

# The effect of wind power on CO<sub>2</sub> abatement in the Nordic Countries

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## Abstract

Simulations with the power market model EMPS and the energy system model EFOM have been made to assess the effects of large-scale wind production on the CO<sub>2</sub> abatement in the Nordic countries. We are mostly focusing on the year 2010, comparing the results with substantial wind power amounts to a base case scenario. The results for the EMPS simulations with 16–46 TWh/a wind production in Nordic countries (4–12% of electricity consumption), show that wind power replaces mostly coal-fired power generation. As a result of all fuels replaced by wind production a CO<sub>2</sub> reduction is achieved, of 700–620 g CO<sub>2</sub>/kWh. The results for the simulations of Finnish energy system show similarly that new wind power capacity replaces mainly coal-fired generation. In another scenario it has been assumed that the use of coal-fired generation is prohibited in order to meet the Finnish Kyoto target. In this case new wind power capacity would replace mainly natural gas combined-cycle capacity in separate electricity production and the average CO<sub>2</sub> reduction would be about 300 g CO<sub>2</sub>/kWh. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

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## 1. Introduction

The purpose of the paper is to study the influence of large amounts of wind production on the CO<sub>2</sub> abatement of the energy sector. This is a relevant question for national policy makers when estimating the costs of CO<sub>2</sub> abatement, for example when comparing different measures.

The electricity supplied by wind power is free from CO<sub>2</sub>—even taking into account the materials and construction of wind farms, the CO<sub>2</sub> emissions are of the order of 10 g CO<sub>2</sub>/kWh wind power produced (Lenzen and Munksgaard, 2002). When wind energy is replacing production forms that emit CO<sub>2</sub>, the CO<sub>2</sub> emissions from the electricity system are lowered. The amount of CO<sub>2</sub> that will be abated depends on what production type and fuel is replaced when wind power is produced.

In both regulated and deregulated electricity systems, the production form in use at each hour that has the highest marginal costs, will be lowered due to wind

energy. It usually means the production of old coal fired plants, resulting in a CO<sub>2</sub> abatement of wind energy of about 800–900 g CO<sub>2</sub>/kWh. This is often cited as the CO<sub>2</sub> abatement of wind energy (e.g. EWEA, 1996).

This is true for most systems with some coal fired production plants, when wind energy provides a minor amount of total electricity consumption. It is a good estimate for the CO<sub>2</sub> effects for the first national targets, when first introducing wind power to a country.

This is also true for large amounts of wind, for the countries that have electricity production mostly from coal. For other countries, the situation may change when adding large amounts of wind power to the system. There might not exist old coal plant capacity for the whole wind power production to be replaced at all times of the year. During some hours of the year, wind would be replacing other production forms, like gas fired production (CO<sub>2</sub> emissions of gas are 400–600 g CO<sub>2</sub>/kWh), or even CO<sub>2</sub> free production forms, like hydro, biomass or nuclear power.

Sometimes estimations of CO<sub>2</sub> abatement are done using the average emissions of electricity sector. In countries with a large share of renewables and nuclear power, this decreases the benefits of wind power considerably compared with the estimates using 800–900 g CO<sub>2</sub>/kWh as the abatement measure.

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Some studies have taken the long-term replacement of wind power as a starting point, when wind power is replacing other new investments (IEA GHG, 2000). If wind power is considered as an alternative to another new capacity, like gas fired plants, then the CO<sub>2</sub> abatement of wind is cited as the avoided emissions of the alternative. That becomes 300–400 g/kWh when looking at future natural gas combined-cycle capacity (IEA GHG, 2000). When looking at the situation today, this way of studying the abatement of wind power neglects the initial CO<sub>2</sub> abatement of the gas plant to the system. This actually reflects the situation in the future, when there is no more coal to be replaced, but the replacement will be gas.

When there are large hydro reservoirs in the system, it is not enough to look at the instantaneous response of the electricity system to some hours of high wind power production: even if the hydro production is reduced instantaneously, the hydro power stored in the reservoirs will be produced at a later instant, reducing fossil fuel fired production at a later time. This is why it would be unusual for wind power to replace hydro power, unless the system is hydro dominated. Interconnected systems can also respond in a way that wind power is partly replacing coal fired production in a neighbouring country.

All this means, that when the electricity system is not consisting mainly of coal fired units, and we are talking about large-scale wind power production, it has to be simulated what would happen in the system when adding wind. Comparing the results of simulations with and without wind capacity will give us the CO<sub>2</sub> abatement of wind. There are not many studies made like that so far, but some examples exist already. In a previous study for the hydro-thermal system of Finland (Peltola and Petäjä, 1993), a probabilistic production cost simulation model was used. Producing 1–6% of yearly electricity consumption with wind power, while maintaining the same reliability of the electricity system, resulted in CO<sub>2</sub> emission savings of 900 g CO<sub>2</sub>/kWh. For the Egyptian hydro-thermal system, simulations show a CO<sub>2</sub> reduction of 640 g CO<sub>2</sub>/kWh wind (El-Sayed, 2002).

In the Nordic countries, the electricity system is characterised by large share of hydro power. There are long traditions in operating the system according to the varying hydrological years: electricity is exported from Norway and Sweden to Finland and Denmark during wet years, and electricity is exported from the thermal plants of Finland and Denmark to Sweden and Norway during dry years. The deregulated electricity market in the countries has led to the joint electricity market Nordpool. The benefits of wind power reducing the CO<sub>2</sub> emissions can result in different countries of the joint electricity system than where the wind power is built. It is therefore relevant to look at the whole Nordic system

for CO<sub>2</sub> emissions with and without wind power. Wind power is still marginal in the system today (4 TWh/a mainly in Denmark). National targets exist for 16 TWh/a in 2010 (Denmark 8, Sweden 4, Norway 3, Finland 1 TWh/a), and considerably more in 2030.

In this paper, the effect of wind power production on CO<sub>2</sub> abatement is simulated in two ways. By running simulations on the EFI's Multi-Area Power Market Simulator (EMPS) model for the whole of the Nordic electricity market, we get the effects of wind power to the dispatch of other production units in the interconnected Nordic electricity system, for an average, wet and dry year. These simulations are based on electricity market operation with a fixed power production capacity, taking into account the operating costs of each power production form only. By running EFOM for the Finnish energy system we get the effects of wind power to one country, taking into account also capacity expansion during a longer time period.

## 2. Simulations with EMPS model for the Nordic area

### 2.1. Description of the model

The power market model EMPS is a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting (Flatabø et al., 1998; Sintef, 2001). EMPS simulates the whole of the Nordic market area. The market is divided into areas with transmission capacities between the areas (Fig. 1). Central Europe is modelled as one big area (Germany and the Netherlands) and treated like a large buffer with which the Nordic system has transmission possibilities. The simulation is here made for 1 year, with weekly time steps. The model simulates the market price, production and export/import for each area. The running/dispatch of the production units is simulated, and the system with the firm consumption pattern and production system are static. This means that new investments to production capacity, changing fuel prices or increasing demand are all changes that must be treated with a new system definition and a new simulation.

We are using 2 systems for the base case: electricity system for year 2000 and a scenario for year 2010. Wind is added to these systems step-by-step, in order to study the incremental effects of wind power on the system.

Electricity consumption and production capacities are modeled for each area, as well as the transmission lines between the areas. The production capacity is shown in Table 1 for both the 2000 and 2010 base case. The thermal capacity is given either as a maximum capacity (MW) or a maximum weekly production (GWh). The electricity consumption contains price elastic demand, mainly in Norway and Sweden. This is provided by



Table 1

Maximum production capacity and electricity consumption as input to the EMPS model (ref2000 plain ref2010 bold)

|                                     | Finland                 | Sweden                    | Denmark <sup>a</sup>    | Norway                    | Central Europe <sup>b</sup> |
|-------------------------------------|-------------------------|---------------------------|-------------------------|---------------------------|-----------------------------|
| Consumption (GWh/a)                 | 78,800<br><b>90,500</b> | 142,400<br><b>152,300</b> | 34,900<br><b>37,000</b> | 120,000<br><b>121,900</b> | 567,100<br><b>567,100</b>   |
| Nuclear (GWh/a)                     | 21,800<br><b>21,800</b> | 70,800<br><b>67,000</b>   |                         |                           | 21,813<br><b>21,813</b>     |
| CHP (GWh/a)                         | 24,800<br><b>28,600</b> | 8741<br><b>15,000</b>     | 8000<br><b>7300</b>     |                           |                             |
| Condense <sup>c</sup> coal/oil (MW) | 4132<br><b>3157</b>     | 435<br><b>435</b>         | 5967<br><b>2900</b>     | 280<br><b>280</b>         | 69,421<br><b>69,421</b>     |
| Condense <sup>c</sup> gas (MW)      | 167<br><b>167</b>       |                           | 815<br><b>2320</b>      |                           | 14,661<br><b>14,661</b>     |
| Condense <sup>c</sup> other (MW)    | 366<br><b>691</b>       |                           |                         | 400<br><b>400</b>         | 600<br><b>600</b>           |
| Gas turbines (MW)                   | 975                     | 195                       | 70                      |                           |                             |
| Hydro <sup>d</sup> (GWh/a)          | 13,000                  | 63,000                    | 3500                    | 115,000                   |                             |

CHP = Combined heat and power.

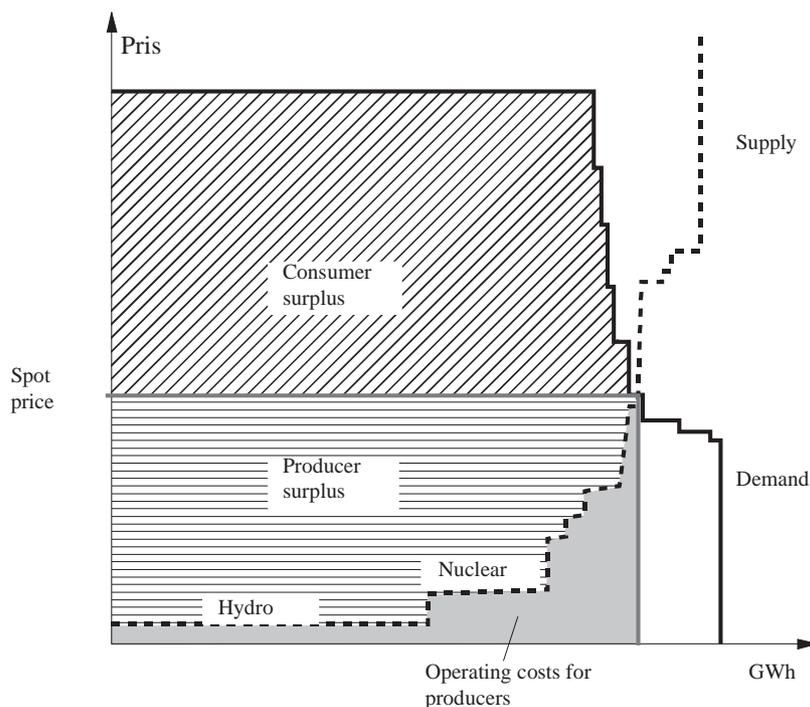
<sup>a</sup>Denmark: part of condense used with heat load. Modelled as max 1840 MW + max 27,000 GWh/a in 2000, max 2500 MW + max 27,000 GWh/a in 2010.<sup>b</sup>Central Europe: condense power modelled as max 40,970 MW + max 196,000 GWh/a.<sup>c</sup>In this paper the terms “condense” and “condensing power” refer to all thermal power plants (excl. nuclear power) that are producing electricity only. This terminology is needed in order to make a clear distinction between power plants and combined heat and power (CHP) plants.<sup>d</sup>Average for 30 years. Wind in DK.

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

stochastic dynamic programming algorithm, maximising the value of hydro production (Flatabø et al., 1998).

With the demand and a price for each production capacity known, the market price is determined by a market cross (Fig. 2). Operating costs given as input values are used for thermal production. Water values are the prices used for hydro plants with reservoirs when

calculating the producer curve in Fig. 2. Demand and production curves are simulated for each week, and four load duration levels are used to take into account the consumption pattern (high/low) inside a week. Technical availability of thermal capacity is taken into account in the simulation, when composing the production/price curve for each time step (Fig. 2). If transmission

Table 2  
Operating costs for power production as input to the EMPS model (ref2000 plain ref2010 bold)

|                   | Finland                  | Sweden                      | Denmark <sup>a</sup>          | Norway                         | Central Europe                |
|-------------------|--------------------------|-----------------------------|-------------------------------|--------------------------------|-------------------------------|
| Nuclear           | 8.7                      | 8.7                         |                               |                                | 8.1                           |
| CHP <sup>a</sup>  | 6.2                      | 6.9–21.2<br><b>6.9–23.7</b> | 0.0<br><b>0.0</b>             |                                | 16.8<br><b>28.7</b>           |
| Condense coal/oil | 16.7<br><b>27.5–32.4</b> | 31.2<br><b>31.2–42.4</b>    | 13.4–20.7<br><b>28.1–31.2</b> | 12.48–56.2<br><b>13.7–82.4</b> | 8.1–39.3<br><b>24.1–45.1</b>  |
| Condense gas      | 32.0<br><b>28.7</b>      |                             | 19.3–26.1<br><b>26.5–27.1</b> |                                | 18.7–31.2<br><b>26.2–32.4</b> |
| Condense other    | 32.2<br><b>27.5</b>      |                             |                               |                                |                               |
| Gas turbines      | 52.4<br><b>60.3</b>      | 52.4<br><b>67.9</b>         | 44.3                          |                                |                               |

CHP = Combined heat and power.

<sup>a</sup>The Danish prioritised, decentral CHP production is modelled as 0 costs.

capacity is restricted, there will be different prices in different areas, so basically the model simulates how the Nordpool market operates.

Because the EMPS model is run with a static production capacity given as input, for year 2010 a new input based on a scenario was made. Electric consumption was added by 32.2 TWh/a in the Nordic countries, and production capacities were changed (MTI, 2000). For Sweden one nuclear plant was shut down, fossil fuel fired condensing power was shifted to biofuels and CHP was added. For Finland more CHP and coal was added (MTI, 2001a). For Norway a new gas-fired power plant (400 MW) was added. For Denmark coal was shifted towards gas (Energy 21, 1996). Improved transmission capacity was foreseen for Norway/Central Europe and between Norway and Sweden (Fig. 2). CO<sub>2</sub> tax of 15.6 Euro/t CO<sub>2</sub> was added to operating costs of fossil fuels. The effect of CO<sub>2</sub> 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 from changing the system from today's system to a 2010 scenario, the simulated thermal production for 2010 was up by 25.4 TWh/a and price elastic demand (dual fueled boilers, and industrial consumption in Norway) was down by 5.7 TWh/a.

The model calculates the emissions produced, by simply multiplying each produced kWh with an emission factor specified for that production type. These emission factors are also an input to the model. Because the production units are grouped to larger groups, where both the efficiency and sometimes part of the fuel input can vary, these emission factors have to be roughly estimated. Biomass, nuclear, hydro and wind production are taken as CO<sub>2</sub> free production forms. We have

used 790–1120 g CO<sub>2</sub>/kWh for coal and coal/oil fired plants; most of the production in Denmark and Finland comes from a range of 800–880 g/kWh, and the plants in Germany are assumed to emit 1025 g/kWh. For gas fired production, emission factors used range between 450 and 520 g CO<sub>2</sub>/kWh. For the combined heat and power production, there is the problem of dividing the emissions between the electricity and heat produced, as we are here only simulating the electricity production. Case studies from Finnish CHP plants suggests that this allocation could be 25–65% for electricity production (Mayerhofer et al., 1997), depending on the technology and allocation principle. We have used a rough estimate of dividing the emissions half and half to electricity and heat. This assumption does not have a notable impact on the results in these simulations, however, as the CHP electricity production is mostly assumed as a by-product of heat demand, bid into the markets with low price and therefore not being replaced by wind power added to the system. In today's system CHP emission factors are only used in Finland and Sweden, for 2010 partly in Denmark also. In Denmark, extraction CHP is used and CHP is operated shifting from condense production to different levels of combined production, which means that also the emissions will be partly like from condense power plants.

As we are looking at what production form wind power would replace, the most important input values to the simulations are the ones determining which production is running at the margin. This is the cost (and amount) input for the conventional production units in the system. For our simulations, looking at Table 2, nuclear and CHP production is bid to the market at a low price, and therefore it will be the condensing power that will first be affected by wind power added to the system.

## 2.2. Simulation of wind power production

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 (Table 3). Wind1 corresponds to existing targets for 2010 and wind3 is near possible targets for 2030.

The model takes into account the different inflow and varying wind situations by using historical inflow and wind data from 30 years as input for the simulation. The results of the simulation are shown as average values, with the minimum and maximum values yielded each week for different inflow situations (dry and wet years). It is also possible to look at the results for a specific inflow year (i.e. examples for a wet and dry year).

Weekly wind production was calculated from wind measurement data (Tande and Vogstad, 1999). The total weekly wind power production, in wind3 simulation, as an average over 30 years, as well as the 30-year-minimum and -maximum weekly values can be seen in Fig. 3.

Table 3  
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 |

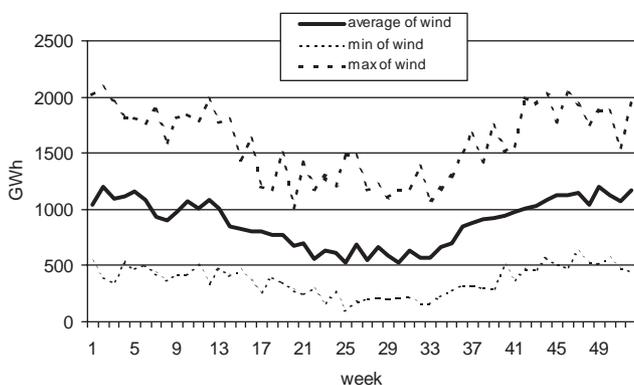


Fig. 3. Input for wind power production for the simulation (wind3, 46 TWh/a). The combined wind power production of all countries is presented as weekly average, maximum and minimum production from 30 years of data.

In Norway, wind power was added to 6 areas, based on 3 wind measurement data points in Middle and North Norway. Wind power was added to South-Sweden based on 3 wind measurement data points in Southern Sweden and Gotland. 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 (Vogstad et al., 2000).

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 in, e.g. hourly data.

Wind production is only weakly correlated between the countries. Yearly wind and hydro production are not correlated, that is, the correlation coefficients for the yearly time series are near 0. This means that wet years are not likely to be good wind years—but are not likely to be bad wind years either, all combinations will occur.

Wind power is modelled as a run-of-river hydro plant: wind energy is the inflow to a plant, which has no reservoir, or flood, which means that all that comes as inflow will be produced. No prediction method for wind is used, but the stochasticity of wind will be taken into account in the dynamic programming phase: when calculating the water values for the stored hydro reservoirs, the probability of future wind production will affect the values the same way as the part of the inflow that flows through the hydro plants without possibilities to store the water.

## 2.3. Results of the EMPS simulations

Wind power will replace the production form that has the highest marginal costs: wind will come to the production curve in Fig. 2 from the left (0 Euro/MWh) and shift the curve to right resulting in some of the production near the market cross to be replaced. As the consumption and production curves will be different for each week, also the production form that wind will replace will differ. If we had a system with abundant coal condensing power production we could say that it will always be coal that wind is replacing. In the Nordic system, with a lot of hydro and nuclear production, as well as CHP produced according to heat demand, it has been simulated week by week to see the result.

The results from wind1 scenario, where there is a total of 16 TWh/a wind power production, compared with the base case scenario (with Danish 3.5 TWh/a wind), summed up from all countries, is as follows: adding 12.5 TWh/a wind to the system will reduce 8.5 TWh/a coal, 1.8 TWh/a gas, 1.4 TWh/a oil and 0.2 TWh/a peat power production. There will be also minor decreases in

biomass and nuclear production, as well as a minor increase in hydro production, all less than 0.1 TWh/a.

Large amounts of wind, 42.5 TWh/a added wind (46 TWh/a total) will replace 28.9 TWh/a coal, 7.2 TWh gas, 3.7 TWh/a oil as well as 0.5 TWh/a peat, 0.3 TWh/a biomass and 0.2 TWh/a nuclear power production. Hydro power will be decreased by 0.2 TWh/a, due to increased floods in springtime coincident with high winds. The replacements do not amount to exactly same amount as wind power added to the system, because slight changes in electricity consumption will occur. Also the transmission losses increase, which can be seen in the wind3 simulation (0.1 TWh/a increased transmission losses between the areas).

In more detail, looking at each country, an example of the simulation results is presented for Finland, in Fig. 4, summed up by production forms. In Finland, wind production replaces condensing power production (mainly coal). Electricity imports to Finland increase. For wet years in the wind3 case (7 TWh/a in Finland

and 46 TWh/a in Scandinavia) the nuclear production is slightly 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 condensing power production, for the little there is to replace, and some of the nuclear and CHP production will be decreased. 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 condensing power (mainly coal) and increasing exports. Both imports and exports in Denmark are increasing with increasing wind in the system.

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

The yearly CO<sub>2</sub> emissions of the simulated cases are presented in Fig. 5. This is the model output, calculated from simulation results of produced electricity from different production forms and the emission factors given as input. The effect of electricity replacing oil used in boilers (price flexible consumption) is to lower the emissions, this is also taken into account in the emissions shown in Fig. 5.

The result of the wind1 simulation, adding the amount of wind foreseen in 2010, is that as a combined result of different fuels being replaced in the Nordic system, a CO<sub>2</sub> reduction of wind power is 700 g CO<sub>2</sub>/kWh: CO<sub>2</sub> reduction 8.7 Mt when adding 12.5 TWh/a wind power to the system. Adding more wind results in somewhat lowered emission reductions: 650 g CO<sub>2</sub>/kWh in wind3 case, CO<sub>2</sub> reduction 28.8 Mt when adding 42.5 TWh/a wind power to the system. For the 2000 scenario the CO<sub>2</sub> reduction is slightly smaller, 680–620 g CO<sub>2</sub>/kWh.

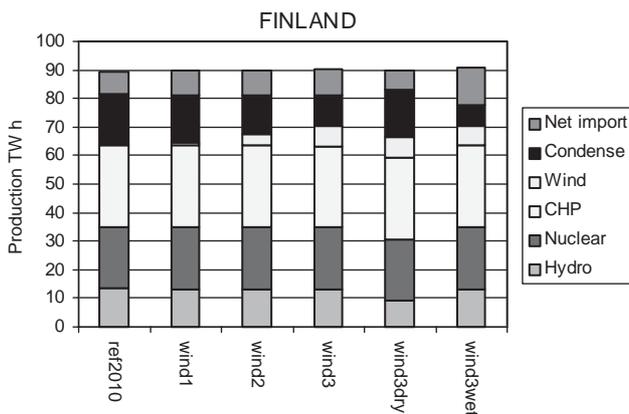


Fig. 4. Production and net import in Finland: reference and wind1–3 simulations for the system in 2010. In addition to the 30-inflow-case-average results, also example years for wet and dry years are presented, for wind3 case (the year of the largest inflow in the Nordic countries was not specifically wet in Finland).

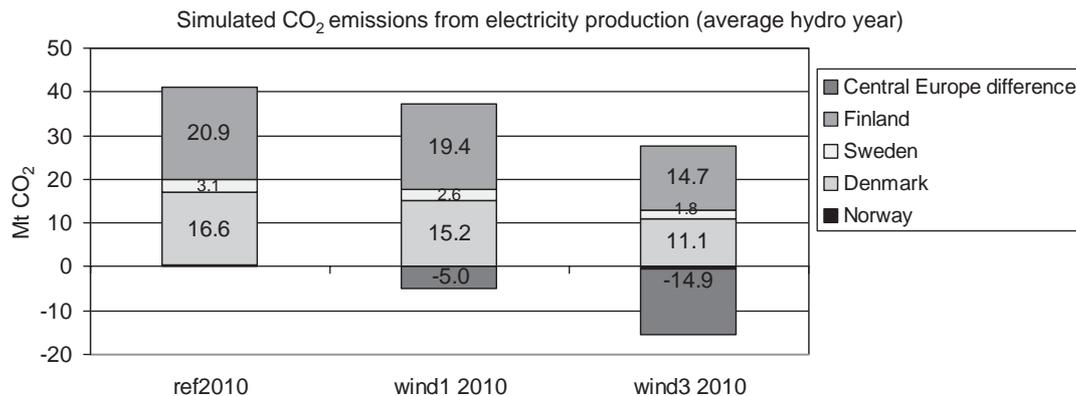


Fig. 5. CO<sub>2</sub> emissions in reference, wind1 and wind3 simulations for an average hydro year.

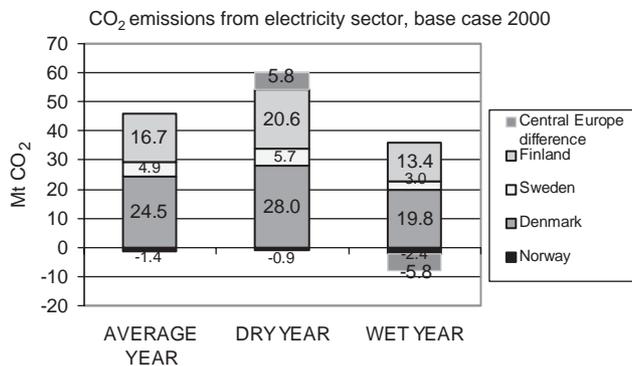


Fig. 6. CO<sub>2</sub> emissions of electricity production in reference simulation for year 2000. In addition to the 30-inflow-case-average results, also example years for wet and dry years are presented.

It is notable that the wind production added to Norway and Sweden will mostly replace thermal power produced in Finland, Denmark and Central Europe. This is a result of having an interconnected system with a common electricity market: the system covers the whole of the area and thus power will be replaced where it is most cost effective. The hydro power in Norway and Sweden will not be replaced even with substantial wind production, as long as there are possibilities to increase the exports to other countries.

It is also notable how much the emissions of electricity sector differ yearly depending on how much CO<sub>2</sub> free hydro is available to the system. The difference is  $\pm 6$  Mt for Central Europe,  $\pm 5$  Mt for Denmark,  $\pm 4$  Mt for Finland,  $\pm 2$  Mt for Sweden and  $\pm 1$  Mt for Norway (Fig. 6). This reflects the way the Nordic system is operated: during wet years the hydro production is exported from Norway and Sweden and during dry years these countries import thermal power from Denmark, Finland, and Central Europe.

### 3. Simulations of the EFOM model for Finland

#### 3.1. Description of the model

The EFOM model is a quasi-dynamic many-period linear optimisation model. It has been widely used to analyse national energy systems and mitigation of greenhouse gas (GHG) emissions (e.g. Lueth et al., 1997; Lehtilä and Pirilä, 1996). Another widely used model of this kind is MARKAL (e.g. Kram and Hill, 1996). More advanced similar kind of models (e.g. TIMES) are being developed under the IEA ETSAP agreement (IEA, 2002).

In EFOM the whole system is represented as a network of energy or material chains. The network of the described energy system starts from the primary energy supply and ends in the consumption sectors. EFOM is a bottom-up model and it is driven by an

exogenous demand for useful or final energy in the consumption sectors. The Finnish EFOM model includes descriptions of other activities that emit greenhouse gases (e.g. waste management and agriculture) and due to national characteristics also detailed subsystems for e.g. domestic fuel supply, pulp and paper industry, and combined heat and power production. The system is optimised by linear programming using the total present value costs of the entire system over the whole study period as the objective function which is to be minimised. The whole study period is divided into sub-periods, which can be of different length. In this study the period is 2000–2025 and the time step is 5 years. The year is divided into winter and summer seasons and therefore the seasonal changes, e.g. in wind and hydro power production can be taken into account. The solution includes the statistics of all model variables for the end of each sub-period (Lehtilä and Pirilä, 1996; Tuhkanen et al., 1999).

EFOM includes wide range of descriptions of both present and new energy production and consumption technologies. Main inputs of the EFOM model are scenarios for final or useful energy in the consumption sectors, scenarios for characteristics of the technologies, and many constraints for, e.g. availability of different energy sources. The most important input concerning this study is the development of the costs of different energy production technologies including investment, fixed, and variable costs. The costs will greatly determine which electricity production technology is used or built less when more wind power is added to the system.

In EFOM the GHG emissions from the energy system are calculated directly by multiplying the annual fuel use with the corresponding emission factor. The factors are mainly based on IPCC (1997) and they are similar to the ones used in the Finnish National Greenhouse Gas Inventory. This methodology is applied to all energy production and other fuel consumption in the model, i.e. power production, CHP, heat production, transport etc. Emission limits, e.g. for total national GHG emissions can be used as a constraint for the optimisation of the energy system.

#### 3.2. Description of the scenarios

The effect of incremental wind power in the Finnish electricity system on CO<sub>2</sub> emissions has been studied by comparing different wind power production levels in two different scenarios: “Baseline” and “Kyoto” up to the year 2025. The only difference between these scenarios is the target for national GHG emissions. In the Baseline scenario no emission reduction targets were set on greenhouse gas (GHG) emissions (i.e. Business-as-Usual scenario), and the development of the energy system is dependent mainly on the costs. In the Kyoto

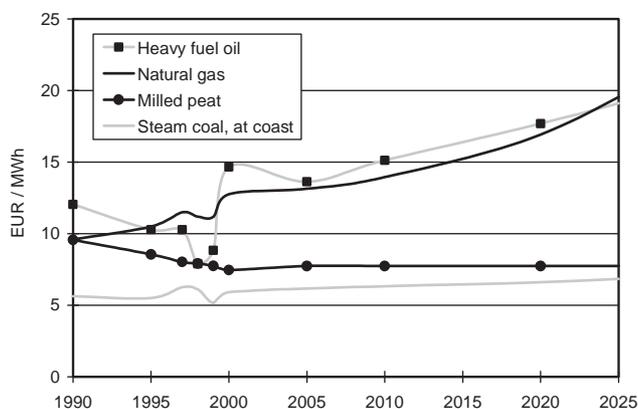


Fig. 7. Trends in main fuel prices in Finland in 2000 prices excluding taxes.

scenario the GHG emissions have to be stabilised to the 1990 level according to the Finland's national Kyoto target. In this case it has been assumed that the use of coal power is nearly prohibited among other measures in order to reach the GHG target. These two scenarios lead to different kind of capacity extension and, consequently, to different CO<sub>2</sub> abatement of wind power.

Fuel prices in the scenarios are of central importance. The assumed trends in main fuel prices in Finland are presented in Fig. 7. The trends for imported fossil fuels are based on IEA World Energy Outlook (2000) with some adjustments due to different characteristics of national fuel supply. The trend for peat fuel is based on national expert judgement.

Especially the significant increase in natural gas price affects the development of electricity supply. In the Baseline scenario it leads to significant extension of coal-condensing power capacity due to its better competitiveness when compared to gas-fired capacity. Both natural gas consumption and the dependency on Russian gas exports in the European Union are expected to increase significantly (European Commission, 2000) which leads most probably to higher price levels in the future. The developments of other costs of different energy technologies included in the model are based on numerous national and international studies and expert judgements.

Nuclear power production starts to decrease gradually around 2020 in both scenarios, and new capacity is not allowed. Hydro power capacity increases slightly during the study period, mainly due to renovations and new small-scale capacity. Maximum electricity imports are set to about 6 TWh/a. The background of the scenarios is described in more detail in Kara et al. (2001). The input data in these scenarios are mainly similar to data used in the scenarios in the Finnish Climate Strategy (MTI, 2001a, b).

Both scenarios were calculated at first by letting the model find the optimal development of energy production mix. Thereafter fixed scenarios for wind power

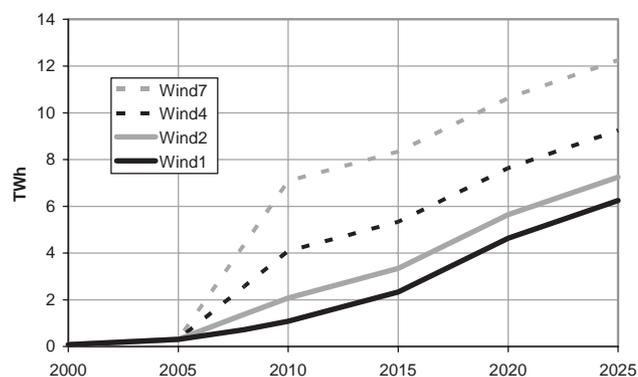


Fig. 8. Assumed development of wind power production in Finland in different cases.

production have been added to EFOM to study the effects of increased wind power production on the energy system and CO<sub>2</sub> emissions. These scenarios were chosen to be consistent with production levels for Finland in the EMPS simulations, i.e. 1, 4 and 7 TWh/a in 2010 (see Table 3). In addition, a scenario in which a level of 2 TWh/a would be reached in 2010 was studied. The development of wind power production in these fixed cases is presented in Fig. 8. In the simulations with fixed wind power scenarios, the EFOM model finds a new optimum for the development of the whole energy system.

In these scenarios most of the new wind power capacity is assumed to be offshore because different factors (e.g. poor wind conditions, land use restrictions, etc.) restrict large-scale wind power production in land areas in Finland. Onshore production is limited to about 2 TWh/a in 2010 and about 3 TWh/a in 2025. Offshore production is, however, more expensive despite the fact that wind conditions are much better. It is assumed to be commercial in Finland after 2005. Estimated development of wind power production costs is shown in Fig. 9. Average full load hours for wind power have been used: 2200 h/a for onshore and 3000 h/a for offshore wind power. Lifetime of 20 years has been assumed for wind power plants and 5% discount rate is used by the model to all power sector investments. This is quite common assumption for discount rate in the energy system analyses.

### 3.3. Results

In the Baseline scenario, wind power production remains quite low throughout the period as can be seen in Fig. 10. In these fixed wind power scenarios (Base-Wind1, etc.), the incremental wind power replaces mainly coal-condensing power. Also small reductions in district heat and power production can be observed, especially in the use of natural gas combined cycle capacity. However, these reductions are typically only

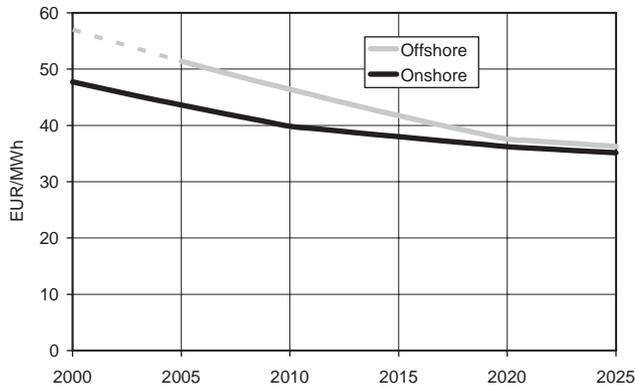


Fig. 9. Estimated production costs for new wind power plant in Finland in 2000 prices.

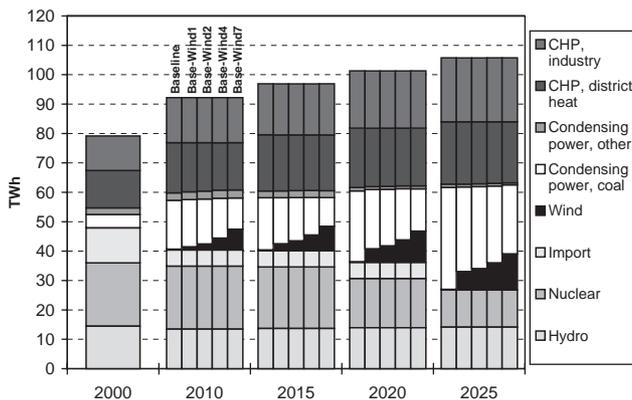


Fig. 10. Total electricity supply in the Baseline scenario with different wind power production levels.

some hundreds gigawatt-hours electricity annually. If all CO<sub>2</sub> emission reductions in the energy system were allocated to incremental wind power production, the GHG emissions will be reduced on the average about 680–700 g CO<sub>2</sub>/kWh during the period 2010–2025 in all cases. The emission levels of other GHGs than CO<sub>2</sub> remain practically stable despite of the changes in the electricity production mix.

Carbon dioxide emissions from the energy system will decrease quite significantly at least in the end of the period in all cases. In 2010 the total CO<sub>2</sub> emissions would be about 1–6% lower and in 2025 about 5–11% lower than in the Baseline scenario.

CO<sub>2</sub> abatement costs for wind power have been estimated by comparing the annual costs of the whole energy systems in different cases, in relation to CO<sub>2</sub> emissions in each case. For Base-Wind1 scenario the average emission reduction costs during 2010–2025 seem to be about 20 €/t CO<sub>2</sub>. When the wind power capacity is further increased the average costs will rise gradually to about 35 €/t CO<sub>2</sub>. This is quite obvious result because at first wind power replaces the most

expensive condensing power capacity and after that the replacement is aimed at less expensive capacity (see e.g. supply curve in Fig. 2) and, therefore, the emission reduction per unit wind power generation becomes more expensive.

In the Kyoto scenario, wind power capacity increases quite remarkably in the cost-optimal case due to its competitiveness as an emission reduction measure. As mentioned earlier the use of coal-condensing power is minimised in this scenario in order to reach the Kyoto target for GHG emissions. Consequently, when more wind power is added to the energy system, the new capacity replaces mainly other condensing power capacity which is in this case natural gas combined-cycle (NGCC) capacity. In district heat and power sector minor changes would occur in the production level and the fuel mix, but a clear replacement of certain technology cannot be observed. The specific CO<sub>2</sub> emission reduction is only about 260–300 g CO<sub>2</sub>/kWh due to the high efficiency of NGCC and other small changes in the energy system. It should be noticed that in the Kyoto scenarios the average CO<sub>2</sub> emission from electricity production is much lower than in the Baseline scenarios, and consequently the achievable emission reduction are clearly lower. Also, part of the wind power potential would be used already in the basic cost-optimal case, against which the wind cases are compared, and so this is the result of increased wind production to the system. Increased wind power production also seems to increase slightly the total electricity supply. In other words some energy saving measures would not be implemented when wind power production is extensively increased. This is due to the nature of the model: it will calculate a new optimum for the development of the whole energy system every time a slight change is implemented, and therefore surprising changes might occur. In realworld the energy saving

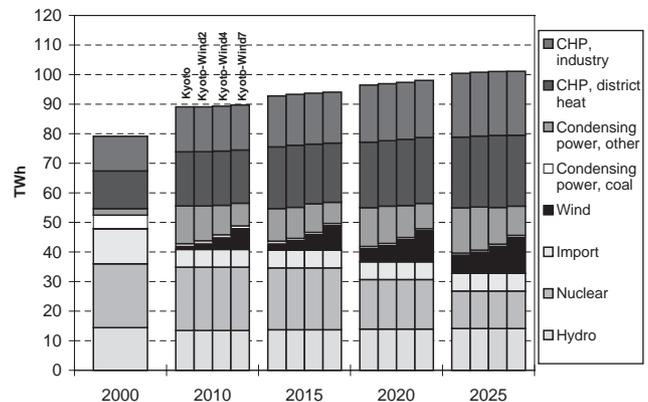


Fig. 11. Total electricity supply in the Kyoto scenario with different wind power production levels. Wind1 scenario is not shown here because the wind power production is nearly the same as in the cost-optimal Kyoto scenario.

measures would hardly compete with wind power. The development of the electricity supply in the Kyoto scenarios is as shown in Fig. 11.

The achievable emission reductions are significantly lower in the Kyoto scenarios and therefore the specific emission reduction costs increase to about 40–60 €/t CO<sub>2</sub>.

#### 4. Comparison of the results and discussion

Two different simulation models for the energy system have been used to assess the CO<sub>2</sub> abatement of wind power in Finland and the Nordic countries. An overview of the simulated cases is presented in Table 4.

These models are not designed for solving this kind of problems in particular. The main usage of EMPS is

simulating the market price taking into account the large hydro power share in the market, and scheduling the hydro power production from the large reservoirs in an optimal way. The strength in EMPS is that it can simulate the running of different production units, like it is operating today, as a large, interconnected area. Therefore it is able to simulate a large amount of different situations, with 30 years of inflow and wind power data, and look into detail in what wind power will replace in a hydro-thermal system during different weeks, with high and low load situations. The weakness of EMPS is that the longer term picture is difficult to form: the system is fixed for each simulation, not allowing capacity expansion. It is not an easy task to formulate future scenarios of the whole Nordic system as an input, making sure that the system operates in a balanced way. Correspondingly, EFOM is mainly used in long-term energy and environmental policy support studies in national level. In the EFOM model the calculation is done in annual basis and only seasonal changes can be taken into account. Consequently, e.g. variation of power production, consumption and cross-border trading are clearly out of the scope of the model. On the other hand EFOM enables estimating the cost effects of different kind of GHG abatement measures and long-term study period is naturally advantage in energy system analyses. Due to the nature of the model both capacity extension and replacement of present capacity are results of optimisation.

Simulating the wind power production in the energy system of Finland and in the electricity system of Nordic countries give consistent results: wind power will replace production in condensing power plants, mostly in coal fired plants, resulting in CO<sub>2</sub> abatement of 620–700 g CO<sub>2</sub>/kWh wind power produced. The exact result depends on the amount of wind power added to the system, and the system inputs of how much coal and gas fired production there will be and at what operating costs. The dispatch of the system was simulated with two quite different assumptions: the system as it is today, and the system with foreseeable changes for year 2010 and a CO<sub>2</sub> tax for fuels. This changed the production form that was operating the margin considerably, as a shift from coal and oil fired plants to gas fired plants could be seen. However, as the amount of gas fired production was still limited in the system, wind power production would replace mostly coal fired production, and the combined effect of wind power production remained in the range of 620–700 g CO<sub>2</sub>/kWh for the different simulations made. The simulations run are not directly comparable between the models EFOM and EMPS. The input for Finland for year 2010 is quite similar—slightly more coal fired production in EFOM and more imports in EMPS. The operating costs of the power plants are not on the same level due to the CO<sub>2</sub> tax used in EMPS, and the higher

Table 4  
Overview of the simulated cases

| Case           | Model | Description  |
|----------------|-------|--|
| Reference 2000 | EMPS  | Simulation of the dispatch of Nordic electricity production with weekly time steps for the year 2000 (30 different inflow and wind years).   |
| Wind1, 2000    |       | Reference case and increasing amounts of wind power production (16–46 TWh/a).  |
| Wind2, 2000    |       |  |
| Wind3, 2000    |       |  |
| Reference 2010 | EMPS  | Simulation of the dispatch of Nordic electricity system with weekly time steps for the year 2010 (a possible scenario for the system, 30 different inflow and wind years). CO <sub>2</sub> taxes added to operating costs of thermal plants. Wind cases same as above.             |
| Wind1, 2010    |       |  |
| Wind2, 2010    |       |  |
| Wind3, 2010    |       |  |
| Baseline       | EFOM  | 25 years of simulation with 5-year time steps for the Finnish energy system. Business as usual scenario, no restrictions to GHG emissions, capacity extension by minimising the costs. Reference case and increasing amounts of wind power production set to year 2010 (1–7 TWh/a) |
| Base-wind1     |       |  |
| Base-wind2     |       |  |
| Base-wind4     |       |  |
| Base-wind7     |       |  |
| Kyoto          | EFOM  | 25 years of simulation with 5-year time steps for the Finnish energy system. Kyoto scenario, restrictions to GHG emissions, capacity extension by minimising the costs. Reference case and increasing amounts of wind power production set to year 2010 (1–7 TWh/a)                |
| Kyoto-wind1    |       |  |
| Kyoto-wind2    |       |  |
| Kyoto-wind4    |       |  |
| Kyoto-wind7    |       |  |

natural gas prices in EFOM. However, as the amount of gas fired production is limited in Finland, this does not alter the results significantly.

The result that a significant amount of electricity produced by wind power in Norway and Sweden would replace fossil fired production in Central Europe can also have implications to energy policy. A country with huge renewable production and limited fossil fired production, that provides national policy support for wind, may not reap the direct CO<sub>2</sub> benefits of those investments. For international policy in Europe, the implications are more complicated. There are currently two market oriented mechanisms in planning phase for the reduction of CO<sub>2</sub> emissions. Tradable emission permits (TEP) affect the emissions directly, whereas the tradable green certificates (TGC) increase the use of renewable energies, which will reduce the CO<sub>2</sub> emissions indirectly. The interactions of the electricity market with TEP and TGC markets have been studied (Jensen and Skytte, 2002; Nese, 2002), and the results are somewhat ambiguous for the energy policy makers—it is not a straightforward relationship between the quotas and prices set by policymakers and the resulted emission savings. There might be problems especially with international trade of TGCs: as the CO<sub>2</sub> benefit is not tied into TGC, the country where it is most cost effective to build the renewable production will benefit the CO<sub>2</sub> reductions, paid for by other countries (Jensen and Skytte, 2002; Nese, 2002). Or then, if the CO<sub>2</sub> benefit is considered, this will result in domestic investments of renewables only, not taking the advantage offered by the international TGC's of building the renewable production where it is most cost effective (Morthorst, 2001). In these studies, it is assumed that renewable energy production reduces CO<sub>2</sub> emissions only in the country where it is built in—with the exception of TGCs increasing the consumer price for electricity with (slight) decrease in consumption. According to our simulations, in countries like Norway and Sweden the wind power production would result in reducing emissions elsewhere in the interconnected market area, which means that also the CO<sub>2</sub> emission benefits of wind power would partly be materialised in other country than where the wind power is installed. If wind power was built with f.ex. Germany's TGC funding in Norway (with better sites for wind power), this would result in part of the emission reduction in Germany. Emission reduction means also an increased amount of TEPs to be traded at the market. In this case it might help the international TGC system working, as the benefits will at least partly be for the country who is paying for the TGC.

There are three main assumptions used in the simulations: first the operating cost inputs, secondly assuming that all the large-scale wind production will be available in the system, and thirdly no considerations to stranded costs of fossil fired units.

The operating costs of thermal power are assumed to be according the inputs to the models. If there are emission limits or emission payments, or the prices of fuel change, this would alter the results of the models. For example if the price of gas becomes very expensive, the marginal (operating) costs of gas plants will become higher than the marginal costs of coal plants, and this would result in wind power replacing gas instead of coal. However, energy taxes normally reflect these changes—taken that the Kyoto targets must be achieved, there has to be some regulative ways to make the use of coal decrease. The difference in results in different scenarios is reflected in the Kyoto scenario simulations of the EFOM model for Finland: when emissions are restricted and the price of gas is assumed increasing substantially, the emission abatement of wind power (or other CO<sub>2</sub> free production forms) reduces to less than half than what it is today.

Assuming that the large-scale wind power is there in the system means that local grid connection issues as well as the system integration of wind power, would be taken care of. This is probably a good assumption for Norway and perhaps for Sweden also, meaning that the large hydro system will be able to absorb the increased hourly variations due to wind power. Wind power production is characterised with large hourly variations, and this might mean more regulating capacity has to be used than the existing hydro power—regulation is not modelled in the simulations and differences in regulation can therefore not be studied with these models. If the existing hydro power in the Nordic countries is not able to take care of the extra production swings seen by the system, this would mean using gas turbines or changing gas fired plants' production levels more and thus increasing the emissions due to that. For the wind power penetration levels studied here (1–10% of yearly electricity consumption) this will, however, not result in a significant amount of emissions for the whole of the Nordic area.

With large-scale wind production, also stranded costs of power production may come into question: this is when wind is replacing so much coal production that some plants need to be shut down even though they would otherwise still be economically viable to maintain. This has not been taken into account in the simulations made here.

## 5. Conclusions

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 for 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-condensing power and oil as fuel for electric boilers. For large amounts of wind power, 8–12% of consumption, also nuclear production is reduced some during wet years, mainly in Sweden. Reductions do not occur in the same countries as the wind production, e.g. coal-condensing power is replaced also in Central Europe. These results can have implications for energy policy, and should be taken into account while designing the TGC market in the area.

As a result of adding wind to 2 different scenarios for the Nordic system, CO<sub>2</sub> emissions will be reduced 700–620 g CO<sub>2</sub>/kWh, according to the EMPS model simulations. According to the EFOM calculations the same result for CO<sub>2</sub> abatement holds in Finland in the Baseline scenario. In the Kyoto scenario in which it has been assumed that coal condensing power is prohibited in order to meet the Finnish Kyoto target new wind power capacity replaces the need for new natural gas combined-cycle capacity leading to CO<sub>2</sub> abatement of about 300 g CO<sub>2</sub>/kWh. This case reflects the situation in the future, when there is possibly no more coal to be replaced.

The costs for CO<sub>2</sub> abatement by increasing wind power capacity in Finland seem to be about 20 Euro/t CO<sub>2</sub> at first and when the capacity is further increased the costs will also rise gradually to 35 Euro/t CO<sub>2</sub>. In the Kyoto scenario the achievable CO<sub>2</sub> abatement is clearly lower due to significantly lower average CO<sub>2</sub> emissions from electricity production and therefore the abatement costs are higher, about 40–60 Euro/t CO<sub>2</sub>.

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

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