Subsidies to Renewable Energy in Inflexible Power Markets

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Abstract

This paper analyzes how the short-term operational efficiency and the emissions of a power system depend on different support schemes provided to wind power and on the flexibility of the power system. This is analyzed in the framework of a numerical power market model, calibrated to current Danish data where the start-up costs and other constraints in fossil-fueled power plants are taken into account.

The main conclusion is that flexibility is crucial for the costs of wind power integration. If thermal power plants are inflexible, subsidies to wind power should strive to increase the flexibility of the market by passing market signals through to wind power. A subsidy that conceals market signals from wind power producers (a production subsidy) or decouples wind power incentives from the market signals altogether (a fixed price) increases costs considerably. The implication is that an inflexible power system should aim to introduce optimal subsidies (a lump-sum investment subsidy) instead of production subsidies or a fixed price. Investment and production subsidies are not equivalent in the short term.

Keywords: Electricity, start-up costs, climate policy, renewables

JEL Classification: C61, L94, Q48, Q58

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1 Introduction

The European Union (EU) has an ambitious target of increasing the share of renewable energy in electricity production to 21% by 2010 (EC, 2001). The choice of a support scheme to promote renewable energy is, however, left to the individual Member States.[1] By considering the support to renewables as a measure to reduce the CO_2 emissions from electricity production, this paper analyzes the effectiveness and efficiency of different support schemes when technical characteristics (such as flexibility) of the existing electricity system are taken into account.

Even though the principal goal of the support is to promote investments in renewables, some subsidy schemes also influence the short-term production decisions of renewables once the investment is carried out. Investment subsidies influence only the choice of technology, leaving production decisions dependent on market prices; thus, investment subsidies may be considered as lump-sum subsidies regarding the short-term (daily) production decisions. Production subsidies, on the other hand, also influence the short-term production decisions: the renewable producer may often produce in order to collect the production subsidy, even if the market price is below the producer's marginal costs. A fixed producer price decouples the production incentive completely from the market signals.

Wind power – the preferred renewable energy source in many countries – may be challenging to accommodate in existing power systems due to its unique characteristics. Wind power represents a variable energy source: put simply, it is only

[1]The common support schemes in the EU – feed-in tariffs and tradable green certificates – are versions of a production subsidy. Feed-in tariffs (guaranteed prices for renewable electricity or guaranteed mark-ups on market price of electricity) are used in Denmark, France, Germany and Spain, among others (COM, 2005). In a green certificate system, electricity producers receive a certificate for every kWh of electricity produced from renewable sources. The certificate provides an extra revenue, in addition to electricity price, to renewable electricity producers. Tradable green certificates are used in Belgium, Italy, Sweden and the UK. Investment subsidies are in force in Finland and Portugal.

possible to produce wind power when the wind is blowing.[2] Thus, the available wind power production in a given hour may vary substantially during the day and is often significantly lower than the nominal installed capacity. On the other hand, due to low marginal production costs and the possibility of adjusting production easily and without cost within the limits of the available wind, one would expect wind power to be produced up to those limits at all times. This is further encouraged by a production subsidy.

The variation in wind power production must be immediately accommodated by other producers in order to maintain the system balance; thus, other power plants must vary their production accordingly. How easy it is to accommodate the variable electricity production from renewables in the market depends on the flexibility of the rest of the power system.

The flexibility of a power system depends first and foremost on power production technology.[3] Most countries in Continental Europe have power systems dominated by thermal power plants. Conventional coal-fired and natural gas-fired thermal power plants are relatively inflexible in the short term due to the costs related to starting the plant (Wood and Wollenberg, 1996). Hence, it is not only the operational marginal costs of every kilowatt-hour (kWh) in a continuous production mode (as commonly assumed in the economic literature), but also the costs of every start-up (or avoided start-up) that determine the thermal producer's production decision in any given hour. Given this, the power plant will occasionally produce, even when the price falls below the operational marginal cost, in order to avoid a shutdown; similarly, it might choose not to start production, even when

[2] Similarly, solar and wave power are also variable, while other renewable technologies (e.g., biomass-based combined heat and power) are more similar to conventional power plants or are flexible (e.g., hydropower).

[3] Hydropower, for instance, is more flexible than thermal power. The size and technology mix of the power system, the possibility for trade and flexibility of demand also play a role for flexibility of the power system. These issues are briefly discussed in sections 5 and 6 below.

the price exceeds the operational marginal cost (Rosnes, 2008). In a market with heterogenous producers, flexibility is as important a determinant of the individual power plant's production pattern as are operational marginal costs.

If an increase in wind power production in a given hour induces a thermal power plant to shut down, it is very likely that the thermal plant must start again later. Bringing the thermal unit back to operating temperature requires additional fuel, before a single kilowatt-hour can be produced. This extra fuel causes additional emissions. In this case, the emissions avoided by stopping the thermal power plant, may be more than offset by higher emissions when the plant starts again. Moreover, due to the start-up costs, it is not necessarily the thermal power plants with the lowest emissions that will start next. Therefore, from the standpoint of minimizing costs or emissions from the power system as a whole, it may sometimes be optimal to reduce wind power production from its maximum available level, even though the wind power has lower marginal costs and no emissions, in order to avoid the shutdown of a thermal plant. Introducing wind power into a system dominated by thermal power plants increases the demand for flexibility from the remainder of the power system.

This implies that the design of the subsidy scheme should strive to maintain correct incentives to wind power in the short term: passing market signals to them would contribute to keeping additional costs and emissions at a minimum. An ill-designed subsidy scheme for renewables (i.e., one that conceals market signals and reduces the responsiveness to market prices), combined with an inflexible system, may amplify the adverse effects of renewables and contribute to excessive cost of emission reductions.

As the principal aim of supporting renewables is to reduce CO_2 emissions through crowding out fossil fuels,[4] it is relevant to examine whether a subsidy scheme con-

[4]Other goals, such as support to domestic industry or regional development, are maybe less

tributes to emission reduction and its cost. Rosnes (2005) shows that the outcome of a CO_2 tax in a power market crucially depends on the flexibility of power plants. The focus of studies analyzing different support schemes for renewables (e.g., Menanteau et al., 2003) has mainly been the *investment efficiency* of support policies, that is, to what extent do the policy measures stimulate investments in the most cost-efficient technologies.[5] Issues pertaining to short-term *operational efficiency* of renewables – the day-to-day or even hourly production efficiency – and the short-term interaction between wind power and thermal power have been neglected in the literature. Furthermore, the implications of the start-up costs of power plants have received very little attention in the economics literature so far, even though these issues have been extensively studied in the electrical engineering literature.[6] The few existing papers in economics confirm that the start-up costs do have implications for economic agents' behavior: in addition to Rosnes (2008) and Rosnes (2005) referred to above, Mansur (2003) shows in an econometric study based on Pennsylvania, New Jersey and Maryland data that power producers' bids in excess of marginal costs may be explained by start-up costs and do not necessarily reflect the abuse of market power, and Tseng and Barz (2002) find that failure to take into account the short-term constraints may lead to overvaluation of power plants.

This paper fills a gap in the literature by focusing on the effects of different support schemes for renewables on operational efficiency (short-term production costs)

pronounced, but nevertheless evident in the variety of renewable support schemes in the EU countries.

[5] The interaction between a tradable green certificates market and the power market has been analyzed in a number of recent papers, including Amundsen and Mortensen (2001), Unger and Ahlgren (2005), Morthorst (2001), Jensen and Skytte (2003). However, these studies also focus on the medium to long term impacts of renewables.

[6] This strand of literature has, however, a different focus, being largely concerned with finding the solution algorithms for the actual operation of large power systems; see e.g., Sen and Kothari (1998) or Sheble and Fahd (1994). Environmental or climate policy issues have not been at the center of attention.

and effectiveness (in terms of emission reduction) in an inflexible power system. The aim of the analysis is to quantify the policy effects in a realistic power system. Therefore, this paper explores the implications of increasing wind power capacity in the Danish market.[7] Given its predominantly fossil-fueled thermal capacity, but with an ambitious goal of boosting wind power to meet 50% of electricity demand by 2025 from 20% at present (TRM, 2007), Denmark provides a highly relevant case for the analysis of flexibility. It is reasonable to assume that as long as wind power constitutes a small share of total production capacity, it is relatively easy to accommodate within the market, despite the possible distortion from subsidies. The adverse effects will become more pertinent as the share of wind power in electricity production increases or is concentrated in some geographical areas. Even though the policy document (TRM, 2007) emphasizes efficiency, it is again only investment efficiency that is the main point of focus. Taking the existing support policies as a starting point, this paper examines how a power system's overall operating costs and emissions are affected by three different subsidy schemes: a production subsidy (a mark-up on the market price per kWh produced), a fixed price per kWh produced (unrelated to market price) and an investment subsidy per MW invested (a lump-sum subsidy concerning the production decision).

2 The model

Consider a deterministic partial equilibrium model for a power market, with a representative consumer and two kinds of producers: a renewable (wind) power

[7] Amundsen et al. (1999), Halseth (1998), Hauch (2003) and Johnsen (1998) use similar partial equilibrium models for policy analyzes of the Nordic power market. However, the time horizon of these models is considerably longer (typically one year with only a few seasons and load periods), making them unsuitable for addressing the short-term issues relating to the start-up of thermal power plants. Hence, with a finer time resolution, the present model may complement the traditional long-term policy analysis.

producer and conventional thermal power producers. The wind power producer, being able to adjust the level of production easily and without cost, is perfectly flexible within the limits of the available wind, while the thermal power producers have limited flexibility due to the presence of start-up costs (the heterogeneity of thermal power producers implies different levels of flexibility; this will be detailed in section 3.2). All producers are price takers. There is no trade.[8] The model is set in an infinite horizon context and allows for simultaneous optimization over an unlimited number of periods.

The producers submit bids stating their willingness to produce at each price level to a market operator.[9] The market operator reviews the bids from all the producers and, by choosing the producers in increasing order of the bids, simultaneously determines production of all power plants in every period t (e.g., hour) throughout a planning horizon T (e.g., a day or a week).[10] In other words, the market operator acts as a social planner, given the producers' bids. Price for each period is determined in an implicit auction. Since this is a simultaneous one-time decision for each T, there is no learning throughout the planning horizon.

The focus is on the short-term interaction of wind power and thermal power, thus, capacity is fixed. Similarly, due to the short time horizon, there is no uncertainty about fuel prices.

The model is deterministic: there is no uncertainty about wind power production or demand in the model. However, the *variability* of wind power is taken into

[8]Even though Denmark has transmission lines to Norway, Sweden and Germany, trade possibilities are ruled out in the present analysis in order to focus on the inflexibility of thermal power plants. Whether this is a realistic assumption, and the implications, are discussed in section 6.1.

[9]There is always a market operator in a power market because of the severe consequences of even a short-term market imbalance. This task is either performed implicitly by a system operator or explicitly by a power exchange (such as Nord Pool in the Nordic region).

[10]This is similar to the Nordic power exchange Nord Pool, where the day-ahead market is cleared simultaneously for each of the 24 hours of the following day (see www.nordpool.com). Real-time market, that operates close to the hour of operation, ensures that deviations between the planned and actual production and demand are balanced. Therefore, a discrete time framework is appropriate.

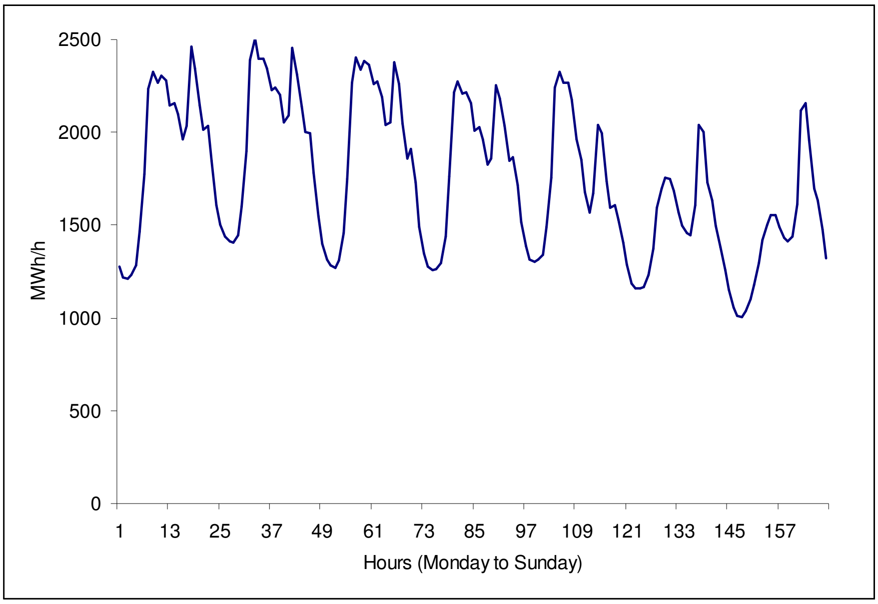

Figure 1: Electricity demand in Western Denmark throughout a week in January 2006. Source: www.energinet.dk

account, as well as the systematic variation in demand.

2.1 Demand

The representative consumer's demand for electricity in period t is q_t^D.

There is a pronounced daily *systematic* variation in power demand: demand is typically higher during the day than the night and on weekdays than on weekends. This systematic demand variation is taken into account in the model: q_t^D varies from hour to hour according to the pattern shown on figure 1.[11] This variation in demand must be accommodated by producers, requiring them to vary their production accordingly.

Demand is assumed to be perfectly price-inelastic in order to get to the heart of

[11] The figure shows the *net demand* faced by thermal producers and wind power combined, after subtracting the power supply of a third type of producer, namely small combined heat and power (CHP) plants. These plants primarily produce heat; power is merely a by-product. Thus, the power output from small CHPs is fixed.

the matter – the impact of flexibility in generation. The realism and consequences of this assumption are discussed further in section 6.2.

2.2 Thermal power producer

Consider a firm i that can produce q_{it} units of output of the homogenous product electricity in each time period t. The *operational marginal costs*, denoted by c_i, involve the costs of producing an additional unit of output when the plant is already running. The operational marginal costs depend on input (fuel) price ρ_i and plant properties that determine fuel use in plant i, denoted by the vector $\boldsymbol{\phi}_i$:

$$c_i = c(\rho_i, \boldsymbol{\phi}_i) \tag{1}$$

In addition to the operational marginal costs, the producer faces a *start-up cost* C_{it}^{start} if he did not produce in the previous period (hour) and starts to produce in this period (hour). The level of start-up costs depends on how many periods the plant has been off before being turned on again. The start-up costs consist of *direct* and *indirect* start-up costs, and are sunk costs.

The *direct* start-up costs C_{it}^{fuel} reflect the cost of extra fuel used during the start-up phase to bring the boiler to the correct operating temperature before a single kilowatt-hour can be produced. The necessary fuel use depends on the fuel price ρ_i and plant properties $\boldsymbol{\phi}_i$, but also on how many periods the unit has been shut off, measured by γ_{it}. If it has been off for a long time, so the boiler is cold, total *cold start cost* C_i^{Cold} is incurred. If the unit has been turned off only recently and the temperature of the boiler is still close to the operating temperature, the necessary fuel use is considerably lower.[12] Denote the fraction of cold start costs that are incurred when the plant has been off γ_{it} periods by $\varphi_t(\gamma_{it})$. The direct fuel

[12] This is called a *hot start* in the industry jargon.

costs of starting plant i in period t (when the plant has been off γ_{it} periods) are then

$$C_{it}^{fuel} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) \tag{2}$$

The direct start-up costs are thus lower when the unit is turned on and off frequently than when it is kept offline for many periods before being turned on again, *ceteris paribus.*

The *indirect* start-up costs $C_i^{indirect}$ are related to the increased wear and tear from start-up that reduce the lifetime of the plant. $C_i^{indirect}$ is a fixed cost per start-up.

The total start-up costs (the sum of the direct and indirect costs) in period t are thus:

$$C_{it}^{start} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) + C_i^{indirect} \tag{3}$$

The producer must decide for each period whether to operate and, if he chooses to operate, the optimal production level. In other words, there are *two decision variables*: the binary variable x_{it} ($x_{it} = 1$ for *operate*, $x_{it} = 0$ for *not operate*) and the continuous variable $q_{it} \in \left[q_i^{\min}, q_i^{\max}\right]$ for the production level.

The decisions in each period depend on the *states* at the beginning of the period:

- a binary variable d_{it} indicating the status of the plant at the beginning of the period ($d_{it} = 1$ if *on*, $d_{it} = 0$ if *off*)
- a discrete variable γ_{it} indicating the number of periods the plant has been *off*, $\gamma_{it} \in [0, \infty)$
- a continuous variable p_t for output price level, with a state space $p_t \in (-\infty, \infty)$

The *equations of motion* for the three state variables are:

$$
\begin{aligned}
d_{it} &= h(x_{it-1}) = x_{it-1} && (4)\\
\gamma_{it} &= g(\gamma_{it-1}, x_{it-1}) = (\gamma_{it-1} + 1)(1 - x_{it-1}) && (5)\\
p_t &= p(q_t) && (6)
\end{aligned}
$$

Equation (4) states that the status at the beginning of period t depends on whether the plant operated or not in period $t-1$. Equation (5) counts how many periods the plant has been off. Equation (6) is the producer price, as determined by the market equilibrium. (Even though the producer does not observe the price at the beginning of each period t, the producer's bids are contingent on prices.)

The profit π_{it} in period t depends on both the state variables p_t, γ_{it} and d_{it} at the beginning of the period and the actions x_{it} and q_{it} in period t :

$$\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) = [(p_t - c_i)q_{it}]\, x_{it} - C_{it}^{start}\,(1 - d_{it})\, x_{it} \tag{7}$$

given equations (1) to (6) and capacity constraint (8):

$$q_i^{\min} \leq q_{it} \leq q_i^{\max} \tag{8}$$

The start-up costs link the production and operation decisions in different periods together: profit in one period depends on the decisions made in other periods. Therefore, it is not necessarily the usual 'price vs. (operational) marginal cost'–rule that determines the production level in each period. Instead, the thermal power producer considers the flow of profits during the entire lifetime of the power plant. The optimal action is the one that balances the immediate payoff and the flow of future payoffs.

The value function $F(p_t, d_{it}, \gamma_{it})$ expresses the maximum achievable payoff throughout the whole planning horizon, given the present states:

$$F(p_t, d_{it}, \gamma_{it}) = \max_{\{x_{it}, q_{it}\}} \left\{ \pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) + F(p_{t+1}, d_{it+1}, \gamma_{it+1}) \right\} \quad (9)$$

Equation (9) is the Bellman equation and expresses the trade-off between the immediate payoff, $\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it})$, and the future payoffs, $F(p_{t+1}, d_{it+1}, \gamma_{it+1})$, that an optimizing agent must balance.

Bids

The Bellman equation (9) determines the thermal producer's optimal bid schedule that he submits to the market operator. The thermal producer's bid schedule may specify a combination of price level and duration of a price level for which he is willing to produce,[13] and the bids may be negative, reflecting the shadow price of a start-up that are incurred if the producer has to stop.

Emissions

Use of some input fuels v_{it} cause emissions e_{it}:

$$e_{it} = \theta_i v_{it} \quad (10)$$

where θ_i is emission coefficient.

The total emissions are the sum of the N thermal producers' emissions during

[13]This bid schedule is similar to the *block bids* that are used at Nord Pool day-ahead market in addition to the common hourly bids. A block bid sets an "all-or-nothing" condition for all hours within the block, and must be accepted in its entirety. It is also possible to define links between block bids, making acceptance of one bid dependent on acceptance of another.

the whole planning horizon T:

$$E = \sum_{t}^{T} \sum_{i}^{N} e_{it}$$

2.3 Wind power producer

A wind power producer is more flexible than a thermal power producer: the wind power producer, having no start-up costs, can change production level easily and without cost within the limits of the available capacity. However, the available capacity varies, even in the short term, depending on the wind availability each hour.[14,15] Thus, the wind power production $q_{wind,t}$ in each hour is limited both by installed capacity $q_{wind}^{\max}$ and by the availability of wind $\sigma_t \in [0,1]$:

$$q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{11}$$

Since there is no link between the costs in different periods, the wind power producer's decision is the usual static problem of choosing a production level to maximize the profit in each t, up to the available capacity limit:

$$\max_{\{q_{wind,t}\}} \Pi_t = (p_t - c_w) q_{wind,t} \tag{12}$$

[14] Availability depends on the wind force in every hour. In order to produce, there must be wind blowing. On the other hand, if the wind blows too hard, the turbines must be turned off in order to avoid damage. However, the exact relationship between wind force (as measured on the Beaufort scale or in m/s) and kilowatt-hours produced is not essential in this analysis. Therefore, the availability parameter σ_t represents the *available capacity converted into kilowatt-hours.* Any wind force that exceeds the possible production threshold is simply denoted $\sigma_t = 0$. Similarly, a windless moment implies $\sigma_t = 0$.

[15] There is also uncertainty about the availability of wind. This is, however, omitted in the present model owing to the computational infeasibility. Instead, it is assumed that wind power availability is known in each hour, but the availability varies. Recent developments in meteorological models have greatly improved the prediction of wind power availability, especially in the short term.

subject to eq. (11). The Kuhn–Tucker first-order conditions determine the optimal bids of the wind power producer:

$$p_t - c_w - \lambda = 0 \tag{13}$$

$$\lambda \left(q_{wind,t} - \sigma_t q_{wind}^{\max} \right) = 0 \tag{14}$$

Either eq. (13) or (14) is binding: when price exceeds marginal costs c_w, the wind power producer produces at the maximum level. λ is interpreted as the shadow price of capacity.

2.4 Market equilibrium

The market must be in equilibrium in each period t, balancing production from the $i = 1, ..., N$ thermal power plants and wind power to meet demand:

$$\sum_{i=1}^{N} q_{it} + q_{wind,t} = q_t^D \tag{15}$$

The market operator responsible for balancing the market reviews the bid schedules from all producers. By choosing the producers in increasing order of the bids and simultaneously optimizing over the next T periods, the market operator determines which producers will produce in each period. The solution to the market equilibrium determines the equilibrium producer price p_t in each period.

Both variation in demand and variation in wind power availability must be accommodated by the market – production in the different thermal power plants must vary accordingly in order to maintain the market balance. In the absence of start-up costs, producers with the lowest operational marginal costs produce first at all times. In the presence of start-up costs, however, it is sometimes cheaper to keep a power plant with higher operational marginal costs running than to use a power plant with lower operational marginal costs if this inflicts additional start-up costs. As the thermal power producers' bids may be negative, reflecting their willingness to carry a short-term loss in order to avoid shutdown, the producer price may be negative. In other words, producers may be required to pay in order to produce.

The wind power producer, on the other hand, has no reason to carry on producing with negative prices. The wind power producer is perfectly flexible within the limits of the available capacity: he can stop and start costlessly when the price exceeds marginal cost. Therefore, when confronted with negative prices, the wind power producer will reduce production from the maximum available level.

2.5 Subsidies to wind power

Subsidies to support wind power may influence the short-term production decision of the wind power producer and, hence, alter his bids. The altered bids affect the equilibrium solution – which producers will produce in different periods. Therefore, thermal power producers are also affected via the market, even though their bids are not affected by the subsidy to wind power.

2.5.1 Lump-sum investment subsidy

An investment subsidy is given as a lump sum S per unit of installed capacity. The short-term production decision of the wind power producer in this case becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (p_t - c)q_{wind,t} + Sq_{wind}^{\max} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{16}$$

Since capacity is given in the short term, the first-order conditions are the same as without a subsidy (eq. 13 and 14). The lump-sum investment subsidy does not distort the short-term production decision, it only improves the profitability of the investment. Hence, it is an optimal subsidy regarding the short-term production decision.

2.5.2 Production subsidy

With a production subsidy, the price that the wind producer receives ($\widetilde{p}_t$) equals the market price in a given period (p_t) plus fixed subsidy s per kWh: $\widetilde{p}_t = p_t + s$. The objective of the wind power producer becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (p_t + s - c_w) q_{wind,t} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{17}$$

The first-order condition eq. (13) is replaced by

$$p_t + s = c_w + \lambda \tag{18}$$

The production subsidy provides an incentive to produce even with negative prices (if the capacity constraint is not binding), until $p_t = c_w - s$. In this case, there is less incentive to adjust the production of wind power to market conditions than in the case with an investment subsidy.

2.5.3 Fixed price

Wind power production is always remunerated with a fixed price $\widehat{s}$, regardless of the market price. The objective of the wind power producer becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (\widehat{s} - c_w) q_{wind,t} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{19}$$

The first-order condition replacing eq. (13) is

$$\widehat{s} = c_w + \lambda \tag{20}$$

As long as $\widehat{s} > c_w$, the wind power producer produces at the maximum available capacity all of the time: $q_{wind,t} = \sigma_t q_{wind}^{\max}$. There is no incentive to limit wind power production, regardless of the market price.

3 Data and assumptions in the numerical model

The numerical model developed to quantify the effects of different support schemes to wind power is populated with current data from Western Denmark.[16,17]

The distinct weekly pattern in power demand, as shown in figure 1, invites for simultaneous optimization over a week, followed by the next week, and so on infinitely. The numerical model therefore assumes simultaneous optimization over a week in the context of an infinite number of weeks.[18] In other words, the numerical model simultaneously solves for the optimal power production in each hour of a week ($t = 1, ..., 168$), assuming that this week is followed by an identical week *ad infinitum* (that is, the terminal condition assumes that demand after Sunday night is equal to demand on the preceding Monday).[19]

3.1 Demand

Demand is fixed and varies according to a predetermined profile, as shown in figure 1. Data from a week in January 2006 is used to specify demand. Electricity demand is higher in winter than in summer in Denmark. Hence, for a given level of thermal capacity, it would be easier to accommodate a given amount of wind power production in the market than in a situation with low demand.

[16] Western and Eastern Denmark constitute separate electrical systems, with no direct connection between them.

[17] The model is developed in the GAMS programming language, using CPLEX/MIP solver (Brooke et al, 1998).

[18] This is different from Nord Pool, where the market is cleared simultaneously for each of the 24 hours of the following day.

[19] In reality, the next week is similar, but not identical due to seasonal variation.

Plant ID	Capacity (MW)	Fuel (production)	Fuel (Start-up)
1	410	Coal	Heavy fuel oil
2	400	Coal	Heavy fuel oil
3	380	Coal	Heavy fuel oil
4	625	Coal	Heavy fuel oil
5	350	Coal	Heavy fuel oil
6	350	Coal	Heavy fuel oil
7	300	Coal	Heavy fuel oil
8	400	Natural gas	Natural gas
9	240	Natural gas	Natural gas
10	50	Light fuel oil	Light fuel oil
11	2400	Wind	

Table 1: Power plants in the model. Source: Company brochures

3.2 Thermal power plants

The thermal power plants are characterized by a number of parameters in the model: age and technology, combined with fuel prices, determine the operational marginal costs and start-up costs of a plant. Capacity determines the upper limit of production ($q_i^{\max}$) for a power plant, while technical minimum production requirement determines the minimum production level ($q_i^{\min}$) of a power plant, once it is operating; typically $q_i^{\min} = 0.3 \cdot q_i^{\max}$ (Wood and Wollenberg, 1996).

The thermal power plants of Western Denmark that were available in 2006 are used in the model simulations; the plants are listed in table 1, ordered according to increasing operational marginal costs. The corresponding fuel and CO_2 prices are listed in table 3 and commented in section 3.3 below.

If plants are permitted to produce continuously, plants with the lowest marginal costs are chosen first. Thus, with the present data, coal-fired plants are preferred in a continuous production mode, while in a start and stop mode, gas-fired plants have an advantage. When demand increases or wind power production decreases from one hour to the next, production can be increased in power plants that are already running if they have spare capacity, otherwise, more plants must be started.

	Coal	Natural gas	Gas turbine
Capacity (MW)	400	400	50
Efficiency (%)	45	49	32
Operational marginal cost (DKK/MWh)	183	222	1048
Start-up: fuel cost of cold start (DKK/MWh)	79 100	34 900	5 200
Start-up: indirect cost (DKK/start)	453 400	294 000	18 800

Table 2: Production and start-up costs of selected power plants. The author's calculations

Which particular power plant is next started depends on the marginal costs, the start-up costs and the (expected) duration of the higher demand. If demand is high for only an hour or two, gas turbines are turned on (small units with low start-up costs, but very high marginal costs); if demand is high for a longer period, a larger coal- or gas-fired plant is turned on (with higher start-up costs, but relatively lower marginal costs).

Table 2 illustrates the significance of the start-up costs compared with the operational marginal costs for some typical plants: namely, a medium-aged coal-fired plant, a relatively new natural gas-fired plant and a gas turbine. The coal-fired plant is cheaper in continuous operation than the natural gas-fired plant, while the start-up costs of the natural gas-fired plant are lower than those of the coal-fired plant. The fuel cost of one start-up in the coal-fired plant is equivalent to the cost of producing at the maximum production level for about one hour (since fuel oil is used as fuel for start-up, not coal). When indirect costs are taken into account, the cost of a start-up in the coal-fired plant corresponds to about seven hours of production costs. For the gas-fired plant, the fuel cost of one start-up corresponds to the production cost for $\frac{1}{2}$ hour and the total start-up costs, including the indirect cost, to four hours of production costs. The gas turbine has much lower start-up costs than the other plants, but the marginal production cost is considerably higher. Therefore, the gas turbine is typically only used for relieving shortage

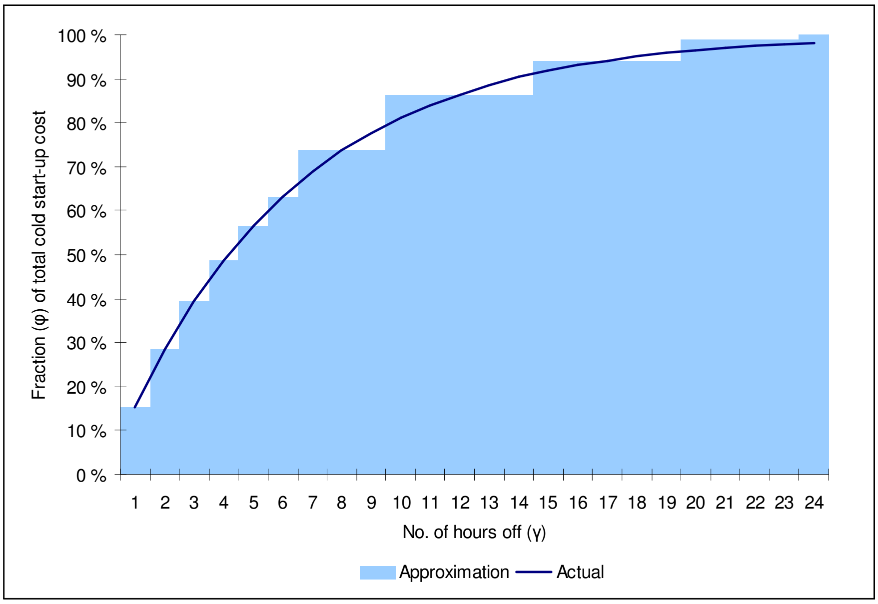

Figure 2: Time-dependency of direct start-up costs: actual and approximation used in the model

situations that last only a few hours and not for prolonged production.

The level of direct (fuel-related) start-up costs depends on how many periods the plant has been off before it is turned on again. However, while the start-up costs differ considerably depending on whether the unit has been off for one or two hours, the difference is much smaller than when the unit has been off about ten hours, and it is almost non-existent when the unit has been off for more than twenty-four hours. Therefore, in order to reduce the complexity of the numerical model, the direct start-up costs (eq. 2) are approximated with a stepwise linear function as illustrated in figure 2. The solid line shows the actual fuel costs (as a fraction of the full cold cost) of a start-up in every hour, depending on how many hours the unit has been off (measured by γ_{it}), while the stepwise linear function shows the approximation used in the numerical model.

Technically, all of the plants in the sample can start production within an hour. Therefore, other constraints that relate to a period shorter than an hour are not

Coal	63	USD/ton
Heavy fuel oil	285	USD/ton
Light fuel oil	585	USD/ton
Natural gas	12.5	EUR/MWh
CO_2	10	EUR/ton

Table 3: Fuel and CO2 price assumptions

relevant to the model.

3.3 Fuel prices and taxes

Fuel and CO_2 prices determine the operational marginal costs and the start-up costs of thermal power plants and, consequently, the relative competitiveness of the plants.

The assumptions relating to the fuel and CO_2 prices are listed in table 3. The fuel prices are averages of 2006 levels, except for the natural gas price where a lower price, reflecting the historical level, is used. In evidence, the natural gas price was very high throughout 2006, making gas-fired power plants prohibitively expensive. The CO_2 price is slightly below the forward price (in 2006) for CO_2 allowances during the 2008–2012 period.

Even with the relatively low gas prices assumed, coal-fired power plants have the lowest operational marginal costs (recall that the plants are ordered according to the operational marginal costs in table 1). An increase in *all* fuel prices would only increase the cost level of all plants, not the relative competitiveness of individual plants. Considerably lower gas prices, higher coal prices or a higher CO_2 price would improve the competitiveness of gas-fired power plants and, by facilitating fuel switching from coal to gas, could also influence the results in a qualitative manner (Rosnes, 2005). Lower coal prices together with higher gas prices, on the other hand, would counteract fuel switching and increase the costs of emission reduction.

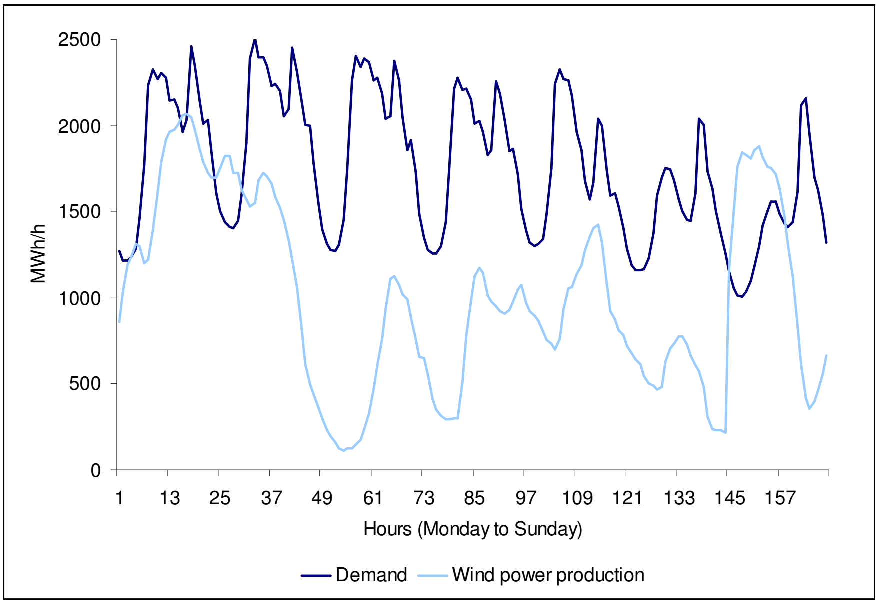

Figure 3: Wind power production (proxy for maximum available wind power) and net demand in Western Denmark throughout a week. Source: www.energinet.dk

There is no uncertainty, either about fuel prices or about the CO_2 price. This is realistic in the short term: day-to-day price variation is usually small.

3.4 Wind power

As explained in section 2.3, wind power production is limited not only by the nominal capacity of wind mills, but also by the presence of wind. Figure 3 shows actual wind power production in Western Denmark for each hour of a week in September 2006. The figure reveals that there is significant variation from one hour to the next: in some hours, production is close to the installed capacity of 2,400 MW; in some hours, it is close to zero. There is no systematic variation over the course of the day. Moreover, figure 3 also reveals that the wind power capacity is large, compared to demand (repeated from figure 1) and in some hours wind power production may exceed domestic power demand.[20]

[20]Note that actual production data may indicate wind power production that exceeds domestic demand, since it is possible to export the excess wind power in reality, a point discussed in section

The wind power availability, $\sigma_t q_{wind}^{\max}$, that determines the upper limit for production is calibrated in the numerical model by using the *actual* observed wind power production over a week in September 2006 (shown on figure 3).

The week in September 2006 was chosen as a sample week because it displays a relatively high level and high variation in wind power production (in a model with perfect information, a little variation would easily be accommodated by the market). At the same time, assuming demand of a winter week (i.e., high demand) facilitates accommodation of wind power in the market, while it would be more difficult to accommodate large amounts of wind power in a summer week (i.e., low demand). Accordingly, these two effects counteract each other.

The actual, rather than average, profile reflects the potential variation of the available wind power (while using average wind power production would level out the variation). However, the wind power producer is flexible within the range $[0, \sigma_t q_{wind}^{\max}]$ – the wind power producer can *reduce* production level from the maximum available level in each period (for instance when market prices are negative).

As wind power producers in Denmark were defined as having priority (i.e., the grid company was obliged to accommodate wind power whenever available) and received relatively high feed-in tariffs under the prevailing policy in 2006, the common belief of the market participants has been that wind power production was equal to the maximum available capacity. Therefore, the actual production provides a good proxy for wind power availability.

The marginal costs of wind power are assumed to be zero ($c_w = 0$), implying that the optimal production level is $q_{wind,t} = \sigma_t q_{wind}^{\max}$ for $p_t \geq 0$ with a lump-sum subsidy and for $p_t \geq -s$ with a production subsidy.

6. This excess production is truncated in the model simulations since total power supply cannot exceed demand. This is in line with the actual operation of the power market: the market operator can disconnect excess production in order to maintain balance in the market.

3.5 Subsidies to wind power

The present support scheme to wind power in Denmark is extremely complex.[21] A production subsidy that is added to the market price forms the basis of the support, but the subsidy level depends on the age and properties of the plant and the accumulated support provided to the plant over time. The highest production subsidy currently equals 270 DKK/MWh, with the total producer price capped at 600 DKK/MWh. In comparison, the average market price was 330 DKK/MWh in 2006, so the production subsidy provides a substantial mark-up on the market price.

In the simulations, I have used a production subsidy level $s = 100$ DKK/MWh that is in the lower range of the possible subsidies (but applies nevertheless to some categories of wind power).[22] The reason for choosing a relatively low subsidy was to allow for some flexibility in the model: obviously, the higher the production subsidy level, the more it resembles the fixed price. Therefore, the model results may overstate the wind power producer's willingness to adjust production.

In the fixed-price case, $\widehat{s} = 600$ DKK/MWh. Even though the current system for wind power support in Denmark does not include a fixed price, the fixed price is still topical in some other countries and therefore of interest. Besides, wind power has for many years had 'priority' over other power sources: that is, whenever wind power is available, it should produce at the maximum available level and the market operator is obliged to accommodate it in the system. This is equivalent to a (sufficiently high) fixed price.

The investment subsidy level does not influence the short-term production decision of the wind power producer and no investments occur in the short term.

[21] An overview can be found at www.energinet.dk.

[22] The renewables support scheme currently proposed in Norway includes a production subsidy of ca. 75 DKK/MWh to wind power.

Therefore, the exact level of the lump-sum investment subsidy S is immaterial. (The investment subsidy obviously affects investments in wind power capacity in the long term. The effect of different levels of wind power capacity is tested in the sensitivity analyses in section 5).

4 The impact of different support schemes

Let me start by analyzing the market outcome under the three different support schemes to wind power: a lump-sum investment subsidy to wind power, a fixed price to wind power and a production subsidy.

4.1 Lump-sum subsidy to wind power

Lump-sum investment subsidies to wind power do not distort the production decisions of the wind power producer, as shown in section 2.5.1. Therefore, the lump-sum subsidy yields the optimal solution for production (within the limits of existing capacity). The wind power producer also takes into account the shadow prices of start-ups and shutdowns in the thermal plants, signalled via the thermal producers' bids and producer prices.

Figure 4 shows demand, production in thermal power plants and wind power production with lump-sum subsidy, as well as the maximum available wind power in every hour of the week. The prevailing pattern revealed in the simulation is that wind power production equals the maximum available capacity *most of the time, but not always* (figure 4). For a given operational status of all plants, it is always cheaper to produce using wind power plants than thermal power plants, because the marginal costs of wind power are always lower than any thermal unit ($c_i > c_w = 0$). However, if wind power production inflicts a change in the operational status of a thermal plant (a shutdown), additional start-up costs will occur in the future. In

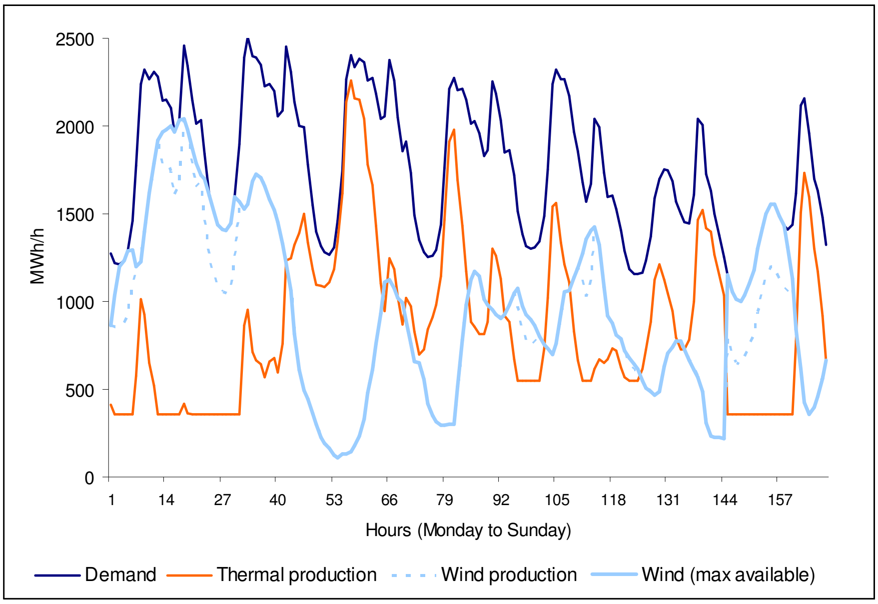

Figure 4: Net demand, wind power and thermal power production with lump-sum subsidy, base case capacity

this case, it is sometimes more profitable to reduce wind power production and let the thermal plants produce continuously instead (in spite of their higher marginal costs), in order to avoid the shutdown of a thermal unit. Shutting down a thermal plant for a short period is not justified because the start-up costs outweigh the cost savings of cheaper production.

This typically happens during low demand periods – nights and weekends – but not necessarily. Wind power availability varies considerably and the variation does not coincide with the variation in demand (as shown in figure 4). Since there is no systematic daily pattern in wind availability, situations with excess wind power production may also occur during high demand periods. In our example, wind power production is reduced even during some workdays (Monday and Friday), in addition to weekend days and nights. Wind power production is lower than the maximum available level for some 49 hours, that is, almost 30% of time. Total wind power production with the lump-sum subsidy is 8% lower than the maximum

	Thermal production (GWh)	Wind power production (GWh)	Emissions (1000 ton)	Production cost (fuel and CO_2) (mill. DKK)
Lump sum	146	150	108.5	32.6
Production subsidy	140	156	104.9	33.1
Fixed price	134	162	97.6	36.4

Table 4: Results of the numerical model, base case capacity

available.

The three cheapest thermal power plants produce nonstop, adjusting production levels between the minimum and maximum level. The other (more expensive) thermal plants start up and produce occasionally.

4.2 Fixed price to wind power

When wind power receives a fixed price, the producer does not respond to market signals (eq. 20). Receiving a fixed price $\widehat{s}$ per kWh, regardless of the market price, the wind power producer chooses to produce at the maximum available capacity ($q_{wind,t} = \sigma_t q_{wind}^{\max}$) all of the time, since $\widehat{s} > c_w = 0$. In order to maintain a balance between total supply and demand, the thermal power producers must adjust production accordingly – even turn off the plants if necessary.

In our example, wind power alone is able to meet total demand in some hours. All of the thermal power plants are 'forced' to turn off during these hours. In total, thermal power production is reduced 9%, compared with the case with lump-sum subsidies (see table 4 and figures 5 (wind power) and 6 (thermal power) for the results in both cases).

In addition to the reduction in total thermal power production, there is a shift between the thermal plants that produce in different hours. Some coal-fired plants produce considerably less, while others – smaller but less efficient – produce more. Gas-fired plants also produce more. These changes are due to the lower start-up

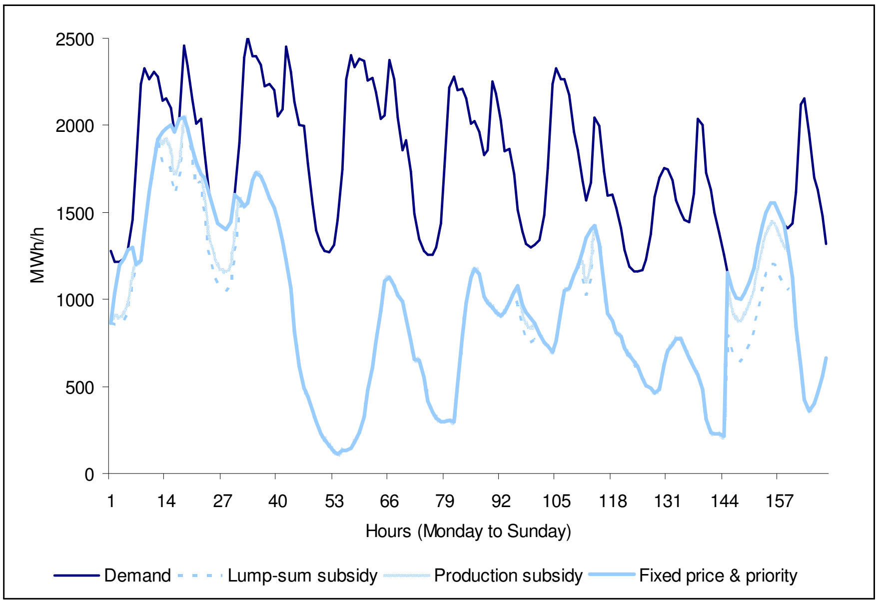

Figure 5: Wind power production with different subsidies, base case capacity

costs and minimum production requirements that outweigh the higher marginal costs in these plants.

Emissions stem from both production and start-up. Lower total thermal production obviously reduces emissions. In the case at hand, the effect of reduced thermal production outweighs the additional emissions from start-ups: emissions are 10% lower than in the lump-sum subsidy case (table 4). Fuel switching to gas-fired plants contributes to lower emissions, while the switch to less efficient coal-fired power plants contributes to higher emissions. All in all, however, emissions are reduced.

However, the remarkable result is that production costs are 12% higher, compared with the lump-sum subsidy case, even though the production level is 9% lower (production costs encompass both fuel costs and CO_2 costs). By forcing some plants to turn off and inflicting additional start-up costs, and by moving production to more expensive plants, production costs increase considerably. As a result, the emission reduction is achieved at considerable cost.

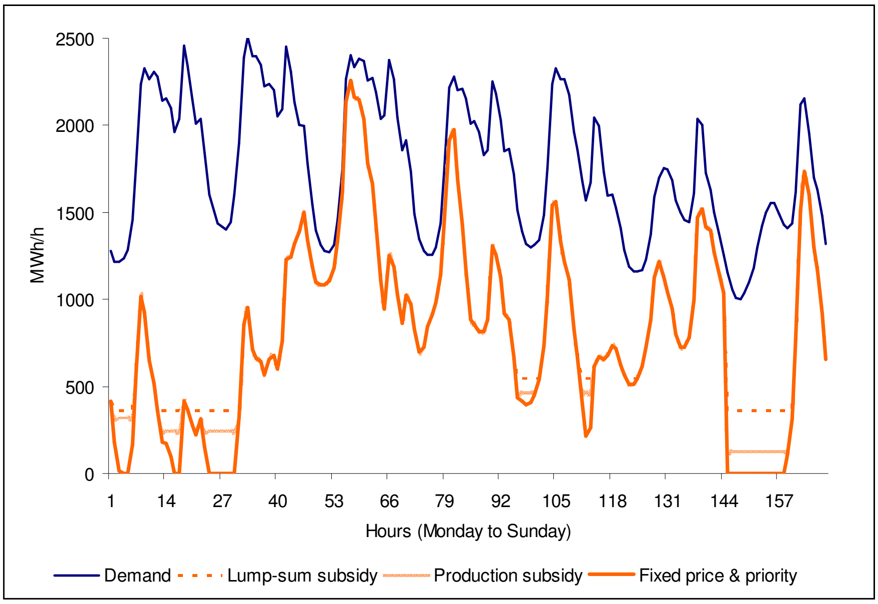

Figure 6: Thermal power production with different subsidies to wind power, base case capacity

4.3 Production subsidy to wind power

What happens if wind power obtains a production subsidy s per kWh? In this case, the wind power producer responds to signals provided by the market (eq. 18), but the signal is distorted by the subsidy. The wind power producer's bids reflect the willingness to produce until $p = -s$ (recall that $c_w = 0$).

In the present sample, the production subsidy of 100 DKK/MWh increases wind power production 4%, compared with the lump-sum subsidy (the results are reported in table 4 and figures 5 and 6). However, it does not yield the same result as the fixed price: production is still lower than with a fixed price and wind power production is reduced from the maximum available level in 42 hours.

By taking into account the shadow prices of the start-ups, the wind power producer accommodates thermal producers. Obviously, the start-up costs are so high that the thermal producers' bids are lower than $-s$ (the wind power producer's bid) in some hours. The results clearly show that it is profitable to reduce wind power in order to save start-up costs in some cases, even when wind power is subsidized.

Lower thermal production contributes to lower emissions: emissions are 3% lower than in the lump-sum subsidy case.

However, total production costs[23] are only 1% higher than in the lump-sum subsidy case and 9% lower than in the fixed price case. The flexibility to adjust to market signals gives considerable cost savings, even in the case of a distorting subsidy.

It is worth noting that the production subsidy level used in the model simulations is relatively low. Therefore, the market signals are distorted to some extent, but the outcome is similar to the one with lump-sum subsidy. A higher production subsidy would give incentives to higher wind power production and the outcome would resemble more the case with fixed price.

The model results indicate that the *optimal* wind power production is lower than the *maximum available* wind power production in many cases, even though the marginal costs of wind power are zero. By forcing some thermal units to turn off and thereby inflicting additional start-up costs later, and by moving production to more expensive units, production costs increase considerably. It is when wind power inflicts a shift in the operational status of a thermal power plant (a temporary shutdown) that costs increase considerably.

5 The impact of wind power capacity

It is reasonable to assume that as long as wind power constitutes a small share of total production capacity, it is relatively easy to accommodate in the market, despite

[23]The subsidy cost to wind power (i.e., the cost to the authorities) is not included in the production cost figure.

the possible distorting subsidies. The adverse effects will become more pertinent as the share of wind power in electricity production increases or is concentrated in some geographical areas. Sensitivities that test the impact of available wind power capacity confirm this intuition.

5.1 Easier to accommodate small amounts of wind power

The simulations presented above assume quite high wind power availability, compared to the annual average in Denmark.[24] There are times when the wind blows less, so available wind power capacity and hence possible wind power production is lower with the same capacity.

With only 50% of the original available wind power (but still the same profile over the week), the fixed price to wind power reduces emissions by 3% and increases costs by 6% compared with the optimum (the results are shown in table 5, labeled *low wind*, while the *base case* repeats these figures for the case commented upon earlier). The results confirm the qualitative effects of the original findings: a fixed price to wind power leads to suboptimal scheduling of power plants and higher total costs. Wind power production is higher and thermal production lower, but total production costs are higher when wind power receives a fixed price. The cost increase is relatively smaller than in the base case: With less wind power, it is obviously easier to accommodate wind power by adjusting the production level in the thermal plants, without turning them off altogether.

5.2 Boost of wind power capacity partly 'in vain'

One of the energy policy goals in Denmark is to double wind power capacity by 2025 (TRM, 2007).

[24]Nevertheless, let me emphasize that the base case above is based on actual data with existing wind power capacity.

	Thermal production (GWh)	Wind power production (GWh)	Emissions (1000 ton)	Production cost (fuel and CO_2) (mill. DKK)
Low wind				
Lump sum	215	81	163.7	45.6
Production subsidy	213	83	159.0	45.8
Fixed price	211	85	159.5	48.3
Base case				
Lump sum	146	150	108.5	32.6
Production subsidy	140	156	104.9	33.1
Fixed price	134	162	97.6	36.4
High wind				
Lump sum	71	225	51.8	18.5
Production subsidy	59	237	43.2	19.0
Fixed price	54	242	39.1	21.9

Table 5: Results of the numerical model

The results of the simulations with twice as much wind power capacity as in the base case confirm the effects found in the base case, but the effects are magnified (the results are reported in table 5, labeled *high wind*).[25] In this case, a fixed price to wind power reduces emissions by 25% and increases costs by 18%, compared to the lump-sum subsidy. A production subsidy (that distorts market signals to wind power, but does not remove them altogether) reduces emissions by 17%, but the costs increase by only 2%, compared with the optimal subsidy. Evidently, even a slight flexibility in wind power pays off.

It is also worth noting that increasing wind power *capacity* does not translate into an equal increase in wind power *availability*. Since the market must be in balance at all times, wind power production must be reduced if it exceeds demand and all thermal plants are turned off. As wind power capacity increases, situations where wind power production exceeds demand become increasingly frequent. Thus, some of the capacity increase is 'in vain'. Therefore, an increase in wind power

[25] The sensitivity with low wind, presented in section 5.1, may serve as an example for less wind power capacity as well. Although deinvestment is not a realistic option, it provides an example for how costs differ when choosing between different investment levels.

capacity by one kWh does not replace one kWh of thermal power – the increase in 'useful' wind power capacity is lower than the nominal increase. In the present case, the doubling of wind power capacity contributes little to 'useful' wind power production: maximum available wind power increases by about 50%, compared to the base case.

6 Alternative sources of flexibility

Two important sources of flexibility – trade and demand flexibility – were ruled out in the model simulations, mainly in order to make the analysis more clear-cut. The realism of these assumptions is commented upon below.

6.1 Trade

The model simulations assumed no trade with neighbouring areas. However, the trade possibilities already exist today: Denmark has interconnectors to Norway (a hydropower system), Sweden (partly a hydropower system) and Germany (predominantly a thermal system). The export and import possibilities provide additional flexibility to the power system: it is possible to export the 'excess' power that is caused by a sudden increase in wind power production or import power to avoid the start-up of a thermal power plant when a sudden calm period reduces wind power production. In a larger interconnected system, it is easier to adjust production level in the operating power plants without turning them off altogether. Connection to a hydropower system is particularly beneficial, since hydropower plants have practically no start-up costs.

The main reason to exclude trade in the model was to focus the analysis on the flexibility of thermal power plants. In the perfect world of the model, hydropower production would adjust immediately in order to accommodate both the varying wind power production and the variation in daily demand. The thermal power plants with lowest marginal costs would produce continuously, without any starts or stops, while other plants would remain idle.

Yet, the transmission lines are congested from time to time in reality. For instance, there were congestions between Western Denmark and Norway about 55% of the time in 2006, most of the time with congestion from Denmark to Norway. In these periods, an increase in wind power production cannot be exported in order to avoid the shutdown of a thermal power plant. Without additional investments, similar situations arising from transmission capacity constraints will become more frequent.

6.2 Flexibility of demand

These model simulations have assumed inelastic demand. Inelastic demand is quite a realistic description of the situation in Denmark in the very short term: most consumers' demand is virtually inelastic from one hour to the next, as most consumers do not observe hourly prices and therefore do not respond to these prices. Besides, the substitution possibilities are limited in the short term.

More flexibility on the demand side would clearly modify the results in the same way as trade with a flexible system and reduce the costs of thermal producers. However, increasing flexibility, for instance by installing two-way-communication,[26] would require additional costs. More flexibility can also be achieved by sending correct price signals to consumers – as long as consumers only see average (monthly) prices, there is no incentive to respond to hourly prices.

[26]Two-way-communication is technology that makes direct communication between the power supplier (distribution company) and consumer possible. By two-way-communication equipment, the distribution company can inform the consumer about price changes instantaneously and manage the consumer's power consumption. In this way, consumption reduction becomes an alternative to production increase.

7 Concluding remarks

The aim of this paper is to show how the costs of wind power integration in an inflexible power system and emissions from the system depend on the subsidy design to wind power. The existing system consists of thermal power plants that are inflexible in the short term because of start-up costs. Three subsidy schemes to wind power are studied: a lump-sum investment subsidy, a production subsidy per kWh (a mark-up on market price) and a fixed price per kWh (unrelated to the market price).

The lump-sum subsidy yields the optimal solution for production: wind power producers take into account the shadow prices of the start-ups, signaled through the bids of the thermal power plants. When wind power is optimally scheduled, it is sometimes profitable to reduce wind power production in order to avoid the shutdown of a thermal unit. When the production subsidy is designed as a mark-up on market price, the market signals are distorted. With a fixed price, wind power produces at the maximum available level and does not take into account market prices or the impact on other producers. With low demand, the thermal power plants are forced to stop in order to maintain balance in the market. Accordingly, investment and production subsidies are not equivalent in the short term.

The results of the numerical model of a sample week show that in the base case, thermal production with the fixed subsidy is 9% lower than with the optimal subsidy, while production costs (fuel costs and CO_2 costs) are 12% higher. In other words, the same production level is achieved with considerably higher costs. Sensitivity analyses with higher gas prices yields similar results, but slightly higher costs.

The wind power capacity and availability profiles used in the model simulations are not hypothetical figures, but actual observed figures. Therefore, the results reflect the situation today and illustrate the challenges in increasing wind power capacity in the future. Typically, the additional costs increase with increasing wind power capacity. Clearly, it is easier to accommodate wind power when wind power capacity is small relative to demand. As long as wind power can be accommodated without a change in the operational status of thermal power plants, the additional costs are relatively low. The results indicate that the incentives to adjust wind power even slightly would pay off: a small reduction in wind power often saves considerable costs. In other words, flexibility has a high value. The larger the market share of wind power, the higher the costs. The results of model simulations with different wind power data yield the same qualitative results.

Another important result is that increasing wind power capacity does not translate into a proportional emission reduction. With more wind power, situations when wind power exceeds demand, and hence cannot be utilized, will become more frequent. Even if wind power availability increases by one kWh, it does not replace one kWh of thermal power.

Modelling uncertainty about demand or wind power availability has not been feasible in the numerical model. Rosnes (2008), in considering a single power plant, has shown that higher uncertainty reduces the flexibility of a thermal power plant by increasing the threshold price for starting and reducing the threshold price for stopping. This indicates that uncertainty would probably increase costs even more.

It is somewhat paradoxical that production subsidies have been the most common support mechanism to renewables in Europe (COM, 2005), even though it is the high investment costs that prevent expansion of renewable capacity. It is probably fair to say that policies to support renewables have been characterized by politicians' determination to act quickly and investment volume has been in focus instead of investment efficiency.[27] Once in place, policies are often difficult to

[27] Germany has often been quoted as a showcase for effectiveness of feed-in tariffs in achieving

change due to lobbying activities. As the renewable technologies have traditionally had a tiny share of the market, the adverse effects were not particularly harmful. However, wind power is envisaged to be the main source of renewable energy in many European countries to fulfill the goal of 21% renewables in electricity production by 2010 (EC, 2001). In addition to Denmark, where wind power provided 23% of domestic electricity consumption in 2005, wind power production amounted to about 5–7% of total electricity production in countries such as Spain, Germany, Ireland and Portugal in 2005, and further expansion is planned; large wind parks are also planned in the United Kingdom and Sweden.

This analysis illustrates and quantifies the costs of integrating renewables in an inflexible power system. While the investment subsidy is shown to be unambiguously superior to other types of subsidies, the adverse effects of the other subsidies depend on the degree of flexibility of the existing power system. Hence, the design of the subsidy scheme should take into account both the characteristics of the existing system and the characteristics of the renewables capacity. An inflexible system should promote technologies that are flexible and reliable,[28] while a flexible system can afford promoting less flexible technologies.

Nonetheless, if wind power is the preferred technology in the inflexible system, it is important to promote flexibility. Flexibility can be achieved by technical measures or economic incentives. Measures to increase flexibility may involve increasing the demand response (either technically, by investing in two-way-communication, or economically, by exposing consumers to actual market prices) or on the supply side (investing in more flexible plants or increasing trade possibilities with other

large investments in wind power. However, the German success is based on the very high level of feed-in tariffs. In other countries, with low feed-in tariffs, feed-in tariffs have failed to contribute to investments.

[28] This means reliable in the sense of being available when needed. As explained earlier, wind power is flexible, but not reliable – it is exactly the periods without wind that cause problems to the system.

regions). A larger system would increase flexibility per se, because it is easier to adjust production in active power plants without shutting down plants in a larger system. Further, trade with a more flexible system that can easily adjust the production level (like hydropower) is even more beneficial. However, these measures to increase flexibility require further investments that add to costs, in addition to the subsidies to wind power.

An economically sound subsidy design that does not distort the production decision of wind power and promotes flexibility in wind power production may be the cheapest way of integrating wind power.

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