Subsidies for Renewable Energy in Inflexible Power Markets

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Abstract

This paper analyses how short-term operational efficiency and the CO_2 emissions of a power system depend on different subsidies for wind power and on the flexibility of the power system. This is analysed in the framework of a numerical power market model, calibrated to Danish data, where the start-up costs and other constraints in fossil-fuelled power plants are taken into account.

The main conclusion is that flexibility is crucial for the costs of integrating wind power in an existing system. If thermal power plants are inflexible, subsidies for wind power should strive to increase the flexibility of the market by passing market signals to wind power. A subsidy that conceals market signals from wind power producers (a production subsidy) or disconnects wind power incentives from the market signals altogether (a fixed price) increases costs considerably. An inflexible power system should aim to introduce optimal subsidies (an investment subsidy) instead of production subsidies or a fixed price. The design of the subsidy scheme should take into account both the characteristics of the existing system and the characteristics of renewables.

Keywords: Electricity, start-up costs, integration of renewables, feed-in tariffs, wind power, intermittent power

JEL classification: L94, L98, Q48, Q58

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1   Introduction

The European Union (EU) has ambitious targets for renewable energy: renewable energy's share of electricity production was to be increased to 21% by 2010 (EC, 2001), and the goals for 2020 and beyond entail even higher targets (EC, 2009). The choice of a subsidy scheme to promote renewable energy is left to the individual Member States, however. This paper analyses the effectiveness and efficiency of different subsidies when technical characteristics (such as flexibility) of the existing electricity system are taken into account.

Even though the principal goal of the subsidy is to promote investments in renewables, some subsidies also influence short-term production decisions concerning renewables once the investment is made. Investment subsidies only influence the choice of technology, leaving short-term (day-to-day and hour-to-hour) production decisions dependent on market prices. Production subsidies like feed-in tariffs, on the other hand, also influence 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.[1]

Wind power – the preferred renewable energy source in many countries – can be challenging to accommodate in existing power systems due to its unique characteristics. Wind power represents a variable – or intermittent – energy source: put simply, it is only possible to produce wind power when the wind is blowing.[2] Thus, the available wind power production in a given hour can vary substantially during the day and is often significantly lower than the nominal installed capacity. On the other hand, wind power is flexible within the limits of the available wind: the production level can be

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[1]The common subsidy schemes in the EU – feed-in tariffs and tradable green certificates – are versions of a production subsidy or fixed producer price. Feed-in tariffs (guaranteed prices for renewable electricity or guaranteed mark-ups on the market price of electricity) are used in Denmark, France, Germany and Spain, among other countries (COM, 2005). Tradable green certificates have been used in Italy, Norway, Sweden and the UK. Investment subsidies have been used in Finland and Portugal.

[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).

adjusted easily and without any cost up to those limits. Therefore, wind power is often expected to be produced up to those limits at all times. This is further encouraged by a production subsidy.

One of the key features of the electricity system is the requirement for immediate balance between production and consumption at every instant if the lights are to be kept on. 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 intermittent 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 primarily on the technology mix, but trade possibilities and flexibility of demand also play a role. Most countries in Continental Europe have power systems that are 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 of starting the plant (Wood and Wollenberg, 1996). Hence, it is not only the marginal costs of every kilowatt-hour (kWh) in 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 marginal cost of operation, in order to avoid a shutdown. Similarly, it might choose not to start production, even when the price exceeds the marginal cost of operation (Rosnes, 2008). In a market with heterogeneous producers, flexibility is as important a determinant of the individual power plant's production pattern as are 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. The emissions avoided by stopping the thermal power plant may be more than offset

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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 perspective of minimising costs or emissions from the power system as a whole, it is not necessarily optimal that wind power produces at maximum available level, even though wind power has lower marginal costs and no emissions.

This means that the subsidy should be designed to maintain the correct incentives for wind power producers: passing market signals to them would contribute to keeping additional costs and emissions at a minimum in the short term. In the longer term, market prices provide information about the profitability of investments in different locations, which is important in order to ensure efficient investments. Combined with an inflexible power system, an ill-designed subsidy that conceals market signals and reduces the responsiveness to market prices could amplify the adverse effects of renewables and contribute to emission reductions being excessively costly.

Since the principal aim of subsidising renewables is to reduce CO_2 emissions through crowding out fossil fuels,[3] it is relevant to examine whether a subsidy contributes to reducing emissions and at what cost.[4] Rosnes (2008), analysing a single power plant's response to climate policies, finds that the effects on total emissions remain ambiguous when only one firm is considered. Critically, the production pattern of an individual producer is determined in interaction with other producers in the market. Rosnes (2007) 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 analysing different subsidies for renewables (e.g. Menanteau et al., 2003) has mainly been on the *investment efficiency* of policies, that is, the extent to which the policy measures stimulate investments in the most cost-efficient technologies.[5] Issues pertaining to the short-term *operational efficiency* of renewables

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[3]Other goals, such as support for domestic industry or regional development, are perhaps less pronounced, but nevertheless evident in the variety of renewable support schemes in the EU countries. Other emissions (SO_2, NO_x) are regulated in other ways.

[4]The EU Emission Trading Scheme (EU ETS) puts a cap on total CO_2 emissions, but emissions caused by starting and stopping thermal power plants could make the necessary emission reduction more expensive than it would otherwise be.

[5]The interaction between a tradable green certificates market and the power market has been

– the day-to-day or even hour-to-hour production efficiency – and the short-term inter-action between wind power and thermal power have been overlooked in the literature.[6] Furthermore, the implications of the start-up costs of power plants have received very little attention so far in the economics literature, even though these issues have been extensively studied in the electrical engineering literature.[7] The few existing papers in economics confirm that the start-up costs do have implications for economic agents' behaviour. In addition to Rosnes (2007) and Rosnes (2008) referred to above, Mansur (2008) shows in an econometric study based on Pennsylvania, New Jersey and Mary-land data that power producers' bids in excess of marginal costs may be explained by start-up costs and do not necessarily represent an abuse of market power, while 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 subsidies for renewables on operational efficiency (short-term production costs) 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. This paper therefore explores the implications of increasing wind power capacity in the Danish market. Given its predominantly fossil-fuelled 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 is a highly relevant case for the analysis of wind power expansion and flexibility. Wind power is seen as the main source of renewable energy in many European countries where existing power systems are dominated by

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analysed in a number of papers, including Amundsen and Mortensen (2001), Unger and Ahlgren (2005), Morthorst (2001), and Jensen and Skytte (2003). However, these studies also focus on the medium to long-term impacts of renewables.

[6] Amundsen et al. (1999), Halseth (1998), Hauch (2003) and Johnsen (1998) use partial equilibrium models for policy analyses 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 could complement the traditional long-term policy analyses.

[7] This strand of literature has a different focus, however, 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 centre of attention.

conventional thermal power plants.

The remainder of the article is organised as follows. Section 2 presents the model: the thermal and wind power producers' intertemporal production decisions are discussed in detail. Section 3 shows how different subsidies change the wind power producers' production decisions. Taking the existing subsidy schemes as its point of departure, this paper examines how a power system's overall operating costs and emissions are affected by three different subsidies: a *production subsidy* (a mark-up on the market price per kWh produced, also called premium feed-in tariff), a *fixed price per kWh* produced that is unrelated to the market price (also called fixed feed-in tariff) and an *investment subsidy* per MW invested (a lump-sum subsidy as regards the production decision). Section 4 presents the assumptions and data used in the numerical model, while the results of the numerical model are discussed in section 5. Section 6 discusses the significance and implications of some important assumptions. Section 7 concludes.

2 The model

Consider a deterministic partial equilibrium model for a power market, with a representative consumer and two kinds of producers: renewable (wind) power producers and conventional thermal power producers. Being able to adjust their production level easily and without cost, the wind power producers are perfectly flexible within the limits of the available wind, but, since the availability of wind varies, their potential production level varies. The thermal power producers are less flexible due to the presence of start-up costs. Therefore, the thermal power producers consider the output price not only in every period t (e.g., hour), but during the whole planning horizon T (e.g., a day or a week) when making their production decisions. All producers are price takers. The production decisions of the different producers are explained in detail in sections 2.2 and 2.3 below.

The focus is on the short-term interaction of wind power and thermal power. Thus,

generation capacity is fixed. Similarly, due to the short time horizon, there is no uncertainty about fuel prices. Transmission constraints are not modelled, implying that there is sufficient transmission capacity between production and demand centres. There is no trade. The importance and implications of these assumptions are discussed in section 6.

The model is deterministic: there is no uncertainty about wind power production or demand in the model. Instead, the variability of wind power is taken into account, as well as the systematic variation in demand. The deterministic model allows us to focus on the impact of flexibility and to distinguish it from the impact of uncertainty.[8] There is no doubt that wind power availability is uncertain, but recent developments in meteorological models have greatly improved the prediction of wind power availability, especially in the short term.

The model is set in an infinite horizon context and allows for simultaneous optimisation over an unlimited number of periods. Since this is a simultaneous one-time decision for all t within T, there is no learning during the course of the planning horizon.

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 during the night and higher on weekdays than at weekends. This systematic variation in demand is taken into account in the model: q_t^D varies from hour to hour in accordance with the pattern shown in figure 1.[9] This variation in demand must be accommodated by producers, requiring them to vary their production accordingly.

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[8]Results from Rosnes (2008), who studies a *single* power producer's response to climate policies, indicate that the impact of uncertainty is probably similar to that of inflexibility.

[9]The figure shows the *net demand* faced by thermal producers and wind power producers 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, which shows a consistent pattern over a week similar to power demand; power is merely a by-product. Thus, the power output from small CHPs is not price-elastic.
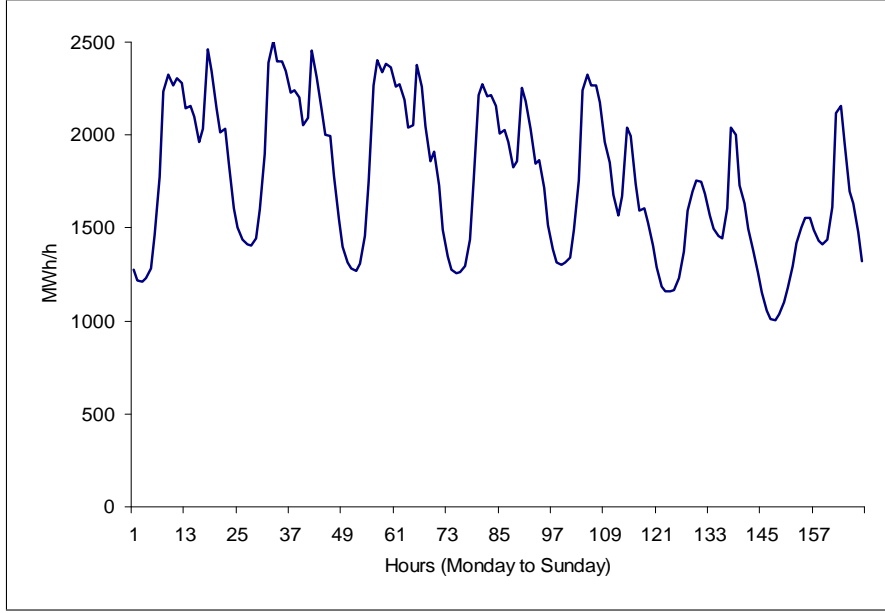
Figure 1: Electricity demand in Western Denmark during a week in January 2006. Source: www.energinet.dk

Demand is assumed to be perfectly price-inelastic in order to get to the heart of the matter – the impact of flexibility in power generation. The few estimates of short-term (hourly) price elasticities that are available confirm that demand is practically inelastic in the very short term, see Lijesen (2007) or Patrick and Wolak (1997). The realism and consequences of this assumption are discussed further in section 6.3.

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 *marginal costs of operation*, denoted by c_i, are the costs of producing an additional unit of output when the plant is already running. The marginal costs of operation depend on input price ρ_i (i.e. fuel price including relevant taxes and CO_2 price) and plant properties that determine fuel use in plant i, denoted by the vector ϕ_i:

$$c_i = c(\rho_i, \phi_i) \tag{1}$$

In addition to the marginal costs of operation, the producer will face a *start-up cost* C_{it}^{start} if he did not produce in the previous period (hour) and starts to produce in

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the present period (hour). The level of start-up costs depends on how many periods the plant has been turned off before being turned on again. The start-up costs consist of *direct* and *indirect* start-up costs, and they 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 fuel cost of a start-up depends on the fuel price ρ_i and plant properties ϕ_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 that the boiler is cold, total *cold start cost* C_i^{Cold} is incurred. If the unit has only recently been turned off and the temperature of the boiler is still close to the operating temperature, the necessary fuel use is considerably lower (this is called a *hot start* in the industry jargon). Denote the fraction of cold start costs that are incurred when the plant has been off for γ_{it} periods by $\varphi_t(\gamma_{it})$. The direct fuel costs of starting plant i in period t (when the plant has been off for γ_{it} periods) are then

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

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 reduces 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:

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

For each period, the producer must decide 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 depend on the states at the beginning of the period:

1. 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*)

2. a discrete variable γ_{it} indicating the number of periods the plant has been *off*, $\gamma_{it} \in [0, \infty)$

3. a continuous variable p_t for output price level, with a state space $p_t \in (-\infty, \infty)$. The output prices $\mathbf{p} = (p_1, p_2, ..., p_\infty)$ are determined in the market and taken as given by the producer.

The equations of motion for the state variables d_{it} and γ_{it} are:

$$d_{it} = h(x_{it-1}) = x_{it-1} \tag{4}$$

$$\gamma_{it} = g(\gamma_{it-1}, x_{it-1}) = (\gamma_{it-1} + 1)(1 - x_{it-1}) \tag{5}$$

Equation (4) states that the status at the beginning of period t depends on whether or not the plant operated in period $t-1$. Equation (5) counts how many periods the plant has been off.

The profit π_{it} in period t depends both on 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 :

$$\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) = [(p_t - c_i)q_{it}] \, x_{it} - C_{it}^{start} \, (1 - d_{it}) \, x_{it} \tag{6}$$

subject to equations (3) to (5) and capacity constraints (7)

$$q_i^{\min} \leq q_{it} \leq q_i^{\max} \tag{7}$$

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. There-

fore, it is not necessarily the usual 'price vs. 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:

$$F(p_t, d_{it}, \gamma_{it}) = \max_{\{x_{it}, q_{it}\}} \left\{ \pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) + \delta F(p_{t+1}, d_{it+1}, \gamma_{it+1}) \right\} \qquad (8)$$

Equation (8) is the Bellman equation, which expresses the trade-off between the immediate payoff, $\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it})$, and the discounted future payoffs, $\delta F(p_{t+1}, d_{it+1}, \gamma_{it+1})$, that an optimising agent must balance.

The Bellman equation (8) determines the thermal producer's supply for each t. Due to the start-up costs, the producer might prefer to continue to produce, even when the price falls below the short-term marginal cost of operation, in order to avoid a later start-up that is incurred if the producer stops.

2.2.1   Emissions

The use of some input fuels v_{it} causes emissions e_{it}:

$$e_{it} = \theta_i v_{it} \qquad (9)$$

where θ_i is emission coefficient (depending on fuel used and plant properties).

2.3   Wind power producer

A wind power producer w is more flexible than a thermal power producer: having no start-up costs, the wind power producer can change its 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 in each hour.[10] Thus, the wind power production q_{wt} in each hour t is limited both by installed capacity $q_w^{\max}$ and by the availability of wind $\sigma_t \in [0,1]$:[11]

$$0 \leq q_{wt} \leq \sigma_t q_w^{\max} \tag{10}$$

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 maximise the profit in each t, up to the available capacity limit:

$$\max_{\{q_{wt}\}} \Pi_t = (p_t - c_w)q_{wt} \tag{11}$$

subject to eq. (10). The Kuhn–Tucker first-order conditions determine the optimal supply of the wind power producer:

$$p_t - c_w + \alpha - \beta = 0 \tag{12}$$

$$\beta \left(q_{wt} - \sigma_t q_w^{\max}\right) = 0 \tag{13}$$

$$\alpha q_{wt} = 0 \tag{14}$$

When price exceeds marginal costs c_w, the wind power producer produces at the maximum level; when the price is lower than the marginal cost, wind power production equals zero. When $p_t = c_w$, the production level is undetermined by the first-order conditions; it is determined by the market equilibrium. β is interpreted as the shadow price of capacity.

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[10] Availability depends on the wind force 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. The availability parameter σ_t in the model 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 $\sigma_t = 0$.

[11] The availability of wind can be the same for all wind power producers (for instance when the wind-mills are located in the same geographical area) or it can be individual (when the wind-mills are located in different areas). For simplicity, it is assumed here that the same σ_t applies to all wind power producers, implying a concentrated wind farm.

2.4 Market equilibrium and market prices

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

$$\sum_{i=1}^{N} q_{it} x_{it} + \sum_{w=1}^{M} q_{wt} \geq q_t^D \tag{15}$$

The solution to the market equilibrium (15) in each period t determines the equilibrium output prices $\mathbf{p} = p_1, ..., p_{\infty}$. The output price may be negative, reflecting the shadow price of start-ups and shutdowns in thermal power plants.[12]

2.5 Numerical model implementation

In order to simplify implementation of the numerical model, the equivalence of a competitive market and social planner is employed (Acemoglu, 2009). Given that all producers are price takers, demand is perfectly inelastic and the costs of environmental externalities are included through CO_2 prices, maximising welfare is equivalent to minimising costs. Efficient production means meeting the demand at the least cost.

Nevertheless, the social planner can be thought of as a market operator running an auction.[13] Profit-maximising behaviour (as explained in sections 2.2 and 2.3) determines the producers' bids, reflecting their marginal and start-up costs.

Based on the distinct weekly pattern in power demand, as shown in figure 1, the numerical model assumes simultaneous optimisation over a week in the context of an infinite number of weeks.[14,15] The social planner minimises the total costs of production (both the marginal costs and the start-up costs of thermal power producers and marginal costs of wind power producers) and simultaneously determines the pro-

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[12]In fact, negative prices were introduced on the European Energy Exchange (EEX) in September 2008 and on the Nordic power exchange Nord Pool's day-ahead market in October 2009.

[13]Due to the severe consequences of even a short-term market imbalance, there is always a market operator in a power market, either implicitly (a system operator) or explicitly (a power exchange).

[14]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.nordpoolspot.com).

[15]In reality, the next week shows a similar pattern, although it is not identical due to seasonal variation.

duction of all power plants in order to meet demand in every period t throughout a planning horizon T. The Bellman equation (8) and Kuhn-Tucker conditions (12) to (14) are replaced in the numerical implementation by the social planner's objective:

$$\min \sum_{t=1}^{T} \left\{ \sum_{i=1}^{N} \left[c_i q_{it} + C_{it}^{start} (1 - d_{it}) \right] x_{it} + \sum_{w=1}^{M} c_w q_{wt} \right\} \tag{16}$$

subject to equations (3) to (5), (7), (10) and (15) and assuming

$$q_t^D = q_{t+T}^D \text{ for } t = -\infty, ...1, ..., T, ..., \infty \tag{17}$$

Eq. (17) implies that $q_{it} = q_{i,t+T}, x_{it} = x_{i,t+T}, \gamma_{it} = \gamma_{i,t+T}$ and $q_{wt} = q_{w,t+T}$ for $t = -\infty, ...1, ..., T, ..., \infty$. For simplicity, it is assumed that $\delta = 1$.

The model is developed and solved in GAMS, using the mixed integer programming (MIP) solver CPLEX (Brooke et al., 1998).

3   Subsidies for wind power

Subsidies for wind power may influence the short-term production decision of the wind power producer and, hence, alter his supply for each price level. The impacts of three different subsidies are examined in this section: an investment subsidy, a production subsidy that is given as a mark-up on the market price (also called premium feed-in tariff), and fixed price (also called fixed feed-in tariff).

3.1   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 becomes in this case:

$$\max_{\{q_{wt}\}} \quad \Pi_t = (p_t - c_w)q_{wt} + S q_w^{\max} \quad \text{subject to} \quad 0 \leq q_{wt} \leq \sigma_t q_w^{\max} \tag{18}$$

Since capacity is given in the short term, the first-order conditions are the same as in the situation without a subsidy (eq. 12 to 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 as regards the short-term production decision.

3.2 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 a fixed subsidy s per kWh: $\widetilde{p}_t = p_t + s$. The objective of the wind power producer becomes:

$$\max_{\{q_{wt}\}} \quad \Pi_t = (p_t + s - c_w)q_{wt} \quad \text{subject to} \quad 0 \leq q_{wt} \leq \sigma_t q_w^{\max} \tag{19}$$

The first-order condition eq. (12) is replaced by

$$p_t + s = c_w - \alpha + \beta \tag{20}$$

The production subsidy provides an incentive to produce even with negative prices (if the capacity constraints are 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.

3.3 Fixed price

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

$$\max_{\{q_{wt}\}} \quad \Pi_t = (\widehat{s} - c_w)q_{wt} \quad \text{subject to} \quad 0 \leq q_{wt} \leq \sigma_t q_w^{\max} \tag{21}$$

The first-order condition replacing eq. (12) is

$$\widehat{s} = c_w - \alpha + \beta \tag{22}$$

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

3.4 Market operator's objective with different subsidies

Subsidies change the wind power producers' optimal production level and hence the bids submitted to the market operator. The market operator's (social planner's) objective functions change accordingly. Following the market operator parallel, assume that the social planner only considers the partial electricity market and takes subsidy levels as given.

Since lump-sum subsidies do not change the short-term production decision of wind power producers, equation (16) is also the objective function in the case of lump-sum subsidies.

In the case of production subsidies, eq. (16) is replaced by

$$\min \sum_{t=1}^{T} \left\{ \sum_{i=1}^{N} \left[c_i q_{it} + C_{it}^{start} \left(1 - d_{it} \right) \right] x_{it} + \sum_{w=1}^{M} \left(c_w - s \right) q_{wt} \right\} \tag{16'}$$

and in the case of a fixed price by

$$\min \sum_{t=1}^{T} \left\{ \sum_{i=1}^{N} \left[c_i q_{it} + C_{it}^{start} \left(1 - d_{it} \right) \right] x_{it} + \sum_{w=1}^{M} \left(c_w - \widehat{s} \right) q_{wt} \right\} \tag{16''}$$

4 Data and assumptions in the numerical model

The numerical model developed to quantify the effects of different subsidies for wind power is populated with data from Western Denmark.

4.1 Demand

Demand is fixed and varies according to a predetermined profile, as shown in figure 1. Data from a week in January 2006 are 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 for the market to accommodate a given amount of wind power production than in a situation with low demand.

4.2 Thermal power plants

The thermal power plants in Western Denmark that were available for production in 2006 are used in the model simulations; the main characteristics of the plants are listed in table 1.

The thermal power plants are characterised by a number of parameters in the model: input prices, combined with the technology and age of the power plant, determine the marginal costs of operation and start-up costs of a plant. Capacity determines the upper limit on production ($q_i^{\max}$) for a power plant, while the 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). Other constraints that relate to a period shorter than an hour are not relevant to the model since, technically, all of the plants in the sample can start production within an hour.

Input prices comprise fuel prices and relevant taxes and CO_2 costs. The fuel costs used in the simulations correspond to the following fuel prices: 48.5 EUR/tonne for coal, 12.5 EUR/MWh for natural gas, 219 EUR/tonne for heavy fuel oil and 540 EUR/tonne for light fuel oil. The fuel prices are averages of 2006 levels, except for the natural gas price where a lower price that reflects the historical level is used.

The CO_2 price of 10 EUR/tonne was slightly below the forward price (as of 2006) for CO_2 allowances at EU ETS during the 2008–2012 period. The cost of CO_2 differs between power plants, reflecting the different CO_2 content in coal, oil and gas, and the

Plant ID	Capacity (MW)	Operational marginal cost (EUR/MWh)	Start-up cost:[*] fuel cost of cold start (EUR/start)	Start-up cost:[*] indirect cost (EUR/start)	CO_2 emissions[**] (g/kWh)	Fuel for production	Fuel for start-up
1	410	23.7	10 400	61 500	728	Coal	Heavy fuel oil
2	400	24.4	10 600	60 500	752	Coal	Heavy fuel oil
3	380	24.7	10 000	56 700	760	Coal	Heavy fuel oil
4	625	25.0	16 700	93 800	769	Coal	Heavy fuel oil
5	350	26.2	9 800	52 500	805	Coal	Heavy fuel oil
6	350	26.6	9 900	52 500	814	Coal	Heavy fuel oil
7	300	29.4	9 600	45 800	900	Coal	Heavy fuel oil
8	400	29.6	4 600	39 200	418	Natural gas	Natural gas
9	240	34.6	4 100	23 700	488	Natural gas	Natural gas
10	50	139.8	700	2 500	833	Light fuel oil	Light fuel oil
11	2 400					Wind	

[*] Start-up costs are rounded off to the nearest hundred.

[**] CO_2 emissions at full load operation.

Source: Company brochures, the author's calculations

Table 1: Power plants in the model

efficiency of the plant.

4.2.1 Start-up costs

Fuel cost of a cold start comprise fuel costs for running the plant at maximum capacity for half an hour. For indirect start-up costs, it is assumed that one start reduces the lifetime of the plant by 25 hours.[16]

The level of direct (fuel-related) start-up costs depends on how many periods the plant has been turned off before it is turned on again.[17] 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 when the unit has been off for about ten hours, and it is almost non-existent when the unit has been off for more than 24 hours. Therefore, in order to reduce the complexity of the numerical model, the direct

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[16] These assumptions are rules of thumb used in the industry (personal communication with Jens Pedersen, Energinet.dk, in June 2004). Indirect costs are essentially asset depreciation costs and they increase as the number of starts increases. However, it is a rule of thumb in the industry to treat them as a fixed cost. This approach is followed here.

[17] The fraction of cold start costs that occurs when the plant has been off for γ_{it} periods is usually modelled as an exponential function: $\varphi_t = (1 - e^{\frac{-\gamma_{it}}{\widehat{\gamma}}})$, where $\widehat{\gamma}$ is the cooling constant measuring how quickly the boiler cools down (Wood and Wollenberg, 1996). The constant $\widehat{\gamma}$ for the Danish plants is typically 6-8 hours (personal communication with Jens Pedersen, Energinet.dk, in June 2004). Here, $\widehat{\gamma} = 6$ is used.
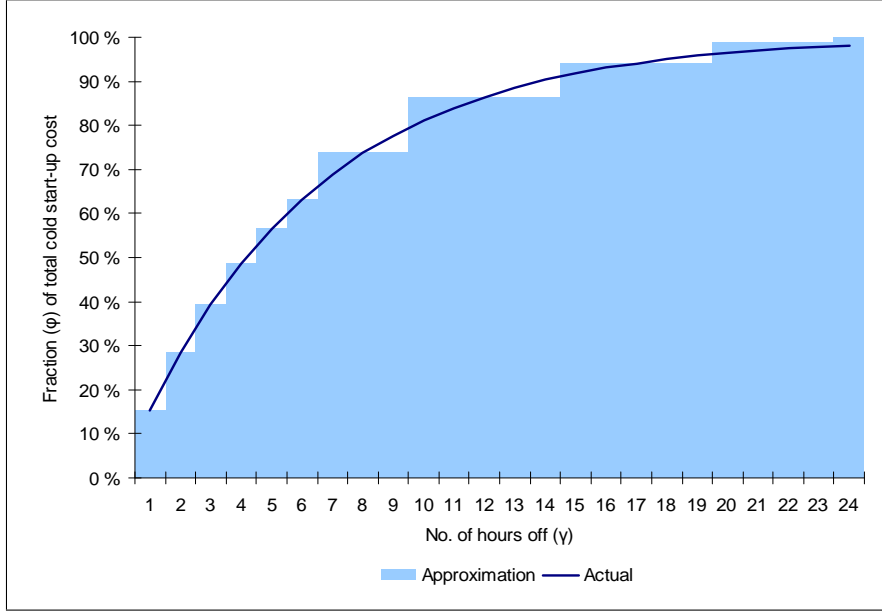
Figure 2: Time-dependency of direct start-up costs: actual and approximation used in the model

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.

Table 1 illustrates the significance of the start-up costs compared with the marginal costs of operation. With the assumed fuel prices, coal-fired plants are cheaper in continuous operation than natural gas-fired plants, while the start-up costs of the natural gas-fired plants are lower than those of the coal-fired plants. Compare, for instance, plant 2 (a coal-fired plant) to plant 8 (a relatively new natural gas-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 (note that 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 half an hour and the total start-up costs, including the indirect cost, to four hours of production costs.
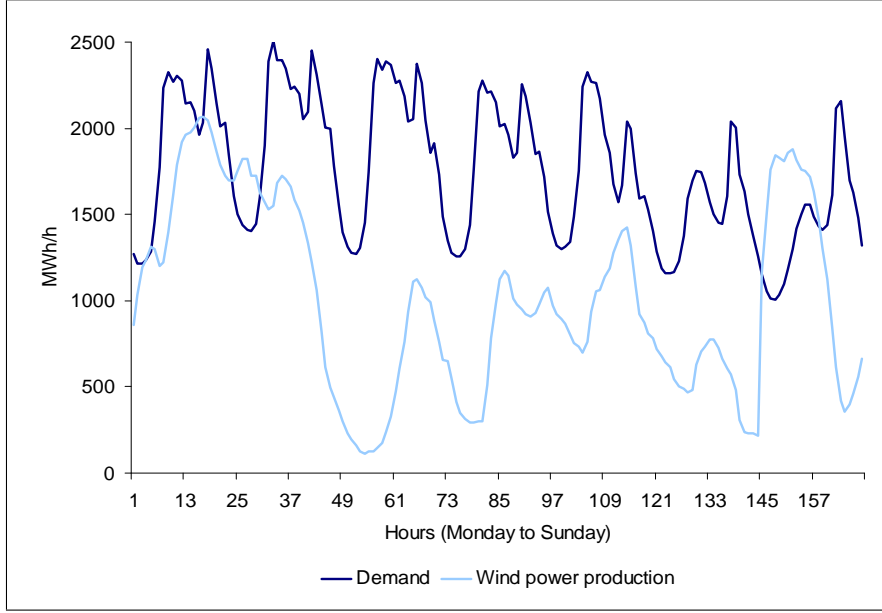
19

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

4.3 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 the 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, while in others, 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 can exceed domestic power demand.[18]

The wind power availability, $\sum_{w=1}^{M} \sigma_t q_w^{\mathrm{max}}$, that determines the upper limit on production is calibrated in the numerical model by using the *actual* observed wind power production over a week in September 2006 (shown in figure 3). The actual profile

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[18]Note that actual production data may indicate wind power production that exceeds domestic demand since, in reality, it is possible to export the excess wind power, a point discussed in section 6.2. This excess production is truncated in the model simulations. 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.

reflects the potential variation of the available wind power better than the average profile would (using average wind power production would level out the variation). Since grid companies were obliged to accommodate wind power whenever available and wind power received relatively high feed-in tariffs under the policy prevailing in 2006, it has been the common belief among market participants that wind power production is equal to the maximum available capacity. Therefore, the actual production is a good proxy for wind power availability.

The week in September 2006 was chosen as a sample week because it displays a relatively high level of 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 in a winter week (i.e. high demand) facilitates the 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). These two effects thus counteract each other.

The marginal costs of wind power are assumed to be zero ($c_w = 0$ for all w). As the marginal costs of wind power are considerably lower than those of thermal plants, this assumption is not crucial; rather, it provides clarity in the interpretation of the results. Maintenance costs, which account for the largest portion of wind power costs, can be regarded as fixed in the short term.

4.3.1 Subsidies for wind power

The existing subsidies are the starting point for the simulations. The present subsidy scheme for wind power in Denmark is extremely complex, see www.energinet.dk or IEA (2010) for an overview. The data used in the simulations are from Energinet.dk (2007).

In the simulations, production subsidy level $s = 13.3$ EUR/MWh has been assumed. This is in the lower range of the actual subsidies. The reason for choosing a relatively low subsidy was to allow for some difference in the scenarios. Obviously, the higher the production subsidy level, the more it resembles the fixed price.

In the fixed-price case, $\widehat{s} = 80$ EUR/MWh. (By comparison, the average market price was 44 EUR/MWh in 2006.) Even though the current subsidy system for wind power in Denmark does not include a fixed price, a fixed price or fixed feed-in tariff has been introduced or is under consideration in other countries and therefore of interest. The historical practice of giving wind power priority over other power sources is also 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 are made in the short term. The exact level of the lump-sum investment subsidy S is therefore 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 5.5.

5 The impact of different subsidies

We compare the market outcome under the three different subsidies for wind power: a lump-sum investment subsidy, a fixed price and a production subsidy. As subsidies for wind power influence the short-term production decision of the wind power producer, they alter his supply for each price level. The altered supply changes the market equilibrium, and, for that reason, thermal power producers are also affected via the market, even though they are not directly affected by the subsidy.

Figures 4 and 5 show production in wind power and thermal power plants, respectively, in every hour of the week in the different cases. Table 2 reports the results.

5.1 Investment subsidy for wind power

Investment subsidies for wind power do not distort the production decisions of the wind power producers (as shown in section 3.1). The investment subsidy therefore results in the same solution for production as would be the case without any subsidy, and it is the optimal solution in the short term (i.e. within the limits of existing

	Investment subsidy	Production subsidy	Fixed price
Wind power production (GWh)	150	156	162
Thermal production (GWh)	146	140	134
– Coal	140	133	119
– Natural gas	6	7	15
– Gas turbines	0	0.04	0.08
No. of start-ups	5	9	22
CO_2 emissions (1000 tonne)	109	105	98
Production cost (1000 EUR)	4 345	4 410	4 848
– marginal production cost (fuel and O&M)	3 011	2 933	2 847
– start-up cost	249	428	1 025
– CO_2 cost (of both production and start-up)	1 085	1 049	976
Marginal unit cost* (EUR/MWh)	28.0	28.4	28.5

* Including fuel, O&M and CO_2 cost, excluding start-up cost and CO_2 related to start-up.

Note: The numbers for production are rounded off and do not necessarily add up to totals.

Table 2: Results of the numerical model

capacity).

The prevailing pattern revealed in the simulation is that wind power production equals the maximum available capacity *most of the time, but not always* (see the dotted line in figure 4). The wind power producers take into account the shadow prices of start-ups and shutdowns in the thermal plants, signalled via output prices. As prices fall, some wind power producers will stop production and total wind power production will be lower than the maximum available level.

Wind power production is lower than the maximum available level for 49 hours (i.e. almost 30% of time). Note that wind power production does not fall to zero in these periods. Total wind power production is 8% lower than the maximum available production. The figures reveal that it is typically optimal to reduce wind power production during low-demand periods (at nights and weekends), but not only then. Since there is no systematic daily pattern in wind availability, situations with excess wind power production can also occur during high-demand periods. In our example, wind power production is even reduced on some workdays (Monday and Friday), in addition to at weekends and at nights.

Plants 1, 2 and 3 (coal-fired plants with the lowest marginal costs) produce non-

stop through the week, adjusting their production levels between the minimum and maximum level. The other (more expensive) thermal plants start up and produce occasionally. It is worth noting that, in addition to plant 4 (next in the merit order), the two gas-fired power plants (8 and 9) produce occasionally: although their marginal costs of operation are higher than those of the other coal-fired plants, lower start-up costs give them an advantage.

5.2   Fixed price for wind power

When wind power is assigned a fixed price, the producer does not respond to market signals (eq. 22). With a fixed price $\widehat{s}$ per kWh, each wind power producer chooses to produce at the maximum available capacity all of the time, regardless of the market price, since $\widehat{s} > c_w = 0$. In order to maintain the balance between total supply and demand, the thermal power producers must adjust production accordingly — and even turn off the plants, if necessary.

In our example, wind power alone is able to meet total demand in some hours and all thermal power plants are crowded out during these hours (see figures 4 and 5). Note that, since these hours are not consecutive, there are four distinct periods when no thermal power plants are producing, implying at least four start-ups later. In total, there are 22 start-ups during the week, compared to only 5 with the lump-sum subsidies (table 2). Thermal power production is reduced by 9%, compared with the optimal case.

However, the remarkable result is that total production costs (fuel and CO_2) are 12% higher, compared with the investment subsidy case, even though the production level is 9% lower. By forcing some plants to turn off and inflicting additional start-up costs on them, and by moving production to more expensive plants, production costs increase considerably. Plant 4 (which has low marginal costs of operation, but is relatively inflexible) is replaced by smaller plants with higher marginal costs of operation (both coal-fired and gas-fired). Plant 10 (gas turbine) is also started three
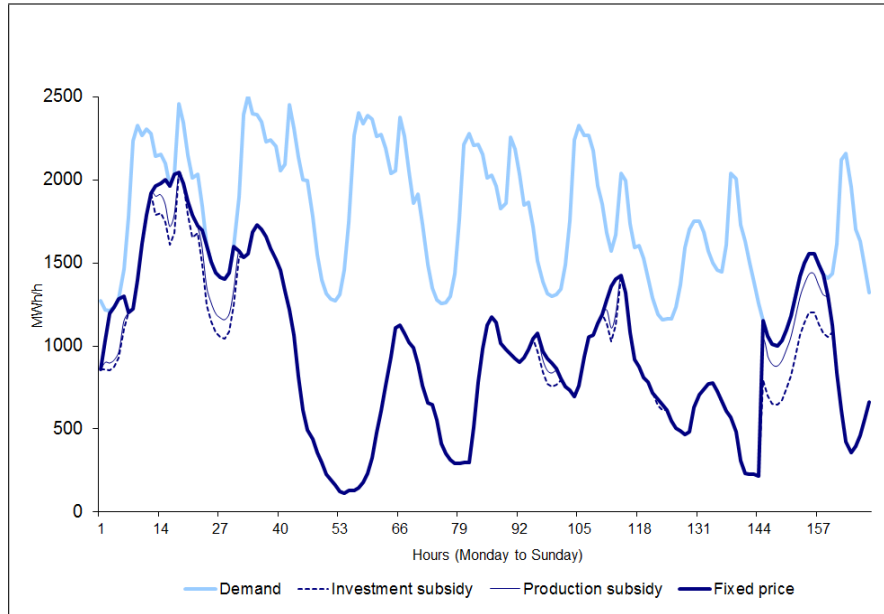
24

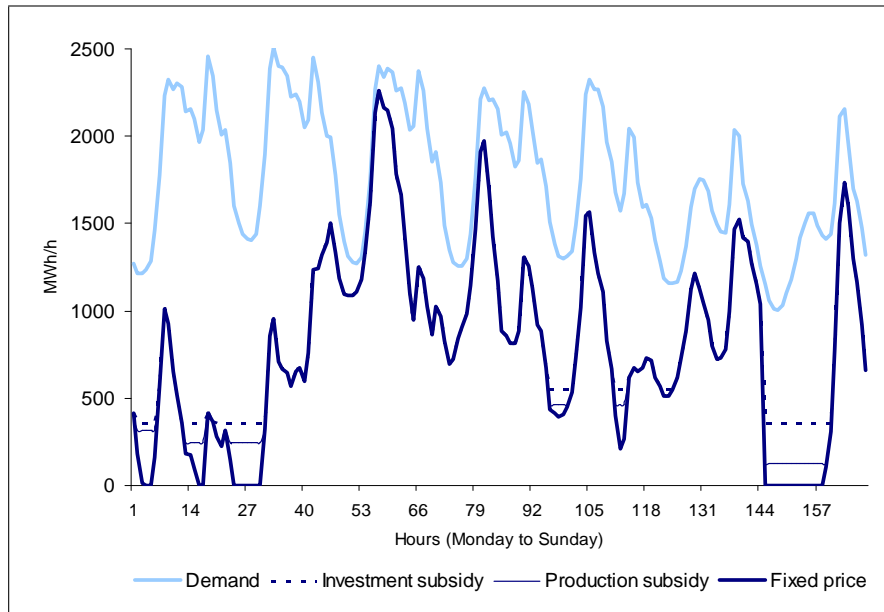Figure 4: Wind power production with different subsidies

Figure 5: Thermal power production with different subsidies for wind power

times, implying price spikes. A comparison of the marginal cost per unit produced reflects the more expensive production mix (table 2).[19] Additional start-ups add to the total costs.

Lower total thermal production reduces emissions, but additional start-ups and switching to less efficient plants may offset this. Fuel switching to gas-fired plants, on the other hand, contributes to lower emissions. In the case at hand, total emissions are reduced: emissions are 10% lower than in the lump-sum subsidy case, but the emission reduction is achieved at considerable cost.

5.3 Production subsidy for wind power

What happens if wind power is subject to a production subsidy s per kWh? In this case, the wind power producer responds to signals provided by the market, but the signal is distorted by the subsidy (eq. 20). The wind power producers are willing to produce until $p = -s$ (recall that $c_w = 0$).

In the present sample, the production subsidy of 13.3 EUR/MWh increases wind power production by 4%, compared with the investment subsidy (the results are reported in table 2 and figures 4 and 5). 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. Total production costs are only 1% higher than in the investment subsidy case and 9% lower than in the fixed price case. Evidently, the most expensive start-ups are avoided (there are only 9 start-ups), and the very expensive gas turbine is started only once (implying fewer price spikes). The flexibility to adjust to market signals results in considerable cost savings, even in the case of a distorting subsidy. 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 subsidised.

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[19]Marginal cost per MWh produced (average for the week) can serve as a proxy for price. Usually, the marginal cost of increasing production by one unit in the model is interpreted as the shadow price. However, this marginal cost must be treated with caution in MIP-models: it is the cost of a marginal production increase for a given operational status of the plants. It may be the case, however, that it is optimal to change the operational status of a plant.

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 that with a lump-sum investment subsidy. A higher production subsidy would give incentives for higher wind power production and the outcome would be more similar to the case with a fixed price.

5.4   Subsidy payment and emission reduction

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.

In addition to increasing the production costs of thermal producers, the subsidy payment is a cost to the authorities.[20] Assuming that the aim of the subsidy is to reduce CO_2 emissions, it is relevant to ask what the implicit cost is of the additional emission reduction due to the subsidy (recall that a CO_2 price is already included).

We cannot compare the subsidy payment per tonne CO_2 reduction in the three cases directly.[21] However, we can compare the subsidy payments in the fixed price and production subsidy cases. In the fixed price case, wind power producers receive almost EUR 11 million more in subsidies than in the production subsidy case, while emissions are reduced by an additional 7 000 tonnes in this sample week (from table 2). This corresponds to about EUR 1 500 per tonne CO_2 avoided for the additional emission reduction. This is very high abatement cost and comes on top of the higher production costs.

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[20] The deadweight loss of collecting taxes is not included here, only the actual amount of money paid to the wind power producers.

[21] We do not know the necessary or optimal level of investment subsidy, and, since the investment subsidy does not influence the production decision, the exact level is not important for the numerical model.

5.5 The impact of wind power capacity

Wind power is envisaged as the main source of renewable energy in many European countries (EC, 2009). It is therefore relevant to ask how the costs of different subsidies vary with wind power capacity.

It is reasonable to assume that, as long as wind power accounts for a small share of total production capacity, it is relatively easy to accommodate it in the market, in spite of the possibly distorting subsidies. The adverse effects will become more pertinent as the wind power's share of electricity production increases or is concentrated in some geographical areas. Sensitivities that test the impact of available wind power capacity confirm this intuitive assumption: the larger the market share of wind power, the higher the costs of an adverse subsidy scheme.

With only 50% of the original available wind power (but still with the same profile over the week as assumed in the base case), a fixed price for wind power reduces emissions by 3% and increases costs by 6% compared with the optimum. The cost increase is smaller relatively speaking than in the base case: with less wind power, it is clearly easier to accommodate wind power by adjusting the production level in the thermal plants without turning them off altogether.

The simulations with twice as much wind power capacity as in the base case also confirm the results, but the effects are magnified. In this case, a fixed price for wind power reduces emissions by 25% and increases costs by 18%, compared to the lump-sum investment subsidy. A production subsidy reduces emissions by 17%, but the costs increase by only 2%, compared with the investment subsidy. Even slight flexibility in wind power clearly pays off.

It is also worth noting that increasing wind power *capacity* does not translate into an equal increase in wind power *availability*. As wind power capacity increases, situations where wind power production exceeds demand become increasingly frequent. Some of the capacity increase is thus 'in vain'. 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 Other ways of increasing flexibility

Some important sources of flexibility – transmission networks, trade and demand – were ruled out in the model simulations to make the analysis more clear-cut. The realism and implications of these assumptions are commented on below. New technologies that provide possibilities for storage could also increase the flexibility of the system in the future.

6.1 Transmission networks

Transmission was omitted from the present analysis, implying sufficient domestic transmission capacity to absorb wind power generation. Roughly speaking, this has been the case in the past, although the situation may change in future: large-scale expansion of wind power is often planned in isolated areas, implying that there may be more (regional) congestion and that the wind power may be "locked in".

Market prices provide information about the value of the power in different geographical locations. Hence, market prices are not just important for short-term production decisions, but also for long-term investment decisions. Regulation and network tariffs may complement these price signals. Therefore, subsidy design, together with market design, is important in order to ensure proper investment signals as well. Even though wind resources must be utilised where they are, not all of them will be developed. Which sites will be developed and in which order is important for efficiency.

Large-scale development of wind power requires additional investments in networks. In deregulated electricity markets, investments in generation and networks are made by different agents. This is a challenge for regulators. Munoz et al. (2013) show that ignoring transmission constraints when considering investments in renewables will increase the total costs.

6.2 Trade

The model simulations assumed no trade with neighbouring areas. The main reason for excluding trade was to make the model clear-cut and focus the analysis on the flexibility of thermal power plants.

In reality, export and import possibilities provide additional flexibility in the power system: it is possible to export the "excess" power that is caused by a sudden increase in wind power production or to import power to avoid the start-up of a thermal power plant when a sudden calm period reduces wind power production. The larger the interconnected system, the easier it is to adjust the production level in operating power plants without turning them off altogether.

Connection to a reservoir-based hydropower system or to a hydropower system with pumped storage is particularly advantageous, since hydropower plants have practically no start-up costs and can therefore easily accommodate variation in wind power. Hence, hydropower can be used as a "battery": in periods with much wind, water can be stored in the reservoirs, to be used in periods with little wind. Pumped storage even provides a "rechargeable battery". This will also level out prices: both price spikes and very low prices are avoided. This type of trade between a thermal system (Denmark) and hydropower systems (Norway and Sweden) has been used in the past to level out the systematic seasonal and daily variation, but it is also beneficial in relation to accommodating the short-term variation caused by wind power.

Even though, in reality, trade possibilities help to accommodate variation in wind power production and demand, transmission lines are congested from time to time. Without additional investments, congestion in transmission networks will become more frequent. A larger system would increase flexibility, but a badly designed subsidy would nevertheless undermine this flexibility.

6.3 Flexibility of demand

The model simulations have assumed inelastic demand. Inelastic demand is quite a realistic description of the situation in Denmark (and many other countries) in the very short term: most consumers' demand is virtually inelastic from one hour to the next, as they do not observe hourly prices and therefore do not respond to these prices. Moreover, 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 power system and reduce the costs of thermal producers. However, increasing flexibility, for instance by installing smart meters, would entail additional costs. More flexibility can also be achieved by sending correct price signals to consumers – as long as consumers only face average (monthly) prices, there is no incentive to respond to hourly prices.

6.4 New technologies and storage

Linking together different energy systems, such as transport and heating, with the electricity system, might provide storage possibilities that increase flexibility in future (Kiviluoma and Meibom, 2010). For instance, charging plug-in electric vehicles for later use in high-wind periods and discharging them in high-demand periods reduces the overall costs of the system. Heat storage (in the form of hot water) could be another possibility. Such integration will require the development of both infrastructure and regulation.

7 Concluding remarks

The aim of this paper is to show how the costs of integrating wind power in an inflexible power system and emissions from the system depend on the design of subsidies for wind power. The existing system consists of thermal power plants that are inflexible in the short term because of start-up costs. Three different subsidies for wind power are

studied: a lump-sum investment subsidy, a production subsidy per kWh (a mark-up on the market price) and a fixed price per kWh (unrelated to the market price).

The investment subsidy yields the optimal solution for production: wind power producers take into account the shadow prices of start-ups in thermal power plants, which are signalled through market prices. When wind power is optimally scheduled, it is sometimes profitable to reduce wind power production in order to avoid shutting down a thermal unit. When the production subsidy is designed as a mark-up on the market price, the market signals are distorted. With a fixed price, wind power is produced at the maximum available level and does not take market prices or the impact on other producers into account. With low demand, the thermal power plants are forced to stop in order to maintain the 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 a fixed price is 9% lower than with the investment 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. Moreover, the emission reduction is achieved at considerable cost to the authorities: the total subsidy payments reveal that the implicit cost of the additional emission reduction is very high.

The results also indicate that incentives to adjust wind power even slightly would pay off: a small reduction in wind power often saves considerable costs. In the simulations with a production subsidy, thermal power production is 4% higher than with the investment subsidy, but production costs are only 1% higher. Evidently, the most expensive start-ups are avoided. In other words, flexibility has a high value.

A deterministic model was used in the simulations in order to focus on the issue of flexibility and distinguish the impacts of flexibility from those of uncertainty. Rosnes (2008), 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 up and reducing the threshold price for stopping. This indicates that uncertainty would probably increase costs even more, thus supporting the results of the present analysis.

The analysis underlines the importance of taking into account the finer details of an industry when devising a regulation. It is somewhat paradoxical that production subsidies have been the most common type of subsidies for renewables in Europe, even though it is the high investment costs that prevent expansion of renewable capacity. It is probably fair to say that policies aimed at promoting renewables have been characterised by politicians' determination to act quickly and that investment volume has been in focus instead of investment efficiency.[22] Analyses that go beyond simple textbook analyses and that take into account industry peculiarities and country-specific characteristics are a prerequisite for successful regulation.[23]

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 should take into account both the characteristics of the existing system and the characteristics of renewables capacity. An inflexible system should promote technologies that are flexible and reliable (in the sense of being available when needed), while a flexible system can afford to promote less flexible technologies.

While the existing technology mix of a power system is largely given, market rules and subsidy design play an important role in the flexibility of the power market. Nonetheless, if wind power or another intermittent power source 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 aimed at increasing flexibility may involve increasing the demand response (either technically, by investing in smart meters, or economically, by exposing consumers to actual market prices) or, on the supply side, by investing in more flexible plants or increasing trade possibilities

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[22] Germany has often been quoted as a showcase for the effectiveness of feed-in tariffs in achieving 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, such tariffs have failed to contribute to investments.

[23] Green (2007), Green (2008), Just and Weber (2008) and Newbery (2012) are examples articles that take into account the nitty-gritty details of electricity markets when analysing the market design.

with other regions. A good example of how to increase the flexibility of the existing system using economic incentives is the introduction of negative prices in day-ahead markets. In the longer term, plug-in electric vehicles and heating could play an important role as storage capacity. However, these measures to increase flexibility require further investments that add to costs, in addition to the subsidies for wind power.

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

Acknowledgements

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