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EFFECTS OF LARGE SCALE WIND PRODUCTION ON THE NORDIC ELECTRICITY MARKET

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ABSTRACT: Simulations with the power market model EMPS with weekly time resolution have been made to assess the effects of large scale wind production to the Nordic electricity market. Two base case scenarios are made, reference for the Nordic market area for years 2000 and 2010, and wind is added to these systems in 3 steps. The results for the simulations with 16…46 TWh/a wind production in Nordic countries (4…12 % of electricity consumption), show that wind power replaces mostly coal condense and oil as fuel for electric boilers. As a result of fuels replaced by wind production a CO_2 reduction is achieved, of 680…620 gCO_2/kWh. Indications for bottlenecks in transmission can be seen, especially to Central Europe, when the wind production is above 20 TWh/a. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind production added to the system. Avoided costs for wind power production are roughly 2 eurocents/kWh for today’s system and 3.1 eurocents/kWh for 2010 system with CO_2 tax and reduced power surplus. Changes in socio-economic surplus for the market is 2.4…2.0 eurocents/kWh for 16…46 TWh/a wind production, i.e.15 % higher than average spot price (for 2010, 3.9 eurocents/kWh, 30 % higher than average spot price).

Keywords: Electrical Systems, Markets, Emissions, Simulations, Electricity market

1 INTRODUCTION

In the Nordic countries, the electricity system is characterised by large share of hydro power. The deregulated electricity market in the countries has led to the joint electricity market Nordpool. Wind power is still marginal in the system today (4 TWh/a) but national targets are existing for 16 TWh/a in 2010 (Denmark 8, Sweden 4, Norway 3, Finland 1 TWh/a), and considerab-ly more in 2030.

The purpose of the paper is to study the influence of large amounts of wind production to the market: differences between the spot prices, power transmission between the countries, production of hydro and thermal power, with and without wind power. This is done by running simulations on the EFI‘s Multi-Area Power Market Simulator (EMPS) model, a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting [1].

2 POWER MARKET MODEL EMPS

2.1 Description of the model

The power market model EMPS simulates the whole of the joint market area, instead of only one country. The market is divided into areas with transmission capacities between the areas (Fig 1). The model description used here is most detailed for Norway, which is modeled as 12 areas. Finland is modeled as one area, Sweden and Denmark as two areas. Central Europe is modeled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities.

The model simulates the market price and the production for each area with weekly time resolution. The simulation is here made for one year. Historical inflow and wind data from 30 years are used as input for the simulation to take into account the stochastic nature of inflow and wind.

The model has a good description of the Nordic hydro power system to be able to take into account the large variations in hydro inflow compensated by large storage reservoir capacities.

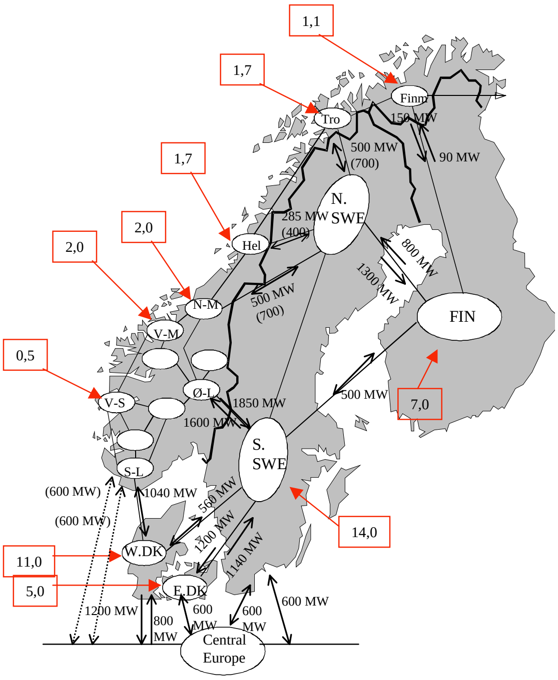

Figure 1: Areas, transmission capacities between the countries (scenario 2010 figures in parenthesis) and wind3 amounts of wind production (TWh/a) in the EMPS model.

Thermal capacity in the Nordic countries is simulated in less detail than the hydro system. Because only weekly resolution is used, no restrictions or costs of regulation or start-ups of the thermal capacity are taken into account. The model assumes that in-week variations are handled by the large hydro reservoirs in the system.

The model optimises the use of hydro power by calculating water values to the amount of water in the reservoirs, by stochastic dynamic programming algorithm. These water values vary both by the time of year and by the current and anticipated water inflow to the reservoirs. They are treated as the marginal cost of hydro power [2]. With a price to each production capacity known, the market price is determined by a market cross (Fig 2). This is done for each simulated week. If transmission capacity is restricted, there will be different prices in different areas.

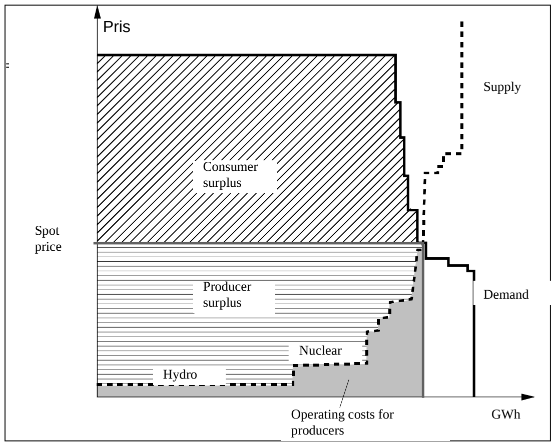

Figure 2: Market cross: the spot price calculation in the power market simulation model EMPS.

2.2 Input for the model. Reference cases.

Input data needed for each area are weekly consumption, operating costs for thermal power, maximum production (or capacity) for thermal power, detailed description for hydro power system, inflow data and transmission capacities between the areas.

The input for thermal power prices are operating costs. This is because we are simulating the bidding process in the market. In the market the producer gets the price determined by the market cross (fig.1), thus it is cost-effective for him to produce as long as the price he gets is higher than his/her variable costs. Wind energy is a price taker in the market, all that is produced will be sold, no matter what price. The marginal price is therefore 0 Euro/MWh for wind, when operating without storage, like it is for run-of-river hydro plants.

The capacities for transmission lines are shown in Fig. 2. Between Norway and Sweden lower limits for the lines than in [3] are used to take into account the technical restrictions in transmission. The production capacity is shown in table 1 for both the 2000 and 2010 base case. The thermal capacity is given either as maximum capacity [MW] or maximum weekly production [GWh]. The electricity consumption contains price elastic use of electricity mainly in Norway and Sweden. This is provided by electric boilers, which can switch from burning oil to using electricity, and also industrial consumption in Norway. Four load duration levels are used to take into account the consumption pattern inside a week.

In the scenario made for year 2010 [4] electric consumption was added by 32.2 TWh/a and production capacities were changed. For Sweden one nuclear plant was shut down, condense was shifted to biofuels and CHP was added. For Finland more CHP and coal was added [5]. For Norway a new gas power plant (400 MW) was added. For Denmark coal was shifted towards gas [6]. Improved transmission capacity was foreseen for Norway/Central Europe and between Norway and Sweden (fig.2). CO_2 tax of 15.6 Euro/tCO_2 (125 NOK/tCO_2) was added to operating costs of fossil fuels. The effect of CO_2 tax is to rise the marginal costs: for coal by roughly 12.5 and gas by 7.5 Euro/MWh. Thermal power costs in Central Europe were adjusted closer to those in Denmark and Finland to reach a balance in the market. As a result, the thermal production was up 25.4 TWh/a and price elastic consumption down 5.7 TWh/a.

Table 1: Maximum production capacity and electricity consumption as input to the EMPS model (ref2000 plain **ref2010 bold**). CHP= Combined heat and power.

	Fin	Swe	Den	Nor	Eur
Consumption [GWh/a]	78800 **90500**	142400 **152300**	34900 **37000**	120000 **121900**	567100
Nuclear [GWh/a]	21800	70800 **67000**			152900
CHP [GWh/a]	24800 **28600**	8700 **15000**	27000 **44000**		196600
Condense [MW]	3000 **4000**	400 **1200**	1800	280 **680**	42500
Gas turbines [MW]	975	195	70		
Hydro* [GWh/a]	13000	63000	3500*	115000	

*wind in DK

3 WIND PRODUCTION DISTRIBUTED IN NORDEL AREA

Wind power was added to the system in 3 phases, cases wind1…wind3, starting from 16 TWh/a (wind1) to reach 46 TWh/a (wind3) annual total production in the Nordic countries. This corresponds to 4…12 % of total electricity consumption and it is divided between the countries as 20…45 % of consumption in Denmark and 2…10 % of consumption in Sweden, Norway and Finland. Wind1 corresponds to existing targets for 2010 and wind3 is near possible targets for 2030.

Table 2: Wind power added to the system. Production in TWh/a and as % of electricity consumption today in the simulated cases.

	Wind1		Wind2		Wind3	
	TWh/a	%	TWh/a	%	TWh/a	%
Norway	3	2.5	6	5.0	9	7.5
Sweden	4	2.8	9	6.3	14	9.9
Finland	1	1.3	4	5.1	7	8.9
Denmark	8	22.9	12	34.3	16	45.7
TOTAL	16	4.3	31	8.2	46	12.2

4 WIND DATA

To catch the effect of varying wind resource, wind production was acquired from the same time period as the hydrological input data, years 1961–1990. Weekly wind production was calculated from wind measurement data. Measured wind speed was converted to power according to power curve of 1.65 or 2 MW wind turbines [7].

In Norway, wind power was added to 6 areas, based on 3 wind measurement data points in Middle and North Norway (table 3). Wind power was added to South-Sweden based on 3 wind measurement data points in Gotland and Southern Sweden. Wind power was added to both areas in Denmark, some more to West Denmark than to East Denmark. From Denmark only one measured wind speed series was available. The East Denmark production was based on South Sweden wind data, near the Danish coast.

Table 3: Weekly wind production data used as an input for the power market model.

Wind data from	Full-load hours, average	TWh/a in wind3	Weekly production, average = 100 %	
			Max	Min
Helnes, NOR	3000	1.1	158	0
Bodø, NOR	3000	3.4	171	0
Ørland, NOR	3000	4.5	196	3
Visby, SWE	2600	5.0	293	7
Säve, SWE	2600	3.0	306	0
Barkåkra, SWE	2600	11.0	298	0
Valassaaret, FIN	2200	7.0	247	2
Risø, DK	3200	11.0	262	3
TOTAL wind	**2700**	**46.0**	**221**	**14**

Large scale wind production would in reality mean production from many, scattered wind parks. Using data for few, single measurement points will overestimate the variations of wind production in a large area. As we are using weekly averages, however, this overestimation is not as profound as it would be f.ex. in hourly data.

Correlation coefficients between the weekly production series of different wind production sites were 0.11…0.76. Wind production is correlated inside Norway and Sweden, and between East Denmark and Southern Sweden. Wind production is only weakly correlated between the countries. The lowest correlation coefficients were between Southern Sweden and Northern Norway.

5 RESULTS OF THE SIMULATIONS

5.1 Effects on the energy balance between the countries

As wind production is added as extra production to the electricity system, about 30 % of the wind production is transferred out of the Nordic countries with the transmission lines to Germany, Poland and the Netherlands (in 2010 scenario about 40 %).

In Finland wind production replaces condense production (mainly coal). Import to Finland increases. For wet years in the wind3 case the nuclear production is also reduced. In Sweden the electricity consumption in electric boilers is increased with increased wind production. This means that wind production is replacing oil (alternative fuel for the boilers). Wind production is replacing condense production, for the little there is to replace, and some of the nuclear and CHP production. Export of electricity is increased substantially. In Norway the consumption in electric boilers increases with added wind production. Export is also increased. In Denmark wind is replacing condense (mainly coal) and increasing export. Both imports and exports in Denmark are increasing with increasing wind in the system.

For the cases wind2 and wind3 there are indications of bottlenecks in transmission in all lines to Central Europe, especially from West Denmark to Germany. Between Norway and Denmark, Norway and Sweden, and within Norway added wind production helps out the situation during dry years but makes some bottlenecks during wet years more profound (these lines have bottlenecks already in the reference cases). Between Sweden and Finland and inside Sweden even a large-scale wind production does not make a substantial increase in the use of transmission lines compared to the reference. However, more detailed time resolution would be neede to conclude on the issue. High wind production in Northern Norway makes a bottleneck to the minor transmission line between North Norway and Finland.

5.2 CO_2 emission reduction

Wind production results in different fuels being replaced in the system. As a combined result of this replacement a CO_2 reduction is achieved. This varies between 680 and 620 gCO_2/kWh in wind1 and wind3 cases respectively. For the 2010 scenario the CO_2 reduction is slightly larger. For comparison, coal, oil and gas fired units emit approximately 800, 650 and 430 gCO_2/kWh respectively.

5.3 Effect on market prices

Simulated spot price for an average inflow situation in the electricity market is about 2.3 eurocents/kWh for today's system. It rises to 3.5 eurocents/kWh for the 2010 scenario due to a CO_2 tax. and reduced power sur-plus (more consumption than production capacity added)

Wind production is seen as extra production in the system with zero marginal price, causing the spot prices on the market to decrease, about 0.2 eurocents/kWh per each 10 TWh/a added wind production (ref2010), little less in ref2000 cases (Fig3). Decrease in spot market price has to do with adding wind power in the market as an extra production. Results of simulations when thermal capacity was decreased while adding wind show only a moderate price decrease (about 0.2 eurocents/kWh per 40 TWh/a added wind production).

5.4 Value of wind energy

The market value of wind energy is the spot market price for the wind production. According to the simulations made here, wind production would be priced on an average about 2 % higher than the spot price. This means that the high price weeks would be slightly more windy than the low price weeks. With large scale wind production in the system (case wind3) this price difference would reduce to about 1 %. Denmark is an exception to this: wind production would be priced 1–2 % lower than the average spot price. Prediction errors in wind production would result in wind producers getting a lower price, when part of the production would be sold in the balance market.

One way of estimating the value of wind energy to the production system is to calculate the avoided costs of thermal power when using wind power. These are the operating costs (mainly fuel costs) of thermal power as well as the fuel saved in electric boilers. The difference in the operating costs of thermal power and electric boilers between the reference case and the wind cases give the avoided costs. For the 2000 system cases the avoided costs by wind power are 2.1 eurocents/kWh in case wind1 decreasing to 2.0 eurocents/kWh in wind3. For the 2010 scenario the avoided costs by wind power are considerably higher than for today's system, because of the CO_2-tax added to fuel cost as well as reduced power surplus: 3.3…3.1 eurocents/kWh (Fig.3).

Another way of estimating the value of wind energy to the system is to calculate the the socio-economic surplus (sum of consumer and producer surplus, Fig 2). When looking at the differences in the socio-economic surplus between reference and wind cases, we get the value of wind to the whole market. For the 2000 system cases this is 2.4 eurocents/kWh decreasing to 2.0 eurocents/kWh with large scale wind production. For 2010 scenario the total value of wind production to the system is 4.4…3.9 eurocents/kWh respectively (Fig. 3).

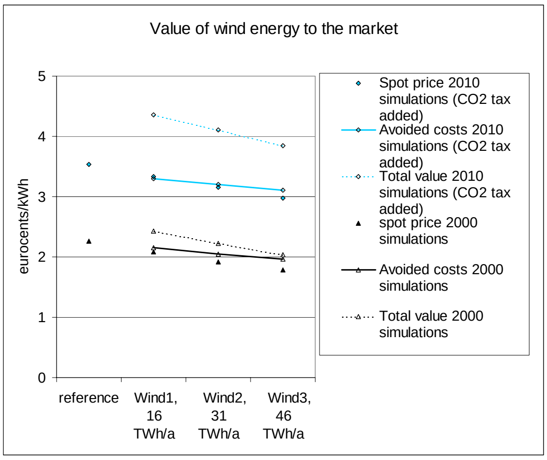

Figure 3: Avoided costs and socio-economic surplus (total value) when comparing the wind cases to the reference cases. For comparison, the average spot price (South-Norway) is shown. (All prices for an average hydro inflow.)

6 CONCLUSIONS AND DISCUSSION

The Nordic electricity market has been simulated with and without wind production to assess the effects of large scale wind production on the market. Results of weekly electricity flow and prices in the market area for different hydrological years can be obtained from the EMPS power market simulation model output.

Wind power replaces mostly coal condense and oil as fuel for electric boilers. For large amounts of wind power, 8–12 % of consumption, also nuclear production is slightly reduced during wet years. Reductions do not occur in the same countries as the wind production, f.ex. coal condense is replaced also in Central Europe. As a result of adding wind to the simulated system, CO_2 emissions will be reduced 680…620 gCO_2/kWh.

Indications for bottlenecks in transmission can be seen, especially to Central Europe, when wind production is above 8 % of the electricity consumption.

Large amounts of wind production in the market will lower the spot price, when wind production comes as an extra production to the system. Average spot market price drops by roughly 0.2 eurocents per 10 TWh/a wind production added to the system. Wind power would get on the average 1–2 % higher price than the spot price, if no prediction error is taken into account. Comparing the market spot prices with total production costs for wind power, it is clear that today's market price would not be enough to initiate investments in wind power, where as market prices as a result of our scenario for 2010 would make the best wind resource sites cost-effective.

Avoided costs for wind power production are 2.0…2.1 eurocents/kWh when adding wind production to today's system, slightly higher than average spot price. This is not taking into account any environmental benefits of wind production. CO_2 tax added to fuels of conventional power brings an environmental bonus to wind power in the 2010 figures, where the avoided costs would be 3.1…3.3 eurocents/kWh. The avoided costs give the value of wind to the total production system, as the reduced operational costs for electricity production.

The socio-economic surplus to the electricity system takes into account both the consumer and producer sides of the market. The socio-economic value of wind energy for the system is 15 % higher than average spot price for today's system and 30 % higher than the average spot price for the 2010 scenario with CO_2 tax and reduced power surplus in the system (more consumption than production added). The socio-economic value is what a market regulator would look into, when analysing whether wind production would be beneficial for the system, and how much wind could be subsidised from themarket point of view.

These conclusions are made from simulations assuming that all the large scale wind production will be available in the system. This means that grid connection as well as the hourly variations of wind would be taken care of. Weekly and hourly scheduling of thermal and hydro power with large wind production share will be questions for further study.

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