CO_2 cost pass-through and windfall profits in the power sector

Jos Sijm[1]*, Karsten Neuhoff[2], Yihsu Chen[3]

[1] *Energy Research Centre of The Netherlands (ECN), PO Box 37154, 1030 AD Amsterdam, The Netherlands*
[2] *Faculty of Economics, University of Cambridge, Sidgwick Avenue, Cambridge CB3 9DE, UK*
[3] *Department of Geography and Environmental Engineering, Johns Hopkins University, 3400 North Charles Street, Baltimore, MD 21218m, USA*

Abstract

In order to cover their CO_2 emissions, power companies receive most of the required EU ETS allowances for free. In line with economic theory, these companies pass on the costs of these allowances in the price of electricity. This article analyses the implications of the EU ETS for the power sector, notably the impact of free allocation of CO_2 emission allowances on the price of electricity and the profitability of power generation. As well as some theoretical reflections, the article presents empirical and model estimates of CO_2 cost pass-through for Germany and The Netherlands, indicating that pass-through rates vary between 60 and 100% of CO_2 costs, depending on the carbon intensity of the marginal production unit and various other market- or technology-specific factors. As a result, power companies realize substantial windfall profits, as indicated by the empirical and model estimates presented in the article.

Keywords: Emissions trading; Allocation; CO_2 cost pass-through; Windfall profits; Power sector

1. Introduction

A major characteristic of the present EU Emissions Trading Scheme (ETS) is that almost all the CO_2 allowances are allocated for free to the installations covered by the scheme. During the first phase of the EU ETS (2005–2007), more than 2.2 billion allowances of 1 tonne each are being allocated per year (EC, 2005). During the first phase of the EU ETS (2005–2007), more than 2.2 billion allowances of 1 tonne each are being allocated per year (EC, 2005), about 60% of which is allocated to the power sector.

Against this background, this article analyses the implications of the EU ETS for the power sector, notably the impact of free allocation of CO_2 emission allowances on the price of electricity and the profitability of power generation. In Section 2 we discuss the effect of different generation technologies being used to generate electricity. How does the internalization of CO_2 allowance prices by individual generators into their bids feed through to the power price and how does this in turn affect profitability? Sections 3–5 present empirical and model findings on passing through

* Corresponding author. Tel.: +31-224-56-8255
E-mail address: sijm@ecn.nl

the costs of CO_2 emission allowances to power prices in the countries of north-western Europe and implications for the profitability of power production in these countries at the national and company level. The article concludes with a brief summary of the major findings and policy implications.

2. Theory

The EU ETS is a cap-and-trade system based primarily on the free allocation of a fixed amount of emission allowances to a set of covered installations. Companies can either use these allowances to cover the emissions resulting from the production of these installations or sell them to other companies that need additional allowances (Reinaud, 2005). Hence, for a company using an emission allowance, this represents an opportunity cost, regardless of whether the allowances are allocated for free or purchased at an auction or market. Therefore, in principle and in line with economic theory, a company is expected to add the costs of CO_2 emission allowances to its other marginal (variable) costs when making (short-term) production or trading decisions, even if the allowances are granted for free (Burtraw et al., 2002, 2005; Reinaud, 2003).

Different generation technologies produce different levels of CO_2 emissions, and therefore the opportunity costs of CO_2 emissions per unit of power produced differ as well. For example, a combined-cycle gas turbine produces about 0.48 t of CO_2 per MWh of electricity, while a typical coal power station emits about 0.85 tCO_2/MWh. A CO_2 price of €20/tCO_2, therefore, increases the generation costs for the gas plant by €9.6/MWh and for the coal plant by €17/MWh.

During a certain load period, the competitive electricity price is only affected by the price increase of the marginal production unit. This can be illustrated by a marginal cost (price) duration curve, as presented in Figure 1. On the *x*-axis the 8760 hours of a year are depicted, sorted in descending order of the marginal system costs. The *y*-axis gives the marginal costs of the marginal generation unit. The competitive electricity price in any one hour is affected by the cap-and-trade system through the price increase of the marginal unit. Hence, the amount at which the power price increases due to the passing through of CO_2 costs may differ per hour or load period considered, depending on the marginal generation unit concerned. As a consequence, the CO_2 cost pass-

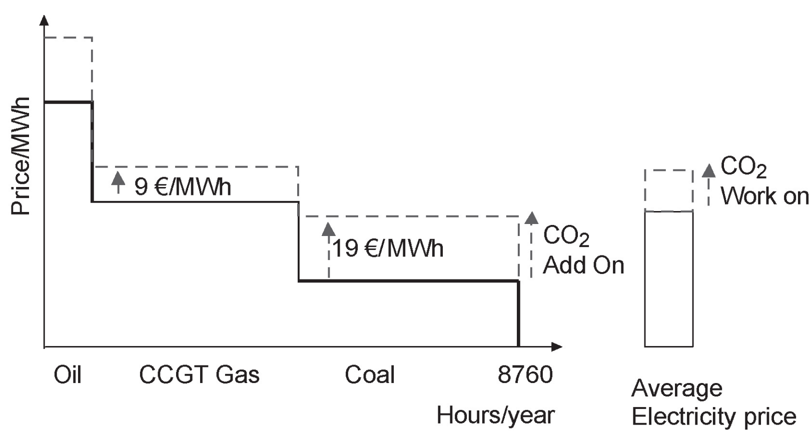

Figure 1. Pass-through of CO_2 opportunity costs for different load periods (at a price of €20/tCO_2).

through is defined as the average increase in power price over a certain period due to the increase in the CO_2 price of an emission allowance.

We represent the difference between the behaviour of individual generators and the impact on the system price by defining the 'add-on' and the 'work-on' rate. In a competitive environment, generators 'add-on' the opportunity costs of CO_2 allowances to the power price. The increase of the bid of the marginal unit will then determine how much of the CO_2 allowance prices are 'worked-on' the electricity price. However, in a liberalized market, prices are ultimately determined by a complex set of market forces. As a result, the work-on rate may be lower than the add-on rate.

One reason why the work-on rate may be lower than the add-on rate is from a market demand response. If higher power prices reduce electricity demand, then an expensive power station might not need to operate and a cheaper generator will set the marginal price. The change in power price is smaller than the change in marginal costs due to emissions trading. Hence, while the add-on rate will remain at 100%, the work-on rate will be lower than 100%. Although price responsiveness is typically rather low for households and other small-scale consumers of electricity, the effect may be more significant for major end-users such as the power-intensive industries. Power-intensive industry would substitute electricity purchases with the self-generation of electricity. This pathway is less attractive, as the EU ETS also covers large-scale self-generation by industry and, therefore, faces similar cost increases, thus reducing the demand response of power-intensive industry. Nevertheless, through self-generation, power-intensive industry would benefit from the economic rent due to the transfer of valuable, freely allocated assets.

The extent to which carbon costs are passed through to power prices also depends on changes in the merit order of the supply curve due to emissions trading. This is illustrated in Figure 2, where the supply curve is characterized by a step function with two types of technologies – *A* and *B*. The vertical dash line indicates the fixed demand. In Figure 2a, when there is no change in the merit order, the change in the power price (Δp_2) will always be equal to the marginal CO_2 allowance costs of the marginal generation technology *B*. The resulting pass-through rate will always be unity (in terms of both the add-on rate and the work-on rate). However, when there is a switch in the merit order – as displayed in Figure 2b – the situation changes. In this case, the marginal technology is *A* with CO_2 allowances costs equal to Δp_3 while the change in the power price is Δp_4. Therefore, while the add-on rate for the marginal production technology *A* is 100%, the work-on

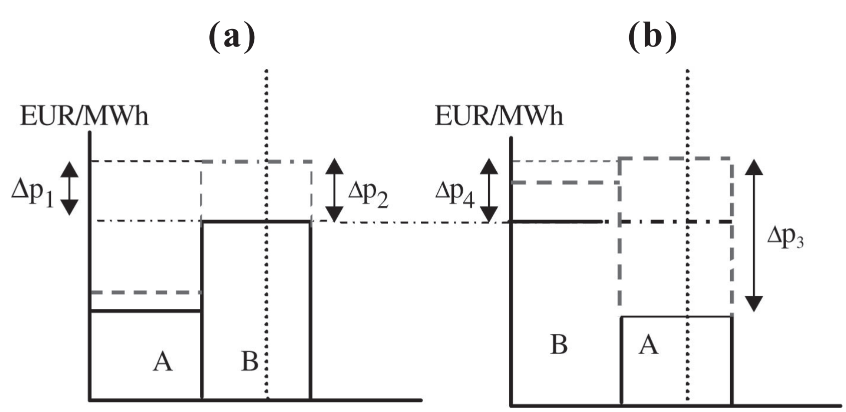

Figure 2. Pass-through rates under changes in the merit order.

rate, Δp_4 / Δp_3, will be less than 1 since $\Delta p_4 < \Delta p_3$.[1] In markets with surplus capacity, competitive pressures from excess generation capacity also impact on the merit order and, in turn, the work-on rate (Reinaud, 2003).

In addition, there may be several reasons why generators do not add on the full CO_2 costs to their power bid prices:[2]

- The expectation of power producers that their current emissions or output will be used as an input factor for the determination of the allocation of allowances in future periods, mainly after 2012 but possibly even 2008–2012. This creates an incentive to increase today's output and thus encourages generators not to add on the full allowance price to their energy bids.
- Voluntary agreements or the regulatory threat of governments to intervene in the market if generators make excessive windfall profits from the free allocation might induce generators to limit the add-on.
- Other reasons, such as the incidence of non-optimal behaviour among power producers, market imperfections, time lags or other constraints, including the incidence of risks, uncertainties, lack of information, and the immaturity or lack of transparency of the carbon market.

2.1. The impact on generators' profits

An important question is how the pass-through of CO_2 opportunity costs affects the profitability of power stations. A main purpose of the free allocation of emissions allowances under the US cap-and-trade programmes for SO_2 and NO_x, as well as under the EU ETS for CO_2, is to obtain the political support of large emitters. Thus, the free allocation aims to ensure that the introduction of the ETS does not reduce the profitability of the eligible companies.

The impact of emissions trading in general and free allocation of emission allowances in particular can be illustrated by means of Figure 2, which illustrates the implications of emissions trading for generators' profits where the supply curve consists of different types of technology. Where emissions trading does not lead to a change in the merit order of the supply curve (and in total demand; see Figure 2a), the change in the power price (Δp_2) is just about equal to the CO_2 costs per MWh of the marginal production unit (*B*). For this unit, this implies that profits do not change where all the allowances have to be bought, while it results in windfall profits in the case of full grandfathering (equal to Δp_2 times volume produced).

For the infra-marginal unit, however, the impact of emissions trading on operational profits does not only depend on the degree of grandfathering but also on whether it is more or less carbon-intensive than the marginal unit. If it is less carbon-intensive, it benefits from the fact that the ET-induced increase in power price is higher than the increase in its carbon costs per MWh. However, if the infra-marginal unit is more carbon-intensive than the marginal unit, it suffers from a loss, as the increase in power price is lower than the increase in its carbon costs per MWh; notably if allowances have to be bought on the market. Therefore, in the latter case, some grandfathering to this infra-marginal unit may be justified to break even, depending on the relative carbon intensity of this unit.

On the other hand, if emissions trading leads to a change in the merit order (while total demand remains the same; see Figure 2b), the change in the power price (Δp_4) is lower than the change in the CO_2 costs per MWh of the marginal production unit (*A*). For this unit, emissions trading results in a profit per MWh (equal to Δp_4) under free allocation, but in a loss (equal to

$\Delta p_3 - \Delta p_4$) if all the allowances have to be bought. Therefore, for this unit, some grandfathering may be justified in order to break even.[3] For the infra-marginal unit (*B*), the increase in power price is higher than the increase in CO_2 costs, regardless of whether allowances have to be bought or not. Therefore, even if this unit has to buy all its allowances, it will benefit from ET and, hence, there is no need for any grandfathering for this unit to break even.[4]

If the electricity demand response to ET-induced price increases is sufficiently large to stop the operation of a set of power generators with higher variable costs, and thus the market clearing price of electricity is reduced to the variable costs of a technology with lower variable costs, this will reduce the profits of all units operating during this period, as all of them will receive revenues corresponding to the lower market clearing price.

3. Empirical estimates of passing through CO_2 costs

This section presents some empirically estimated rates of passing through CO_2 opportunity costs of EU emissions trading to power prices in Germany and the Netherlands. We use two different approaches to estimate these rates. First, we look at the forward power market, particularly the year-ahead market where, for instance, electricity delivered in 2006 is traded during every day of the year 2005. In this approach, we assess the extent to which changes in forward power prices can be explained by changes in underlying forward prices for fuel and CO_2 allowances. Secondly, we study the spot market, notably the German power exchange (EEX), by comparing hourly spot electricity prices for the period from January 2005 to March 2006 with the corresponding hourly electricity prices in the year 2004. More specifically, we examine to what extent a change in the spot power price, for example at 9a.m. on the first Monday in January 2006 relative to the first Monday in January 2004, can be explained by a change in the price of a CO_2 allowance on the EUA market.

First of all, however, some background information will be provided on trends in prices for fuel and CO_2 allowances and dark and spark spreads in the power sectors of Germany and The Netherlands during the years 2004–2005.

3.1. Trends in forward prices and costs

For the years 2004–2005, Figures 3 and 4 present power prices versus fuel and CO_2 costs to generate one MWh of power (assuming a fuel efficiency of 40% for coal and 42% for gas, a related emission factor of 0.85 and 0.48 tCO_2/MWh for coal and gas, respectively, and full 'opportunity' costs for generating electricity by either coal or gas). While Figure 3 covers the case of coal-generated off-peak power in Germany, Figure 4 presents the case of gas-generated peak power in the Netherlands.[5]

The German case shows that the fuel (i.e. coal) costs to generate power have been more or less stable at a level of about €16/MWh during the years 2004–2005. In addition, the CO_2 costs of coal-generated power have been stable during the second part of 2004 but have approximately tripled during the first part of 2005 from about €6/MWh in January to about €18/MWh in July. This suggests that the increasing off-peak prices in Germany over this period may have been caused primarily by the rising CO_2 prices (and not by higher fuel prices). However, during the second part of 2005 (August–December 2005), CO_2 costs per coal-generated MWh have been generally stable while off-peak prices have continued to rise. This indicates that factors other than fuel and CO_2 costs influence power prices.

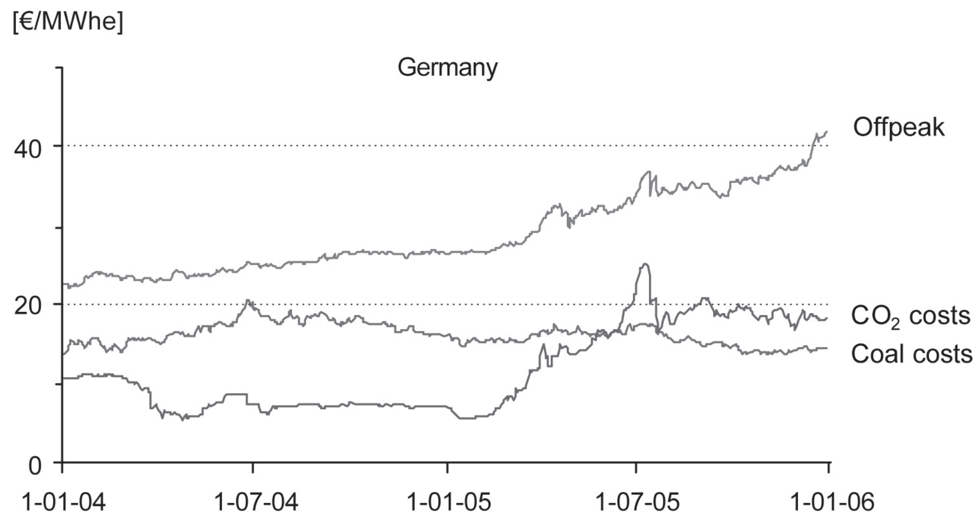

Figure 3. Off-peak power prices versus fuel/CO_2 costs in Germany (year-ahead, 2004–2005).

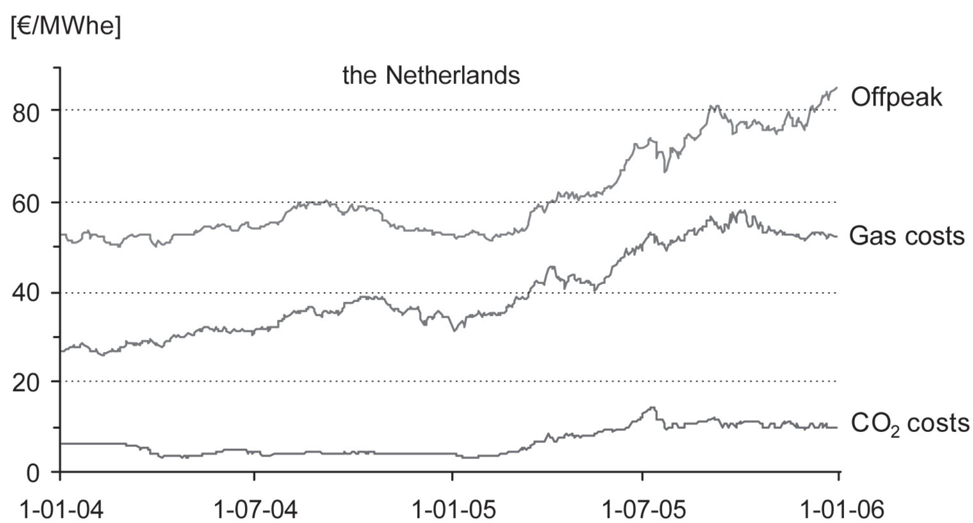

Figure 4. Peak power prices versus fuel/CO_2 costs in The Netherlands (year-ahead, 2004–2005).

The Dutch case illustrates that the fuel (i.e. gas) costs to produce electricity have risen substantially from around €33/MWh in early January 2005 to about €56/MWh in early September 2005. CO_2 costs of gas-generated power have also increased over this period, but less dramatically, i.e. from €4 to €11/MWh (partly due to the relatively low – but constant – emission factor of gas-generated electricity). This suggests that, besides the CO_2 cost pass-through, the rising peak load prices in The Netherlands over this period – from about €52 to €80/MWh – are largely due to other factors, especially the rising gas prices. However, comparable to the German case, where both gas and

CO_2 costs have been more or less stable during the last quarter of 2005 (or even declined slightly as far as gas costs are concerned), peak power prices continued to increase to €84/MWh in late December 2005.

3.2. Trends in dark and spark spreads on forward markets

Figures 5 and 6 present trends in dark/spark spreads and CO_2 costs per MWh over the years 2004–2005 in Germany and The Netherlands, based on forward (i.e. year-ahead) prices for power, fuels and CO_2 emission allowances. For the present analysis, a *dark* spread is simply defined as the difference between the power price and the cost of *coal* to generate 1 MWh of electricity, while a *spark* spread refers to the difference between the power price and the cost of *gas* to produce 1 MWh of electricity. If the costs of CO_2 are included, these indicators are called '*clean dark/spark spreads*' or '*carbon compensated dark/spark spreads*'.[6]

For Germany, Figure 5 depicts trends in dark spreads in both peak and off-peak hours, based on the assumption that a coal generator is the price-setting unit during these periods.[7] In addition, it

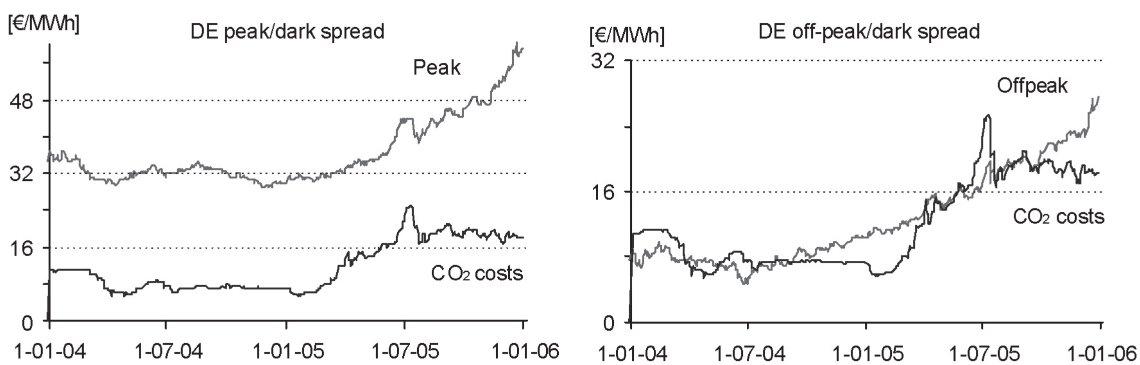

Figure 5. Trends in dark spreads and CO_2 costs per coal-generated MWh in Germany during peak and off-peak hours (year-ahead, 2004–2005).

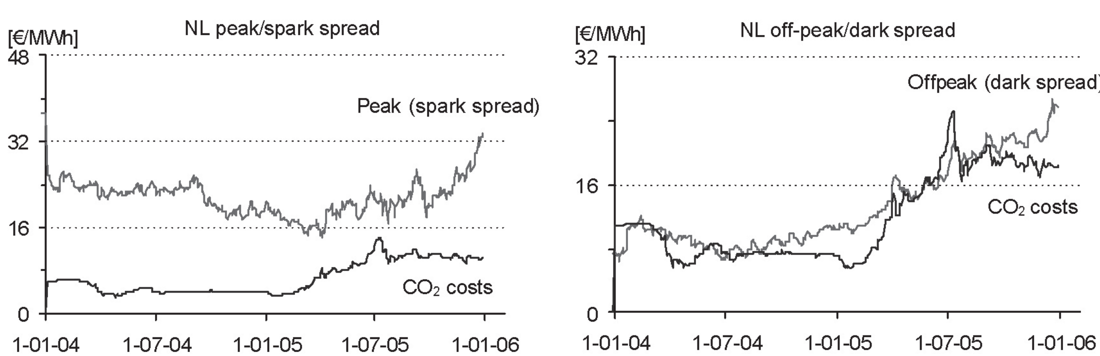

Figure 6. Trends in spark/dark spreads and CO_2 costs per gas/coal-generated MWh in The Netherlands during peak and off-peak hours (year-ahead, 2004–2005).

shows the costs of CO_2 allowances required to cover the emissions per MWh generated by a coal-fired power plant (with an emission factor of 0.85 tCO_2/MWh). The figure suggests that up to July 2005, changes in the dark spread can be largely explained by changes in the CO_2 costs per MWh. Since August 2005, however, this relationship is less clear, as the CO_2 costs have remained more or less stable, while the dark spreads have continued to increase rapidly.

For the Netherlands, Figure 6 depicts trends in the spark spread during the peak hours and the dark spread during the off-peak hours, based on the assumption that a gas- versus coal-fired installation is the price-setting unit during these periods, respectively. In addition, it presents the costs of CO_2 allowances to cover the emissions per MWh produced by a gas- and coal-fired power station, with an emission factor of 0.48 and 0.85 tCO_2/MWh, respectively. Similar to the German case, Figure 7 suggests that, during the period January–July 2005, changes in the dark/spark spreads in The Netherlands can be largely attributed to changes in the CO_2 costs per MWh, but that afterwards this relationship is less clear.

3.3. Statistical estimates of CO_2 cost pass-through rates on forward markets

Below, we provide empirical estimates of pass-through rates of CO_2 emissions trading costs to forward power prices in Germany and The Netherlands for the period January–December 2005.

The basic assumption when estimating CO_2 cost pass-through rates is that during the observation period the dynamics of the power prices in Germany and The Netherlands can be fully explained by the variations in the fuel and CO_2 costs over this period (see Figures 3 and 4). Hence, it is assumed that during this period other costs, for instance operational or maintenance costs, are constant and that the market structure did not alter over this period (i.e. changes in power prices cannot be attributed to changes in technology, market power or other supply–demand relationships).

Based on these assumptions, the relationship between power prices (P), fuel costs (F) and CO_2 costs is expressed by Eqn (1), where superscripts c and g indicate coal and gas, respectively. Likewise, the term $CO2_t$ is the CO_2 cost associated with coal and gas at time t. Thus, it is equal to the product of the CO_2 allowances price at time t and the time-invariant CO_2 emission rate of coal or gas generators. In our analysis, fuel costs are assumed to be fully passed on to power prices.[8] This is equivalent to fixing the coefficient β_2 at unity.

$$P_1 = \alpha + \beta_1 CO2_t^{c,g} + \beta_2 F_t^{c,g} + \varepsilon_t \tag{1}$$

By defining Y_t as the difference between power price and fuel cost, Eqn (2) becomes the central regression equation of which the coefficient β_1 has been estimated. In fact, Y_t represents the dark spread for coal-generated power and the spark spread for gas-generated power.

$$Y_t = \left(P_t - F_t^{c,g}\right) = \alpha + \beta_1 CO2_t^{c,g} + \varepsilon_t \tag{2}$$

Like most price series, power price data exhibit serial correlation. Hence, the error term ε_t is characterized by a so-called I(0) process (integrated of order zero).[9]

$$\varepsilon_t = \rho\varepsilon_{t-1} + u_t, \tag{3}$$

where u_t is a purely random variable with an expected value of zero, i.e. $E(u_t) = 0$, and a constant variance over time, i.e. $\mathrm{Var}(u_t) = \sigma^2$.

In 2005, electricity forward contracts were traded at the German power exchange EEX for only a limited number of days. For the remaining days, a settlement price was reported based on the chief trader principle. This requires all chief traders to daily submit a spreadsheet with their evaluation of prices for more than 40 different contract types. It is unlikely that all contract types would be updated on a daily basis commensurate with CO_2 prices. Since the different protocols used by various companies for reporting power prices are proprietary information, we do not possess such information and are unable to consider it in the estimation procedure. Thus, to illustrate the effect, we assume in the Appendix that the reported prices are a weighted average over the prices during the previous days or weeks. Estimating Eqn (1) without considering this creates an error on the left-hand side of the equation that we are estimating. This error creates a bias in the estimation of β_1.

This bias exists if we estimate β_1 using an ordinary least-square estimation, but can increase significantly if we estimate a non-cointegrated process based on Eqn (3), using other approaches that iteratively determine both β_1 and p. The alternative approach we would usually apply in such a situation is an estimation based on the first differences. But once again we show in the Appendix that the error on the left-hand side of the equation can create a very strong bias in this estimation.

Hence, we conclude that the least affected alternative is a simple OLS estimator. We accept that we have an estimator that might slightly underestimate the CO_2 pass-through. We are somewhat concerned about the fact that price series are typically autocorrelated. In fact, both power prices and CO_2 costs series are I(1) processes. Thus, if CO_2 and electricity price series are not also cointegrated, then the error terms follow an I(1) process and will fail to converge to zero. However, since both forward electricity prices and CO_2 prices are bounded, this turns out to be less of an issue in our analyses. Finally, we know that the typical confidence intervals reported by our estimation will no longer accurately represent the uncertainty in the estimation. Therefore, we apply bootstrapping to illustrate the accuracy of our estimation. In particular, we estimate β_1 using the data from a restricted observation period; thus we can examine the robustness of the estimation. More specifically, we first construct a subset of data for bootstrapping (e.g. January–October). We repeat this process by sliding the 2-month window (e.g. January–February merged with May–December), resulting in a total of six regressions with bootstrapped data.

Table 1 summarizes the estimated CO_2 pass-through rates in Germany and The Netherlands and also gives the maximum and minimum values of the OLS estimator associated with various bootstrapping estimations. With a confidence of about 80%, we can say that these rates are within the interval of 60 and 117% in Germany, and between 64 and 81% in The Netherlands. In light of the aforementioned methodological difficulties, the results presented in Table 1 need to be interpreted with caution. In particular, we offer some explanations of possible complexities and discuss the potential direction of bias.

First, the very high pass-through rate for Germany might be partially explained by increasing gas prices during 2005. Given that gas generators (instead of coal generators) set the marginal price in German markets during some peak hours, this could contribute to power prices increasing in peak forward contracts. As coal generators benefit from this gas cost-induced increase in power prices, this leads to an overestimation of the pass-through rate of CO_2 costs for coal-generated power.

Finally, Sijm et al. (2005, 2006) present and discuss a wide variety of further estimations of CO_2 pass-through rates. In general, the estimations based on the period January–July 2005 result in lower pass-through rates than estimations based on the period 2005 as a whole. For instance, the pass-through rate for The Netherlands peak hours is estimated at 38% for the period January–July 2005, while it is estimated at 78% for 2005 as a whole. This difference in estimated pass-through

Table 1. Empirical estimates of CO_2 pass-through rates in Germany and The Netherlands for the period January–December 2005, based on year-ahead prices for 2006 (%)

				Bootstrap (2 months)	
Country	Load period	Fuel (efficiency)	OLS	Min	Max
Germany	Peak	Coal (40%)	117	97	117
	Off-peak	Coal (40%)	60	60	71
Netherlands	Peak	Gas (42%)	78	64	81
	Off-peak	Coal (40%)	80	69	80

rates between the period January–July and 2005 as a whole could possibly be caused by some delays in the market internalizing the CO_2 price (i.e. market learning), rapidly rising gas prices (notably during the first period of 2005), higher power prices due to increasing scarcity and/or market power (particularly during the latter part of 2005), or by various other factors affecting power prices in liberalized wholesale markets.

3.4. Empirical estimate using the hourly spot markets in Germany

Another approach to assessing the impact of the CO_2 allowance costs on the wholesale power price is to compare the day-ahead electricity prices per hour on the German power exchange (EEX for every day in 2005 with the corresponding prices in 2004). The implicit assumption is that factors other than CO_2 and fuel costs remained unchanged during these two years. According to Eqn (4), the difference in the electricity price during a particular hour after the introduction of the ETS and the corresponding hour in 2004 is explained by the difference in coal prices during the hours concerned, the impact of the CO_2 price on the EUA market, and by an error term:

$$p_{2005,t} - p_{2004,t} = p^{coal}_{2004,t} - p^{coal}_{2004,5} + \beta p^{co2}_{2005,t} + \varepsilon_t \tag{4}$$

We set $p^{co2}_{,t}$ to reflect the costs of CO_2 emissions at the daily allowance price for a coal-fired power station with an emission rate of 0.9 tCO_2/MWh. As coal is at the margin during most of the day, this can then also be interpreted as the work-on rate for coal power stations.

Figure 7 depicts β for different hours of the day. We have split the observation period into three sections, mainly to examine whether the daily pattern is consistent over time. While this pattern did not change during the day, the level of work-on rate increased for each subsequent period considered.

Figure 7 invites three observations. First, during off-peak periods the work-on rate seems to be less than 1. This could be partly explained by intertemporal constraints of power stations – they prefer to operate during off-peak periods if this saves start-up costs. As CO_2 costs increase the start-up costs, they also create additional incentives to lower prices during off-peak periods to keep the station running (Muesgens and Neuhoff, 2006). Second, if coal generators set the price during peak periods, then these are usually vintage stations with higher heat rates and therefore higher emission costs. Finally, the increase in gas prices during the year 2005–2006 is likely to also explain some of the price increase during peak periods. As open-cycle gas turbines might be called upon during some peak periods, their increased costs with higher gas prices can further push up the power price.

Therefore we now focus on the hour 3–4 p.m., for which intertemporal effects and the gas-price impact from peaking units running at maximum a few hours a day is least prevalent, as indicated

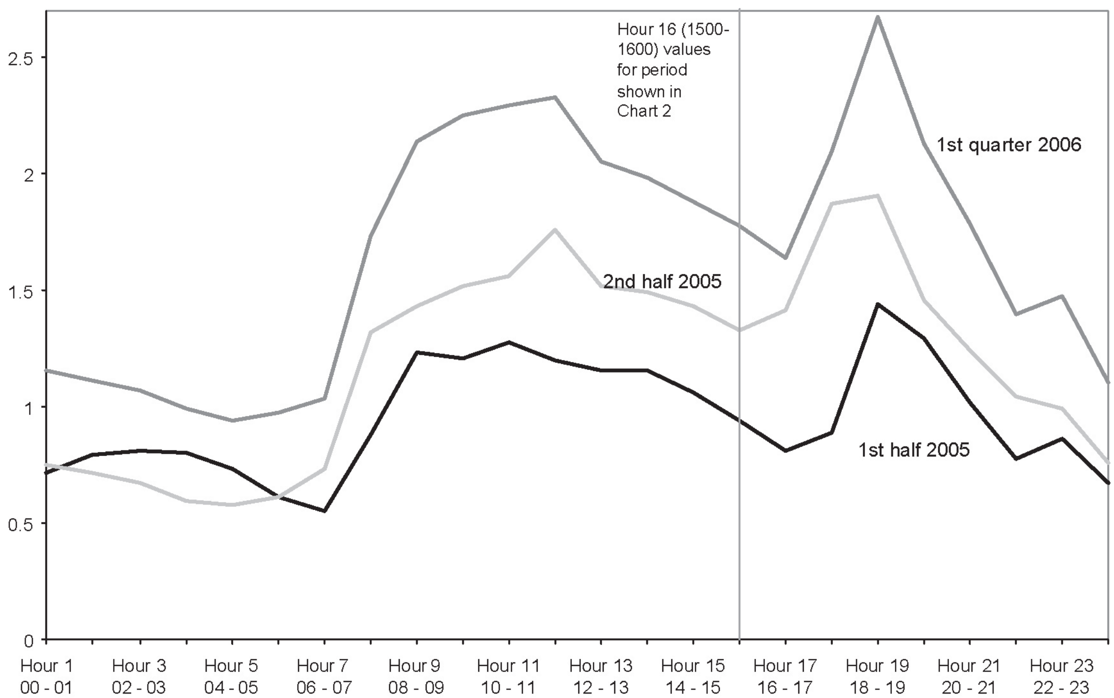

Figure 7. Work-on rate of CO_2 costs on the German spot power market for different time periods, assuming coal generators are at the margin.

by the lower value for this hour relative to other peak hours in Figure 7. Figure 8 depicts for each day the price increase of electricity in the hour 3–4 p.m. relative to the pre-ETS year 2004. The curves are again corrected for coal prices and therefore *de facto* depict:

$$p_{2005,t} - p_{2004,t} - \left(p_{2005,t}^{coal} - p_{2004,5}^{coal}\right) \tag{5}$$

As can be seen from Figure 8, during January the entire CO_2 price was not passed through, but subsequently a close link seems to exist between the increase in the CO_2 cost and the increase in the electricity price relative to 2004. In September the public debate in Germany revolved about whether the inclusion of CO_2 opportunity costs into the electricity price is appropriate, and induced generation companies to proceed with some caution. It seems that eventually the power firms' management took the position that any other behaviour than pass-through is inappropriate, and publicly acknowledged such behaviour, thus allowing traders to return to the habit of fully internalizing the CO_2 opportunity costs.

By the end of the year 2005, the German electricity prices further increased. We did not analyse the reasons for this development. The price increase could be attributed to one of the following three factors: (i) scarcity of generation capacity, (ii) higher gas prices than in previous winters, thus higher prices when gas is at the margin, and (iii) the exercise of market power.

Looking at the overall picture suggests that market participants in Germany have fully passed through the opportunity costs of CO_2 allowances in the spot market.

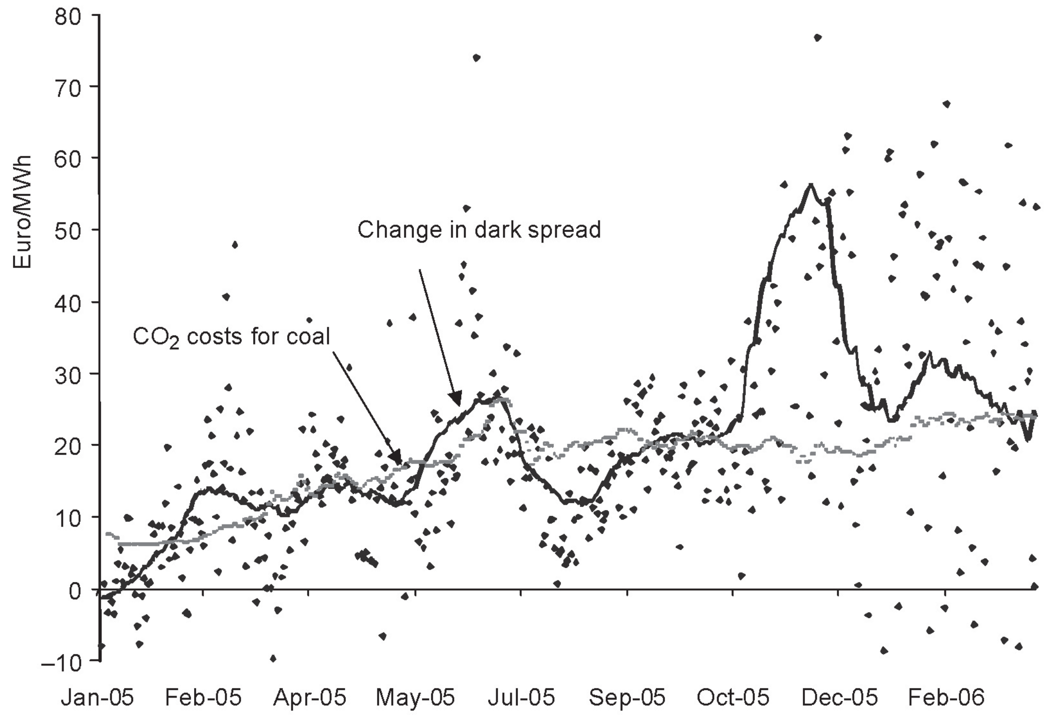

Figure 8. Coal-price-corrected price increase for electricity (3–4 p.m.) depicted as dots and their 40-day moving average (dark line) and the evolution of the CO_2 price (grey line).

4. Model estimates of CO_2 cost pass-through

In addition to the empirical estimates, CO_2 cost pass-through rates have been estimated for some EU countries by means of the COMPETES model.[10] COMPETES can simulate and analyse the impact of the strategic behaviour of large producers on the wholesale market under different market structure scenarios (varying from perfect competition to oligopolistic and monopolistic market conditions). The model has been used to analyse the implications of CO_2 emissions trading for power prices, company profits and other issues related to the wholesale power market in four countries of continental north-western Europe (Belgium, France, Germany and The Netherlands).

The major findings of the COMPETES model with regard to CO_2 cost pass-through are summarized in Table 2. They are compared to model results from the Integrated Planning Model (IPM), which are described in more detail by Neuhoff et al. (this issue). As results are very sensitive to the gas/coal shift, small differences in the assumptions about gas prices, available gas generation capacity and interconnection capacity can explain the differences between the results of both models for The Netherlands.

Table 2. Model estimates of electricity price increases (in €/MWh) due to CO_2 costs at €20/t

	Belgium	France	Germany	Netherlands	United Kingdom
COMPETES	2–14	1–5	13–19	9–11	
IPM			17	15	13–14

Under all scenarios considered, power prices turn out to increase significantly due to CO_2 emissions trading. In case of a CO_2 price of €20/tonne, these increases are generally highest in Germany (€13–19/MWh) with an intermediate position for Belgium (€2–14/MWh) and The Netherlands (€9–11/MWh). The model predicts very low price increases for France (€1–5/MWh), which reflects the predominant nuclear generation basis of this country.

Differences in absolute amounts of CO_2 cost pass-through between the individual countries considered can be mainly attributed to differences in fuel mix between these countries. For instance, during most of the load hours, power prices in Germany are set by a coal-fired generator (with a high CO_2 emission factor). On the other hand, in France they are often determined by a nuclear plant (with zero CO_2 emissions), while The Netherlands take an intermediate position – in terms of average CO_2 emissions and absolute cost pass-through – due to the fact that Dutch power prices are set by a gas-fired installation during a major part of the load duration curve.

In relative terms (i.e. as a percentage of the full opportunity costs of EU emissions trading), COMPETES has generated a wide variety of pass-through rates for various scenarios and load periods analysed. While some of these rates are low (or even zero where the power price is set by a nuclear plant), most of them vary between 60 and 80%, depending on the country, market structure, demand elasticity, load period and CO_2 price considered.

In addition, Table 2 provides the results of simulation runs by the IPM, a detailed power sector model for the EU developed by ICF Consulting. At a price of €20/tCO_2, the average amount of CO_2 cost pass-through in the UK is estimated at €13–14/MWh, while for Germany and The Netherlands this amount is estimated at €17 and €15/MWh, respectively.[11]

5. Estimates of windfall profits

As COMPETES includes detailed information at the operational level for all (major) power companies in the countries covered by the model, it can also be used to estimate the impact of emissions trading on firms' profits at the aggregated level as well as at the level of major individual companies. Such quantitative results are helpful in order to understand the qualitative impact, but the numbers should only be taken as an indication of the order of magnitude involved. We discuss this aspect in more detail at the end of the section.

Table 3 presents a summary of the changes in total companies' profits due to emissions trading under two scenarios: perfect competition (PC) and oligopolistic competition, i.e. strategic behaviour by the major power producers (ST). These ET-induced profit changes can be divided into the following two categories.

1. *Changes in profits due to ET-induced changes in production costs and power prices*. This category of profit changes is independent of the allocation method. In fact, the estimation of this category of profit changes is based on the assumption that all companies have to buy their allowances and, hence, that CO_2 costs are 'real' costs.
2. *Changes in profits due to the free allocation of emission allowances*. This category of profit changes is an addition or correction to the first category for the extent to which allowances are grandfathered – rather than sold – to eligible companies.

We start with the analysis of the impact in a perfectly competitive environment. In the fourth column of Table 3 it is assumed that all companies have to buy all their emissions allowances on

Table 3. Changes in aggregated power firms' profits due to CO_2 emissions trading in Belgium, France, Germany and The Netherlands, based on COMPETES model scenarios

Scenario[a] (1)	Price elasticity (2)	Total profits [M€] (3)	Change in profits due to: Price effects [M€] (4)	Change in profits due to: Free allocation [M€] (5)	Total change in profits due to emissions trading [M€] (6)	Total change in profits due to emissions trading [%] (7)
PC0-ze	0.0	13919				
PC20-ze	0.0	27487	5902	7666	13567	98
PC0	0.2	13919				
PC20	0.2	21904	1712	6272	7984	57
ST0-le	0.1	53656				
ST20-le	0.1	59570	–82	5996	5914	11
ST0	0.2	32015				
ST20	0.2	36782	–542	5308	4767	15

[a] PC and ST refer to two different model scenarios, i.e. perfect competition (PC) and oligopolistic (or strategic) competition (ST). Numbers attached to these abbreviations, such as PC0 or PC20, indicate a scenario without emissions trading (CO_2 price is 0) versus a scenario with emissions trading (at a price of €20/tCO_2). The additions 'ze' and 'le' refer to a zero price elasticity and low price elasticity (0.1), respectively, compared with the baseline scenario with a price elasticity of 0.2.

the market, i.e. there are no windfall profits due to grandfathering. Even under this condition, total company profits increase in the perfect competition scenarios. This results from the fact that, on average, power prices are set by marginal units with relatively high carbon intensities that pass their relatively high carbon costs through to these prices. Infra-marginal units with relatively low carbon intensities are not faced by these high carbon costs but benefit from the higher power prices on the market. Profits increase by €6 billion if we assume no demand response, and by €2 billion if we assume a very strong demand response of 0.2.[12] Thus, the high demand elasticity scenarios (i.e. 0.1 and 0.2) provide a lower bound estimation of windfall profits. Note that in the long-term investment equilibrium we expect a fixed ratio between demand and the number of power stations, and hence a reduction of demand will not affect profitability of individual power stations. The total profits of power generators are obviously further increased if we consider the impact of the free allocation (column 5), as illustrated in column 6).

The model provides additional insights into the impact of the strategic behaviour of power generators. If we assume that power generators act strategically, they will push up prices and, hence, their profits will double in the reference case that ignores emissions trading. Further empirical work would be needed to assess to what extent this level of profits corresponds to the situation before the introduction of emissions trading. If we now introduce emissions trading into the model scenarios, then profitability in the absence of free allocation is slightly reduced (by less than 1%). While all generators profit from the higher prices, the effect of a smaller market dominates this effect and therefore slightly reduces their revenues.

COMPETES is based on the assumption of a linear demand function, which implies a lower rate of passing through under oligopolistic competition than that in competitive markets. If constant elasticity of demand supply were assumed in the model, then higher pass-through rates than for competitive markets would result. These lower pass-through rates in the case of oligopolistic competition explain why profits due to emissions trading (excluding free allocation) are slightly reduced in the ST scenarios. Note, however, that due to strategic behaviour, profits in the reference ST scenario are significantly higher than in the CP scenario. Free allocation (column 5) once again makes all scenarios very profitable for power industry (column 6).

Under the present EU ETS, however, companies do not have to buy their emission allowances on the market but receive them largely for free. This implies that they are able to realize windfall profits due to grandfathering, as they still pass on the carbon costs of grandfathered emission allowances. The fifth column of Table 3 shows estimates of these profits, based on estimates of total firms' CO_2 emissions and the assumption that power companies receive, on average, 90% of the allowances to cover their emissions for free. At a price of an emission allowance of €20/tCO_2, these windfall profits vary between €5.3 and 7.7 billion, depending on the scenario considered. As total production and total emissions are generally higher under the competitive scenarios (because companies do not exercise their market power to withdraw output), total windfall profits due to grandfathering are also higher under these scenarios (compared to the oligopolistic scenarios based on strategic behaviour).

There are major differences, however, in profit performance due to emissions trading at the individual firm level, as can be seen from Table 4. This table presents changes in profits due to emissions trading under two scenarios – PC20-ze and ST20 – for the major power companies covered by COMPETES, including the so-called 'competitive fringe' of these countries.[13] Even if they have to buy their allowances, companies such as E.ON and EdF seem to benefit most from emissions trading, especially from the increase in power prices due to the pass-through of carbon costs (i.e. type 1 windfall profits). This is not surprising, given the high share of nuclear production in total generation by these companies.

On the other hand, some companies make a loss due to emissions trading when they have to buy their emissions allowances. In both scenarios, these companies are, in particular, ESSENT, NUON, STEAG AG and Vattenfall Europe. The losses for ESSENT and NUON are mainly due to the fact that these Dutch companies lose market shares in favour of foreign, less carbon-intensive companies, while they tend not to make profits from ET-induced price increases in the Dutch market, as marginal gas generators push up the price in line with cost increases of inframarginal units. The losses for STEAG AG and Vattenfall Europe are predominantly due to their portfolio mix. For STEAG AG, this portfolio is purely based on coal, while a large component of Vattenfall's portfolio is based on brown coal. Brown coal is more carbon-intensive than Germany's electricity-price-setting coal. This unbalanced portfolio is reflected in profit losses in the absence of free allowance allocation.

Once the additional profits due to grandfathering are accounted for, however, all companies benefit from emissions trading under both scenarios presented in Table 4. As coal- and other carbon-intensive companies (such as RWE, STEAG AG and Vattenfall Europe) receive relatively large amounts of CO_2 emission allowances for free, they benefit relatively more from this effect of emissions trading on firms' profits.

Although the above-mentioned quantitative estimates of changes in profits are helpful in order to understand the qualitative impact of the EU ETS on the profitability of power generation at the firm level, they have to be judged in light of the restrictions of the modelling approach:

First, it is a static model, which therefore does not capture the impact on investment decisions or, alternatively, the restraint of the potential threat of entrants or regulatory intervention put on power generators to keep prices down. In the long run, new investment is required, and therefore the best estimate for long-term power prices is the cost of the entry of a new generator. This

Table 4. Changes in profits of individual power companies operating in Belgium, France, Germany and The Netherlands, based on two COMPETES model scenarios (in M€)

Perfect competition (PC)	Total profits PC0	Total profits PC20-ze	Change in profits due to: Price effects	Change in profits due to: Free allocation	Total change in profits
Comp Nationale du Rhone	127	154	28	0	28
Comp Belgium	204	340	84	51	135
Comp France	200	326	7	119	126
Comp Germany	743	2119	147	1230	1376
Comp Netherlands	128	172	–22	66	44
A	2007	4575	1517	1051	2568
B	1722	2883	625	536	1161
C	4405	6807	2178	225	2402
D	768	1890	748	373	1122
E	319	535	–42	257	216
F	204	261	–90	148	57
G	1861	4565	802	1902	2704
H	52	92	13	27	41
I	217	438	–25	245	220
J	962	2329	–69	1436	1367
Total	13919	27487	5902	7666	13567

Oligopolistic competition (ST)	Total profits ST0	Total profits ST20	Change in profits due to: Price effects	Change in profits due to: Free allocation	Total change in profits
Comp Nationale du Rhone	425	433	8	0	8
Comp Belgium	250	269	–60	80	20
Comp France	1576	1422	–472	317	–155
Comp Germany	1972	2997	–319	1344	1025
Comp Netherlands	392	469	–59	136	77
A	3269	4226	757	199	956
B	2775	3220	245	199	445
C	12287	12709	323	98	422
D	1646	2182	330	205	536
E	775	923	–99	247	147
F	650	620	–195	166	–29
G	2896	3245	–119	468	349
H	339	348	–51	60	9
I	658	1001	–196	539	343
J	2103	2718	–636	1251	615
Total	32015	36782	–542	5308	4767

PC and ST refer to two different model scenarios, i.e. perfect competition (PC) and oligopolistic (or strategic) competition (ST). Numbers attached to these abbreviations, such as PC0 or PC20, indicate a scenario without emissions trading (CO_2 price is 0) versus a scenario with emissions trading (at a price of €20/tCO_2). The additions 'ze' and 'le' refer to a zero price elasticity and low price elasticity (0.1), respectively, compared with the baseline scenario with a price elasticity of 0.2.

model therefore provides insights into profitability during the transition period when emissions trading is implemented, but the structure of generation assets has not adjusted to reflect the new optimal investment mix. Thus we see this analysis as a guide towards understanding the type of compensation that power generators can expect in the transition period before we shift towards a new equilibrium.

Second, modelling of strategic behaviour tends to capture qualitative effects, but the quantification typically requires stronger assumptions. For example, market design of transmission or balancing markets can have a significant impact on opportunities to exercise market power by strategic players.

Third, in the strategic model scenarios we assume a linear demand function. With linear demand functions, strategic firms reduce the CO_2 cost pass-through relative to the competitive model scenarios. Analytical research shows that this result is inverted if we instead assume a constant elasticity of demand function. In this case, strategic firms increase the CO_2 pass-through rate relative to a competitive scenario. However, we believe that the empirical demand curves would be somewhere between two extreme cases: constant elasticity and linear demand (i.e. zero elasticity). Furthermore, given the fact that all the economic rent from introducing EU ETS goes to producers (at the expense of consumers) under fixed demand scenarios, the profitability of firms under constant elasticity cases would be less than that under liner demand cases in general.

5.1. Estimates of windfall profits at national level

Recently, Frontier Economics (2006) has estimated windfall profits due to the EU ETS for the four largest power companies operating in The Netherlands (ESSENT, NUON, E.ON and Electrabel). For the year 2005, these profits are estimated at €19 million for the four companies as a whole. This estimate is rather low, as it is based on some stringent, specific assumptions and conditions for the year 2005. On the one hand, it is assumed that 90% of the power produced during 2005 was already sold in 2003 and 2004, when CO_2 prices and (assumed) pass-through rates were low, resulting in additional revenues of power sales in 2005 of €69 million. On the other hand, it is assumed that the 'allocation deficit' of the four companies (i.e. the difference between the allowances grandfathered and the allowances needed to cover their emissions) was met by market purchases in 2005 only, when CO_2 prices were high, resulting in a total cost of €50 million.[14]

Although the estimate by Frontier Economics of the windfall profits in The Netherlands (and the underlying assumptions and conditions) can, to some extent, be justified for the year 2005, it does not provide an adequate, 'representative' estimate of the windfall profits due to the EU ETS in the years thereafter. A more representative estimate of these windfall profits can be based on one of the following three approaches.

Firstly, based on the COMPETES methodology outlined above, changes in profits due to CO_2 emissions trading have been estimated for the operations of the four largest power companies in the Netherlands in an 'average' year. Table 5 shows that, at a price of €20/tCO_2, these changes vary between €250 and 600 million for the four companies as a whole, depending on the scenario considered. As explained, these changes are the result of two different effects of emissions trading, called the price and grandfathering effects. As can be observed from Table 5, the price effect – based on the assumption that power companies have to buy all their emission allowances – leads to losses in three out of four scenarios. This is due to the fact that (i) power demand is assumed to respond significantly to higher prices (i.e. we assume demand elasticities of 0.1 and 0.2 in the scenarios with losses due to the price effect), (ii) the share of non-carbon power generation in The Netherlands is relatively low (and, hence, the benefits of ET-induced price increases for non-carbon generators are low), and (iii) the share of gas-fired power-generation – setting the power price – is relatively high in The Netherlands

Table 5. Changes in aggregated profits due to CO_2 emissions trading for the four largest power firms in The Netherlands (E.ON, Electrabel, ESSENT and NUON), based on COMPETES model scenarios

Scenario[a]	Price elasticity	Total profits [M€]	Change in profits due to: Price effects [M€]	Free allocation [M€]	Total change in profits due to emissions trading [M€]	[%]
PC0		995				
PC20	0.2	1394	–78	477	399	40
PC20-ze	0.0	1580	109	477	585	59
ST0		2151				
ST20	0.2	2408	–179	436	257	12
ST20-le	0.1	3359				
ST20-le	0.1	3610	–185	436	251	7

[a] PC and ST refer to two different model scenarios, i.e. perfect competition (PC) and oligopolistic (or strategic) competition (ST). Numbers attached to these abbreviations, such as PC0 or PC20, indicate a scenario without emissions trading (CO_2 price is 0) versus a scenario with emissions trading (at a price of €20/tCO_2). The additions 'ze' and ' le' refer to a zero price elasticity and low price elasticity (0.1), respectively, compared to the baseline scenario with a price elasticity of 0.2.

(and, hence, high-carbon generators such as coal-fired installations are faced by high carbon costs that are not matched by equally higher power prices).

On the other hand, when assuming that the power companies in The Netherlands receive 90% of their needed emission allowances for free, the grandfathering effect far outweights the price effect, resulting in major total windfall profits due to emissions trading based largely on free allocation.

Secondly, following the methodology used by Frontier Economics for an average, 'representative' year, it may – for instance – be assumed that (i) total CO_2 emissions of the four major power companies in The Netherlands is about 37.5 MtCO_2 per year, while the amount of allowances grandfathered to these companies is 35 MtCO_2 per annum (hence, the allocation deficit is 2.5 MtCO_2 per year; i.e. about 7% of total emissions), (ii) the price of a CO_2 allowance bought is, on average, equal to the price of a CO_2 allowance passed through to power prices, and amounts to €20/tCO_2, and (iii) the average pass-through rate is 50%. In that case, the total windfall profits of the four major power companies in The Netherlands amounts to €325 million.

Finally, the third approach to estimating windfall profits is based on ET-induced price increases of domestically produced power sales in The Netherlands. These sales amount to around 100 TWh per year. Assuming that (i) 75% of this volume is sold during peak hours and the remaining part during the off-peak period, (ii) during peak hours, power prices are set by a gas-fired installation with an emission factor of 0.4 tCO_2/MWh and during the off-peak period by a coal-fired plant with an emission factor of 0.8 tCO_2/MWh, (iii) the CO_2 price is, on average, €20/t, (iv) the average pass-through rate is 40% during the peak and 50% during the off-peak, and (v) the allocation deficit for the power sector as a whole is equivalent to 4 million tCO_2 per year. In that case, the total windfall profits amount to €360 million per year.[15]

To conclude, at a price of €20/tCO_2, estimates of windfall profits due to the EU ETS in the power sector of The Netherlands for an average, 'representative' year vary between €300 and 600 million. This compares to about half the value of the emission allowances grandfathered to the power sector or some €3–5/MWh produced in The Netherlands.[16] It should be emphasized, however, that these estimates ignore the impact of ETS-induced profit changes on new investments in generation capacity and, hence, on production costs, power prices and company profits in the long run towards a new equilibrium.

UK power sector profits from the EU ETS were estimated at £800m/yr in a report to the DTI (IPA Energy Consulting, 2005). Such profits occur even though power sector emissions (157 $MtCO_2$) exceeded free allocation (134 $MtCO_2$), making the UK power sector by far the largest buyer on the EU ETS market. In the IPA model, the UK power sector in aggregate would break even if free allocation were cut back to 45 $MtCO_2$/yr. At this point the earnings from higher power prices, after accounting for impact on demand, would fund the purchase of emission allowances from auctions, other sectors or internationally. The profit impact is sensitive to the CO_2 price (assumed to be €15/t) and can increase if with lower gas prices the electricity price is set by more CO_2 intensive coal plants. Profits are also highly unequally distributed between individual companies, as the previous section illustrated for The Netherlands. In the first year of the ETS, utilities might not have realised all the modelled profits, as some production was covered by longer-term contracts and because changes in wholesale prices take time to feed through to retail price changes.

6. Summary of major findings and policy implications

In theory, power producers pass on the opportunity costs of freely allocated emission allowances to the price of electricity. For a variety of reasons, however, the increase in power prices on the market may be less than the increase in CO_2 costs per MWh generated by the marginal production unit. This is confirmed by empirical and model findings, showing estimates of CO_2 cost pass-through rates varying between 60 and 100% for wholesale power markets in Germany and The Netherlands. Using numerical models we find that, at a CO_2 price of €20/t, ET-induced increases in power prices range between €3 and 18/MWh, depending on the carbon intensity of the price-setting installation. As most of the emission allowances needed are allocated for free, the profitability of power generation increases accordingly. Model and empirical estimates of additional profits due to the EU ETS show that these ‘windfall profits’ may be very significant, depending on the price of CO_2 and the assumptions made. For instance, at a CO_2 price of €20/t, ETS-induced windfall profits in the power sector of The Netherlands are estimated at €300–600 million per year, i.e. about €3–5 per MWh produced and sold in The Netherlands.

Acknowledgements

We thank Prof. Benjamin F. Hobbs of the Johns Hopkins University (Baltimore, USA) as well as those ECN staff members who contributed to the ‘CO_2 Price Dynamics’ project, notably Stefan Bakker, Michael ten Donkelaar, Henk Harmsen, Sebastiaan Hers, Wietze Lise and Martin Scheepers (for details, see Sijm et al., 2005, 2006). We also thank Alessio Sancetta for guidance on the econometric analysis, Jim Cust for research assistance, and the UK research council project TSEC and Climate Strategies for financial support.

Notes

1 Model analyses show that when CO_2 costs exceeds €20/t, emissions trading would induce substantial changes in the production merit order (Sijm et al., 2005).
2 For a full discussion and illustration of these reasons, see Chapter 4 of Sijm et al. (2005).
3 It should be observed, however, that the change in the merit order might occur only during a certain load period. This has to be accounted for when analysing the impact of emissions trading on firms’ profits and the implications for assessing the extent of grandfathering to break even.

4 Similar findings can be derived by means of Figure 1, showing different types of technology along the load duration curve. By comparing the revenues (price/MWh × hours loaded) and the corresponding real/opportunity costs with and without emissions trading, changes in profits can be derived for different types of technology, including a change in the merit order of these technologies.

5 In this section, unless otherwise stated, coal refers to the internationally traded commodity classified as coal ARA CIF AP#2, while gas refers to the high caloric gas (with a conversion factor 35, 17 GJ/m^3) from the Dutch Gas Union Trade & Supply (GUTS). Moreover, prices for power, fuels and CO_2 refer to forward markets (i.e. year-ahead prices).

6 These spreads are indicators for the coverage of other (non-fuel/CO_2) costs of generating electricity, including profits. For the present analysis, however, these other costs – for instance capital costs, maintenance or operating costs – are ignored as, for each specific case, they are assumed to be constant for the (short-term) period considered – although they may vary per case considered – and, hence, they do not affect the estimated pass-through rates.

7 It is acknowledged, however, that during certain periods of the peak hours – the 'super peak' – a gas generator is the marginal (price-setting) unit but, due to lack of data, it is not possible to analyse the super-peak period in Germany separately.

8 In Sijm et al. (2006), this assumption was dropped, but it turned out that the estimated pass-through rates for fuel and CO_2 costs were unreliable due to the observation that fuel and CO_2 costs are highly correlated.

9 An I(0) (integrated of order zero) is an autoregressive process with one period of lag, i.e. AR(1) and with a propensity factor $|\rho|<1$ (see Eqn (3)) (Stewart and Wallis, 1981). This indicates a process of correlation frequently experienced in everyday life. For instance, if the ambient temperature was high yesterday and there are no major changes in the weather conditions, the temperature today should be more or less similar. In this case, the temperature today provides a prior belief from which tomorrow's temperature can be inferred. Statistically, when assuming that ε_t is characterized by an I(0) process (i.e. $|\rho|<1$) in Eqn (3), the series is at least weakly independent. Therefore, both PW and OLS will be adequate to estimate pass-through rates given the correct specification. However, we are aware of the possibility of a non-cointegration process since three series – power prices, fuel costs and CO_2 costs – follow an I(1) process based on the Dickey–Fuller test. Thus, in this article, we intend to provide a preliminary assessment of the empirical CO_2 pass-through rates.

10 COMPETES stands for Comprehensive Market Power in Electricity Transmission and Energy Simulator. This model has been developed by ECN in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University (Department of Geography and Environmental Engineering, Baltimore, MD, USA). For more details on this model, see Sijm et al. (2005) and references cited therein, as well as the website http://www.electricitymarkets.info.

11 The high estimate for The Netherlands (compared to a similar estimate by the COMPETES model) might be caused by the older nature of the IPM model, with coal having a stronger influence on power prices.

12 This implies an increase in the wholesale price level from €20 to €30/MWh, and hence of the retail price level (including transmission, distribution and marketing costs) from let's say €70 to €90/MWh, would result in a reduction of demand by 10%.

13 The competitive fringe of a country – denoted as Comp Belgium, Comp France, etc. – refers to the collections of (smaller) producers in a country that lack the ability to influence power prices due to their small market share and, therefore, they were modelled behaving competitively (i.e. as price takers).

14 However, in May 2006, when the verified emissions of the four companies were published, it turned out that these companies did not have an allocation deficit but rather a small surplus. This implies that the estimate of the windfall profits by Frontier Economics was indeed quite conservative, as actually it is at least €50 million higher.

15 This figure includes not only the windfall profits of the four largest power companies in The Netherlands but also of all other Dutch power producers benefiting from ET-induced increases in the price of electricity.

16 Note that in The Netherlands the share of non-carbon fuels in total power production is low and that power prices are usually set by carbon-fuelled installations, notably gas-fired plants. In countries where the share of non-carbon fuels is much higher or where power prices are set by either high carbon-fuelled (i.e. coal) installations or by a non-carbon fuelled generator, the windfall profit per MWh or allowance grandfathered may be substantially different than in The Netherlands.

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Appendix 1

Biased estimation of pass-through rate if frequency of estimation is higher than frequency of observation of forward electricity prices

While EEX offers daily clearing prices for the forward prices, these are typically not based on trades but on averages of the survey results among various traders. Given that chief traders are expected to submit daily an updated price prediction on 40 contract types, it is unlikely that they will update this prediction daily, and hence the daily prices overstate the information content of the data.

This note attempts to understand why a delay in observing the forward electricity price p_t results in a bias in the estimation b of the pass-through rate r. Let us assume that electricity prices are formed according to:

$$p_t = rc_t + e_t \quad \text{with } e_t \text{ independent and identical distributed} \tag{A1}$$

but we can only observe q_t with

$$q_t = \frac{p_t + p_{t-1}}{2} \tag{A2}$$

This reflects that trading volume is limited, with trades only on a few days. In the absence of trades, the power exchange asks traders to report their best guess of trades and uses the average reported prices. However, traders only infrequently update their reports; hence the reported price is an average of the real price over various periods. How does this effect the estimation b of the pass though rate? We estimate that

$$q_t = bc_t + \eta_t \tag{A3}$$

1. OLS estimation

First, assume we use OLS, and therefore chose b to minimize $\sum_t \eta_t^2$

$$\hat{b} = \frac{\sum c_t q_t}{\sum c_t^2} \quad \text{(using def of } q_t\text{)}$$

$$= \frac{\sum c_t \frac{p_t + p_{t-1}}{2}}{\sum c_t^2} \quad \text{(using def of } p_t\text{)}$$

$$= r\frac{\sum c_t \left(c_t + c_{t-1}\right)/2}{\sum c_t^2} + \text{error term (assume independence of } c \text{ and } e\text{)}$$

$$= r - \frac{r}{2}\frac{\sum c_t \left(c_t - c_{t-1}\right)}{\sum c_t^2} = \begin{Bmatrix} < r & if & c_0 < c_T \\ > r & if & c_0 > c_T \end{Bmatrix} + \text{error}$$

2. AR(1) estimation

Second, assume we estimate using an AR(1) process with $\eta_t = p\eta_{t-1} + \gamma_t$ with γ_t independent and identical distributed.
We minimize

$$\sum \gamma_t^2 = \sum \left(\eta - p\eta_{t-1}\right)^2$$

$$= \sum \left(q_t - bc_t - \rho\left(q_{t-1} - bc_{t-1}\right)\right)^2$$

$$= ..\left[without \quad b\right]... - 2b\sum \left(c_t - \rho c_{t-1}\right)\left(q_t - \rho q_{t-1}\right) + b^2 \sum \left(c_t - \rho c_{t-1}\right)^2$$

Using the first-order condition

$$\hat{b} = \frac{\sum \left(c_t - \rho c_{t-1}\right)\left(q_t - \rho q_{t-1}\right)}{\sum \left(c_t - \rho c_{t-1}\right)^2} \text{(using def of } q_t\text{)}$$

$$= \frac{\sum \left(c_t - \rho c_{t-1}\right)\frac{p_t - \rho p_{t-1} + p_{t-1} - \rho p_{t-2}}{2}}{\sum \left(c_t - \rho c_{t-1}\right)^2} \text{(using def of } p_t\text{)}.$$

(assume independence of c and e)

$$= r\frac{\sum \left(c_t - \rho c_{t-1}\right)\frac{c_t - \rho c_{t-1} + c_{t-1} - \rho c_{t-2}}{2}}{\sum \left(c_t - \rho c_{t-1}\right)^2} + \text{error term}$$

$$= \frac{r}{2} + \frac{r}{2}\frac{\sum \left(c_t - \rho c_{t-1}\right)\left(c_{t-1} - \rho c_{t-2}\right)}{\sum \left(c_t - \rho c_{t-1}\right)^2} + \text{error}$$

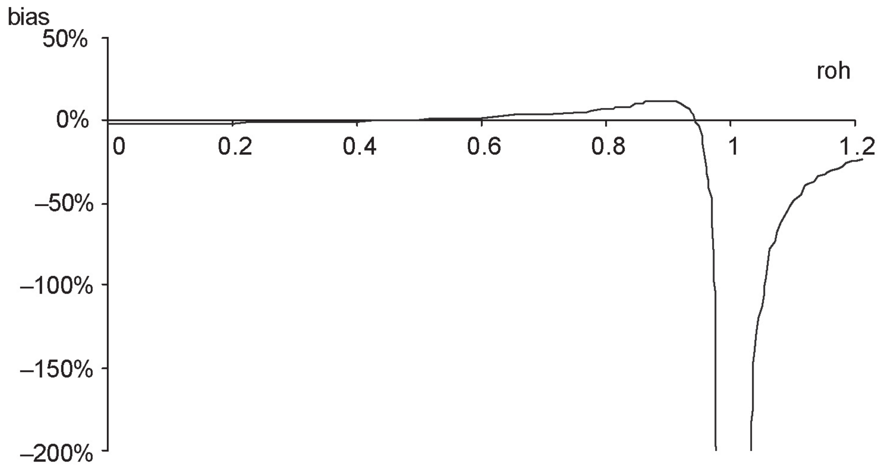

Figure A1. Bias in estimated pass-through rate.

3. Quantification of bias

We use the CO_2 prices from January–December 2005 as input for c_t and calculate the bias in the estimated pass-through rate at the example of a time lag of 20 days. This reflects the delays in updating under the chief trade principle applied to determine the contract settlement prices. The OLS creates a bias of 2%. Figure A1 presents the bias that results if the AR(1) process is assumed, depicted for different values of ρ.

An AR(1) process is usually estimated in an iterative two-stage procedure. In this case the biased estimator for b will result in a wrong estimation of the error term, thus influencing the estimation of ρ, which in turn feeds back to the next estimation of b. Hence the effect might be further distorted. This analysis suggests that the OLS estimator will provide a less biased estimation of the pass-through rate b than AR estimation. This is caused because rather than p, the underlying forward price, only a time averaged q is available for the estimation.

4. Cointegration

We note that both approaches fail to address an aspect that is typically present in commodity price data: they are autocorrelated. If forward prices and CO_2 prices are not cointegrated, then error terms under both estimations might not converge. The typical response is to run an estimation using the first differences. This is typically a successful approach in the case of non-cointegrated AR(1) processes (but does not have the quick convergence properties that otherwise characterize estimations using levels).

However, once again the price formation process precludes such attempt for the daily forward prices. Let us define $dc_t = c_t - c_{t-1}$ and likewise for dq_t and dp_t. As above, we would estimate:

$$\hat{b} = \frac{\sum dc_t dq_t}{\sum dc_t^2} \left(\text{using def of } q_t\right)$$

$$= \frac{\sum dc_t \frac{dp_t + dp_{t-1}}{2}}{\sum dc_t^2} \left(\text{using def of } p_t\right)$$

$$= r \frac{\sum dc_t \left(dc_t + dc_{t-1}\right)/2}{\sum dc_t^2} + \text{error term}$$

(assume independence of c and e)

$$= \frac{r}{2} - \frac{r}{2} \frac{\sum dc_t \left(dc_{t-1}\right)}{\sum dc_t^2} \sim \frac{r}{2}$$

This suggests that, given the price formation, a first difference estimation using daily price data will bias the estimation of b significantly downward. One possible alternative approach would be to use monthly average prices, but then the number of observation points is reduced.

