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Carbon Price and Wind Power Support in Denmark

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Summary

This paper aims at characterizing the conditions of wind power deployment in order to infer a carbon price level that would provide wind power with comparable advantage over fossil fuel technologies as effective wind support policies. The analysis is conducted on Danish data from 2000 to 2010, i.e. after market liberalization took place in 2000. Probit technique is used to analyze the connection of new turbines to the grid each month and tobit analysis is employed on the additional capacity installed monthly. I find that the level and type of the support policy are the dominant drivers of deployment. Electricity price impact is not visible. The investment cost impact is not significant either, but the effect of the interest rate, although not visible in the probit analysis, is significant in the tobit analysis. The number of turbines already installed, that is taken as a proxy for the sites availability, does not have any significant effect either. A feed-in tariff significantly brings more wind power in than a premium policy. The fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed monthly by up to several tens MW. The additional capacity installed monthly increases by up to thousand kW for each additional e/MWh of support. If the policy is a premium, I find that 24 e/MWh of support in addition to electricity price is needed to observe the connection of new turbines to the grid with a 0.5 probability. I convert this support level into a carbon price of 28 e/ton if wind power competes with coal, and 50 e/t if it competes with gas.

This work was completed by the Climate Policy Research Unit of the European University Institute and the Centre d'Economie de la Sorbonne, which is part of Paris 1 Panthéon-Sorbonne University and is affiliated with the Paris School of Economics. This paper supersedes the EUI working paper entitled 'Carbon price as renewable energy support? Empirical analysis on wind power in Denmark' (RSCAS 2012/19, May 2012).

Keywords: Wind Power, Renewable Energy, Subsidy, Carbon Price, Feed-in Tariff, Emissions Trading, Climate Policy

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Carbon Price and Wind Power Support in Denmark

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Abstract

This paper aims at characterizing the conditions of wind power deployment in order to infer a carbon price level that would provide wind power with comparable advantage over fossil fuel technologies as effective wind support policies. The analysis is conducted on Danish data from 2000 to 2010, *i.e.* after market liberalization took place in 2000. Probit technique is used to analyze the connection of new turbines to the grid each month and tobit analysis is employed on the additional capacity installed monthly. I find that the level and type of the support policy are the dominant drivers of deployment. Electricity price impact is not visible. The investment cost impact is not significant either, but the effect of the interest rate, although not visible in the probit analysis, is significant in the tobit analysis. The number of turbines already installed, that is taken as a proxy for the sites availability, does not have any significant effect either. A feed-in tariff significantly brings more wind power in than a premium policy. The fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed monthly by up to several tens MW. The additional capacity installed monthly increases by up to thousand kW for each additional €/MWh of support. If the policy is a premium, I find that 24 €/MWh of support in addition to electricity price is needed to observe the connection of new turbines to the grid with a 0.5 probability. I convert this support level into a carbon price of 28 €/ton if wind power competes with coal, and 50 €/t if it competes with gas.

Keywords:

Wind power; renewable energy; subsidy; carbon price; feed-in tariff; emissions trading; climate policy.

1 Introduction

1.1 Context

In Europe, the climate and energy package aims at meeting the European Union (EU) climate and energy targets. The 2020 package included three objectives: reducing the EU greenhouse gases emissions by 20% compared to 1990 levels, raising the share of the EU energy consumption produced from renewable resources to 20%, and improving the energy efficiency in the EU by 20%. Within this package, national renewable energy (RE) support policies (EU, 2009) have coexisted with a common carbon market. While the European Union Emission Trading Scheme (EU ETS) is designed to curb carbon emissions, renewable energy support policies aim at increasing the share of renewable energy sources in total energy consumption. However, renewable energy resources are not necessarily the most efficient way to decrease carbon emissions. As the 2030 climate and energy package is discussed, the debate on the coexistence of an emissions trading scheme and renewable energy targets is back. Palmer and Burtraw (2005) as well as Fischer and Newell (2008) underline that, if the main goal is to reduce greenhouse gases emissions, renewable energy support policies are less cost-effective than a cap-and-trade system or a carbon tax. Energy consumption reduction as well as efficiency improvement might be other ways to reduce emissions. The coexistence of these instruments raises several questions. What is the actual abatement cost of renewable energy support policies? What is their impact on carbon price? What is the impact of the latter on renewable energy deployment? Do the instruments mutually reinforce or weaken one another?

Some studies already enlighten these questions. For example, Marcantonini and Ellerman (2013) calculate the annual CO_2 abatement cost of renewable energy incentive in Germany in the time period 2006-2010. They find that CO_2 abatement cost of wind power is relatively low (the average for 2006-2010 is 43 €/tCO_2) while CO_2 abatement cost for solar energy is very high (the average for 2006-2010 is 537 €/tCO_2). Fischer and Preonas (2010) develop a theoretical framework to explain interactions between overlapping energy and climate policies. Morris (2009) shows that, in the U.S., a renewable energy portfolio standard (RPS) in addition to an emission trading scheme would increase welfare cost compared to a trading scheme alone. The reason is the RPS reduces the flexibility for power producers to choose the cheapest abatement solutions. Other studies on the United States case question the usefulness to have renewable energy policies in parallel of a national cap-and-trade system (Paltsev *et al.*, 2009; McGuiness and Ellerman, 2008). On the European case, Weigt *et al.* (2012) model the German power sector to analyze the carbon abatement due to renewable energy in Germany and the impact of carbon price on this, for the time period 2006-2010. They estimate that CO_2 emissions from the electricity sector are reduced by 10 to 16% of what estimated emissions would have been without any RE policy. They also find that the abatement attributable to RE injection is 4 to 10% greater in the presence of a carbon price than otherwise. In conclusion, Weigt *et al.* actually find that both instruments reinforce one another.

Relative to the impact of renewable support policies, and the carbon price level that would have comparable effect, Blanco and Rodrigues (2008) compute a carbon credit level equivalent to each national wind support policy in effect in Europe in 2006. Their analysis includes the 27 member states of the European Union. They use assumptions on the amount of greenhouse gases avoided by wind energy but they do not take account of the actual impact of each policy on wind power deployment. On the other hand, many studies compare the impact of various types of renewable support policies, without necessarily taking into account the stringency level of each of them. It is the case of Menz and Vachon (2006) on the United States experience.

1.2 Main question addressed

The purpose of the work presented here is to analyze the conditions that lead to wind power deployment, to infer the carbon price level that would provide wind power with a comparable price advantage over fossil technologies, and to compare this level with the carbon price observed in the second phase of the EU-ETS. The analysis focuses on Denmark, which has a long wind power history including several support policy changes over time. The wind power profit function is used to identify the parameters that might impact wind power deployment. A discrete choice econometric model (probit) is employed to test the effect of these parameters on new on-shore[2] wind turbine connections to the grid on a monthly basis for the time period 2000-2010, *i.e.* after the market liberalization that took place in 1999.[3] Tobit technique is used to estimate the effect of the same parameters on the additional wind power capacity installed each month. The probit estimates allow calculating the probability of new connections to the grid as a function of the support policy type and level. The support level needed to attain wind power deployment with a probability of 0.5 can be converted into a carbon price that would provide wind power producers with a comparable price advantage compared to coal or gas power plant owners. This carbon price is computed from the difference in profitability between renewable and fossil fuel technologies.

1.3 Structure

In Section 2, the history of wind power in Denmark is presented as the context of the work. At the aggregate level, the observation of wind capacity over time in parallel with the support policy changes

[2] On-shore wind capacity and generation were respectively 2.82 GW and 5.072 TWh in Denmark in 2009, compared to 0.662 GW and 1.644 TWh for off-shore wind. Total power capacity was approaching 13 GW in 2009 and total power generation was 34 TWh (see Figures 1 and 4).

[3] The choice is made to focus on on-shore wind power only as off-shore wind power is significantly different, for example in terms of cost and grid infrastructure development.

already provides some indications about the impact of the various types of support and about the support level needed to have wind power deployment.

The econometric analysis that quantifies these impacts is presented in Section 3. The model that is used is based on the profit function for wind energy. The database preparation is explained. The results of the probit and tobit analysis are presented. The robustness of these results is discussed.

In Section 4, the comparison between the profits expected from wind power projects and fossil fuel power plants is used to compute a carbon price that would provide wind power producers with a price advantage comparable to the support level needed to see new connections of turbines to the grid with probability 0.5.

2 Wind energy in Denmark

Denmark is chosen for its long wind power history, the frequency of changes in the type and level of its wind support policies and the large amount of data available for wind energy.

On shore wind support policies began in Denmark in 1976 (Energistyrelsen; Jaureguy-Naudin, 2010). They are summarized in Table 1. Between 1976 and 2000, several policies juxtaposed each other and sometimes overlapped. From 1976 to 1989, the Danish state reimbursed part of the investment for building wind turbines. The support was originally 40% of the investment cost and was then reduced gradually until the scheme was cancelled in 1989. From 1984 to 2001, the electricity price paid to producers of wind power was 85% of the local retail price of electricity excluding taxes. In 1991, a fixed price premium of 36 €/MWh was introduced in addition to the previous scheme. It was in place until 2001.

In 1999, the Danish electricity market was liberalized. Existing turbines were then covered by a special feed-in tariff (FIT)[4] which resulted in a comparable income for producers as under the previous support scheme. For existing wind turbines connected before the end of 1999, producers received a feed in tariff of 80 €/MWh for a number of full load hours (25,000 full load hours for turbines below 200 kW, 15,000 full load hours for turbines below 600 kW, 10,000 full load hours for turbines larger than 600 kW). After full load hours were used, producers received a feed-in tariff of 58 €/MWh until the turbine was ten years old. They then received a price premium of maximum 13 €/MWh until the turbine was 20 years old. The sum of market price and price premium was limited to 48 €/MWh. An additional price premium of 3 €/MWh was paid to cover balancing costs[5] in the electricity market.

From 2000, four policies were successively in place. For turbines connected to the grid between 2000 and 2002, producers received a fixed feed-in tariff of 58 €/MWh for the first 22,000 full load hours. They then received the wholesale spot market electricity price (37 €/MWh in 2008) in addition to a premium of 13 €/MWh, until the turbine is 20 years old. The sum of the market price and the price premium was limited to a maximum of 48 €/MWh. In 2002, the support scheme changed from a feed-in tariff to a variable premium to better integrate with the recently liberalized electricity market. For turbines connected to the grid in 2003-2004, the premium scheme was associated with a cap on the total remuneration per unit of electricity produced. For the first 20 years of the turbine lifetime, producers received the wholesale spot market electricity price in addition to a premium of 13 €/MWh. The sum of the market price and the price premium was limited to 48 €/MWh. In 2005, the cap

[4]A feed-in tariff is a guaranteed price that power producers receive for every kWh they produce, instead of receiving the market electricity price. It provides more revenue certainty than a premium policy under which the electricity price uncertainty remains, despite the premium that is offered on top of it.

[5]A producer, for example a wind turbine owner, has to forecast the production in advance and sell it to the power exchange. Any deviation from the forecasted wind production is covered by means of regulating power. The costs of offsetting the imbalances in wind power production are charged to turbine owners. The 3 €/MWh allowance is paid to turbine owners to help them pay these balancing costs.

on the total remuneration per unit of electricity produced was removed. For turbines connected to the grid between January 2005 and February 20^{th} 2008, producers received the wholesale spot market electricity price in addition to a premium of 13 €/MWh for the first 20 years of the turbine lifetime. In 2008, the current regime came into effect when the premium was increased. For turbines connected to the grid after February 21^{st} 2008, producers receive the wholesale spot market electricity price in addition to a premium of 34 €/MWh for the first 25,000 full load hours. Under all four regimes and for the entire lifetime of the turbine, an additional allowance of 3 €/MWh has been paid to producers to cover balancing costs.

Aggregate on-shore wind capacity in Denmark in the last decades is presented in Figure 1.[6] Its observation in parallel with the support policy history shows a correspondence between the growth in capacity and the support scheme: most of the growth in wind capacity occurred either between 1995 and 2002, or after 2008, which means either under a premium of 36 €/MWh, a feed-in tariff of 58 €/MWh or under a premium of 34 €/MWh. Given electricity prices in 2000-2002, the feed-in tariff of 58 €/MWh can be seen as equivalent to a premium of more than 30 €/MWh, under revenue certainty equivalence. This suggests a threshold effect, that is to say, the existence of a support level above which new turbines are connected to the grid and below which no new connections are made.

[6]Data source: Energistyrelsen.

Table 1: On-shore wind support policies in Denmark (Source: Jauréguy-Naudin, 2010).

Date of connection to the grid	***Support scheme***
From 1976 to 1989	Financial support from the Danish state.
From 1984 to 2001	Electricity price paid to producers: 85% of the local retail price, excluding taxes.
From 1991 to 2001	Fixed premium of 36 €/MWh in addition to the previous scheme.
Existing turbines bought before the end of 1999	Feed-in tariff of 80 €/MWh for a number of full load hours. Then feed-in tariff of 58 €/MWh until the turbine is 10 years old. Then premium of 13 €/MWh or less until the turbine is 20 years old.
From 2000 to 2002	Feed-in tariff of 58 €/MWh for 22,000 full load hours. Then premium of 13 €/MWh or less untile the turbine is 20 years old with a limit of 48 €/MWh on the sum of market price and premium. Additional premium of 3 €/MWh.
From 2003 to 2004	Premium of 13 €/MWh or less until the turbine is 20 years old, with a limit of 48 €/MWh on the sum of market price and premium. Additional premium of 3 €/MWh
From 2005 to February 20^{th} 2008	Fixed premium of 13 €/MWh until the turbine is 20 years old. Additional premium of 3 €/MWh
After February 21^{st} 2008	Premium of 34 €/MWh for the first 25,000 full load hours. Additional premium of 3 €/MWh.

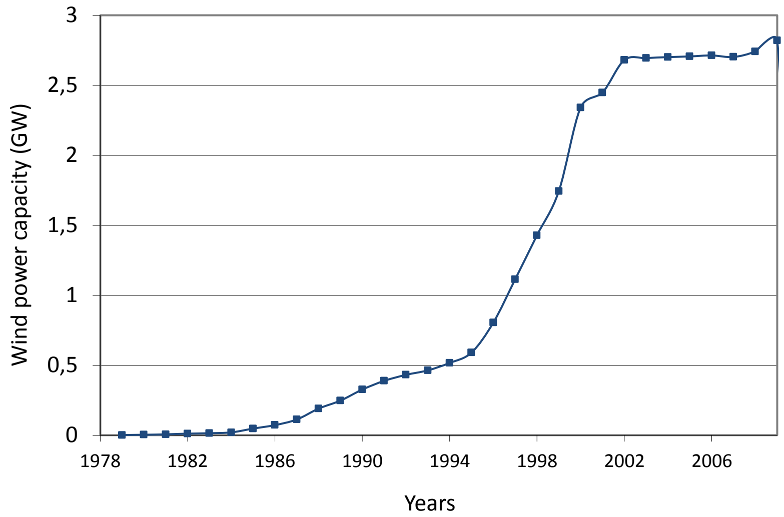

Figure 1: On-shore wind capacity in Denmark since its early stage.

The purpose of the analysis presented in this paper is to take advantage of this diverse history of wind power in Denmark to quantify the impact of wind support policies and to infer a carbon price that would attain comparable wind power deployment. Econometric analysis is used to do this empirical analysis and a discrete choice model is chosen as an appropriate approach to analyze the connection of new turbines to the grid each month and take account of a possible threshold effect. Tobit analysis on the additional capacity that is installed monthly complements the results from the probit technique.

The analysis is done for on-shore wind power for the time period 2000-2010. I indeed chose to focus on the time period after liberalization. The first reason is that, after liberalization, policies are clearly juxtaposed and they do not overlap. Then, for the econometric estimations, it would not be possible to find a consistent electricity price time series before and after liberalization. A premium on top of a government set electricity price is indeed not comparable to a premium on top of a market electricity price. Finally, the current debate on the coexistence of renewable energy support policies and an emission trading scheme is conducted in the context of a liberalized electricity market. This work provides some insights on the issue in this context.

3 Econometric analysis of the conditions of wind power deployment

The econometric analysis uses both probit and tobit techniques. It is based on the profit function for wind energy producers. After the latter is presented, the econometric model is introduced and the data preparation is explained. Results are then presented and their robustness is discussed. At this stage, I do not introduce the comparison between wind power and fossil technologies. Indeed companies like Vattenfall and DONG Energy that also have activities in thermal power production do own some of the wind turbines in Denmark, but two thirds of the Danish wind power capacity is actually owned by individuals (e.g. farmers) who base their decision on a cost-return consideration. Hence, I build the model for the following econometric analysis on the profit function of wind power only. I introduce the comparison with the other power production technologies in Section 4.

3.1 Profit function for wind energy

For power production from technology i, the profit Π_i for each kWh produced can be defined as follows:

$$\Pi_i = \frac{\int_0^T (p_t^i + x_t^i - em_t^i - vc_t^i) q(t) e^{-rt} dt - FC_i}{\int_0^T q(t) e^{-rt} dt} \tag{1}$$

where:

p_t^i is the electricity price received by power producers at time t,

x_t^i is the potential premium received by producers if technology i is subject to some support policy at time t,

em_t^i is the emission penalty if technology i produces emissions that are subject to some mitigation policy at time t,

vc_t^i represents the other variable costs for technology i,

$q(t)$ is the quantity of electricity produced at time t,

r is the discount rate,

FC_i represents the fixed costs for technology i,

and T is the plant lifetime.

Hence Π_i can be decomposed in the sum of an electricity price revenue, P_e, and a premium revenue, X_i, minus emissions costs, E_i , and other costs, C_i, as follows:

$$\Pi_i = P_e + X_i - E_i - C_i \tag{2}$$

where:

$$P_e = \frac{\int_0^T p_t^i q(t) e^{-rt} dt}{\int_0^T q(t) e^{-rt} dt} \tag{3}$$

$$X_i = \frac{\int_0^T x_t^i q(t) e^{-rt} dt}{\int_0^T q(t) e^{-rt} dt} \tag{4}$$

$$E_i = \frac{\int_0^T em_t^i q(t) e^{-rt} dt}{\int_0^T q(t) e^{-rt} dt} \tag{5}$$

$$C_i = \frac{\int_0^T vc_t q(t) e^{-rt} dt}{\int_0^T q(t) e^{-rt} dt} + \frac{FC_i}{\int_0^T q(t) e^{-rt} dt}. \tag{6}$$

For a renewable technology r, there is no emission cost and the profit function is

$$\Pi_r = P_r + X_r - C_r. \tag{7}$$

For wind power, costs are mainly fixed costs.

$$C_r \approx \frac{FC_r}{\int_0^T q(t)e^{-rt}dt}. \tag{8}$$

C_r can be approximated by the upfront investment cost. A large part of it is the turbine price, which depends on the turbine capacity. The quantity of electricity produced is a function of the turbine capacity as well and the wind power density (W/m^2) of the site where it is built. Hence C_r is a function of the investment cost in €/kW divided by the wind power density of the turbine site.

3.2 Econometric model

The decision to build a new turbine depends on the profit that can be expected from it. The decision is made only if the profit is positive or equal to zero. Hence, given the profit function described above, this decision may depend on the electricity price projections, the investment cost and the interest rate when the decision is made to connect a new turbine on a given site. The wind characteristics of the site that is chosen may also have an influence as well as the availability of good sites.

Although in the four regimes considered between 2000 and 2010, the support policy actually varies between the main part of the turbine lifetime (*i.e.* the first 22,000 full load hours for the regime in place from 2000 to 2002, the first 20 years of operation for the regimes in place from 2003 to February 20$^{\text{th}}$ 2008, and the first 25,000 full load hours for the regime in place after February 21$^{\text{st}}$ 2008), and the rest of it, the bulk of the support revenue comes from what is received in the main part of the turbine lifetime.[7] Hence, the support policy I consider for each of these four time periods in the econometric analysis is the support actually provided in the main part of the turbine lifetime. For turbines connected to the grid between 2000 and 2002, wind power producers receive a feed-in tariff of 58 €/MWh, *i.e.* a fixed tariff that is independent of the electricity price. For turbines connected to the grid in 2003 and 2004, wind power producers receive a premium of 13 €/MWh or less in addition to the electricity price. The variable premium is computed as a function of the electricity price: if electricity price is below 35 €/MWh, the premium is 13 €/MWh; if electricity price is between 35 and 48 €/MWh, the premium is the difference between the electricity price and 48 €/MWh; if electricity price is above 48 €/MWh, there is no premium. For turbines connected to the grid between 2005 and February 20th 2008, wind power producers receive a fixed premium of 13 €/MWh in addition to the price of electricity. For turbines connected after February 21st 2008, power producers receive a fixed premium of 34 €/MWh in addition to the price of electricity. In addition, for all regimes, wind power producers receives 3 €/MWh for balancing costs.

In terms of time scale, although the exploration of a site may start up to five years before a turbine is connected to the grid on that site, there is usually one year between the start of the actual building of the turbine and the date of connection to the grid. The start of the building of the turbine can be seen as the point of irreversibility in the decision process. Appropriate lags are taken into account for the relevant explanatory variables of the econometric analysis as explained later on.

3.2.1 Probit model

Probit analysis is chosen to examine the impact of electricity price projections, the support type (feed-in tariff, fixed premium or variable premium), the support level and the levelized cost on the decision to build a new turbine. This decision is a binary variable and is observed through the connection or the absence of connection of new turbines to the grid per month. As the electricity price and support level impacts may vary with the type of support policy that is used, dummy variables are introduced

[7] The typical lifetime of a wind turbine is 20 years.

to characterize the support policy type and to differentiate the support level and policy type effects. The econometric model used for the probit analysis is the following:

$$Prob(Y_t = 1|A_t) = F(\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP \\ +\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} + \beta_9\ R_{t,-n} + \beta_{10}\ TotTb_t) \tag{9}$$

where:

Y_t is a binary variable: it is worth 1 if at least one new turbine is connected to the grid in time period t, it is equal to 0 otherwise.

A_t is the vector of all explanatory variables considered.

F is the cumulative distribution function of the standard normal distribution.

$Elecprice_t$ represents electricity price projection at time t.

$Support_t$ is the support level at time t. If the policy type is a fixed premium, $Support_t$ is the premium itself. If the policy type is a feed-in tariff, the support level is calculated as the difference between the tariff and the electricity price at time t.

FIT and VP are the dummy variables for the feed-in tariff and the variable premium policies. The fixed premium policy is taken as the reference category. The variable $Support_t * FIT$ (respectively $Support_t * VP$) is the interaction term between $Support_t$ and the dummy variable FIT (respectively VP). In the database, the interaction term between the VP dummy variable and the $Support_t$ variable was almost perfectly collinear with the VP dummy variable. The reason is that, in 2003 and 2004, electricity price was such that the support variable as I calculate it is the full premium (13 €/MWh) for most of the observations during that time period.

$Cost_t$ is the levelized cost of wind power. For wind power, costs are mainly fixed costs. Levelized cost can be approximated by the investment cost divided by the quantity of electricity produced during the turbine lifetime. The investment cost itself is the product of the investment cost in €/kW and the turbine capacity, while the quantity of electricity produced during the turbine lifetime is function of the turbine capacity, the turbine lifetime, and the wind potential of the site where the turbine is built. As a consequence, the levelized cost does not depend on the turbine capacity as higher energy production compensates for the increase in the turbine price (Bolinger and Wiser, 2011). Neither wind power density, nor the capacity factor is observed when there is no new connection to the grid. Investment cost in €/kW is then taken as a proxy for the cost term.

R_t is the interest rate of long-term Danish government bonds.

$TotTb_t$ is the number of turbines already installed at time t. It is a proxy for the sites availability: the higher the number of turbines already installed, the lower the number of remaining sites that are available.

Lags up to five years are tested for electricity price and up to two years for the support level, interest rate and cost terms. These values correspond to the length of the decision process to build a new turbine, as explained in the introduction of Section 3.2. Past electricity prices are used as a proxy for electricity price projections. I tested the use of forward contracts prices, but the spot market offers the longest data series (as early as July 1999).

Given the profit function described previously, β_2 and β_3 are expected to be positive while β_8 and β_9 are expected to be negative. Previous comparisons between various types of wind support policies (for example Menz and Vachon, 2006) conclude that a feed-in tariff regime attains larger wind power deployment (Couture *et al.*, 2010). For this reason, β_4 is expected to be positive. On the contrary, β_5 is expected to be negative as a variable premium would provide wind power producers with a lower revenue certainty than a fixed premium.

3.2.2 Tobit model

I use tobit analysis to estimate the effect of the same factors on the additional capacity that is installed each month. I include the same explanatory variables as for the probit analysis. I add $Dec02$, a dummy variable for December 2002, month for which a significantly larger capacity of wind power was installed (226 MW compared to 10MW on average for the time period 2000-2010).[8] The model for the tobit analysis is the following:

$$\begin{aligned} AddCap_t = (&\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP \\ &+\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} \\ &+\beta_9\ R_{t,-n} + \beta_{10}\ TotTb_t + \beta_{11}\ Dec02) * \mathrm{I}[B_t > B^*] \end{aligned} \tag{10}$$

where:

$AddCap_t$ is the additional capacity installed each month,

I[.] is the indicator function, equal to 1 if the relation specified as argument is true, zero otherwise,

B_t is the latent variable defined as:

$$\begin{aligned} B_t = &\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP \\ &+\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} + \beta_9\ R_{t,-n} \\ &+\beta_{10}\ TotTb_t + \beta_{11}\ Dec02 \end{aligned}$$

B^* is the threshold value of B_t below which no new turbine is connected to the grid.

3.3 Data preparation

A monthly database on the time period 2000-2010 is built. The values of the variables needed for the econometric analysis and introduced above are defined as follows.

Data on Danish wind turbines come from Energinet (energinet.dk), the Danish transmission system operator for electricity and natural gas. A large database on all turbines that have been in operation in Denmark allows identifying the date of connection of each Danish turbine to the grid so that they can be grouped into monthly observations, in order to define $AddCap_t$, the additional capacity installed each month, and Y_t, the binary variable representing the connection ($Y_t = 1$) or absence of connection ($Y_t = 0$) of new turbines to the grid in Denmark each month.

Electricity price data come from NordPool. Monthly averages are calculated from hourly data on working days only[9] from 1999 to 2010.[10] I chose to use the spot market because it provides the longest electricity price time series, but I also tested the estimations with forward contracts and futures electricity prices for the time periods for which these series are available. I found similar results as

[8] The addition of a significantly larger wind power capacity in December 2002 is explained by the fact that it was the last month the feed-in tariff regime was in place. This is consistent with the clear preference of wind power producers for guaranteed tariffs, as mentionned in Section 3.2.1.

[9] Data on working days only are used instead of data on all days, as the latter are available from 2002 only while the former are available from 1999 onwards. Regressions were run on the time period 2002-2010 with the two electricity price series. No significant difference was observed. Average is done on available data: West Denmark only from 01/07/1999 to 28/09/2000 and West and East Denmark from 29/09/2000.

[10] The comparison between the averages on electricity price when weighted with hourly wind power production (hourly wind power production data are found on energinet.dk) and the simple averages proved that the difference between them was not significant. This allowed taking simple averages in the econometric analysis.

with the spot price average. Monthly averages are corrected for inflation[11] so that all figures are in constant €2000. Electricity price data are reported in appendix.

The support variable is defined as the amount of money received by wind power producers for each kWh produced in addition to electricity price. It includes the 3 €/MWh allowance for balancing costs mentioned in Section 2. When the support policy is a feed-in tariff, I define $Support_t$ as the difference between the feed-in tariff and the electricity price at time t. Hence for the feed-in tariff period (2000-2002), the support variable is defined as the difference between the electricity price and 61 €/MWh (sum of 58 €/MWh of feed-in tariff and 3 €/MWh allowance for balancing costs). Electricity price is never above 61 €/MWh in that time period. When the support policy is a variable premium, I define $Support_t$ as a function of the electricity price and the maximal value of the premium. For the time period 2003-2004, given the variable premium policy presented in Section 2, three cases are considered. For the months for which electricity price is above 48 €/MWh, the support variable is defined as 3 €/MWh (balancing cost allowance only). For the months for which electricity price is below 35 €/MWh, the support variable is defined as 16 €/MWh corresponding to 13 € of premium in addition to 3 € of balancing costs allowance. For the months for which electricity price is between 35 and 48 €/MWh, the support is defined as the difference between electricity price and 48 € in addition to the 3 € allowance for balancing costs. When the support policy is a fixed premium, $Support_t$ is defined as the value of the premium. For the time period from 2005 to February 20th 2008, the support variable is defined as 16 €/MWh corresponding to 13 €/MWh of fixed premium and 3 € of balancing cost allowance. For the time period after February 21st 2008, the support is defined as 37 €/MWh corresponding to 34 €/MWh of fixed premium in addition to 3 € of balancing cost allowance. As is done for the electricity price, the support premium is then corrected for inflation so that all figures are in constant €2000.

For the cost term, yearly wind power investment cost data from the European Wind Energy Association are used as a proxy (Moccia *et al.*, 2011). They are also corrected for inflation, so that $Elecprice_t$, $Support_t$ and $Cost_t$ are all in real terms in the database.

R_t is the interest rate of Danish ten-year government bonds (source : OECD).

Regarding endogeneity concerns, Y_t might have an impact on $Elecprice_t$ without lag. For the premium time period (after 2002), this is not a problem since what is tested in the analysis is the possible impact of electricity price projections at the date when the decision to build a turbine is made. These electricity price projections are based on past electricity prices. Y_t cannot have an impact on past electricity prices due to the causality principle. In this time period, endogeneity concerns between Y_t and the support variable are also excluded. Y_t is defined monthly as the presence or absence of connections of new turbines to the grid each month while the support policy changes every two or three years. The fact that new turbines are connected to the grid at time t cannot impact the support policy at the exact same time. In the FIT time period (2000-2002), $Support_t$ is computed from $Elecprice_t$ and there could be endogeneity between Y_t and the support variable. However the feed-in tariff does provide a premium and the question remains whether the level of implicit premium matters. Tests with lags both for the electricity price and support variables allowed addressing this concern. The dummy variable FIT helps to control for this situation. Regressions were run on the whole time period as well as on the post-FIT period only (after 2002) and the results from the regression on the whole time period remain robust on the post-2002 period (this point is discussed at the end of Section 3.4.1). The correlation table is given in Appendix.

The database does not include particularly small turbines (turbine capacity less than 20 kW or hub height less than 20 m).

[11] Inflation data from International Monetary Fund, World Economic Outlook Database, end of period consumer prices.

3.4 Results and interpretation

Regression results from the probit and tobit analysis are presented. In order to understand and interpret the probit estimations, the probability distribution they quantify is drawn. It is found that the support level and policy type are the dominant parameters that explain new turbine connections to the grid. Past electricity prices have no significant impact. A feed-in tariff significantly brings more wind power in than a premium policy. No clear difference is observed between the impacts of a fixed and a variable premium on the decision to connect new turbines. This can be nuanced by the fact that, for the variable premium regime time period (2003-2004), $Support_t$ is nearly always the full value of the premium (electricity prices are rather low), and hence the variable premium actually presented little variability. The cost term does not present any significant impact in the analysis. The site availability does not have a clear effect either. The interest rate effect is not visible in the probit analysis but it is significant in the tobit estimations.

3.4.1 Probit estimations

Table 2 presents the results of a sample of six representative probit regressions of Y on the explanatory variables introduced in Section 3.2.1. Lags for electricity prices are tested from six months to five years. Results for one or two-year lags only are presented. Regressions (A) and (E) use a twelve-month lag for electricity price while regressions (B), (C), and (F) use a two-year lag for electricity prices. Regressions (A) includes the interaction term between $Support_t$ and the dummy variable VP while the other regressions do not. Regressions (A), (B) and (F) include the cost term without lag, while regression (C) include a one-year lag for it. Regression (A) to (D) include the interest rate, regression (E) includes it with a one-year lag. Regressions (A) to (D) include $TotTb$, the proxy for the sites availability. As regression (D) presents the highest $Wald\ \chi^2$ test statistics, it is chosen for calculating the probability distribution of observing the connection of new turbines to the grid as a function of the support level and policy type. This distribution is plotted in Figure 2.

The support level has a clear impact on the decision to build and connect new turbines to the grid. The corresponding coefficient is always significant (z-value above 2 and p-value below 1%).

The policy type impact is tested through the dummy variables FIT and VP, with or without interaction terms. The reference category is the fixed premium regime. The variables associated with the feed-in tariff regime, FIT and $Support * FIT$, have a significant impact on the probability to observe the connection of new turbines to the grid, while the variables associated with the variable premium regime do not.[12] Under a feed-in tariff regime, the probability of observing new turbines connections to the grid is larger than under a premium regime, for the same equivalent level of support. This is consistent with the fact that a feed-in tariff regime insures revenue certainty to wind power producers. This observation is in line with previous observations on the impact of feed-in tariffs on renewable energy (Menz and Vachon, 2006 or Couture *et al.*, 2010). The 2008 IEA report *Deploying Renewables: Principles for Effective Policies* (IEA, 2008) also concludes that, for on-shore wind power, the most effective policies to attain deployment are feed-in tariff regimes, even with relatively modest remuneration levels.[13]

No clear difference is found between the impacts of the variable and fixed premium regimes.

Past electricity prices do not have a significant impact on the connection of new turbines to the grid.[14]

[12] Given the electricity price data in the time period 2003-2004, the interaction term between VP and $Support_t$ is nearly collinear with the dummy variable VP. The regression results confirm that the inclusion of this interaction term does not improve the explanatory power of the model.

[13] This IEA report bases its analysis on the comparison between national support policies and effective deployment of renewable energy.

[14] The use of forward contracts electricity price rather than spot prices was tested. It does not change the results.

Table 2: Probit regressions of Y, the observation or absence of observation of new turbines connections to the grid.

	(A)	(B)	(C)	(D)	(E)	(F)
Support	0.1006***	0.0965***	0.0705**	0.0995***	0.0896***	0.0961***
	(3.22)	(2.61)	(2.05)	(3.89)	(3.57)	(3.38)
VP	-10.52	2.288***	1.497	0.3705	0.0979	0.5004
	(-1.21)	(2.12)	(1.61)	(0.95)	(0.21)	(0.57)
FIT	5.7011**	13.806***	11.13***	3.9693***	3.7402***	10.934***
	(2.39)	(3.15)	(2.76)	(3.84)	(4.08)	(3.22)
*Support*FIT*	-0.1071	-0.2475**	-0.2337**	-0.1087**	-0.0977***	-0.2871***
	(-1.55)	(-2.15)	(-2.03)	(-2.08)	(-3.17)	(-2.93)
*Support*VP*	0.8483					
	(1.39)					
Cost	0.0025	0.0056*				0.001
	(0.77)	(1.7)				(0.38)
Cost(-12)			0.0028			
			(1.11)			
Elecprice(-12)	0.0243				0.0228	
	(1.39)				(1.41)	
Elecprice(-24)		0.0147	0.0084			0.0116
		(0.93)	(0.52)			(0.7)
R	-0.7314*	-0.8331**	-0.8706**	-0.5315		
	(0.38)	(-2.1)	(-1.85)	(-1.62)		
R(-12)					0.1206	
					(0.36)	
TotTb	-0.0003	0.00424	0.0009	-0.0016		
	(-0.1)	(0.67)	(0.15)	(-0.91)		
Constant	-2.1038	-24.67	-6.2745	6.7258	-3.074**	-3.7668
	(-0.14)	(-0.91)	(-0.24)	(0.87)	(-2.06)	(-0.9)
Wald χ^2	39.74***	49.03***	47.46***	49.82***	40.08***	49.1***
Pseudo R^2	0.3326	0.3036	0.2945	0.3263	0.3000	0.2664
Observations	122	110	110	128	122	110

Note: The z-value corresponding to each coefficient is indicated in parenthesis below the coefficient value. ***, ** , and * respectively indicate a 1, 5, and 10% significance level.

The cost term impact is not visible in the probit analysis; the site availability does not have any significant effect either. The coefficient associated with the interest rate is significant in regressions (A) to (C) but it is not significant in regressions (D) to (E). The impact of the interest rate is clearer in the tobit estimations presented in Section 3.4.2.

To interpret and understand the coefficients from the probit analysis, the marginal effect of the support level and the support policy type is computed. The predicted probability of observing new turbines connections to the grid is plotted as a function of the support level and type and presented in Figure 2. The choice is made to present the graph associated with regression (D) as it is the one with the highest $Wald\ \chi^2$. The robustness of the curves as a function of the regression chosen is discussed afterwards. For the "*Mean*" curve, the value at each point is the average, on all observations, of the predicted probability calculated using the specific value for the support variable and the sample values for the other predictor variables.[15] For the "*Feed-in tariff*", "*Variable premium*" and "*Fixed premium*" curves, the predicted probability of having new connections depending on the policy type is computed for each support level, using the average values for the other explanatory variables.

This shows that the probability of investment increases with the support level regardless of the form it takes. This form makes a considerable difference with the feed-in tariff increasing probability considerably. The extra benefit of this form diminishes as the support level increases. The "*Mean*" curve shows that, on average, the probability of observing new turbine connections to the grid is 50% for a support level of 20 €/MWh. Under a feed-in tariff regime, the probability is higher for the same support level, while it is lower under a premium policy. For example, for a support level of 30 €/MWh, the probability of new connections is 0.84 on average, but it is 0.95 under a feed-in tariff regime. "*Fixed premium*" and "*Variable premium*" curves are not significantly different. For the "*Feed-in tariff*" curve, the part of the graph corresponding to support values below 30 €/MWh is not robust as it is nearly an out-of-sample extrapolation (for the feed-in tariff period, the support variable is above 30 €/MWh except for two months). The probability difference of observing connection of new turbines to the grid between the fixed premium and the feed-in tariff regimes can be seen as the benefit of certainty on the electricity price revenue. Indeed, under a fixed premium regime, wind power producers know the exact premium level but the electricity price uncertainty remains. Under a feed-in tariff regime, there is certainty on the whole amount they receive, which is equivalent to certainty on both the electricity price and the premium.

The robustness of the probit results is now discussed. The support level needed to observe new turbines connections to the grid with a probability of 50% is deduced from regression (D). It is 20 €/MWh on average. With the other regressions, this value varies between 19 and 22 €/MWh. Under a premium regime, this value varies between 24 and 28 €/MWh. The "*Mean*", "*Variable premium*", and "*Fixed premium*" curves as well as the part of the "*Feed-in tariff*" curve above 30 €/MWh do not change significantly if they are inferred from the other regressions. On the contrary, the part of the "*Feed-in tariff*" curve below 30 €/MWh is not robust, as previously explained. The ranges of probability for each curve at 5, 25 and 45 €/MWh are presented in Table 3. These ranges take account of the standard errors defined when computing the predicted probability as a function of the support level and the support policy type, for each regression. This confirms the fact that the difference between the impacts of a variable premium and a fixed premium regime is not visible in this analysis. Despite the fact that the part of the "*Feed-in tariff*" curve for low support level is not robust, the feed-in tariff regime still does bring more wind power in than other schemes.

Regressions were also done on the post feed-in tariff period (after 2002) to test the relative impact of the support and electricity price if the analysis is done on these years only. The support level

[15] For each point of the "*Mean*" curve, for example for a support level of 5 €/MWh, the regression coefficients are used to calculate a probability for each observation. This computation takes account of the specific value for the support variable (5 €/MWh) and the observation values for the other predictors. Then, these probabilities for all observations are averaged to give the value that appears on the curve (ex: 0.07 for a support level of 5 €/MWh). The advantage of this curve is that it uses the diversity of all observations for the explanatory variables other than the support level or the support policy type.

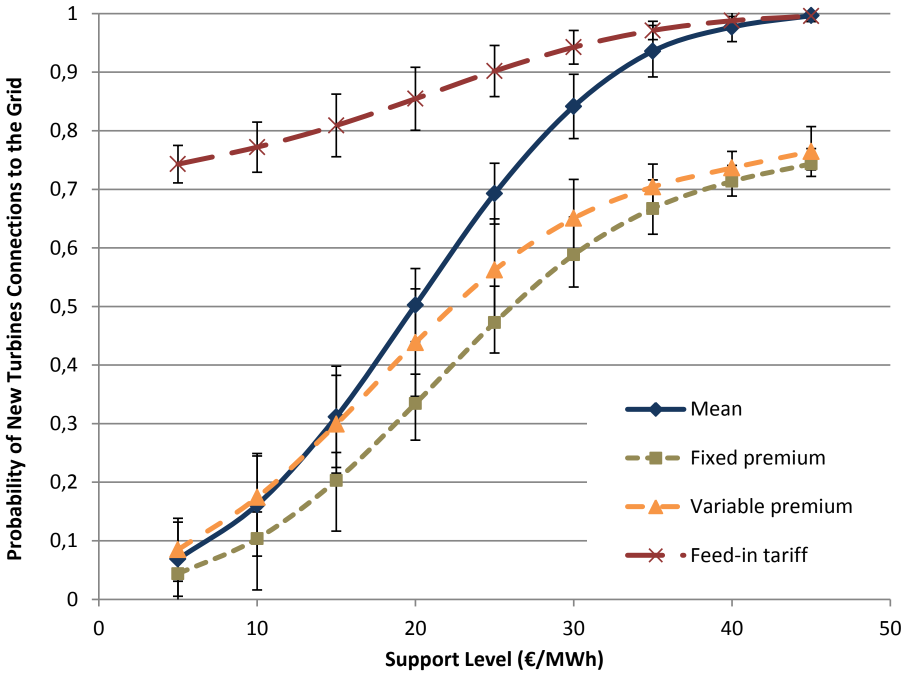

Figure 2: Probability of new turbine connections to the grid as a function of the support policy level and the policy type.

Table 3: Ranges of predicted probabilities of observing new connections of turbines to the grid, as a function of the support level and the policy type, and for all regressions reported in Table 2.

Support level	***5 €/MWh***	***25 €/MWh***	***45 €/MWh***
Mean	0.00-0.34	0.54-0.82	0.92-1.00
Fixed premium	0.00-0.26	0.16-0.68	0.61-0.96
Variable premium	0.00-0.69	0.10-0.85	0.16-0.86
Feed-in tariff	0.71-0.96	0.85-0.99	0.99-1.00

remains the dominant factor and past electricity prices do not have a significant and robust impact. In addition, the support level for which the probability of observing new turbines connection to the grid is 0.5 remains in the range indicated by the regressions on the entire time period.

3.4.2 Tobit estimations

The results from the tobit regressions of the additional wind power capacity connected to the grid each month are presented in Table 4. The tobit analysis complements the probit estimations by quantifying the relative impact of each explanatory variable.

As in the probit analysis, the tobit regressions show that the support level and the support policy type have a significant impact, with a feed-in tariff regime bringing more wind power in that a fixed premium policy. The tobit analysis suggest that a feed-in tariff regime increases the additional capacity installed monthly by several tens MW (28 MW according to regression (J) estimates if I consider an average support level of 37 €/MWh) while each additional €/MWh of support increases the additional capacity

Table 4: Tobit regressions of the additional wind power capacity connected to the grid each month.

AddCap	(G)	(H)	(I)	(J)	(K)	(L)
Support	779***	486**	1669***	663**	1034***	1636***
	(2.66)	(2.17)	(4.81)	(2.36)	(3.99)	(4.67)
VP	-356390*	18928**	-200430	-187772	1645*	16310
	(-1.34)	(2.05)	(-0.75)	(-0.95)	(0.23)	(1.37)
FIT	100390***	71592***	40805	68604***	60361***	33914
	(3.72)	(3.23)	(1.44)	(4.07)	(2.72)	(1.18)
*Support*FIT*	-1155*		-1039	-1090*	-1856***	-938.6
	(-1.71)		(-1.39)	(-1.82)	(-3.13)	(-1.17)
*Support*VP*	27231		15816**	14346		
	(1.4)		(0.82)	(1)		
Cost	51.94	37.75	50.21		-5.326	39.43
	(1.61)	(1.36)	(1.48)		(-0.23)	(1.09)
Cost(-12)				15.05		
				(0.78)		
Elecprice(-12)						343*
						(1.8)
Elecprice(-24)	157.86	131.44			172.57	
	(1.1)	(0.89)			(1.1)	
R	-6298**	-5542*	-10355**	-5943*		-12017***
	(-2.05)	(-1.77)	(-2.42)	(-1.85)		(-2.79)
R(-12)					-662.7483	
					(-0.21)	
TotTb	95.94**	129***	-43.11	56.19*		-61.37**
	(1.82)	(3.12)	(-2.39)	(1.79)		(-1.73)
Dec02	177554***	197015***	246058***	184168***	187478***	250305***
	(9.2)	(11.14)	(10.8)	(10.07)	(9.27)	(10.83)
Constant	-469840*	-588629***	117162	-247070*	-16796	203790
	(-1.92)	(-3.01)	1.12	(-1.8)	(-0.46)	(1.13)
LR χ^2	152.26***	145.44***	157.88***	160.69***	140.47***	140.71***
Pseudo R^2	0.1128	0.1077	0.0892	0.1096	0.104	0.0868
Observations	110	110	128	116	110	122

Note: The t-value corresponding to each coefficient is indicated in parentheses below the coefficient value. ***, **, and * respectively indicate a 1, 5, and 10% significance level.

installed by several hundred kW (up to more than 1600 kW if I consider the results from regression (I)). This confirms that the revenue certainty provided by a feed-in tariff regime is determinant for wind power deployment. The variable premium impact is not clearly different from the fixed premium effect. The coefficients associated with the cost and electricity price terms are not significant. The proxy for the site availability does not present a clear effect.

While the interest rate effect was not obvious in the probit analysis, it appears in the tobit regressions: when the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 12 MW. This is explained by the fact that when the interest rate is low, it is less costly for wind power producers to borrow money to build new turbines, while, when it is higher, borrowing is more expensive.

Finally, the $Dec02$ dummy variable coefficient is always significant. Its value is beyond 177 MW. This is related to the fact that an unusually large number of turbines was installed in December 2002, *i.e.* before the support policy changes from a feed-in tariff to a premium regime. This observation corroborates the previous results on the impact of a feed-in tariff policy. These results reflect the preference of wind power producers for a guaranteed tariff, which provides them a higher revenue certainty than the other schemes.

To conclude, both tobit and probit results indicate that the dominant parameters for the decision to connect new turbines to the grid are the support level and policy type. A feed-in tariff policy brings more wind power in than a premium regime. No difference is observed between a fixed and a variable premium regime. On average, a support level of 20 €/MWh[16] in addition to electricity price leads to a probability of 0.5 to observe connections of new turbines to the grid. Under a premium regime, this threshold value is around 24 €/MWh. Tobit estimations indicate that the fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed each month by up to several tens MW, while for each additional €/MW of support, it increases by several hundred kW. This finding is also consistent with the observation that an usually large number of turbines was installed in Denmark in December 2002, just before the wind support policy changes from a feed-in tariff to a premium regime. The support type seems to have more effect than the support level. Such a result is explained by the revenue certainty provided by a guaranteed tariff to wind power producers. It is consistent with Mulder's conclusion (2008) that the remuneration level alone is not enough to attain wind power deployment.

The interest rate effect is not clear in the probit analysis but visible in the tobit regressions: when the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 10 MW. Electricity price effect is not visible in the analysis, nor is the investment cost impact. Regarding the cost term, the absence of visible impact might be related to the fact that the wind potential of the site where the turbine is built is not taken into account in the proxy. Indeed, it cannot be defined for the months during which no new turbine is connected to the grid although it matters for the levelized cost. The sites availability does not appear to be a dominant factor in the analysis.

The carbon price inference conducted in the following section uses the critical support level value provided by the probit analysis as the support level needed to observe the connection of new turbines to the grid with a probability of 0.5.

4 Carbon price inference

The econometric analysis presented in Section 3 provides indications on the conditions under which there is wind power deployment. It focuses on wind power producers only, as most of the wind capacity in Denmark is owned by individual entities such as farmers. Projections in electricity prices do not

[16] All support level figures indicated from the regression results are in constant €2000.

have a significant impact while the support level and policy type clearly matter. The probit regressions show that, on average, a support of 20 €/MWh leads to a probability of 0.5 to observe new connections of turbines to the grid. Under a premium policy, this probability is attained for a support level of 24 €/MWh. The purpose of this section is to infer the necessary condition on the carbon price level to make companies that also operate gas or coal power plants be equally attracted by wind power projects. While carbon price is a penalty for fossil technologies, a renewable energy support policy is an advantage for wind power. The purpose of the following paragraphs is to infer the necessary carbon price that would provide comparable price advantage to wind power over fossil technologies as the effective support policies. The comparison between wind power and fossil technologies can be conducted in various ways. I first compare the profit for each kWh produced by the two types of technologies. I then extend this comparison to the lifetime profit of two installations, taking into account the different capacity credits and capacity factors of the two types of technology. I finally compare the returns on investment expected from renewable and fossil energy power projects. Such comparisons may not take account of some other factors that also play a major role for the deployment of some specific technologies (for example grid development or portfolio management within energy companies).

4.1 Comparison between renewable energy and fossil fuel technologies

Using the notations introduced in Section 3.1, I first compare the profit per kWh produced by each type of technology.

$$\Pi_r = \Pi_f \tag{11}$$

$$P_r + X_r - C_r = P_f - C_f - E_f \tag{12}$$

$$X_r + E_f = P_f - C_f - (P_r - Cr) \tag{13}$$

Equation 13 shows an equivalence between X_r and E_f with regard to the profit per kWh comparison between wind power and conventional thermal energy. If the carbon market alone has to cover the difference in profitability between the two kinds of technology, we have:

$$E_f = P_f - C_f - (P_r - Cr) \tag{14}$$

$P_r - C_r$ can be deduced from the results of the econometric analysis. Indeed, the probit technique indicates the support level needed to make wind power producers have a positive profit. With the same notations as in Equation 3.1, the reasoning is the following. The positive profit condition expressed in equation 15 translates into a condition on X_r as expressed in equation 17.

$$\Pi_r > 0 \tag{15}$$

$$P_r + X_r - C_r > 0 \tag{16}$$

$$X_r > X_r^* \tag{17}$$

with

$$X_r^* = C_r - P_r. \tag{18}$$

The probit analysis provides indications on X_r^*: it is around 24 €/MWh under a premium policy.

From equations 14 and 18, we deduce that, if a technology f becomes profitable ($P_f - C_f = 0$), the emission penalty needed to make technology r competitive is equal to X_r^*.

I now compare the lifetime profit of two types of installation. I take into account a new constraint related to the difference in capacity credit and capacity factor between intermittent and fossil energy. Due to its intermittency, a kWh of wind power is indeed not a perfect substitute of a kWh produced by a coal or gas plant. Wind power has a capacity factor of about 25-30% while a base load power plant has a capacity factor of about 90%. The amount of conventional reserve capacity that can be retired when wind capacity is added to the system without affecting the system security or robustness can be expressed as a percentage of this wind capacity. This defines the wind power capacity credit, CC_r. At low levels of penetration, the capacity credit of wind power is about the same as its capacity factor. When wind penetration increases, the capacity credit drops. In other words, a wind power installation of capacity Cap_r can replace a conventional power installation of capacity $Cap_f = CC_r * Cap_r$.

If I express the equalization between the lifetime profit of the two kinds of installations under this new constraint, I obtain:

$$Cap_f * CF_f * T_f * 8760 * (P_f - C_f - Ef) = Cap_r * CF_r * T_r * 8760(P_r + X_r - C_r) \tag{19}$$

$$CC_r * Cap_r * CF_f * T_f * (P_f - C_f - Ef) = Cap_r * CF_r * T_r * (P_r + X_r - C_r) \tag{20}$$

with

Cap_r is the renewable energy project capacity (in kW),

Cap_f is the conventional power project capacity (in kW),

T_r is the typical lifetime of a renewable energy project (in years),

T_f is the typical lifetime of a conventional power plant (in years),

CF_r is the capacity factor for a renewable energy technology (around 30% for wind power),

CF_f is the capacity factor for a fossil technology (85% for coal or gas plants),

8760 is the number of hours in a year,

P_r, X_r, C_r, P_f, E_f, and C_f are the levelized variables defined in Section 3.1.

After calculations, I obtain:

$$E_f + \beta X_r = P_f - Cf - \beta(P_r - Cr) \tag{21}$$

with

$$\beta = \frac{CF_r * T_r}{CF_f * T_f * CC_r} \tag{22}$$

Equation 21 can be seen as an equivalence between E_f and βX_r with regards to the lifetime profit comparison between a wind power installation and a fossil fuel power plant with equivalent impact on the power system security.

Finally, I compare the returns on investment of the two types of technologies. Using the same notations as above, I define the return on investment for renewable energy as follows:

$$ROI_r = \frac{Cap_r * CF_r * T_r * 8760}{Cap_r * I_r^0} * (P_r + X_r - C_r) \tag{23}$$

where

ROI_r is the return on investment for renewable energy,

I_r^0 is the initial investment cost per kW installed (€/kW).

For a fossil technology in a context where carbon is priced (either by a tax or through a trading scheme), there is no premium but there is an emission penalty so that the return on investment is:

$$ROI_f = \frac{Cap_f * CF_f * T_f * 8760}{Cap_f * I_f^0} * (P_f - E_f - C_f) \tag{24}$$

where

ROI_f is the return on investment for the fossil technology considered,

I_f^0 is the initial investment cost per kW installed (€/kW).

The equalization between the returns on investment for renewable energy and fossil technology[17] leads to:

$$\alpha(P_r + X_r - C_r) = P_f - E_f - C_f \tag{25}$$

with

$$\alpha = \frac{I_f^0 * CF_r * T_r}{I_r^0 * CF_f * T_f}$$

and hence:

$$E_f + \alpha X_r = P_f - C_f - \alpha(P_r - C_r) \tag{26}$$

This relation can be seen as an equivalence between E_f and αX_r with regards to the return on investment comparison between a wind power installation and a fossil fuel power plant.

If an emission penalty alone has to make renewable energy projects as attractive as fossil technologies installations, the relation becomes:

$$E_f = P_f - C_f - \alpha(P_r - C_r) \tag{27}$$

From equations 27 and 18, we obtain:

$$E_f = P_f - C_f + \alpha X_r^* \tag{28}$$

If an emitting power production technology f becomes profitable ($P_f - C_f = 0$), αX_r^* is the necessary emission penalty to make the return on investment of a wind power projects as attractive as the return for this technology.

[17] As the capacity term appears both in the nominator and denominator of the return on investment, the capacity credit term does not appear in this equalization.

The three comparisons presented in these sections provides three conditions on the emission penalty needed to be make wind power equally attractive as conventional thermal technologies. Given the quantity of carbon dioxide emitted for each kWh of electricity produced by coal or gas plants, this emission penalty can be converted into a carbon price.

However, as shown in the results of the econometric analysis, the revenue certainty is an important factor for investment in wind power. In this perspective, any necessary condition indicated here is to be used with caution. The price stability provided by a carbon tax could be compared with the stability of a premium received on top of the market electricity price. A carbon price set by a market presents more variability than a carbon tax. A feed-in tariff provides higher revenue certainty (it can be seen as a regime that provides a premium on top of a fixed electricity price).

4.2 Carbon price inference from regression results

For the numerical application of the relations presented above, I assume that the lifetime of a fossil fuel power plant is 40 years, while it is 20 years for a wind turbine. I assume a capacity factor of 85% for coal and gas plants, 30% for wind turbines, and a capacity credit of 30% for wind power. I consider an initial investment cost of 1100 €/kW for wind power and 1000 €/kW for fossil technologies. This gives a value of 0.16 for α, and a value of 0.58 for β.

The econometric analysis shows that, under a premium regime, the support level needed to observe connection of new turbines to the grid with probability 0.5 is around 24 €/MWh. This is converted in an emission penalty of 24 €/MWh according to equation 13, 14 €/MWh according to equation 21, and 3.8 €/MWh according to equation 28. The most stringent condition is the one provided by equation 13. I use the result from it for the conversion of the emission penalty into a carbon price.

If I consider that electricity production from coal emits 0.85 tons of CO_2/MWh (Sijm, Neuhoff, and Chen, 2006) and that electricity production from gas (combined cycle) emits 0.48 tons of CO_2/MWh, a support level of 24 €/MWh provides a price advantage to wind power producers that is equivalent to a carbon price of 28 €/ton if competing with electricity production from coal, and 50 €/ton if competing with electricity production from gas. However, one of the main conclusions of the econometric analysis conducted in Section 3 is that a feed-in tariff significantly brings more wind power in than a premium. This result underlines the importance of revenue certainty for wind power investors. In addition, the carbon price set by a market also presents significant volatility. As a consequence a carbon price alone may not provide revenue certainty equivalent to such policies. A higher carbon price than the figures provided here might be needed to provide wind power producers with comparable advantage over fossil technologies as the existing effective wind support policies.[18]

5 Conclusion

The purpose of the work presented here is to use the Danish experience to conduct an empirical analysis of the conditions that attain renewable energy deployment and to infer a carbon price level that would provide a price advantage to wind energy over fossil fuel technologies comparable to the advantage provided by the support level under which new turbines are connected to the grid. The analysis is focused on on-shore wind power in the context of a liberalized Danish electricity market, in the time period 2000-2010. Probit and tobit econometric techniques are used to test the drivers of wind power deployment on a monthly basis. The potential factors influencing it are identified by the profit function of wind energy. Probit technique is used to estimate the effects of the support policy

[18]Previous analysis demonstrated the importance of long range energy policy in stabilizing the conditions required for renewable energy development (Meyer, 2007). More work on uncertainty and wind power investment could be done, based on more general research on uncertainty and irreversible investment, following Favero *et al.* (1992).

type and level, electricity price projections, investment cost, interest rate and sites availability on the observation of connection of new turbines to the grid. Tobit technique is used to assess the impacts of the same factors on the additional capacity installed each month.

The analysis shows that the support level and policy type are the dominant parameters. A feed-in tariff policy has a significantly larger impact than a premium policy. A variable premium does not have a significantly different impact from a fixed premium. The effect of electricity price projections is not significant in this analysis. Neither are the effects of investment cost or sites availability. The interest rate impact is significant in the tobit analysis but does not appear to be so in the probit estimations. The probit analysis indicates that, on average, a 20 €/MWh support in addition to electricity price is necessary to observe connections of new turbines to the grid with a probability of 0.5. Under a premium policy this probability is reached for a support policy of 24 €/MWh. The observation that a feed-in tariff policy brings more wind power in than a premium policy is related to the revenue certainty insured by a fixed tariff. It is consistent with previous analysis reported in the literature (Menz and Vachon, 2006; Couture *et al.*, 2010).

The absence of visible effect of the cost term might be related to the fact that, although the levelized cost of wind power depends on the wind potential of the site where the turbine is built, the wind power density is not taken into account in the analysis as it cannot be defined for the months during which no new turbine is connected to the grid.

The tobit analysis shows that the additional capacity installed each month increases by up to thousand kW for each additional €/MWh of support. The fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed each month by up to several tens MW. When the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 12MW . The tobit analysis also allows taking into account the specificity of December 2002, when a large additional wind power capacity was installed before the replacement of the feed-in tariff by a premium regime. The tobit estimations confirm the strength of a feed-in tariff regime to support wind power deployment. The final inference with regard to carbon price is based on the figures from the probit analysis.

The comparison between the profits expected from renewable projects and fossil fuel power plants is used to infer a carbon price that would provide wind power producers with comparable price advantage over gas or coal plant owners as the support level previously mentioned. This induces an equivalence relationship between a support premium and an emission penalty. Under certainty revenue equivalence, the support level of 20 €/MWh indicated above can be converted into an equivalent carbon price of 23 €/ton if renewable energy competes with electricity production from coal or 41 €/ton if it competes with electricity production from gas. The support level threshold of 24 €/MWh observed under a premium regime is equivalent to a carbon price of 28 €/t if renewable energy competes with coal, and 50 €/t if it competes with gas.

This figures are higher than the EUA price observed in the second phase of the EU ETS but still in the same order of magnitude. In terms of variability, a carbon tax may be seen as comparable to a premium on top of a market electricity price. A carbon market price presents more variability. That would result in a higher necessary carbon price.

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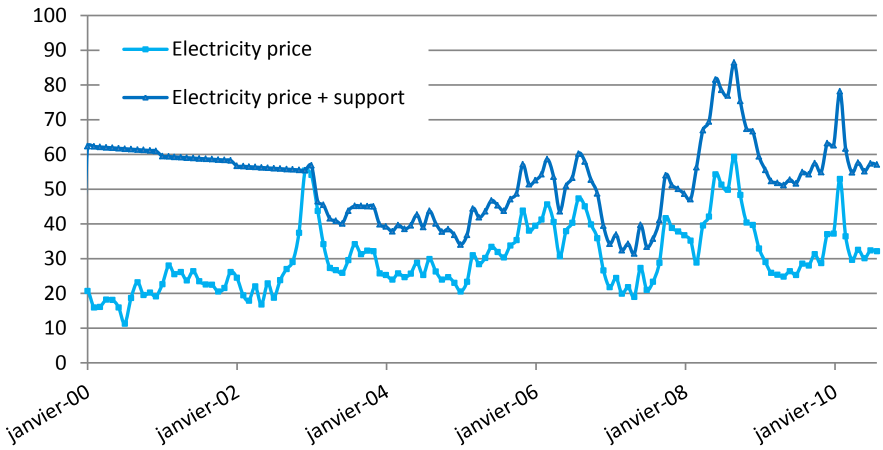
Appendices

A. Electricity price and support variables

Figure 3: Real electricity price in Denmark and definition of the support variable.



Note : Monthly averages are calculated from Nordpool hourly data on working days.

B. Correlation table of the explanatory variables used in the probit and tobit regressions

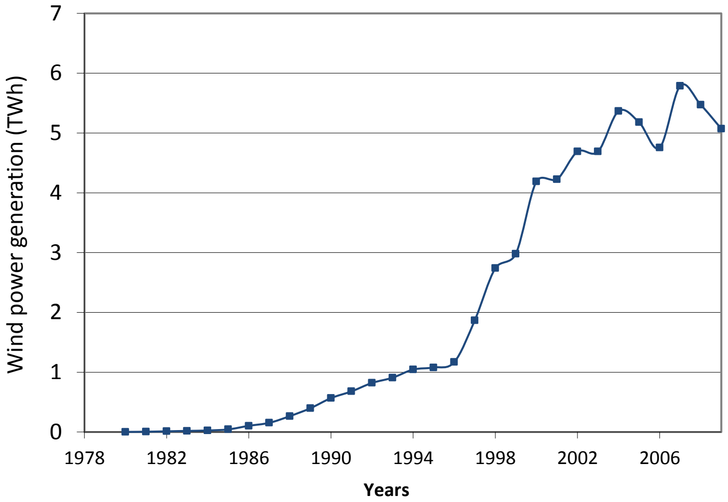
Table 5: Correlation table of the variables used in the regressions.

	Y	*AddCap*	*Support*	*Elecprice(-12)*	*VP*	*FIT*	*R*	*Cost*	*TotTb*
Y	1								
	-								
AddCap	0.3919***	1							
	(0.0000)	-							
Support	0.5575***	0.2736***	1						
	(0.0000)	(0.0018)	-						
Elecprice(-12)	-0.0818	-0.1284	-0.3198***	1					
	(0.3702)	(0.1587)	(0.0003)	-					
VP	-0.2542***	-0.1748**	-0.4238***	0.0306	1				
	(0.0038)	(0.0484)	(0.0000)	(0.7378)	-				
FIT	0.4906***	0.4555***	0.7624***	-0.5152***	-0.3005***	1			
	(0.0000)	(0.0000)	(0.0000)	(0.0000)	(0.0006)	-			
R	0.2838***	0.3309***	0.6039***	-0.3723***	0.0055	0.7980***	1		
	(0.0012)	(0.0001)	(0.0000)	(0.0000)	(0.9510)	(0.0000)	-		
Cost	-0.2800***	-0.2328***	-0.3156***	0.4244***	-0.4063***	-0.6116***	-0.4592***	1	
	(0.0014)	(0.0082)	(0.0003)	(0.0000)	(0.0000)	(0.0000)	(0.0000)	-	
TotTb	-0.3823***	-0.4154***	-0.7429***	0.5613***	0.1685*	-0.8546***	-0.8209***	0.4079***	1
	(0.0000)	(0.0000)	(0.0000)	(0.0000)	(0.0573)	(0.0000)	(0.0000)	(0.0000)	-

Note: P-values are given in (); *, **, and *** respectively refer to the 1%, 5% and 10% significance levels of the estimated coefficients.

C. Wind power generation in Denmark

Figure 4: On-shore wind power generation in Denmark since its early stage.



Data source: Energistyrelsen.

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