50 pct. Wind Power in Denmark and Power Market Integration

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Abstract — This paper presents the results of an extensive analysis of how to incorporate 50 pct. wind power in the Danish electricity system and what the welfare economic costs and benefits will be for Denmark as well as for the North European Region.

To estimate the consequences for the development of the power system and the costs and benefits of the increased wind power, model analysis has been carried out using the electricity market model, Balmorel. For this analysis the model covers the Nordic countries and Germany. Two scenarios have been analysed. In the first scenario, the reference scenario, all investments in production capacity including wind power is based on market mechanisms. In the second scenario, the 50 pct. wind scenario, the investments in wind power in Denmark are governed by a target of establishing 50 pct. wind power in Denmark in 2025. In the second scenario 3500 MW wind power is established on land and by 2025 Denmark will have 2900 MW wind power off shore.

The calculations result in a welfare economic benefit for Denmark of approximately 20 million DKK pr. year on average. For the Nordic countries and Germany as a whole, the benefit is 660 million DKK pr. year on average. This benefit is dependent on a welfare economic discount rate of 3%. The welfare gain takes into account costs of additional infrastructure, trade effects, savings on fuel consumption, investment and operating costs on plants as well as reduced consumption of CO_2 quotas, and the damaging effects of NO_x and SO_2 emissions.

Index Terms — Mathematical market modelling, System analysis, Wind power integration.

1. INTRODUCTION

In January 2007 the Danish Government published its proposal for an energy policy for Denmark “A visionary Danish energy policy”. The long term goal is to make Denmark independent on fossil fuels and the proposal includes an aim for 2025 of doubling the share of renewable energy in the energy supply to 30 pct. In the proposal it is mentioned that an important contribution could come from doubling the wind power capacity to 6.000 MW in 2025 thus covering 50 pct. of the Danish power demand.

According to the Danish policy proposal essential contributions could come from:

- A doubling of wind power capacity from approx. 3,000 MW to 6,000 MW.
- Approx. 50% of electricity demand in Denmark supplied by wind turbines in 2025.
- 500 – 1,000 offshore wind turbines producing electricity equivalent to consumption in Denmark’s residential sector.

A number of questions arise on the future increase in wind power capacity in Denmark:

- How is it possible to technically integrate a greater amount of wind power into the Danish electricity system?
- What are the consequences for the North European electricity market and for security of supply?
- Which drivers and barriers do investors in Denmark encounter compared to the investment climate in other countries?
- What are the costs and benefits of a target of 50% wind power in 2025?

In this paper, emphasis is given to the final question, i.e. determining the costs and benefits of 50 pct. wind power in Denmark in 2025. Additionally, scenarios with 30% and 40% have been analyzed for comparison.

The model assumptions and simulations are also used to discus the value of wind power capacity in the Nordic electricity system, and the cost of wind power integration.

The results presented in this paper should be viewed in conjunction with results presented in the conference paper “50 pct. Wind Power in Denmark – Establishing the Necessary Infrastructure” at the Nordic Wind Power Conference 2007. This second conference paper details suggested steps towards securing adequate infrastructure to realize the 50 pct. vision for Danish wind power.

2. DEFINITIONS AND CLARIFICATIONS

To be precise, by “50 pct. wind power in Denmark” it should be understood that wind power generation in Denmark, should annually equate to 50 pct. of the Danish gross consumption (prior to network losses). Denmark is a part of an international power market with connections to the Nordel power region and to the UTCE system. Power flows across Danish are different in each individual hour. The quantity of imports and exports are extensively influenced by the amount of precipitation to which falls in the Norway and Sweden as well as by fuel prices, and temperature variations.

By costs and benefits it is understood to be costs and benefits for society as a whole. This implies costs and benefits for consumers, generators, system operators and to a lesser extent public finances. This includes environmental costs which are not priced in the market (externalities).

3. GENERAL METHODOLOGY

In order to quantify the costs and benefits of a 50 pct. wind power vision for Denmark a number of model simulations were performed using the Balmorel model.

3.1. Socio-economic quantification

In the analyses, the socio-economic costs and benefits of the 50 pct. wind power target, as well as the distributional effects, are quantified by comparing a model simulation with and without the wind power target.

The socio-economic effects considered are the total costs in the electricity and district heating systems from procurement of fuels, operation and maintenance, investments etc. Other implications for society are not considered and as such this is a partial analysis of the electricity and district heating sectors, where the relevant agents are producers, consumers, system operators and public finances.

For each year in the calculations, the total costs of the system are accounted. Specifically, calculations were made on the years 2010, 2015, 2020 and 2025. The yearly costs and revenues in the years in-between are interpolated. An annual socio-economic discount rate of 3 pct. is employed, and the average yearly costs are determined.

It is important to note, that although in general, perfect markets are assumed, with respect to risk premiums and required investment returns, a perceived value the market demands is used namely 11.75 pct, rather than a socio-economic interest rate. With respect to risk, a balanced investment climate is assumed, which does not favour one technology over another. This assumption favours investments in risk prone technologies such as technologies with a relatively high cost burden from capital costs over variable costs.

In spite of the required annual return on investment being just below 12 pct, investment costs are quantified using the social discount rate of 3 pct. Investments in generation technologies are annualised over an assumed lifetime of 20 years and then, each annuity value is discounted with the 3 pct. This implies that if the entire lifetime of the technology was represented, the impact on the social accounting issue would be the investment cost discounted to the year 2006. However, since investments are made which have a positive economic benefit beyond the model horizon, the annuity values of these years are not included in the social accounting.

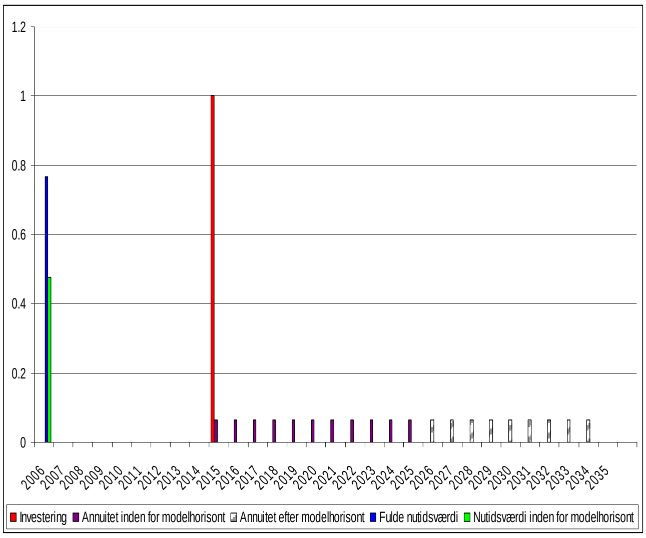

Figure 1: Method of accounting investment costs with short-term costs. If 1 Euro is invested in 2015 (red), an annuity equivalent is made over 20 years. The “annuity payments” which fall within the model horizon are included in the overall value calculation (purple), whereas payments after the horizon are assumed to be matched by revenues after the horizon (grey). The full net-present value (NPV) of the investment (blue) is therefore not included, but the perceived NPV within the model horizon is (green).

Figure 1 illustrates how investments are accounted for in the socio-economic problem. The virtue of this method is that scrap-values issues are resolved implicitly.

Investments are made on the basis of profitability in an average year of precipitation and electricity consumption. Therefore investments in peak load capacity may have been overlooked in the optimisation, as the effect of precipitation levels in the Nordic region is defining for the level of the electricity price.

4. THE BALMOREL MODEL

The Balmorel model is a partial equilibrium model covering the electricity and combined heat and power (CHP) sectors. The model is a linear programming model which by interpretation assumes perfect competition. The objective function maximizes the social-surplus, subject to technology constraints and policy (i.e. taxation) distortions. This corresponds to the social-planner minimizing total costs of satisfying demand when end-user demands are assumed to be unresponsive to prices. Costs for generation units in the model are fuel costs, fixed and variable O&M costs, capital costs, emissions and energy taxes, CO_2-quota prices and balancing costs of wind power.

The model is multi-regional consisting of a number of electricity regions with limited transmission capacity between regions. Balance of supply, demand and net exports are maintained in each region and in each subordinate district heating system. Balances from heat storages and hydropower with reservoirs ensure chronology and a temporal equilibrium between marginal costs, which are interpreted as market prices under perfect competition.

The model has the capacity to generate optimal investment decisions, on the basis of a given investment climate (i.e. required return on investments). Investment decisions are myopic beyond one year of full foresight. In addition the model simulates optimal operation in a climate of perfect competition and full foresight. This generates outputs such as generation on specific or aggregated plants, consumption of fuels, emissions from generation, losses, international transmission, etc. Relevant taxes are included and the CO_2 emissions trading system is represent through a price on CO_2 emissions.

The model is fitted with data for nominal annual projections and temporal variations for electricity and district heating demand, technical parameters for generating units (efficiencies, capacities, emission factors etc.), variations in water inflow for hydropower and wind power variations as well. Central assumptions are presented in section 5.

In the calculations performed for this project, a time resolution with 8 representative time steps in 52 weeks has been used. The precise time aggregation is optimized to represent variations in Danish electricity demand and variations in wind power generation.

For further information on the Balmorel model, please refer to [1] or the website www.balmorel.com.

4.1. Implementing a political target for wind power

In order to analyse a target for wind power share of consumption, such a target was incorporated in the Balmorel model as a new constraint. When this constraint is active, the model finds the best solution which satisfies this constraint. Since electricity demand is exogenously given in the model, the amount of wind power which must be generated each year is known to the model a priori.

The use of electricity in the production of district heating is however endogenous, but assumed negligible in Denmark, and as such is not included in the target. However, this could easily be modified.

The Balmorel model uses a generic optimization algorithm to find the best solution for the system as a whole, subject to specified assumptions. This makes it possible to interpret the impact on and incentives for different agent groups in the market by evaluating dual variables to the different constraints. Each agent group demonstrates price-taking and profit maximising behaviour.

A target for wind power generation, implemented as a model constraint, thus has a dual variable which can be interpreted as the marginal subsidy required for achieving the wind power target. However, it says nothing about how such a subsidy package is composed, only that on the margin, the subsidy is equal to the dual price from the model.

The simplest form of interpretation is the price a *wind power generation certificate* would attain in a market. However, a fixed predefined production subsidy per energy unit would give the same result. An efficient tendering process would give the same result on the margin, but with different wealth distributional consequences.

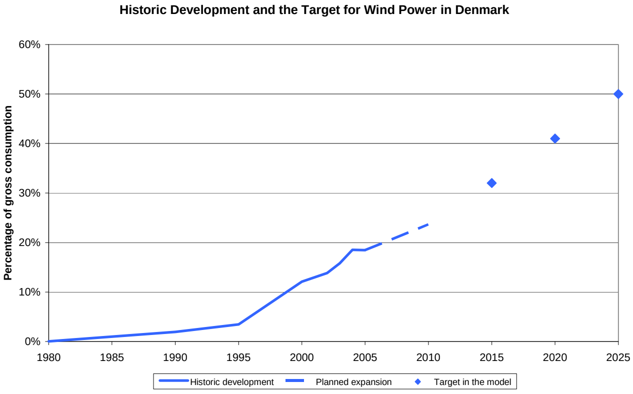

Figure 2: The wind power penetration targets assume 32 pct. in 2015, 41 pct. in 2020 and 50 pct. in 2025. The figure also shows the historic development of wind power generation as ratio of total capacity.

5. CENTRAL ASSUMPTIONS

5.1. Geography and transmission constraints

The model used for this study covers the Nordic and the German electricity and district heating systems. In Balmorel the system is divided in regions to represent capacity constraints in the power system. The Nordic system is divided in 10 regions and the German system in 3 regions. The figure below illustrates the modelled capacity constraints between the different regions.

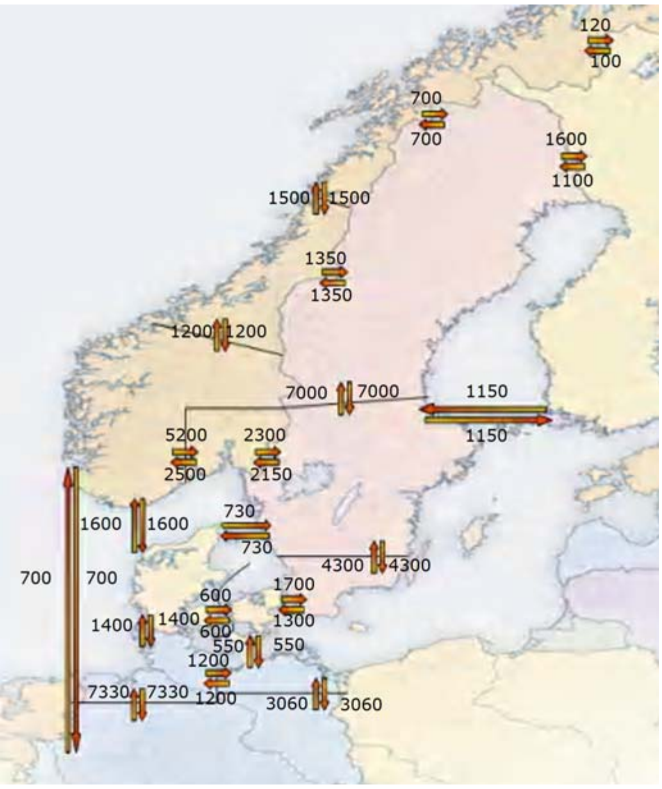

Figure 3: Transmission capacities between regions in the model. It is assumed that the 5 Nordic prioritized cross-sections are established. Also, a 4000 MW expansion of capacity over the German "Elben snit" is assumed to go along with the German windpower expansion. In Norway, Capacities between Northern and Central Norway, as well as Central and Southern Norway are assumed expand by 500 MW. 90% availability of transmission capacity is assumed at all times.

5.2. Electricity demand

The assumptions on electricity consumption are based on the most recent projections from the Danish Energy Authority [7].

Table 1: Projections of electricity consumption in the analysis (TWh/year).

TWh	Denmark	Finland	Norway	Sweden	Germany
2005	35,7	85,0	125,9	147,3	533,8
2015	37,2	98,1	134,9	156,1	585,8
2025	39,4	104,3	138,7	159,7	646,6

5.3. Fuel prices and CO$_2$ costs

The fuel price projections are also based on the latest projections from the Danish Energy Authority. These are again based on IEA's World Energy Outlook 2006. The prices used are shown in the table below.

Table 2: Fuel prices used in the analysis.

DKK06/GJ	Light oil	Fuel oil	Coal	Natural gas	Straw	Wood
2005	67,0	37,5	15,4	36,6	33,8	33,1
2015	67,2	37,6	13,7	37,8	33,8	33,1
2025	69,4	38,9	14,3	39,7	33,8	33,1

The price for CO$_2$ is assumed to be 150 DKK/ton throughout the analyzed period of time.

To represent balancing costs for wind power an extra cost of 20 DKK/MWh is added in the beginning of the period rising to 40 DKK/MWh in 2025. This is discussed further in section 7.

5.4. New investments in production capacity

Only known investments in new production capacity are included as exogenous investments in the model. This includes the new 1.600 MW nuclear plant in Finland. An exception is the expansion of wind power in Norway, Sweden, Finland and Germany. It is expected that this expansion is partly politically driven and therefore the current plans for wind power expansion have been included based on the EWIS study and the DENA Grid Study [9], [11], [12].

Table 3: Projections of wind capacity in the countries around Denmark (MW).

Capacity (MW)	Finland total	Norway total	Sweden total	Germany onshore	Germany offshore
2010	410	1275	2000	22.248	5.400
2015	610	3250	4000	26.200	9.800
2020	860	6000	6000	27.900	20.400
2025	860	6000	6000	27.900	20.400

All other new investments are determined by the model calculations. The investment data for new technologies are based on the Danish Technology Catalogue [4] except the data for new wind power investments. During the project it was estimated that the investment cost for wind power in the Catalogue were too optimistic. Therefore, for wind power the investment data has been adjusted according to data from IEA and BTM-Consult ([7] and [8]). The figure below shows the assumed development investment costs for wind power, on shore and off shore.

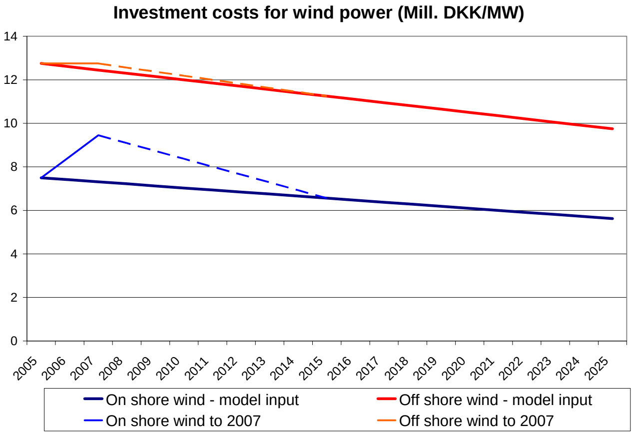

Figure 4: Investment data for wind power. A linear decrease from the price level to a estimated price level in 2025 has been assumed. The 2025 estimate is based on Danish Technology Catalogue [4] and IEA [7]. The figure also shows the increase in prices that has been experienced from 2005 to 2007.

An upper limit for the number of wind turbines installed in Denmark was set for on shore and off shore wind power in Eastern and Western Denmark respectively. Furthermore a maximum number of new wind power investments was set at 500 MW/year.

5.5. Environmental externalities

In this project, the approach was to include environmental externalities in the socio-economic accounting.

Results from European research project ExternE show that climate change and air pollution are the most important environmental externalities linked to energy production. Because of the significant uncertainties related to climate models ExternE recommends using an ”avoidance cost”-principle to set the cost of CO_2. In this study a price of 150 DKK/ton is used and the cost of CO_2 is internalised in the power market through the market for CO_2.

Except for CO_2 the externalities are not included in the model optimisation. In the optimisation any existing tax rates on emissions are included, so in principle, if these tax rates were the same as the social values of the externalities, the optimal market incentives with respect to externalities would be included.

Considering air pollution the ExternE analyses demonstrate that the emission of classic pollutants such as SO_2, NO_x and particles are much more serious than other pollutants such as CO, dioxins and furans. Therefore only SO_2, NO_x and particles were considered in these analyses.

Air pollutants have a number of negative impacts on the environment such as increased corrosion of buildings, reduces crop yields, damage to ecosystems and human health effects. Of these health effects have the largest economic impact.

Making an accurate assessment of the socio-economic consequences of air pollutants from specific plants is rendered complex by a number of scientific and methodological issues. Most pressing and controversial is the value set on lost human lives or life years. Two competing approaches are found relevant. The VSL approach (Value of Statistical Life attributes the same value to any human life. The VLYL approach (Value of Life Years Lost) attributes a lower value on older people’s lives, as they loose less life years upon premature death. There is no consensus among environmental economists as to which approach is correct. For this reason, results from both methods have been employed and weighted equally in these calculations.

Table 4: External cost of emissions according to the CAFE (Clean Air For Europe program under the EU.

External cost (DKK/kg)	CAFE 2005 Low est. (VLYL)	CAFE 2005 High est. (VSL)
Particles	120	360
NO_x/nitrate	33	91
SO_2/sulphate	39	113

In this study the environmental benefits of wind power are estimated with the Balmorel model. The installation of additional wind power can be seen to push out more polluting existing capacity. In reality, the net-effects are difficult to quantify in general terms, however, with a solid representation of existing power generation options, alternative investment options, the net effects can be quantified by use of a sector model such as the Balmorel model.

6. MODEL RESULTS

As part of the study modelling and cost analysis have been carried out in detail for a reference scenario and a 50 pct. Wind power scenario for Denmark in 2025. Furthermore sensitivity analyses for lower penetration of wind power as well as for different fuel prices and CO_2 allowance prices have been undertaken.

6.1. Investments in the reference and the 50 pct. Wind scenarios

Two scenarios have been analysed. In the first scenario, the reference scenario, all endogenous investments in production capacity including wind power is based on the market mechanism. In the second scenario, the 50 pct. wind scenario, the investments in wind power in Denmark is governed by a target of establishing 50 pct. wind power in Denmark in 2025. In the second scenario 3500 MW wind power is established on land and by 2025 Denmark will have 2900 MW wind power off shore. The investments in electricity generation capacity in Denmark determined by the model are shown in the figure below.

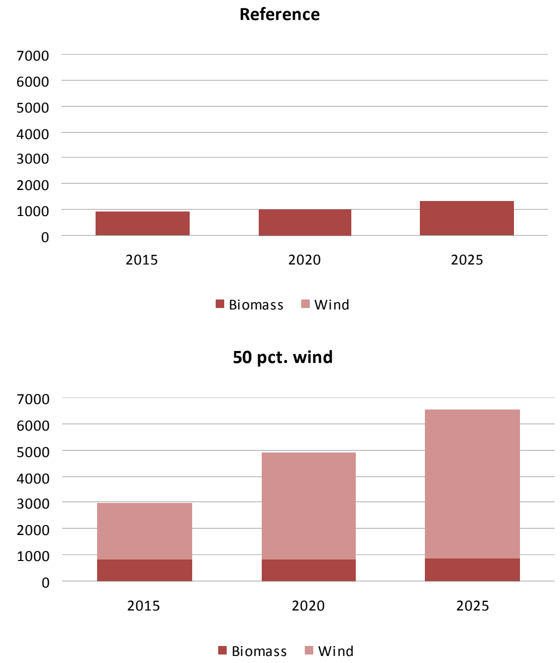

Figure 5: Increase of power plant capacity in Denmark in the two scenarios. In the reference scenario, biomass-fired power plants are established, especially at the beginning of the period. In the 50 pct. wind power scenario, wind power is increased steadily as a consequence of the 50 pct. objective. In addition to this, new thermal plants are established.

The figure below shows endogenous investments in electricity production capacity in the countries around Denmark in the reference and in the 50 pct. wind scenarios. It has been assumed in the model calculations that there is no allocation of free CO_2 allowances to new plants.

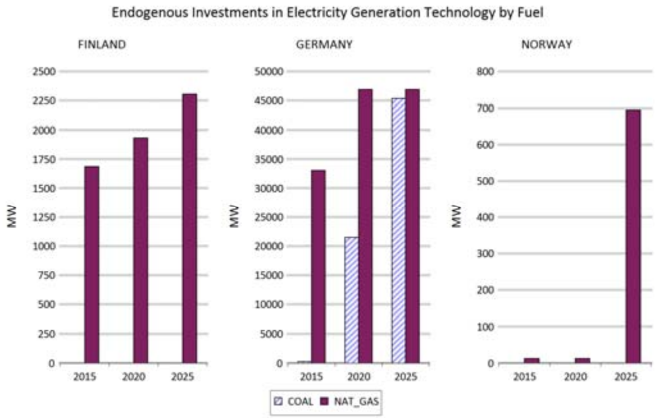

Figure 6: Investments in power production capacities in the two scenarios in other countries than Denmark. Note that the Y-axes are of different scale.

No new investments are undertaken in Sweden according to the model results.

According to the model all new investments in electricity production capacity are coal or gas fired plants. The main part of the investments is situated in Germany. As a consequence of the Danish target for expansion with wind power the investments in thermal capacity is reduced in the wind power scenario compared with the reference scenario. In Norway a new gas fired condensing plant is not established in the wind power scenario and in Finland the number of investments in gas fired capacity is also somewhat reduced. In total the investments in new thermal capacity are reduced by 1.460 MW because of the accelerated Danish wind power expansion. Of this reduction 420 MW is reduced in Denmark and the remaining 1.040 MW are in the other countries. This is later used to asses the capacity value in section 7.1.

Note that both scenarios have extensive wind power expansions in the other countries.

6.2. International Trade

In the 50 pct. scenario there is a larger export of electricity from Denmark than in the reference scenario.

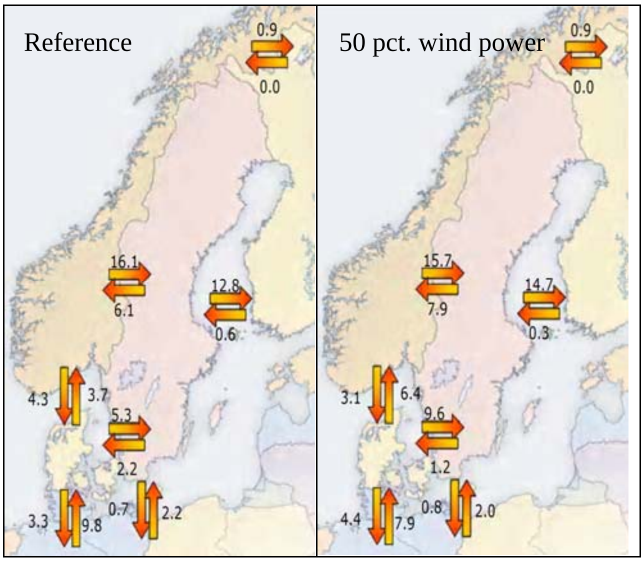

Figure 7: Yearly electricity transmission between countries in the two scenarios in 2025.

The transit flows on Figure 7 demonstrate how electricity is transmitted between countries on an annual basis. In both scenarios Denmark is a transit country for German wind power and Nordic hydropower, but the transit is reduced in the 50 pct. wind power scenario. The fact that additional wind power in Denmark results in increased net annual exports is not surprising. In the wind power scenario, more capacity was established in Denmark and less elsewhere. Again, recall that progressive wind power expansions in neighboring countries are assumed in both scenarios.

International electricity trade ensures that the expansion of generation capacity (e.g. wind power capacity) pushes the most inefficient capacity out of the market irrespective of geography, as long as transmissions capacity is sufficient. Progressive wind power scenarios can thus be motivator to expand international electricity transmission capacity. Also, in scenarios with plentiful wind power, the advantage of electricity transmission capacity is extensive, since wind generates power at different times with respect to geography.

6.3. Impact on electricity prices

The development of electricity prices in the two scenarios can be seen in the figure below.

Figure 8: Electricity price development in the two scenarios 2010 - 2025.

The consequence of the increased wind power capacity in Denmark is that the price of electricity in Denmark in 2025 decreases from 361 DKK/MWh to 330 DKK/MWh.

A more detailed illustration of the electricity prices is shown in the figure below. The figure shows the electricity price duration curve for 2010, for 2025 in the reference scenario and in the wind power scenario.

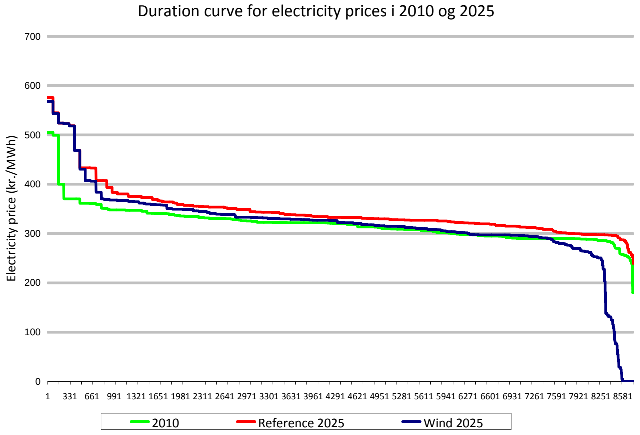

Figure 9: Duration curve for the electricity price in 2010 and 2025.

The increasing wind capacity gives a larger quantity of low electricity prices in 2025. The number of low electricity prices increases compared to the reference scenario where the wind power expansion is lower. An interesting observation is, that the peak electricity prices, i.e. when the electricity capacity balance is most strained, is not higher in the 50 pct. wind power scenario. This implies that although the prices are under pressure from wind power investments, there is still sufficient incentive to ensure available capacity, without having extreme peaks form in the market.

The necessary investments to achieve the 50 pct. wind target will not be realized under free market conditions. With the assumed fuel prices and technology data a subsidy is needed to make investors invest in wind power instead of conventional capacity. This can be seen from the figure below that shows the necessary marginal subsidy needed in 2015, 2020 and 2025 to make the model invest in the necessary wind capacity to realize the targets.

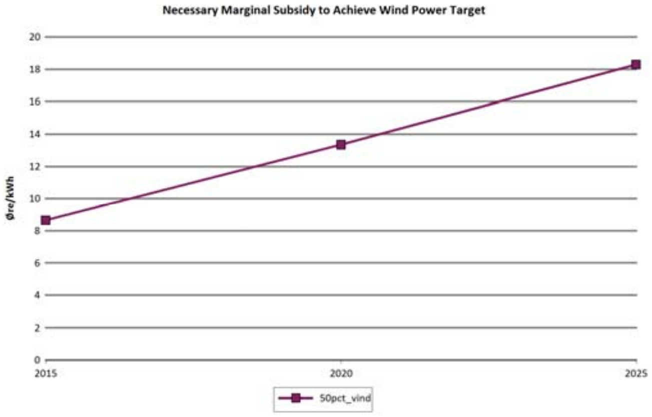

Figure 10: Necessary marginal subsidy to achieve the wind power targets in 2015, 2020 and 2025.

From the figure it can be seen that the necessary subsidy is 80-90 DKK/MWh i 2015. This target can be achieved by on shore wind alone and therefore the subsidy is equivalent to the necessary subsidy to on shore wind power with the expected technology development to 2015. In 2020 the marginal subsidy is 130 DKK/MWh and in 2025 it increases to 180 DKK/MWh. The reason for the increasing subsidy is that different types of wind turbines and locations are marginal in the different years. In 2015 only on shore wind is established and the marginal location is Eastern Denmark. In 2020 more on shore wind power is established in Eastern Denmark and some off shore wind power in Western Denmark where the wind conditions are better than in Eastern Denmark. The off shore wind sets the level of the marginal subsidy. In 2025 the maximum level of off shore wind power in Western Denmark is reached and the wind power expansion continues in Eastern Denmark. In this case the offshore wind power in Eastern Denmark determines the level of the marginal subsidy.

This can be compared with the current subsidy levels where power from turbines established after January 1st 2005 is remunerated according to the market price plus a 100 DKK/MWh production subsidy during the first 20 life years of the turbine.[1]

6.4. Socio economic consequences

By comparing the two scenarios, the economic consequences of the Danish 50 pct. objective can be assessed. In the analyses, these costs have been assessed both for Denmark alone and for the entire area (Denmark, Norway, Sweden, Finland and Germany). An important result of the model calculations are the overall annual energy costs of meeting the needs for electricity and heat in the five countries included in the model area. The costs comprise capital costs for new plants, fuel costs, operation and maintenance as well as balancing costs for wind power.

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[1] Additionally a 120 DKK/MWh subsidy is awarded for the first 12.000 full load hours, if decommissioning certificates were used in the establishment. Turbines connected between January 1st 2005 and December 31st 2009 are thus entitled. (DEA 2007: www.ens.dk)

The emission of CO_2 is not the same in the two scenarios, and one economic advantage of the 50 pct. scenario is lower costs for purchase of CO_2 quotas.

The additional expenses for grid infrastructure are due to investments in installations to connect the offshore wind farms to the main grid and the necessary grid reinforcements. The overall costs of the infrastructure elements are estimated at well over DKK 8.0bn over 16 years, equivalent to well over DKK 3.6m per MW offshore wind farm. This investment makes it possible to set up 2,250 MW new offshore wind turbines and ensures a cable solution without constructing any new overhead lines for achieving this.

The reduction in the cost of environmental impact is a result of reduced emissions of SO_2 and NO_x as production from thermal plants is replaced by emission-free wind power.

In the basic calculation, a socio-economic discount rate of 3% is used. The table shows that calculated as an average over the years 2010 – 2025, the 50% objective would produce a socioeconomic profit compared to the reference. Our analysis shows that the profit will be around 20 million DKK per year for Denmark and approx. DKK 660m per year for the area as a whole. Alternatively, at a discount rate of 6%, Denmark would get a deficit of DKK 215m while there would be a profit of approx. DKK 240m per year for the entire model area.

Table 5: Socio-economy of 50% wind power in Denmark expressed as the average cost in the period 2010 – 2025, at a 3% discount rate.

Million DKK per year	Denmark	The whole area
Fall in energy costs	27	- 287
Less consumption of CO_2 quotas	97	406
Grid infrastructure	- 236	- 236
Reduction in cost of environmental impact (SO2 and NOx)	132	777
Total gain	20	660

6.5. Sensitivity analyses

A number a sensitivity analyses have been carried out in order to test the robustness of the economic conclusions. The sensitivity analyses are carried out after two different principles. In the first type of sensitivity analysis the total investment pattern in the electricity system is recalculated with the new assumptions in the reference and in the wind power scenarios. This principle has been used in an analysis of the consequences of a development where the expected price decrease on the investment price of new wind power is not realised. In the other sensitivity analyses a new investment pattern is not calculated with the model. The reference and the wind power scenario have just been recalculated with other assumptions on fuel prices and CO_2 prices. In this way the robustness of the economy of the 50 pct. wind power scenario is tested.

Table 6: Socio-economy of 50% wind power in Denmark expressed as the average cost in the period 2010 – 2025, at a 3% discount rate.

Million DKK per year	Denmark	The whole area
50 pct. wind power – base calculation	20	660
No price decrease for wind power	-161	479
Higher fuel prices (75 $/barrel)	246	806
Lower CO_2 price (75 DKK/ton)	-158	161
Higher CO_2 price (300 DKK/ton)	590	1,259

The sensitivity analyses show that the socio economic consequences for Denmark are dependent on the development of fuel prices, CO_2 prices and investment prices for wind power. Rising fuel prices and CO_2 prices will make the economy better whereas lower CO_2 prices and higher investment costs will worsen the economy for Denmark and for the total model area. In some case the wind power investments have a negative impact on the socio-economic results for Denmark whereas the wind power investments in all cases have a positive socio-economic impact for the total model area.

7. MARKET INTEGRATION OF WIND POWER

Three main issues with regard to wind power integration are:

- Generation intermittency
- Production gradient
- Uncertainty

Intermittency is covered in the model as historic profiles for wind power generations are represented with a reasonable level of detail. The time resolution is optimized with respect to intermittency and variations in demand in the Danish market. The supply and demand balance is enforced strictly during each time step, ensuring that intermittent capacity is complemented by dispatchable capacity. Thus in a free market, capacity balances become an economic issue rather than a technical issue.

Production gradient refers to the notion that wind power can change the level of production from one hour to the next on a large scale. This would instil the need for quickly regulating power plants to complement wind power. We do not explicitly consider constraints on production gradients of the power system in the model. The frequency of large changes in wind power generation from one hour to the next is low historically (see Figure 11). The presence of large numbers of decentralized generation units, international transmission capacity, and Nordic hydropower, makes changes on this scale appear insignificant.

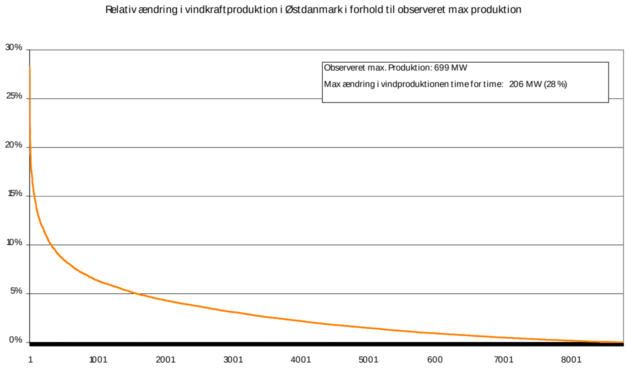

Figure 11: Relative hourly change in wind power generation in relation to observed maximum generation. Data from Eastern Denmark (1.12.2004-30.11.2004).

The Balmorel model is a deterministic model and therefore does not shed light on the cost of wind power uncertainty. The methodology is therefore to define balancing costs a priori.

Currently in the Danish system, there are two options to ensure balancing with respect to this uncertainty. The balancing task can be left to the system operator, Energinet.dk, or it can be handled privately. Energinet.dk charge a balancing tariff, currently 23 DKK/MWh fed into the system. This is used to finance the purchase of balancing power from other generators in the system. This price is driven by the average price on balancing power and the average prediction error of wind power between submitting bids to the spot market and the hour of operation. The level of the balancing costs in 2005-2006 was 30 DKK/MWh for Eastern Denmark [2] and the average prediction error has been estimated to be 35% when the bid is given 13-36 hours before the hour of operation as it is today in the Nordpool market [2].

Since wind power is increased from now until 2025 in the simulation it has been chosen to use an increasing cost of balancing from 20 DKK/MWh to 40 DKK/MWh in 2025. This is founded on a number of assumptions.

- Market development, especially the active use of the Nordic intraday market Elbas, will increase until 2025, hence put pressure on the price of regulating power.
- Balancing power trade will expand internationally. Balancing Danish wind power with Nordic hydro power for instance.
- Improvements in wind power forecasting methods and or changes in market design to better accommodate wind power (i.e. by moving spot bids closer to the hour of operation). It is assumed that the average error in prediction will decrease to 25%. (This assumption means that the cost of balancing in general is assumed to increase to 160 DKK/MWh in 2025, thus giving a cost for balancing wind power of 40 DKK/MWh).

With respect to wind power generation forecasts it is also important to note that with increased wind power competition between forecasting methods is intensified. This adds robustness to the forecasts as different wind power generators will use different forecasting methods, thus diversifying the effects of unavoidable systemic errors in forecast methods.

7.1. Evaluating the capacity value of wind power

As mentioned above the intermittent nature of wind power is implicitly included in the model calculations. The capacity value of wind power can be evaluated from the model results.

The term capacity value is used to express the value of generation to the electricity system. Basically this is a question of timing: plants which are able to adjust their production according to the system demand have a high value whereas intermittent technologies such as wind power would usually have a lower value.

There are several ways to assess the capacity value of an electricity production technology. In a well developed electricity market, the value of the electricity production can be assessed as the price a technology may obtain in the electricity market. In the Nordic market there is no separate capacity value payment and it can thus be assumed that the spot price in the mature electricity market reflects the real value of electricity production (energy and capacity value) hour by hour. In other studies, the capacity value has been assessed in different ways – for instance for wind power, it has been estimated what the extra investment will be for sufficient backup capacity for periods without wind.

Based on an evaluation of the value of wind power electricity in the market Ea Energy Analyses have previously estimated the capacity value of wind power to be 20 DKK/MWh [16].

A UKERC [17] report estimates the costs to maintain system reliability to be 37 – 60 DKK/MWh under British conditions. IEA [6] refers to the ILEX [18] study and the Green-net study [19] and estimates the capacity costs of wind power to be between 22 and 50 DKK/MWh.

The capacity value is not a constant technology parameter. The value of wind power for the system is very dependent on the incumbent capacity of the system. In a system with high penetration of hydropower with reservoirs or with many fast regulating gas turbines, the capacity value for wind power will be high, compared to a system with an abundance of slowly regulating nuclear or coal power.

As explained earlier the Balmorel model was used to calculate a reference scenario based on market driven investments and a scenario where a target of 50 pct. wind power was implemented. Furthermore, two scenarios with a target of 30 pct. and 40 pct. wind power have been calculated. In order to analyze the capacity value of wind power the table below shows the installed new wind power capacity in the 3 scenarios as well as the quantity of thermal capacity replaced by the new wind power capacity.

Table 7: Investments in thermal and wind power capacity in the 30 pct., 40 pct. and 50 pct wind power scenarios compared to the reference scenario.

	30 pct. wind	40 pct. wind	50 pct. wind
New investments in wind power capacity (MW)	3,589	4,539	5,670
Reduced investment in thermal capacity compared to the reference scenario (MW)	943	1,132	1,459
Replaced thermal capacity / new wind power	0.263	0.249	0.257

The model results show that for each MW of wind power the investments in thermal plants are reduced by 0.25-0.26 MW. In other terms for each MW of wind power 0.75 MW of thermal capacity is required according to the model. In the case that all this extra capacity is built only to handle the intermittent nature of wind power and ensure that power can be supplied in every hour also when the wind does not produce the extra costs can be calculated by calculating the extra capacity costs of the needed thermal capacity. Assuming that the 0.75 MW pr. MW wind is established as single cycle gas turbines at 3.5 million DKK/MW the yearly capacity cost of 1 MW off shore wind power will be 73 DKK/MWh. However, this will be an upper limit of the capacity cost related to the wind power since the extra gas turbine capacity can also be used for other purposes in the electricity market.

Another indicator of capacity value is the average MWh-price awarded to wind power in the market, in comparison with the average electricity price and other technologies.

This is a more relevant indicator in the Nordic market since the capacity value is included in the market price (there is no separate capacity market). The figure below shows the results of the model calculations. The figure shows the difference between the yearly average electricity price and the average price in the market for an efficient existing coal fired plant, an efficient existing biomass fired plant, and land and sea based wind power where the years represent the level of technological development. Model results for 2025 are shown for the 30%, 40% and 50% wind scenarios.

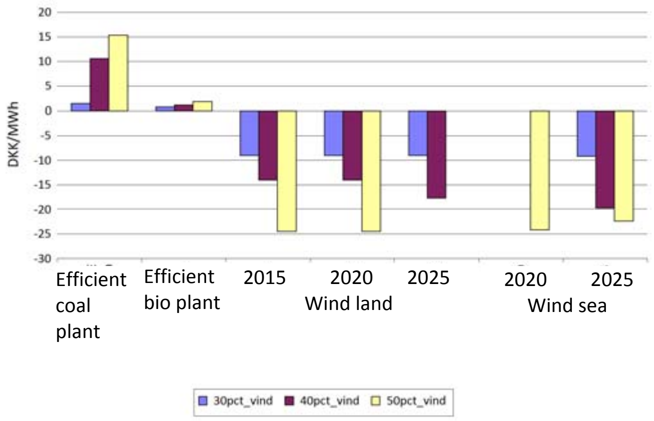

Figure 12: Model results for 2025. Capacity value of an efficient existing coal fired plant, an efficient existing biomass fired plant which is similar to the technology in which is invested, and land and sea based wind power where the years represent the level of technological development (see Figure 4).

It can be seen that the coal plant gets a price in the market that is higher than the average yearly electricity price and thus has a positive capacity value. The average price for the wind power units is lower than the average yearly electricity price and they therefore have a negative capacity value. The capacity value for wind decreases with increasing quantity of wind in the system.

With the coal fired plant as reference the capacity value of wind power is 10 DKK/MWh in the 30% scenario, 25 DKK/MWh in the 40% scenario and 40 DKK/MWh in the 50% scenario.

8. CONCLUSION

It is technically feasible to incorporate 50 pct. wind power in the Danish electricity without reducing the security of supply in the electricity system. The prerequisite for reaching the target with good economy for society is establishment of the necessary infrastructure, development of a more dynamic electricity system and an efficient, international market where also the regulation and operational reserves can be handled internationally.

Three aspects of wind power integration have been discussed. Although many values can be presented, even from the same simulation results, for the capacity value of wind power, we propose that capacity value of wind power must be seen in context with the flexibility of the electricity system. Methods which relying on calculating “necessary” quantities of back-up capacity, tend to grossly overestimate the cost of integrating wind power. So called backup capacity can have multiple sources of revenue. Also, the presence of well functioning international power markets, sufficient quantities of international transmission capacities, ensure that the cost of integrating wind power is lowered. Geographical spacing of wind power diminishes intermittency issues in well connected systems.

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