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Implication of Large Scale Wind Power in Northern Europe

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1. Background

Wind energy in the EU has experienced impressive growth rates: A four fold increase from 1998 to 2003, a growth of above 50 % per year since 2003, and in 2007 wind capacity grew more in Europe than any other power-generating technology (EWEA 2008). With national plans and policies for more wind power and offshore wind parks in Sweden, Norway, Denmark, Finland, Germany, the Netherlands, Belgium, and the UK this trend is likely to continue. This trend is also supported by the EU Commission by a recent proposal for a directive on renewable energy. The objective of the directive is to implement the overall EU target of 20 % renewable energy in 2020 by setting binding national targets for the minimum share of renewable energy sources (RES) in final energy consumption.[1] For Denmark a target of 30 % has been proposed.

The proposed targets are set for all renewable energy sources including wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogas. The directive leaves it to the Member States to implement the targets by e.g. setting specific sector targets (e.g. for the electricity sector) or for specific technologies like wind power. National plans for implementation have to be notified to the Commission by March 2010 at the latest. However, the directive sets a specific target for the transport sector claiming that transports have to fulfil a minimum binding target of 10 % renewable energy in 2020.

If the proposed directive on renewable energy is approved by the Member States, it will be a driver for large scale wind power development in Europe. Large volumes of wind power will impact the power market with regard to: investments in other electricity generating sources than wind, the electricity price structure and price volatility, the profits made by the power producers and the emission of green house gases. This paper analyses the impacts of large scale wind power in Northern Europe including Norway. Norway is not a member of EU but is integrated in the North European power market. The analyses presented in this paper are deducted from Econ Pöyry's models for the North European electricity market and based on scenarios for wind energy deployment towards 2020.

This paper is based on a Multi Client project: Implications of Large Scale Wind Power in Northern Europe carried out by Econ Pöyry on behalf of stakeholders from the energy sector.

2. Scenarios to be analysed

We apply two models: the long term Classic model and the short term BID model (se model descriptions in Section 3) to analyse two scenarios:

[1] EU COM(2007)0001 and EU COM(2008)19 final January 23, 2008.

- A Reference Scenario in which wind power follows a (modest) development according to national development plans up to 2020
- A Large Scale Wind Scenario in which we assume that the EU goals for 2020 are achieved, with respective consequences for the power mix in Europe.

Common for both scenarios is that consumption of electricity in EU is expected to increase with about 1,000 TWh from 2005 to 2020, see Table 1. To get a benchmark for this increase total electricity in Denmark is in range 35 TWh per year.

	2005	2020
EU	3,200 TWh	4,180 TWh
Norway	125 TWh	147 TWh
EU + Norway	3,325 TWh	4,327 TWh

Table 1, Expected final consumption of electricity in 2020. Source: *EU, 2006, Primes Base scenario.*

At EU level we have estimated the share of renewable energy in the electricity sector to be 34% of the total electricity production in 2020 but with big national variations as illustrated in Figure 1. Shares if renewable energy in the electricity sector have been estimated by using information about national targets, prognoses for the energy consumption, RES potentials and the fact that the transport sector will have a separate minimum binding target for 2020 of 10 % biofuels.

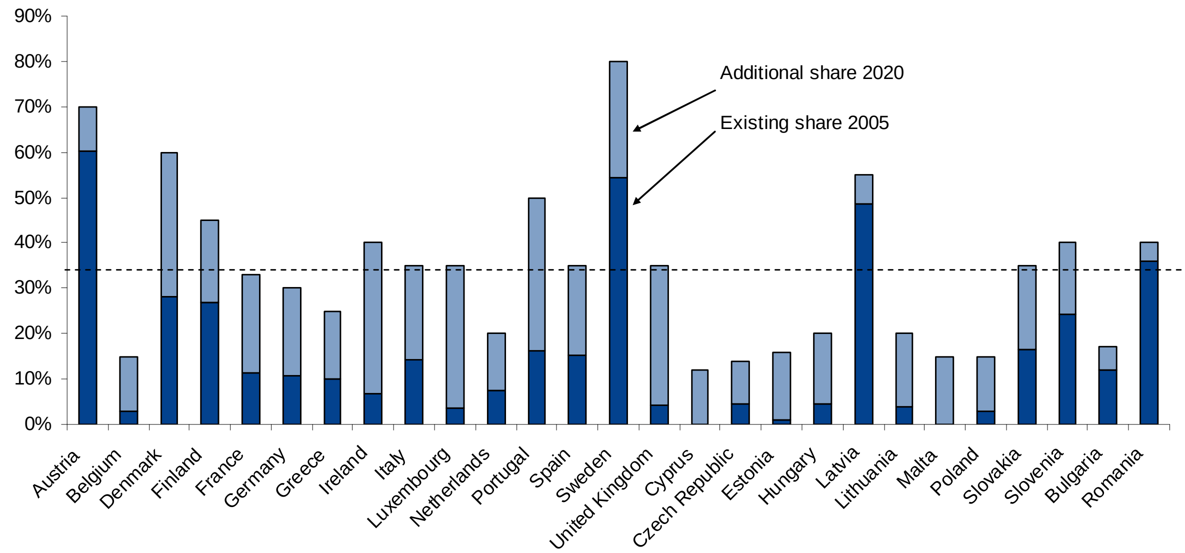

Figure 1 Estimated renewable energy targets for the electricity sector in EU member countries. Econ estimations**.**

It will be a huge challenge to meet a RES-E share of 34% for the electricity sector. From 373 TWh in 1997 and 465 TWh in 2005 in EU27 the amount of RES-E has to increase to around 1.400 TWh in 2020. But it is possible to meet the challenge and wind power can play a major role in future RES development, as shown by the results in Section 4.

3. Econ's power market simulation models

Two different models developed by Econ Pöyry have been used for analysing the impact on the power market from the two renewable energy scenarios as defined above.

The ECON Classic model: Price level and investments

ECON Classic has been developed to simulate long term developments of the European power market. This means, the Classic model has been used to analyse a) the impact of large scale wind investments on price levels and b) the impact on investments. The Classic model is a long term power market simulation model that, in addition to power prices and electricity flows, also calculates investments needed to meet a given demand. Investments are calculated based on short run marginal costs and fixed investment costs.

The model includes most of Europe. The time unit in the model is one month, and each month is divided into five different load blocks. As opposed to the short term BID model, the Classic model is a perfect foresight model and does not take into account stochasticity in wind power production.

In the Classic model used for the price level and investment analysis, each country is modelled as one region, except from Denmark, which is divided into Zealand and Jutland. In the BID model, with focus on North-Western Europe, we have a further division of Sweden and Norway into price zones (i.e. regions in which the electricity price might differ to the price in neighbour regions according to bottlenecks in the transmission system).

ECON BID: Price structure and price volatility
The BID model is used to simulate effects of high volume wind power on price volatility and structure. The BID model is a power market simulation model an hourly basis, taking start-up costs and part-load efficiencies for thermal units into account. The geographical scope of the model is North-Western Europe, including Germany, The Netherlands, BeNeLux, France, Austria, Switzerland, Poland, and the Nordic Countries. In addition, Norway is divided into seven zones, and Sweden is divided into four zones. Furthermore, the BID model has an advanced way of dealing with hydro generation in the Nordic area by using dynamic programming in order to find water values, i.e. the marginal (opportunity) costs of generating hydro power.

The BID model does not calculate endogenous investments. So, in order to run the model for 2020, we used the investments as calculated by the Classic model as inputs for the BID model runs. Since the BID model breaks down production in one-hour-periods (as opposed to one month periods in Classic) the BID model expose bottlenecks in the electricity market. Consequently, it has been necessary to add additional gas capacities in order to avoid too high and frequent production and price peaks. In this respect we added gas turbines in the different countries to the extent that it would be profitable to invest into such units.

The BID model has been developed with support from Statnett, Energinet.dk, TenneT, NVE (the Norwegian Regulator), and the Norwegian Ministry for Petroleum and Energy. Today it is, among others, used by Statnett and NVE.

4. Results

This section presents some results for the scenario analyses.

Wind power penetration and RES-E composition in 2020
By combining the estimated national RES-E targets with national technology targets (i.e. specific wind targets) and the RES-E potentials in each member state (Green-X database) we have estimated that wind power will constitute a major part of new deployment of RES-E with 56% at the EU level. Biomass[2] based electricity counts for 29 %, and hydropower counts for 8 % of the increase in RES-E production, see Figure 2.

[2] Biomass will also be used for heating and biofuels for transport, which contributes towards national priorities to wind and hydro for electricity production.

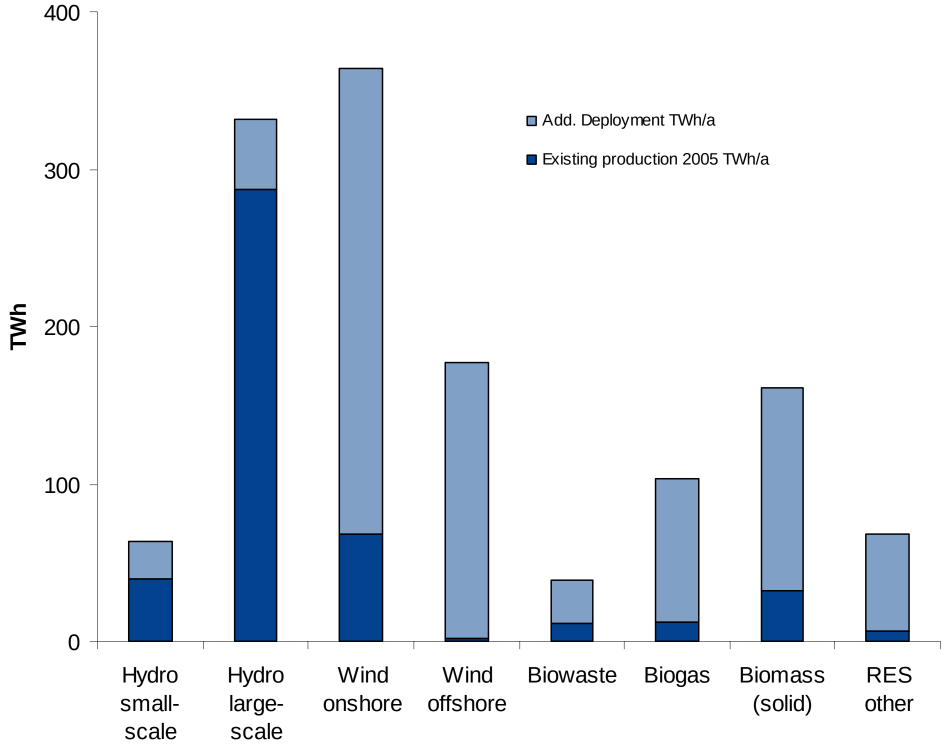

Figure 2, Existing and expected production of RES-E in 2020. Source: Econ estimations.

Compared to the fuel mix in 2005 wind power will have a much more dominating share in the future fuel mix. With the large deployment of wind power, it will constitute more than 40 % of the total RES-E production at the EU level in 2020. One third will be offshore windpower.

Price impacts – long term perspective

In the EU the estimated price level is around 5.4 cent €/kWh in average in 2020 for the Reference Scenario (Figure 3) with a slightly higher price at the continent than in the Nordic countries, but with smaller price difference than today. In the Large Scale Wind Scenario, the average price level in the EU is 5.1 cent €/kWh which is a bit lower than the price in the Reference Scenario. However, different prices can be seen in the hydropower dominated Nordic countries than in the thermal based countries at the European continent. In the Large Scale Wind Scenario, the effect of wind energy is a lowering of the price level to around 4 cent €/kWh in the Nordic countries. Germany and the UK keep the high price level. In other words, wind energy creates larger price differences between the Nordic countries and the European continent.

One implication of price decreases in the Nordic countries is that conventional power production becomes less profitable. For large scale hydropower the general water value decreases. In Norway, hydropower counts for the major part of power production. However, a large scale implementation of wind creates a demand for flexible production that can deliver balancing services – opening up a window of opportunities for flexible production like hydropower.

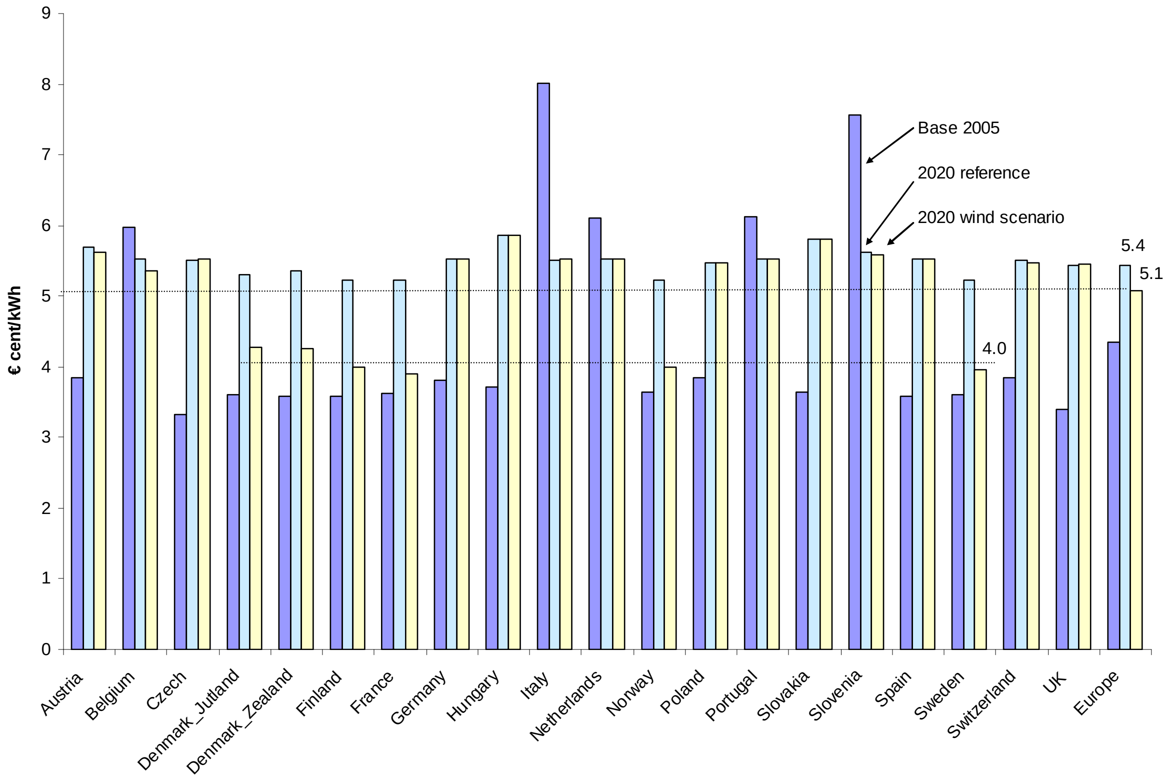

Figure 3, Price levels – 2005 and 2020 for the Reference and Large Scale Wind Scenario

The price levels at the power market are to a large extent determined by the level of the expected fossil fuel prices in 2020. In Table 2 our assumptions are shown.

	Scenario assumptions
Oil	60 $/barrel
Natural gas	16.6 €/MWh
Coal	59 $/tonne

Table 2: Assumed fossil fuel prices in 2020

The CO_2 price is assumed to be 30 €/tCO_2.

Short-term price effect of wind investments

We found that large amounts of wind power lead to significant decreases in the price level in hydro based systems, whereas in thermal systems like Germany the average price level is more or less unaffected. This, however, does only concern average prices.

Regarding daily price structures, i.e. the shape of the hourly price curve, we see that large amounts of wind do have a significant effect on thermal systems based on fossil fuels (e.g. coal and natural gas). First, we observe that large effects of wind lead to a significant increase in the number of hours per year where zero or very low prices appear. This is indicated for Northern Europe in Figure 4 below. While there are almost no hours with zero prices in the Reference Scenario, the number of zero-price hours increases to some 1,600 per year in both Zealand and Sweden in the Large Scale Wind Power Scenario which is equivalent to nearly 20 % of all 8.760 production hours in one year. In addition, the number of hours with zero prices in the other regions is also significant.

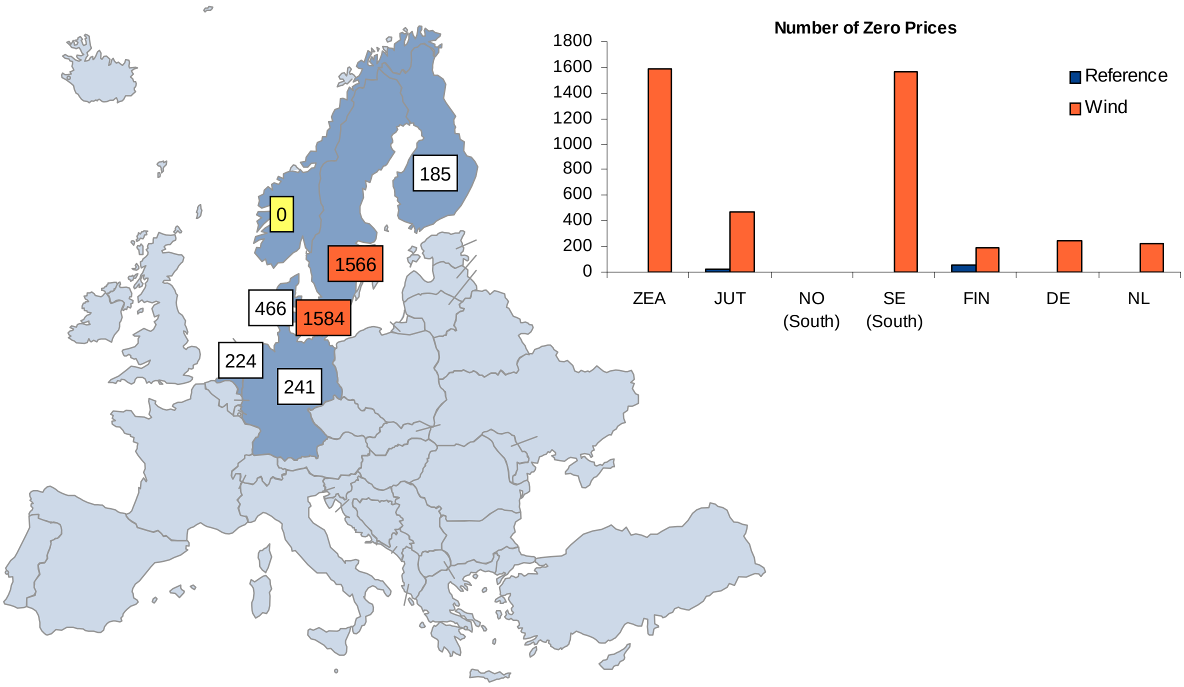

Figure 4: Effect of wind investments on the number of hours with zero prices

The reason for this is that with wind capacities as a kind of cheap "base-load" that produce at almost zero variable costs whenever the wind blows, the prices drop in low load hours when there is in addition other base-load generation that is running (for example CHP or nuclear that is running over night). With most of the wind capacity in the Nordic countries to be installed within Southern Sweden and around Denmark, this effect on the prices is most significant in these regions. The Eastern part of Denmark (Zealand) is especially influenced by the expansion of wind in Southern Sweden simultaneously with additional wind power in Zealand and Jutland. This result indicates the need for more transmission capacities between regions in order to eliminate bottlenecks in the transmission system. This issue is highlighted in the next paragraph.

In this respect it is worth noticing that in Norway, where a lot of hydropower capacity is located, no zero prices are observed even with large amounts of wind. In the same way that large amounts of wind increase the number of zero prices, it also increases the number of hours with high peak prices. This is indicated in Figure 5 below. Again, for Norway (south) we see that there is no effect on the number of peak hours.

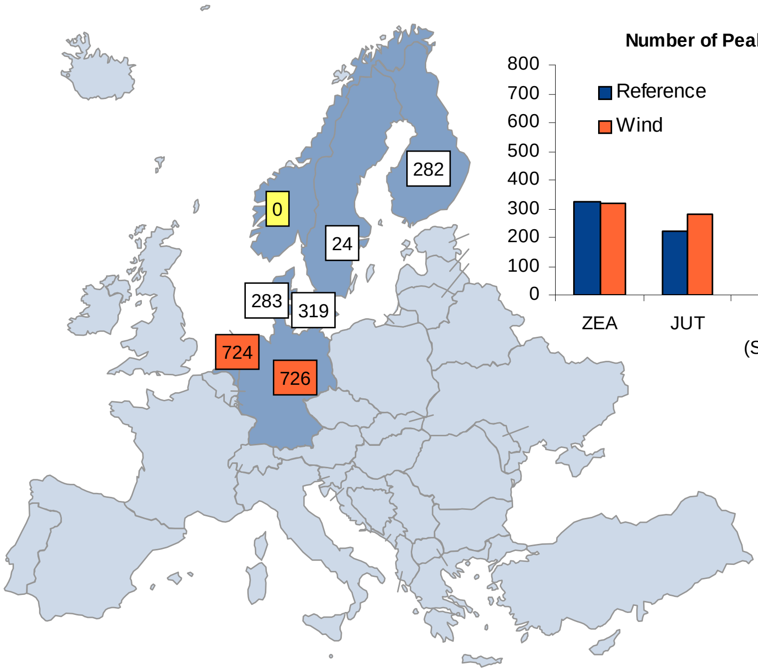

Figure 5: Effect of Large Scale Wind Investments on the Number of Peak Prices

All this indicates that hydro systems like Norway are well suited to balance and absorb large amounts of wind. Please note in this context that the prices reported for Sweden are those for Southern Sweden. With bottlenecks within Sweden and most of the hydro capacity being located in the North, it also shows that in this case the hydropower cannot balance the wind as well (due to bottlenecks). Furthermore, more base-load and must-run units in Sweden (Nuclear and CHP) contribute to the number of hours with very low prices.

Wind power reduces CO_2 emissions

The emission level of the Reference Scenario lies at 1025 million tons at carbon price level of 30 €/ton the emissions The expected future wind power investments in the power sector until 2020 are reducing CO_2 emissions of the European power sector by approximately 170-200 million tons per year.

The impact of the EU's renewable energy target and increasing RES investments on the European carbon market will be the reduced demand for emission allowances from the European power sector through lower baseline emissions. A general lower demand for GHG emission abatements would generally result in lower carbon price levels. But carbon price levels also influence power price levels, especially if coal or gas present the marginal abatement cost in the scheme. However, the effect on power prices would also be dependent on the future design of the emission trading scheme, especially on the method of allocation. Any free allocation would dampen this price effect.

The EU Commission has decided, in the EU ETS third trading period, to place a relatively higher burden on the power sector (stricter allocation targets plus 100% auctioning) compared with the industrial sectors. As a result, more of the abatement costs will be passed on to the electricity customers. An expected stricter market balance in the post Kyoto period will lead to increased carbon price levels which in turn defer fossil power sector investments and hence drive up power prices in the medium and long term.

Model results show a carbon price effect on power price levels of on average 2.5 €/MWh once the carbon price level increases by 5 €/ton, i.e. an increase of 0.5 €/MWh of the power price per 1 €/tCO_2 increase.

Under constraint carbon market conditions (strict emission reduction targets) RES investments gain in competitiveness because higher carbon and power price levels increase the relative cost efficiency of renewable energy sources compared with fossil energy sources. In this case, lower support levels would be needed for RES to compete with fossil power generation investments. However, our model analyse indicate that long-term power prices are too low to make incentives for significant RES investments in future. Even at very high fuel and carbon price levels, the cost efficiency of RES investments is not reaching a competitive level as compared to fossil power investments. Despite a constraint carbon market and high power prices, financial incentives to RES technologies would still be required to make them competitive to fossil fuel power technologies.

Increased inter-connector capacities reduce price volatility

The results obtained from the Reference and Large Scale Wind Scenario indicate that, with large amounts of wind power in the power market, there will be an increased need for further transmission capacity (interconnection) between regions in the North-European power market. This is also confirmed by the fact that, in the model runs with large scale wind investments in place, the congestion rent (i.e. the cable income) increases on most transmission lines. This is also something one would expect: With more volatility in the system, there is a need for further interconnection in order to better being able to balance the system.

In order to simulate the effect of further interconnection, we therefore repeated the same model runs as above, i.e. the Large Scale Wind Scenario and the Reference Scenario, but this time with a 1000 MW inter-connector between Norway and Germany in place, the so-called *NorGer* Cable.We found that the congestion rent on such a cable would be around 160 million € in year 2020 in the Reference Scenario, while it would be around 200 million € in the Large Scale Wind Scenario. This is a strong indication that, with large amounts of wind in the system, the likelihood of the existence of such a cable by 2020 is large.

With the NorGer in place it will have a significant effect on the average prices in the system, not only Norway and Germany, but also the other countries in the model. This is illustrated by Figure 6 below. In the Nordic area the average prices will increase, while in Germany and the Netherlands they will decrease. This is due to the fact that, in the high peak price hours, power is flowing from Norway to Germany. This is reducing the peak prices in Germany, while it increases the water values in Norway. In the off-peak low price hours, the flow goes into the other direction, with Germany exporting to Norway in those hours where prices in Germany are very low. This increases off-peak prices in Germany and decreases water values. However, the overall effect is such that one has higher prices in Norway and lower prices in Germany (compared to the situation without a cable).[3]

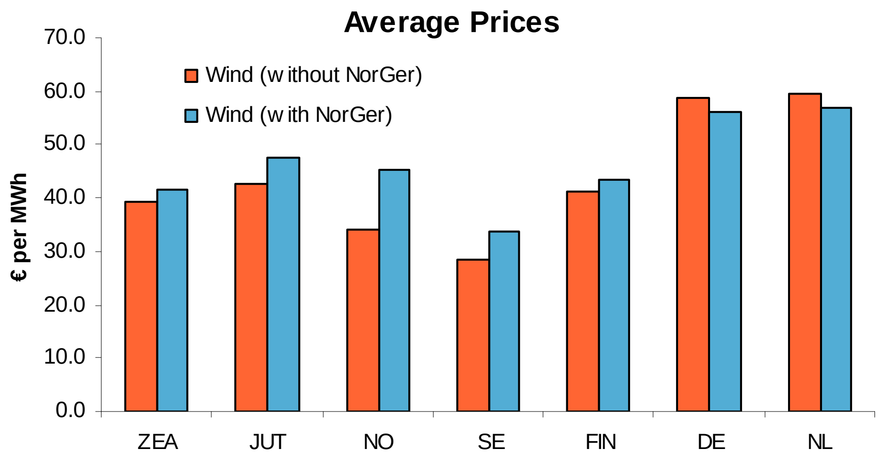

Figure 6: Average prices in the Large Scale Wind Scenario - with and without the NorGer Cable

[3] Although this follows in a way what one would expect, this does not always have to be the case. In other cable analysis projects we found that an inter-connector between a thermal high price area and a hydro low price area may well reduce prices in both areas.

The NorGer Cable also has an effect on the profitability of wind in the different countries. This is illustrated in Figure 7. In Denmark the average price level increases (especially in Jutland), hence making wind generation investments in Denmark (if exposed to the spot market) more profitable. In Germany the profitability of wind generation is reduced. This is due to the fact that although the low prices in Germany when wind power is generated are somehow increased (due to the cable), the peak-price hours in which the wind is generating is reduced at the same time (although in tendency less wind is generated in these hours). Overall, the effect is negative for both Germany and the Netherlands due to the asymmetry between off-peak prices and peak prices.

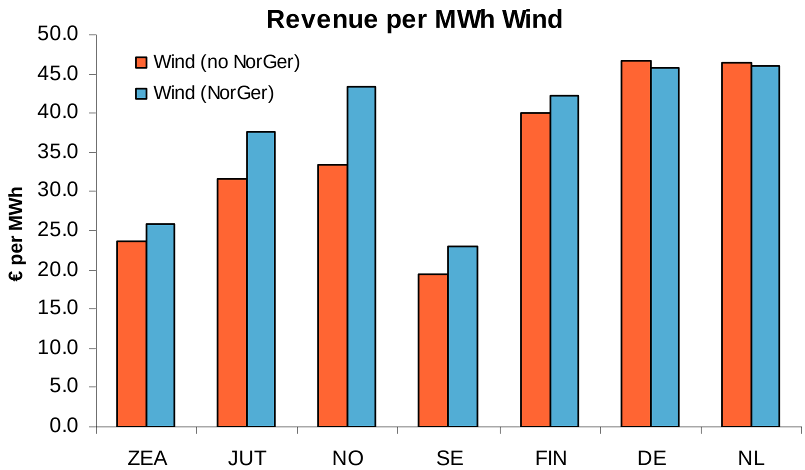

Figure 7: Effects of the NorGer Cable on the Profitability of Wind Investments

5. Conclusions

Though wind power already has shown incredible growth rates in the EU, the future will show even higher growth rates. This is due to the EU proposal on 20 % renewable energy in EU by 2020. Our model analyses show that the EU directive will be a driver for large scale wind power development in Europe. Our results show that most of renewable energy deployment up to 2020 will be wind power. More that 40 % of power production from renewable energy will be wind power in 2020. There will be a high wind penetration in Germany and Sweden.

A large scale wind power scenario will have an impact on the EU electricity price level in 2020. We expect a significant price reduction in the Nordic countries, whereas continental electricity prices will be nearly unaffected. Moreover wind power is expected to increase the volatility of electricity prices. Our model analyses detect a strong increase in zero-price-hours in 2020 in some regions. Most extreme will be the Southern region in Sweden and Zealand in Denmark. More price peaks are also to be expected.

More wind power will reduce the profitability of wind power production and thereby weaken the incentive to invest in more wind power. Most reduction in profitability will appear in Denmark and Sweden. Financial incentives to renewable energy technologies will still be required to make them competitive to fossil fuel power technologies in 2020.

The expected future wind power investments in the power sector until 2020 are expected to reduce CO_2 emissions of the European power sector by approximately 170-200 million tons per year. This is equivalent to 3-4 times the total national emissions of Denmark.

Our analyses show that bottlenecks in the interregional transmission will be exposed by a large scale wind power development. An indicator is the higher volatility of electricity prices. Building a new 1000 MW interconnector between Norway and Germany will have a big impact on the power market.

The price gap between the Nordic and the continental countries will be reduced. The average electricity price will increase from 4 to 5 cent €/kWh) in Nordic countries. Thereby the interconnector will influence the profitability of wind power production – there will be winners and losers. Compared to the Reference Scenario a large scale wind power will increase the profitability of the NorGer investment by 20-25 %.