind power in the system: in Western Denmark in 2009 the average price was 37.19 €/MWh with wind production below 750 MW and 34.46 €/MWh with wind production above 1750 MW. As wind power is an unpredictable source of power (wind might also be blowing at low demand levels) Nielsen et al. (2011) demonstrate that occasionally the system price has in fact decreased to negative values due to too much power from low cost sources: in the night between December 25th and 26th 2009 Western Denmark had negative prices (i.e producers had to pay in order to put power into the network) during 8 consecutive hours with prices reaching -119 €/MWh. Negative prices are increasingly becoming a normal sight: before negative prices were allowed in Germany, oversupply was cut on a pro-rata basis which led to inefficiency (Nicolosi, 2010). Renewable production is not the only reason for oversupply: as explained by Nicolosi (2010) conventional power plants are not designed for fluctuating demand (this would reduce the lifetime of some parts that are exposed to high levels of pressure and heat) and can thus incur costs for later ramp-up if asked to ramp-down. Therefore, it is efficient to introduce such opportunity costs to the bid. Indeed, Nielsen et al. (2011) confirm that combined heat and power plants (with large start-up costs) had their share in Danish negative prices as did bottlenecks in transmission out of Western Denmark.

Figure 4. Correlation between hourly NordPool Spot prices in the DK1 price zone and consumption and wind production forecast in 2011. Authors’ drawings based on NordPool Spot data.
Analysis of market data carried out by the authors of this paper shows that negative prices have occurred on a number of occasions in Denmark during the night hours but not necessarily at the highest wind production hours or during the lowest consumption levels (ref. Figure 4). In the NordPool Elspot system the minimum requirement for a single hourly order is two price steps, minimum price (-200 euro) and maximum price (2000 euro). Negative prices are the result of market design and the equilibrium of supply and demand at any given hour. Occurrence of negative prices can be expected to continue in the coming years especially in price areas where wind production is likely to increase the most in the NordPool Spot area.

As explained earlier, profit-maximizing firms set their marginal cost equal to their perceived marginal revenue. In perfect competition price equals marginal costs and hence the perceived marginal revenue (Hjalmarsson, 2000). NordPool functions the same way, hence electricity trading is based on short-run marginal costs instead of long-run marginal costs. This is a natural choice given the way the market operates – if producers indicated (higher) long-run marginal costs, they would have a lower chance of winning the auction as the system price is determined after all sales bids have been received. In the case of some technologies – such as the above-mentioned CHP plants and new generation technology which is subsidised (e.g. some biomass, wind and solar power plants) – it is therefore profitable to bid even at very low price levels and occasionally even with negative prices as has already happened in Denmark according to the example provided by Nielsen et al. (2011) above. Indeed, as demand varies throughout the day and year energy is valued differently. Since wind farms have different generation patterns, wind energy pricing should take into consideration the different value of energy expressed in forward and balancing market signals (Hiroux and Saguan, 2010): an increased number of hours with reduced prices could result in less income from the electricity market for wind power, making investments less feasible and less likely to take place (Nielsen et al., 2011). Hence new market entrants will be effectively competing against the short-run marginal costs of existing units in the market.

The above data are sufficient to prove that if the share of renewable power production capacities continues to be increased in NordPool then significant changes in the short-run cost curve can be expected. This would introduce increased volatility in price levels. The following section attempts to model some potential impacts to better illustrate expectations.

**Implications for future price trends: modelling methodology**

The authors of this paper have estimated the potential impact of additional wind farms on the NordPool Spot System price for 2011. According to the European Wind Energy Association total installed wind capacity in the NordPool area was 7843 MW in 2011 and 9460 MW in 2012 (European Wind Energy Association, 2013). Two scenarios were used: in the first case an additional 10 000 MW of wind capacity would be available on the market i.e. doubling existing wind capacity. In the second scenario an additional 20 000 MW of wind capacity was used, i.e. tripling existing wind capacity. Even though it is unlikely that all new capacity will only be based on wind power (some new renewable capacity will be based on biofuels and solar power), wind nevertheless proves a good example as technology which is subsidised and with very low marginal costs. Official hourly market data (wind production prognoses, trading volume, Elspot system price curves, Elspot prices etc.) published by NordPool were used in modelling. Year 2011 was chosen as the only full year with available bidding curve
data used in NordPool spot system price calculations (Nordpool Spot, 2012) at the moment of modelling. For wind production modelling, the sum of hourly day ahead wind predictions from NordPool Danish price areas DK1 and DK2 were used. Only Danish wind data were chosen as not all the relevant countries publish hourly wind production forecasts for the whole period. Prediction data and not actual production data were used as actual production data are not available at the moment of bid submission in NordPool (i.e. previous day 12:00 CET). The assumption was made that the wind parks sell their entire production to NordPool Elspot and act as price takers i.e. submit bids at the marginal cost level. As feed-in-tariffs are usually available for producers, the marginal cost for wind parks was assumed to be -30 EUR/MWh (i.e. operational costs 5 euro/MWh less by subsidy 35 euro/MWh (Egeberg-Gjelstrup, 2011)). It was also assumed that other producers will not change their bidding behaviour. For each hour a new system spot price was calculated based on existing bidding curves and additional wind production volume. It was assumed that additional wind production would participate in the spot market. Additional wind production will therefore shift the bid (supply) curve to the right. It was assumed that short-run electricity demand is price inelastic. Figure 5 illustrates the price calculation principle used.

![Figure 5](image_url)

**Figure 5.** Price change estimation from more renewable production. The solid line is the actual bidding curve for a given hour and the dotted line the new bidding curve shifted to the right by estimated wind production for a given hour.

### Results of modelling

Figure 6 shows consolidated actual NordPool Elspot year 2011 system prices (in descending order) and results of estimated new prices given the two scenarios of additional 10 000 MW and 20 000 MW of wind power. It can be seen that further implementation of renewable (wind) capacity will have a relatively small impact during peak hours, but will significantly increase price volatility during medium and low price hours, especially in a +20 000 MW scenario. This is consistent with results in Milstein and Tishler (2011) who analysed introduction of solar PV production to the Israeli electricity market. As seen from Figure 6, only 223 out of 8760 hours in year 2011 had actual prices of less than 10 EUR/MWh. In the case of a +10 000 MW scenario 1607 hours can be expected to be less than 10 EUR/MWh; the figure in +20 000 MW scenario is respectively 3218 hours.
The actual average system spot price for 2011 in Nord Pool was 47.05 EUR/MWh, in a +10 000 MW scenario the yearly average price would drop to 36.74 EUR/MWh and in a +20 000 MW scenario to 23.93 EUR/MWh. At these prices it is not feasible to invest in new production capacities and higher subsidies are needed (ceteris paribus). Mount et al. (2012) prove that more wind generation capacity also results in higher transmission system operating costs. As such costs are outside the scope of this article they are here ignored.

Figure 6. Nord Pool Spot actual system price curve for 2011 (in descending order) and estimated prices if an additional 10 000 MW or 20 000 MW of wind power is installed in the Nordic power system. Price estimations are based on actual Nord Pool bid curve data for 2011.

Table 1. Average NordPool Spot System Price in 2011 and in the case of 10 000 MW & 20 000 MW. Saved variable costs and lost revenue for producers due to price decrease.

<table>
<thead>
<tr>
<th></th>
<th>NordPool spot system</th>
<th>+ 10 GWh wind</th>
<th>+20 GWh wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average price (EUR/MWh)</td>
<td>47.05</td>
<td>36.74</td>
<td>23.93</td>
</tr>
<tr>
<td>Price decrease (EUR/MWh)</td>
<td>-10.31</td>
<td>-23.12</td>
<td></td>
</tr>
<tr>
<td>Wind production forecast (TWh)</td>
<td>7.9</td>
<td>23.9</td>
<td>47.8</td>
</tr>
<tr>
<td>Saved fuel and O&amp;M costs (mEUR) *</td>
<td>1 100</td>
<td>2 200</td>
<td></td>
</tr>
<tr>
<td>Loss of producer revenue (mEUR)</td>
<td>2 800</td>
<td>6 500</td>
<td></td>
</tr>
<tr>
<td>Loss of producer cash flow (mEUR)</td>
<td>1 700</td>
<td>4 300</td>
<td></td>
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Replacing fossil fuel based power plants translates to savings on fuel, emissions and O&M costs. In the case of the +10 000 MW scenario 24 TWh of thermal production could be replaced and 48 TWh in the case of +20 000 MW wind power. For calculation purposes costs saved are assumed to be equal to coal fired power plant costs (net efficiency 40%, O&M 4 EUR/MWh, coal market prices in North-Western Europe (Reuters, 2012)). Under these assumptions some 1.1 – 2.2 billion EUR could be saved in variable costs annually. However due to sale price decrease all producers in NordPool would lose revenues totalling 2.8 – 6.5 billion EUR to consumers.

That means producers would have approximately 1.7 – 4.3 billion EUR less to cover fixed and capital costs and invest in new production capacities. Table 1 underlines that lower mar-
ginal costs could create a feedback mechanism that would lead to a volatile power market; which in turn means that new investments would need even more (and/or different) support than today.

Discussion

The European Union’s 20-20-20 targets commit member countries to 20% renewable energy use by year 2020 with expectations for renewable electricity share as high as 60%. Even larger ambitions are being considered for 2050 with almost 100% of electricity used in the European Union coming from non-CO₂ emitting sources. In order to achieve these ambitious goals large investments in renewable or nuclear capacities are required in the coming years. This paper demonstrates that these investments might not be feasible at current market prices and with the current market pricing mechanism.

The market price in the Nordic and Baltic countries is established on the hourly day-ahead spot market NordPool. Similar spot price establishment principles are also used in several other power markets. Roughly 80-90% of the electricity consumption in the Nordics is traded through the Elspot market, making it the most liquid and transparent power market. The Nordic countries have also been the forerunners in investing in renewable energy sources. Despite a large share of renewable electricity generation in the power mix, usually coal-fired power plants are needed to meet the load in the region. The planned move from fossil fuelled power plants to an even larger share of renewable production capacities will radically change the cost structure of power production under current support schemes, impacting bidding cost curves on the spot market.

Modelling the potential impact of increasing wind power capacity two or three times in the region shows that such an increase of low-marginal-cost-based capacity would significantly alter the electricity production merit order in the region by altering the producers’ bidding curve. This would result in potential price collapses on the spot market during otherwise low price periods. The resulting decrease of the spot price (which means savings for consumers) would be bigger than the avoided variable costs in power plants (which means lost revenue for producers). Thus in the long run the price from the day-ahead market where participants bid at their short-run marginal cost levels cannot support the full cost of new investments. Savings that arise from fuel and emissions costs are by far smaller than loss in revenue, thereby reducing producers’ ability to cover capital and fixed costs. Also the volatility of the power price on the spot market would increase as additional wind capacity would have a limited effect on peak prices when conventional power plants are needed to cover electricity consumption.

Extrapolating these findings towards the European Union’s ambitious goal of increased share of renewable electricity sources in power production, it can be assumed that NordPool-like price discovery would not lead to sustainable price levels for new investments or even for existing power plants to recover fixed and capital costs. As the spot market price falls, the significance of the spot market price would be reduced both for consumers and producers as well. New sources of revenue would be required for producers in order to ensure long-term financial sustainability of the power sector.
It seems inevitable that at least in the near term the pricing policy at NordPool Spot is likely to remain unchanged; so the discussion rather needs to focus on long run options. The bigger the subsidies are, the more subsidies are needed in order to cover full costs after spot market revenues if the subsidisation period is not capped. One solution could be capacity markets where only non-intermittent (i.e. not wind or solar) producers could participate. Another option would be to integrate the entire power system management from “smart consumption” through “smart grids” to flexible power generation from lower base load capacity as discussed by Milstein and Tishler (2011) and Nicolosi (2010).

Whatever the ultimate solution, the key is for producers to have more incentives for long-term planning so that when the countries in Northern Europe assume to be making a commitment to a “greener future”, it is also clear how to financially sustain it.

**Limitations**

Issues highlighted in this article are inevitably constrained by a number of limitations. Actual wind power data from Denmark has been used to model all wind production in Northern Europe and also used to illustrate effects from biofuels and other renewable technology. As argued, this is sufficient to make the point of decreasing marginal costs.

The authors also acknowledge that their modelling is a simplification since additional wind power would somewhat reduce the use of hydro power, which can keep water in reservoirs for production during low wind production periods. Such a hydro production potential would have additional decreasing impact on middle and peak prices. The implications of the wind-hydro feedback loop in the spot market should be studied further.

Also, the authors take a *ceteris paribus* approach to analyse the effect on system price from addition of more wind. De Miera et al. (2008) explain that in addition to short-term effects from direct substitution of fossil technologies with renewable generation a more long-term indirect effect will also be felt as higher amounts of renewable energy generation lead to lower demand for conventional electricity and thus to a reduction in CO₂ allowances to comply with EU 20-20-20 goals. The complexity of analysing indirect effects has prevented their modelling: use of *ceteris paribus* is a common way to show isolated effect, at the same time the authors acknowledge that the power system is a universe of different variables and factors, hence modelling results obtained here can be too theoretical. Nevertheless such modelling is useful for triggering what-if analyses.

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