PUBLICATION III

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In: Wind Energy, Vol. 10, pp. 321–337.

WIND ENERGY
Wind Energ. 2007; **10**:321–337
Published online 21 March 2007 in Wiley Interscience
(www.interscience.wiley.com) DOI: 10.1002/we.224

Research Article

Value of Electric Heat Boilers and Heat Pumps for Wind Power Integration

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Key words:
wind power;
system integration;
heat pumps;
electric heat boilers;
stochastic
optimisation

The paper analyses the economic value of using electric heat boilers and heat pumps as wind power integration measures relieving the link between the heat and power production in combined heat and power plants. Both measures have different technical and economic characteristics, making a comparison of the value of these measures relevant. A stochastic, fundamental bottom-up model, taking the stochastic nature of wind power production explicitly into account when making dispatch decisions, is used to analyse the technical and economical performance of these measures in a North European power system covering Denmark, Finland, Germany, Norway and Sweden. Introduction of heat pumps or electric boilers is beneficial for the integration of wind power, because the curtailment of wind power production is reduced, the price of regulating power is reduced and the number of hours with very low power prices is reduced, making the wind power production more valuable. The system benefits of heat pumps and electric boilers are connected to replacing heat production on fuel oil heat boilers and combined heat and power (CHP) plants using various fuels with heat production using electricity and thereby saving fuel. The benefits of the measures depend highly on the underlying structure of heat production. The integration measures are economical, especially in systems where the marginal heat production costs before the introduction of the heat measures are high, e.g. heat production on heat boilers using fuel oil. Copyright © 2007 John Wiley & Sons, Ltd.

Received 28 March 2006; Revised 23 January 2007; Accepted 7 February 2007

Introduction

Problem Overview

A basic property of power systems is that power production must continuously be equal to power consumption including transmission and distribution losses. Wind power production varies with the wind speed and is only partly predictable. Large power plants have start-up times of several hours as well as minimum up times and minimum down times of several hours. The decisions about which power plants to run in a certain operation hour (unit commitment decisions) therefore need to be taken several hours in advance based on forecasts of the wind power production, load and availability of power plants in the operation hour. In the actual oper-

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Contract sponsor: European Commission; contract number: ENK5-CT-2002-00663.

ation hour, power plants outages and deviations between the load and wind power forecasts, and realised load and wind power are covered by up- or down-regulation of fast-responding power plants or flexible load.

In the Nordic power system, unit commitment and dispatch of power plants are partly determined by trade on the day-ahead market (called Elspot) on the Nordic power pool, Nord Pool. The market is cleared at 12:00 for the following day. To handle the demand for regulation power, i.e. reserve power with an activation time of maximum 15 min, the Nordic transmission system operators (TSOs) operate a regulating power market in each operation hour. Flexible producers and consumers can submit regulating power bids to this market up to 1 h before the actual operation hour. When a regulation need arises in the operation hour, the regulation bids are invoked with the cheapest first. Producers and consumers are required to pay balancing costs when deviations between the amounts sold and bought on the day-ahead market and the actual production and consumption in a given operation hour arise. For a given operation hour, the balancing costs are proportional to the difference between the day-ahead power price and the price on the regulating power market. This also applies for newly installed wind power capacity in Denmark, and it is assumed to apply for all wind power production in this paper.

The Danish power system is characterised by a large share of production from combined heat and power plants and wind power, and the share of wind power is expected to increase in the coming years. The electricity production from combined heat and power (CHP) plants is to some extent driven by the heat demand in the district heating grids connected to the CHP plants. In situations combining a large heat demand, low electricity demand and large wind power production, e.g. a cold winter night with high wind speeds, the electricity demand will be covered by electricity production from heat demand driven CHP plants, wind power production and minimum production on large power plants required for system stability reasons. This production is bid cheaply into the power market, because it has either low marginal costs (wind power) or has to be produced due to coverage of heat demand or due to system stability constraints, and therefore causes the electricity prices to decrease, e.g. the Elspot price at Nord Pool for Western Denmark was zero during 29 h in 2006. The amount of heat demand-driven power production in CHP plants can be relieved by introducing heat storages, heat pumps and electric heat boilers in connection with the CHP plants. Thereby the duration of zero price periods in Western Denmark can be reduced, and thus the value of the wind power production can be increased.

Furthermore, the flexibility introduced in the power system by these measures can be used to provide regulating power asked for by the TSOs, when differences between planned and actual power production arise. As the demand for regulating power will increase with the increasing share of variable and only partly predictable wind power production, measures providing regulating power will also be of value for wind power integration. In the Nordic power system, the owner of electrical heat pumps or boilers will submit bids to the regulating power market offering down- or up-regulation of power consumption. This in turn will reduce the price differences between the regulating power market and the day-ahead market, thereby lowering the imbalance penalties.

Also, power producers with CHP units in their portfolio can use the extra flexibility introduced by these measures when making unit commitment decisions in order to meet production plans. Finally, these measures will also be valuable in their ability to assist CHP plants in covering peak heat loads thereby reducing the use of oil in oil-fired heat boilers.

When electricity price is lower than the price of heat production, it is profitable to operate electric heat boilers to produce heat. Investment costs for electric boilers are low and therefore relatively few operation hours are needed to cover the investments costs. Compared to electric boilers, it is profitable to operate heat pumps more often, since they use two to five times less electricity to produce the same amount of heat.[1] On the other hand, they have higher investment costs. When the system is trying to avoid wind power curtailment with heat pumps or electric boilers, it is more useful to replace CHP production before replacing heat boilers, since one is simultaneously replacing the heat demand-driven electricity production from the CHP plants.

Literature Review

Lund and Münster[2] evaluate the ability of heat pumps and electric boilers to increase the flexibility of a power system with a high share of CHP and wind power production. The model used, EnergyPLAN, is a determin-

DOI: 10.1002/we

istic simulation input/output model of Western Denmark with the rest of the Nordic power system treated as a price interface to Western Denmark. Results indicate high feasibility of investments in flexibility especially for wind power production inputs above 20% of the electricity consumption.

Elkraft[3] (now Energinet.dk) analyses a high wind power scenario in the Nordic power system with 21 GW wind power capacity in 2025 supplemented with a large increase in natural gas power plants. A bottom-up, deterministic, optimisation model covering the Nordic countries is used in the analysis. The study finds that the costs of operating the power system decreases when installing either 500 MW heat pumps or 1000 MW electric boilers in the CHP systems in Denmark.

Comparing previous approaches[2,3] with the one used in this paper, the main difference on the methodological side is the usage of deterministic models treating wind power production as perfectly predictable, compared to the usage in this paper of stochastic optimisation treating wind power production forecasts as stochastic parameters. The usage of stochastic optimisation is the theoretically soundest way of treating stochastic input parameters compared to e.g. running a deterministic model with different deterministic wind power production inputs. This is due to the unit commitment and dispatch decisions made in the stochastic optimisation model being taken under consideration of the distribution of wind power production forecasts. The stochastic optimisation model allows endogenous evaluation of the value of providing regulating power to the system. As the uncertainties in wind power production predictions generate an increased activation of up- and down-regulation in the operation hour in question, the model is able to quantify the costs connected to the prediction errors of wind power production.

Outline of Approach

Comparison between different heat measures for wind integration is delicate, since there are several determinants for the end results. The model is not capable of doing investment decisions, i.e. determining the optimal mix of heat measures in a given power system. Instead, each heat measure is analysed separately. Three different district heating networks are used to evaluate how much is dependent on the system setting. Two simple criteria have been used to determine the sizes of the heat measures: (i) the heat production capacities of the measures are set to the same value, and (ii) this heat production capacity is set equal to half of the heat production capacity of the CHP plants present in each district heating area. Criteria 1 implies that the impact on the heat system of heat pumps and electric boilers will be comparable in size.

The article has the following structure: Section 'Model Description' introduces the model used in the analysis. Section 'Case Studies' outlines the cases used in the analysis, and section 'Simulation Results' presents results from the model. Section 'Discussion' mentions the uncertainties in the study, and 'Conclusion' sums up the study and elaborates on the possibilities for future work and on the role of different heat measures.

Model Description

The model analyses power markets based on a description of generation, demand and transmission between model regions and derives electricity market prices from marginal system operation costs. Model regions are defined in order to achieve good correspondence with most important bottlenecks in the power system. The model is a stochastic linear programming model with wind power production as the stochastic input parameter. It optimises the unit commitment, taking into account trading activities of different actors on different energy markets. Three electricity markets and markets for heat are included in the planning model:

1. A system-wide day-ahead market for the planned delivery of electricity being cleared at 12:00 for delivery the next day. The average of the wind power forecasts for the next day is sold at the day-ahead market.
2. A system-wide intra-day market for handling deviations between expected production and consumption agreed upon the day-ahead market and the realised values of production and consumption in the actual operation hour. The demand for regulating power is in the model caused by the forecast errors connected to the wind power production, because wind power production is the only stochastic parameter in the model.

DOI: 10.1002/we

3. For each model region, a day-ahead market for automatically activated reserve power (frequency activated or load-flow activated). The demand for these ancillary services is determined exogenously to the model.
4. Due to the interactions of CHP plants with the day-ahead and intra-day market, markets for district heating and process heat are included such that each CHP plant is allocated to a specific heat market. A heat market corresponds either to a specific district heating grid or an aggregation of district heating grids or an aggregation of process heat demands. No exchange of heat between heat markets is allowed.

A more detailed description of the model is given in Meibom *et al.*[4]

Objective Function and Restrictions

The objective function consists of the sum of the operational costs of heat and power plants (fuel costs, variable operation and maintenance costs, start-up costs, CO_2 emission costs, taxes and tariffs on certain types of power and heat production), and of the sum of the value in the end of the optimisation period of having energy stored in heat storages, electricity storages and hydropower reservoirs. The model also has the possibility of including price flexible electricity demand in the objective function, but this is not used for these studies. The model thereby minimises the operation costs in the whole system.

The model optimises the unit commitment and dispatch of all units in the system simultaneously. Power production costs of hydro reservoir plants are modelled through water values, which are calculated with the help of a long-term model optimising the use of water over a year-long optimisation horizon using water inflow as a stochastic input parameter.[5]

The technical consequence of the consideration of the stochastic behaviour of wind power generation is the partitioning of decision variables for power production and power transmission. For power production of the unit i at time t in wind power production scenario s, we find

$$P_{i,s,t} = P_{i,t}^{\text{DAY-AHEAD}} + P_{i,s,t}^{+\text{INTRA-DAY}} - P_{i,s,t}^{-\text{INTRA-DAY}}. \tag{1}$$

The variable $\boldsymbol{P}_{i,t}^{\text{DAY-AHEAD}}$ denotes the energy sold at the day-ahead market and has to be fixed the day before. Therefore, it does not vary for different wind scenarios. $\boldsymbol{P}_{i,s,t}^{+\text{INTRA-DAY}}$ and $\boldsymbol{P}_{i,s,t}^{-\text{INTRA-DAY}}$ denote the up- and down-regulation of power production depending on the wind power production scenario. The model allows wind power curtailment in both markets. The decision variables for power transmission are defined accordingly.

The capacity restrictions for electricity-producing units are defined for maximum and minimum electric power output. Since the model is defined as a multi-regional model, capacity restrictions of transmission lines have to be met as well. Transmission loss is considered to be proportional to the amount of electricity transmitted.

In typical unit commitment models, the restrictions for start-up costs, minimum power output, reduced efficiency at partload operation, start-up times and minimum up and down times include integer variables. However, this is hardly feasible for a model covering several countries with the resulting large number of units. Therefore, a linear approximation of these restrictions as proposed by Weber[6] is used in the model. Meibom *et al.*[4] describes these restrictions in more detail. The approximation involves the introduction of an additional decision variable 'the capacity online' with the consequence that the model allows arbitrarily small amounts of capacity to be brought online.

Although the model allows inclusion of minimum up and down times, these constraints have been considered less important than start-up times and start-up costs and are therefore ignored. Ramp rates restricting the up- or down-regulation of the production from committed power plants are for most power plants not binding in an hourly timescale and have been ignored. Unscheduled outages of units and load uncertainty are not included in the model.

The flexibility of the unit dispatch is restricted by the use of lead times that describe the start-up times of conventional power plants. Hence, the model is constrained to make decisions whether to bring additional conventional capacity online before the precise wind power production is known.

Dispatch of heat-generating units like CHP plants and heat boilers at the local heat markets is optimised as well. In order to represent individual district heating grids, the model regions are accordingly subdivided into

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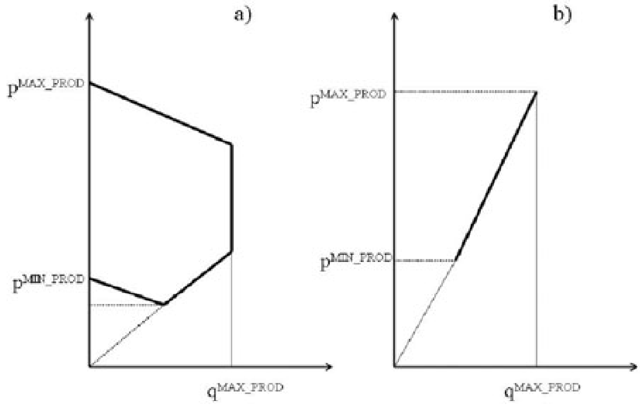

Figure 1. Simplified PQ chart for (a) extraction-condensing turbines and (b) back-pressure turbines

heating areas. CHP plants are distinguished between extraction-condensing units and back-pressure units. The PQ charts (electric power vs. thermal power charts) show the possible operation modes of the CHP plants representing the possible combinations of electric power and thermal power produced. In Figure 1, simplified PQ charts for the two different types of CHP plants included in the model are shown. These technical restrictions require additional equations.

Maintenance rates of power plants in the system are taken into account by week dependant availability factors that express how much of the installed capacity of a unit that is available during the week in question.

The Stochastic Approach of the Model

The inclusion of uncertainty about the wind power production is considered in the optimisation model by using a scenario tree that represents wind power production forecasts with different forecast horizons corresponding to each hour in the optimisation period. For a given forecast horizon, the scenarios of wind power production forecasts in the scenario tree are represented as a number of wind power production outcomes with associated probabilities, i.e. as a distribution of future wind power production levels. The construction of this scenario tree is based on historical data of wind speed and of recorded forecast errors. A multidimensional autoregressive moving average model (ARMA) time series simulates for each station the forecast error increasing with the forecast horizon and additionally taking into account the correlation between the forecast errors at different stations. These ARMA time series contain normal distributed error terms that are generated by Monte Carlo simulations resulting in a pre-defined large number of scenarios for the forecast error.

In order to obtain for each region a forecast for wind power from the wind speed forecast, technological aspects of the wind power stations located in the considered region are needed. Additionally, their spatial distribution within each region has to be taken into account. This yields an aggregation of the power generation in each region by smoothing the wind power curves (see Figure 2).

In order to reduce computation times for models representing a market with a huge number of generating units, only significantly less scenarios than the scenarios created by the Monte Carlo simulations mentioned before can be used. Therefore a stepwise backward scenario reduction algorithm based on the approach of Dupacova *et al*.[8] is used to derive the needed scenario trees.

As it is not possible to cover the whole simulated time period with only one single scenario tree, the model is formulated by introducing a multistage recursion using rolling planning. In stochastic multistage linear recourse models, there exist two types of decisions: 'root' decisions that have to be taken before the outcome of uncertain events (stochastic parameters) is known and hence must be robust towards the different possible

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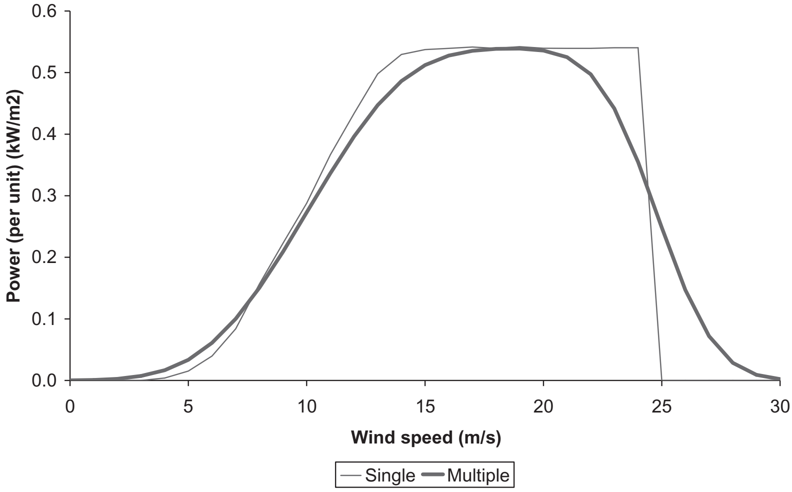

Figure 2. A standard normalised power curve ('single') and the corresponding smoothed power curve ('multiple')[7]

outcomes of the uncertain events, and 'recourse decisions' that can be taken after the outcome of uncertain events is resolved. With these 'recourse decisions', actions can be started which might possibly revise the first decisions. In the case of a power system with wind power, the power producers have to decide on the amount of electricity they want to sell at the day-ahead market before the precise wind power production is known (root decision). In most European countries, this decision has to be taken at least 12–36 h before the delivery period. And as the wind power prediction is not very accurate, recourse actions in the form of up- or down-regulations of power production are necessary in most cases.

In general, new information arrives on a continuous basis and provides updated information about wind power production and forecasts, the operational status of other production and storage units, the operational status of the transmission and distribution grid, heat and electricity demand as well as updated information about day-ahead market and regulating power market prices. Thus, an hourly basis for updating information would be most adequate. However, stochastic optimisation models quickly become intractable, since the total number of scenarios has a double exponential dependency in the sense that a model with $k + 1$ stages, m stochastic parameters, and n scenarios for each parameter (at each stage) leads to a scenario tree with a total of $s = n^{mk}$ scenarios (assuming that scenario reduction techniques are not applied). It is therefore necessary to simplify the information arrival and decision structure in the stochastic model. In the current version of the model, a three-stage model is implemented. The model steps forward in time using rolling planning with a 3 h step. For each time step, new wind power production forecasts (i.e. a new scenario tree) that consider the change in forecast horizons are used. This decision structure is illustrated in Figure 3 showing the scenario tree for four planning periods. For each planning period, a three-stage stochastic optimisation problem is solved having a deterministic first stage covering 3 h, a stochastic second stage with five scenarios covering 3 h, and a stochastic third stage with 10 scenarios covering a variable number of hours according to the rolling planning period in question. In planning period 1 starting at 12:00, the amount of power sold or bought from the day-ahead market for the next day is determined. In the subsequent replanning periods, the variables for the amounts of power sold or bought on the day-ahead market are fixed to the values found in planning period 1, such that the obligations on the day-ahead market are taken into account when the optimisation of the intraday trading takes place.

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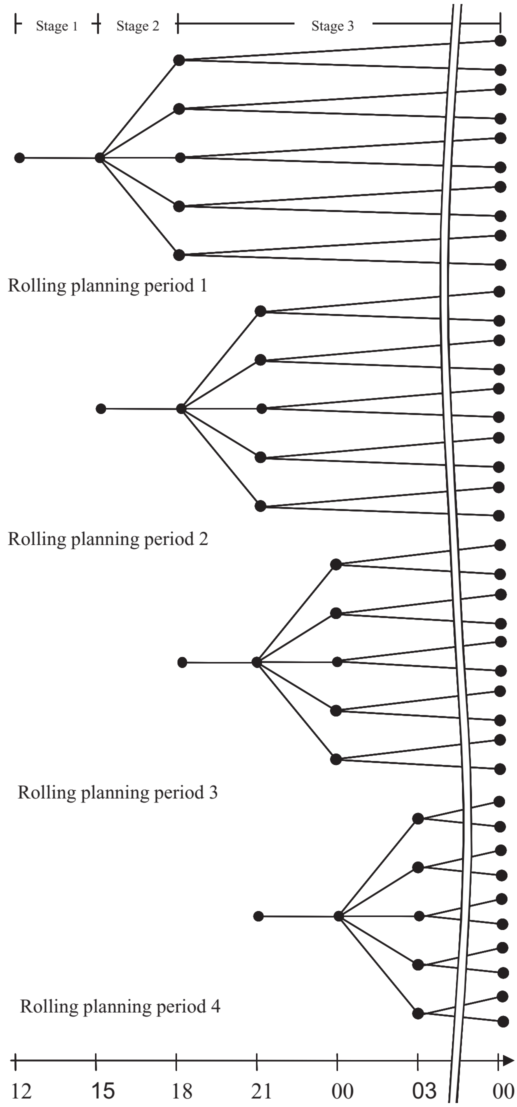

Figure 3. Illustration of the rolling planning and the decision structure in each planning period

Case Studies

The base power system configuration for the cases is a projection of the present power system configuration in Germany and the Nordic countries to 2010 by introducing investments in power plants and transmission lines that are already decided today and scheduled to be online in 2010, and by removing power plants that have been announced to be decommissioned before 2010. As the installed wind power capacity needs to be fairly large for the heat measures to be needed, a strong growth of installed wind power capacity in the period

DOI: 10.1002/we

2005–2010 has been assumed. Therefore, for Norway, Sweden and Finland, an unrealistic strong expansion of wind power covering 20% of the yearly energy consumption in 2010 is used. For Denmark and Germany, a more plausible high growth scenario has been assumed with the wind power covering 28 and 11%, respectively, of the electricity consumption in 2010. The wind profiles used are based on 2001 wind power production and wind speed data. This wind power case is named the '20%' case. Its wind power production is large enough to bring about situations where one needs to use wind power curtailment or the price goes low enough for the heat measures to be used.

The 2010 system means that planned new transmission lines between Eastern and Western Denmark (Storebælt), Finland and Sweden (Fennoskan2), and north-east and north-west of Germany are in place. Power plant investments are mainly gas in Germany and Norway, nuclear and wood in Finland, upgrade of existing nuclear power plants in Sweden and very little investment in Denmark.

The capacity balance for the 20% case in 2010 is tighter than the capacity balance in 2001, if one does not take wind into consideration. Since wind power has some merits in capacity balance, the situation in the 20% case is only slightly more challenging than in 2001 (Figure 4).

Due to calculation time considerations and data limitations, the units in the model in some cases represent a group of power or heat plants in the real world. Only power plants of the same technology type (e.g. extraction, condensing and hydropower) and main fuel type have been aggregated together. Furthermore, the aggregation also takes the age of the plants into account. Table I shows typical parameters assumed for the power-producing units in the model. All monetary values in this paper are expressed in EUR 2002 values.

CO_2 allowance price is set to 17 EUR ton^{-1} CO_2. The fossil fuel price scenario implies a continuation of the present high price levels with fuel oil, natural gas and coal prices being respectively 6.16, 6.16 and 2.25 EUR GJ^{-1}. All countries share the same fuel prices. Currently there are taxes in the Nordic countries on heat produced by electricity (67.4 EUR MWh^{-1} in Denmark and 6.9 EUR MWh^{-1} in Finland). Danish tax has been implemented in order to decrease the usage of electricity for heat production, since heat production wastes the exergy of electricity. However, during wind power curtailment, electricity would be wasted completely. To improve the feasibility of using electric boilers or heat pumps, we have therefore assumed that there is no such tax. Furthermore in the Nordic countries, there are also taxes on fuel used for producing heat in CHP plants and heat boilers. As we have removed the tax on electricity used to heat production, these fuel taxes are also set to zero to avoid profits from using electricity to produce heat due to tax distortions.

As previously mentioned, heat production capacity from each measure is set to be the same. For each district heating area analysed, we set the heat production capacity from the measure to be equal to half of the

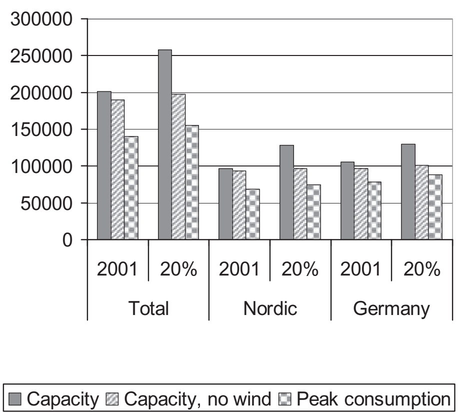

Figure 4. Capacity balance

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Table I. Assumptions about technical characteristics of the power producing units in the model distributed on fuel type and location

Parameter	Assumption			
	Nordic countries		Germany	
Start-up time [h]	20	nuclear	3	biomass, coal, nuclear
	5	biomass, coal	0	natural gas, oil, wind, hydro
	1	natural gas, fuel oil, light oil		
	0	wind, hydro		
Partload factor	0.90–0.96	thermal plants	0.96	thermal plants
	1	wind, hydro	1	wind, hydropower
Minimum load factor	0.50	nuclear	0	wind, hydro
	0.25	biomass, coal	0.50	all other
	0.20	fuel oil		
	0.10	natural gas, light oil		
	0	wind, hydro		
Start up costs [EUR MW^{-1}]	133	nuclear	3	nuclear, natural gas
	20	biomass, coal	6	biomass, coal
	13	fuel oil	5	fuel oil
	2	natural gas, light oil	0	wind, hydro
	0	wind, hydro		

Partload factor is the efficiency when producing at minimum load relatively to the efficiency when producing at maximum load. Minimum load factor is the minimum power production relatively to the installed capacity of the unit. Start-up costs are the costs connected with bringing 1 MW capacity online. Heat boilers have zero start-up time, minimum load factor and start-up costs and 1 in partload factor.

Table II. Capacities of CHP plants and heat boilers in each district heating system in MW

	BP, elec	BP, heat	Extr, elec	Extr, heat	Fuel boiler
Copenhagen	224	612	1069	1232	1500
Odense	24	64	556	776	600
Helsinki	549	898	494	423	2030

BP = back-pressure plant; Extr = extraction plant.

Table III. Capacities of each heat measure in MW

Measure	Copenhagen	Odense	Helsinki
Elec boiler	922	420	660
Heat pump	922	420	660

heat capacity of the area's CHP plants. The data for the CHP systems are shown in Table II and the resulting sizes of each heat measure are shown in Table III. Copenhagen is situated in Eastern Denmark, Odense in Western Denmark, and Helsinki in Finland.

One model run covers all three examined heating areas. A one month stochastic run was done for each measure and also a one month stochastic run without any measures for comparison. The time period chosen is February 2001, which had high wind speeds and high heat demands. The assumptions behind the coefficient of performance (COP) used are given in Table IV. The COP is the ratio between the heat output and the power input of a heat pump, i.e. expresses the efficiency of the heat pump.

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DOI: 10.1002/we

Table IV. COPs of heat pumps in February in each heat area

	Copenhagen	Odense	Helsinki
Heat reservoir	Sea water	Air	Sea water
T_low [°C]	3	0	3
T_high [°C]	100	90	100
COP theoretical	3.8	4.0	3.8
COP realised	2.7	2.8	2.7

The Carnot efficiency (realised COP relatively to theoretical COP) for large state-of-the-art heat pumps in 2010 is set to 0.7.[1,10]

Simulation Results

Price Influence and Utilisation

In the base case without new heat measures, the CHP plants cover 82, 95 and 87% of the heat consumption in February in Copenhagen, Odense and Helsinki, respectively, with the rest being covered by heat boilers. Studied heating areas behave quite differently in regard to the heat measures. During February, Copenhagen uses heat pumps most of the time whereas Odense and Helsinki utilise them with capacity factors of about 45%. Electric boilers have capacity factors of 16% in Copenhagen, 12% in Odense and 7% in Helsinki. Both heat measures replace fuel oil boilers in Copenhagen and Odense and thus decrease the heat prices strongly (Figure 5 showing a high wind situation, where the electricity price goes down especially around 21st of February). Fuel oil boilers in Copenhagen are in the base case without heat measures in some hours used to replace CHP production on extraction plants. This is caused by the low electricity prices in these hours making the marginal heat production price on fuel oil boilers lower than the corresponding price on natural gas-fired extraction plants.

In the base case, Helsinki coal-based heat boiler replaces natural gas extraction plant during high winds, but it does not replace the coal-based back-pressure plant, which is producing most of the demanded heat. However, both heat measures replace part of the coal CHP as well. The profitability of the heat measures stays low in Helsinki, since marginal heating plant is usually CHP and the price of heat is low to start with.

Figure 6 shows the duration curves of power prices (prices sorted in descending order) on the intra-day market in Eastern Denmark for the three cases. As expected, the impact of each heat measure is mainly to increase the lower power prices relatively to the base case. Because of the larger electricity-consuming capacity of the electric boilers relatively to the heat pumps, electric boilers increase the power prices more than heat pumps do. Figure 6 also shows that none of the measures are able to completely remove zero power price hours, i.e. the number of zero price hours is changed from 15 in the base case to 6 and 7 in the case of electric boilers and heat pumps, respectively.

The heat measures will also increase the regulating power capacity in the system. In case of the expected wind power production sold on the day-ahead market being higher than the realised wind power production, the rest of the system will have to up-regulate and as a result the intra-day power price will be higher than the day-ahead price. A wind power producer being in imbalance will be penalised proportional to the price differences between the day-ahead market and the intra-day market. Therefore, the impact of the heat measures on the price of regulating power can be measured by calculating the average price difference between the day-ahead and the intra-day market in the case of up- and down-regulation, respectively (see Figure 7). As expected, both heat measures reduce the penalties connected to being in imbalance. The impact is highest in Eastern Denmark where the capacities of the heat measures are largest relatively to the rest of the production capacity in the region.

DOI: 10.1002/we

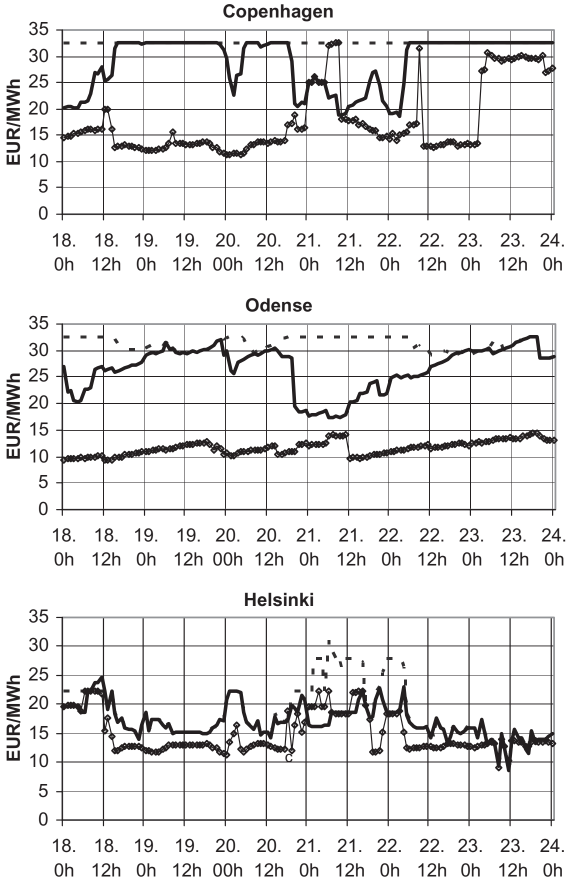

Figure 5. Heat prices of different cases in the studied heating areas. Base case (dotted line), electric boilers (full line), heat pumps (line with diamonds)

Wind Power Curtailment and Wind Power Profit

The total wind power production in the base case in the period 4–28 of February is 12.9 TWh in the whole system. 75 GWh (0.58%) of this production is curtailed, i.e. the wind power production is reduced because this is the optimal way of operating the power system in these situations. The heat measures reduce the amount of wind power curtailment with 13 and 20% for heat pumps and electric boilers, respectively.

Although the reduction in wind power curtailment due to the heat measures only constitutes 0.08 and 0.1% of the total wind power production for heat pumps and electric boilers, respectively, the impact of the heat measures on the revenue for wind power producers is considerably larger, because the power prices increase also in hours without wind power curtailment (see Figure 6) and the penalties of being in imbalance are reduced (see Figure 7). The revenue of wind power producers increases from 381.0 MEUR (million euros) in the base case to 388.7 MEUR in case of electric boilers and 390.8 MEUR in case of heat pumps, i.e. an increase of 2.0 and 2.6% for electric boilers and heat pumps, respectively, relative to the base case. Heat pumps increase the revenue more, because heat pumps are used more than electric boilers, thereby increasing also the higher power prices.

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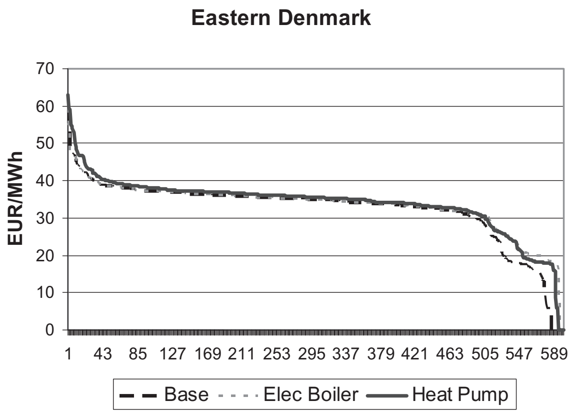

Figure 6. Power prices on the intra-day market in Eastern Denmark sorted in descending order for the three cases in the period 4–28 of February

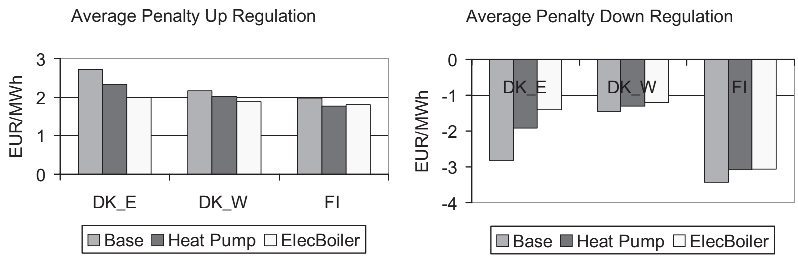

Figure 7. Average difference between day-ahead market prices and intra-day market prices in the case of down-regulation (intra-day price < day-ahead price) and up-regulation for Finland, Eastern and Western Denmark in the three cases in the period 4–28 of February

Operational Example

Figure 8 shows operation of plants grouped according to fuel in Copenhagen during high wind situation 19–22 of February. Electricity price is presented with a black line and for a while it goes down to zero due to wind power curtailment. Uppermost graph is the base case with no heat measures. Oil boilers provide heat when CHP plants are not profitable. In the middle graph, electric boilers take the place of oil boilers when the price of electricity is low enough. In the bottom graph, heat pumps do not wait for low prices — they produce full power almost all the time, replacing natural gas CHP besides oil boilers. Both electric boilers and heat pumps are able to remove the zero price hours occurring around hour 0, on 22 February in the base case.

System-Wide Effects of Heat Measures

Effects of heat measures are not restricted to the areas where the measures take place. Most notably they have a large effect on the usage of hydropower in Sweden and Norway. The hydropower model calculating water values is not yet fully calibrated, which creates uncertainty to the results that concern usage of the reservoir water. Due to this, Table V lists monetary benefits of the heat measures both with and without the value of the changed usage of hydropower.

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DOI: 10.1002/we

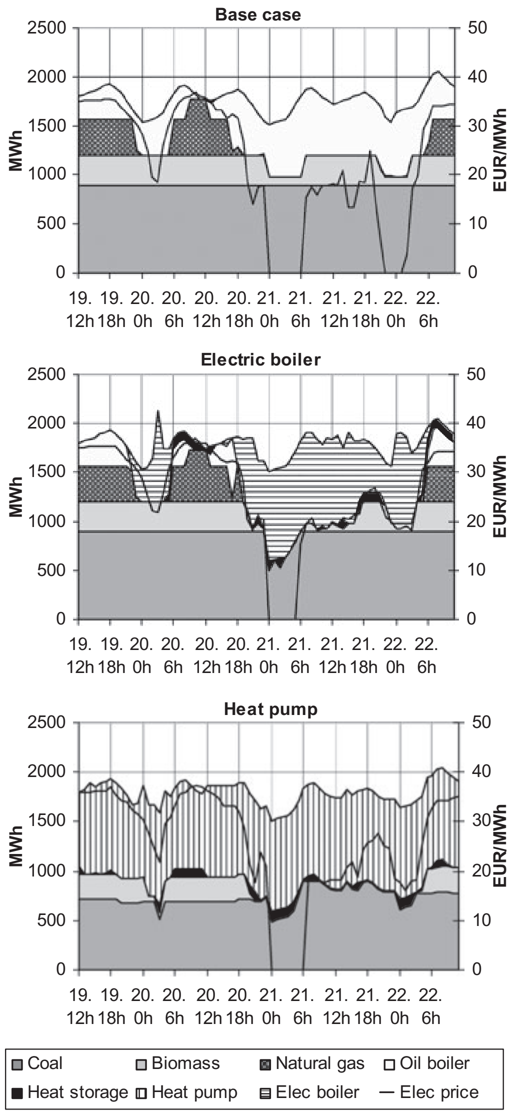

Figure 8. Heat production [MWh per h] of different groups of plants in Copenhagen during high wind situation. Coal plants are in the bottom, wood and straw CHP plants have a bit higher operational costs followed by natural gas plants and oil boilers. Electricity price [EUR MWh^{-1}] is presented with a black line

In the case of heat pumps, reservoir hydropower is used more than in the base case. In system costs, this is partly offset by the higher water value in the end of the period. The higher usage of reservoir water happens because it is profitable to use hydropower to operate heat pumps in Copenhagen.

System benefits are calculated by deducting the operational costs of each heat measure case from the same values of the base case. Operational costs include fuel costs, CO_2 allowance prices, O&M costs, start-up costs, transmission costs and subsidies for wood-based CHP production in Helsinki. For hydropower, the difference

DOI: 10.1002/we

Table V. Total system benefits in million EUR of the heat measures calculated as change in operational costs from the base case to the case in question

Benefits without hydro		Price of hydro change		Total system benefits	
Heat pump	Elec boiler	Heat pump	Elec boiler	Heat pump	Elec boiler
22.35	1.55	−10.82	−0.12	11.53	1.43

Benefits are calculated both with and without the value of changed usage of hydropower for the analysed period in February.

Table VI. System benefits and annuity in MEUR of the heat measures in each region for February

Region	System benefits		Annuity		Benefits/Annuity	
	Heat pump	Elec boiler	Heat pump	Elec boiler	Heat pump	Elec boiler
DK east	8.30	0.99	37.18	2.48	0.22	0.40
DK west	1.87	0.23	16.94	1.13	0.11	0.21
Finland	1.15	0.10	26.62	1.77	0.04	0.06

Annuities have been calculated based on the following assumptions: Investment costs of 0.6 and 0.04 MEUR MW^{-1} heat for heat pumps[10] and electric boilers,[11] respectively, disregarding annual operation and maintenance costs, a discount rate of society of 3% (we calculate in fixed prices so inflation is excluded from the discount rate), and a lifetime of 20 years.

in operational costs when using more hydropower in one case relatively to the other is the difference in hydropower production times the water value.

To be able to discuss the feasibility of the heat measure in each region, it is required to allocate the system benefits on regions. This can be done approximately by adjusting the system benefits per region for the change in transmission between cases, such that the amount of transmission to and from a region is equalised between the two cases. The correction is based on the observation that power import from other regions replaces production on power plants that have operational costs equal to or higher than the power price in the region, because the power price is equal to the production costs on the most expensive power plant operating in the hour in question. A lower bound on the reduction in operational costs in a region because of net power import is therefore equal to the net import multiplied by the power price in the region. Likewise, an upper bound on the increase in operational costs in a region due to net export to other regions is given by the net export times the power price in the region. When net import into region A is higher in the base case than in the heat measure case, the system benefits are increased by the extra power import in the base case relatively to the heat measure case times the average of the power price in the two cases. A more thorough explanation of the methodology is given in Meibom *et al*.[9]

Table V shows the total system benefits of the heat measures, whereas Table VI shows the system benefits in each region containing a heat measure, where the system benefits have been allocated to regions using the methodology explained earlier.

Comparing the system benefits with the annualised investment costs of heat pumps and electric boilers is difficult, because we have not yet calculated the system benefits for a whole year. Furthermore, the amounts of installed capacities of electric boilers and heat pumps are not optimised in any way. Still the results summarised in Table VI show that in 25 days in February, the system benefits in Copenhagen (DK East) cover 22 and 40% of the annualised investment costs of heat pumps and electric boilers, respectively. Although February probably represents a month with high system benefits of the heat measures due to the high heat demand, the system benefits during a whole year will probably be large enough to cover the investment costs of heat pumps or electric boilers in Copenhagen. The same applies for electric boilers in Odense, whereas heat pumps in Odense and both heat measures in Helsinki have lower system benefits compared to the annuity. These results correspond with the higher utilisation times of the heat measures in Copenhagen compared to Odense and Helsinki.

The reason for the high system benefits in Copenhagen compared to Helsinki is mainly that in Copenhagen the heat measures frequently replace production on heat boilers using fuel oil, which have a high heat production costs compared to CHP plants, whereas in Helsinki the heat measures replace production on coal heat boilers and coal CHP plants with lower heat production costs.

The installation of electric boilers or heat pumps decreases total CO_2 emissions in February with 0.04 and 0.6%, respectively, which with the assumed CO_2 allowance price of 17 EUR ton^{-1} CO_2 represents a value of 16 and 29%, respectively, of the total system benefits. The CO_2 emission reductions arise due to reduction in the usage of fuel oil in both cases, natural gas in the case of heat pumps, and on the expense of a growth in production from base load plants using coal in the case of electric boilers.

Profitability of the Heat Measures

A straightforward way to estimate the value of the heat measures for the potential investor is to calculate the revenue from selling heat and deduct the costs of buying power. The results of this calculation are shown under heading Investor profits in Table VII. However, if the heat measure sets the heat price on the heat market, i.e. constitute the marginal plant in the operation hour in question, the power price will directly be transferred into the heat price only modified with the COP value of the heat pump or electric boiler (2.7 or 1), so the profit of the investor is zero in these hours. An alternative approach is to use the heat production price of the marginal plant on the heat market without the heat measure in place as the heat price paid to the heat measure, i.e. calculating investor profits using heat prices from the base case and electricity prices from the heat measure case. The results of this calculation are shown under the heading ‘Profits with base case heat prices’ in Table VII.

Copenhagen area shows the most promising figures for investments into heat measures. For private investors, we have used 8% interest rate and 15 years payback time. We used the higher profit values from Table V. A 922 MW heat pump in Copenhagen with cost of 0.6 MEUR MW^{-1} would have an annuity of 64.6 MEUR. The 25 days in February would cover about 16% of the annuity. A 922 MW electric boiler with cost of 0.04 MEUR MW^{-1} would mean 4.3 MEUR in annuity. This time the 25 days would cover 19% of this. Especially the electric boiler is getting close to profitability. For other areas, one could try out smaller units and see how they would fare. Profitability would also increase if the share of wind power was higher.

Discussion

Investment costs of heat pumps and electric boilers are not easy to estimate. Especially electric boiler costs are very much dependant on the existing infrastructure and therefore the price of the investment varies a lot. Since operational costs are small, profitability is very sensitive to investment cost. It is also sensitive to the chosen interest rate, although interest rate probably has a smaller range of variation. Analysis of the sensitiv-

Table VII. Investor profits in EUR MW^{-1} from the heat measures during the modelled 25 days

	Electric boiler		Heat pump	
	Investor profits	Profits with base case heat prices	Investor profits	Profits with base case heat prices
Copenhagen	409	901	3,087	10,892
Odense	200	688	517	5,618
Helsinki	32	254	1,200	2,537

DOI: 10.1002/we

ity of results on the base of assumptions about investment costs and interest rates should be performed in future studies.

The model underestimates prices and price differences compared to the real market. This is due to several factors: (i) the model assumes a perfect market with full information, i.e. it does not include market power and limited information; (ii) transmission line availability is higher than in real life; and (iii) marginal curve of water value is too flat. Higher electricity prices mean less utilisation for the heat measures, but on the other hand more profits once they are utilised. This is a source of further uncertainty for the results.

A more realistic analysis should include power plant outages and load uncertainty in addition to wind power production uncertainty. Outages and load uncertainty will on average increase the demand for regulating power, thereby increasing the profitability of electrical heat pumps and heat boilers. Work is undertaken to extend the model to cover these issues.

Conclusion

This paper has analysed the consequences of introducing heat pumps or electric boilers in three district heating systems in the North European power system characterised by a base configuration, representing the development of the present power system until 2010 and a large share of wind power covering 20% or more of electricity consumption in each Nordic country. Changes in day-ahead and intra-day prices, revenue of wind power production, system benefits and profitability of heat pumps and electric boilers have been analysed using a stochastic partial equilibrium model of the power systems in Denmark, Finland, Germany, Norway and Sweden with wind power productions as a stochastic input parameter.

The introduction of heat pumps or electric boilers is beneficial for the integration of wind power in that the curtailment of wind power production is reduced, the price of regulating power is reduced and the hours with very low power prices are reduced, making the wind power production more valuable. The system benefits of heat pumps and electric boilers are connected to replacing heat production on fuel oil heat boilers and CHP plants using various fuels with heat production using electricity and thereby saving fuel.

The work outlined in this paper will be continued, focusing on extending the analysis to a full year, making estimation of system benefits more precise.

Acknowledgement

This work has been carried out as part of the EU-funded fifth framework research project WILMAR (www.wilmar.risoe.dk) with contract number ENK5-CT-2002-00663.

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DOI: 10.1002/we