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CO₂ cost pass through and windfall profits in the power sector¹

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Abstract

In order to cover their CO₂ 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 to the price of electricity. This paper analyses the implications of the EU ETS for the power sector, notably the impact of free allocation of CO₂ emission allowances on the price of electricity and the profitability of power generation. Besides some theoretical reflections, the paper presents empirical and model estimates of CO₂ cost pass through, indicating that pass through rates vary between 40 and 100 percent of CO₂ costs, or – in absolute terms – between 3 and 18 €/MWh, depending on the carbon intensity of the marginal production unit and other, market or technology specific factors concerned. As a result, power companies realise substantial windfall profits, indicated by empirical and model estimates presented in the paper. In order to avoid these windfall profits, the paper concludes that free allocation to power companies should be phased out in favour of auctioning.

Keywords: Emissions trading; allocation; CO₂ cost pass through; windfall profits; power sector

JEL: C81, L11, L94

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1. Introduction

A major characteristic of the present EU Emissions Trading Scheme (ETS) is that almost all CO₂ 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 allocated per year (EC, 2005). At average market prices for 2005 (i.e. about 26 €/tCO₂, this represents a social value of approximately € 40 billion per annum, about 60 percent of which is allocated to the power sector.

Against this background, the present paper analyses the implications of the EU ETS for the power sector, notably the impact of free allocation of CO₂ emission allowances on the price of electricity and the profitability of power generation. First of all, Section 2 discusses the effect of different generation technologies being used to generate electricity. How does the internalisation of CO₂ allowance prices by individual generators into their bids feed through to the power price and how does this in turn effect profitability? Subsequently, Sections 3 to 5 present empirical and model findings on passing through costs of CO₂ emission allowances to power prices in countries of North-western Europe and the implications for the profitability of power production in these countries at the national and firm level. Finally, the paper 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 a 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 on the market (to other companies that need additional allowances (Reinaud, 2005)). Hence, for a company using an emission allowance represents an opportunity cost, regardless 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 CO₂ 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, Palmer et al., 2002; Reinaud, 2003; Burtraw, Palmer et al., 2005).

Different generation technologies produce different levels of CO₂ emissions, and therefore the opportunity costs of CO₂ emissions per unit of power produced differ as well. For example, a Combined Cycle Gas Turbine produces about 0.48 tonnes of CO₂ per MWh of electricity, while a typical coal power station emits about 0.85 tCO₂/MWh. A CO₂ price of 20 €/tCO₂, 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 CO₂ costs may differ per hour or load period considered, depending on the marginal generation unit concerned. As a consequence, the CO₂ costs pass through is defined as the average increase in power price over a certain period due to the increase in the CO₂ price of an emission allowance.

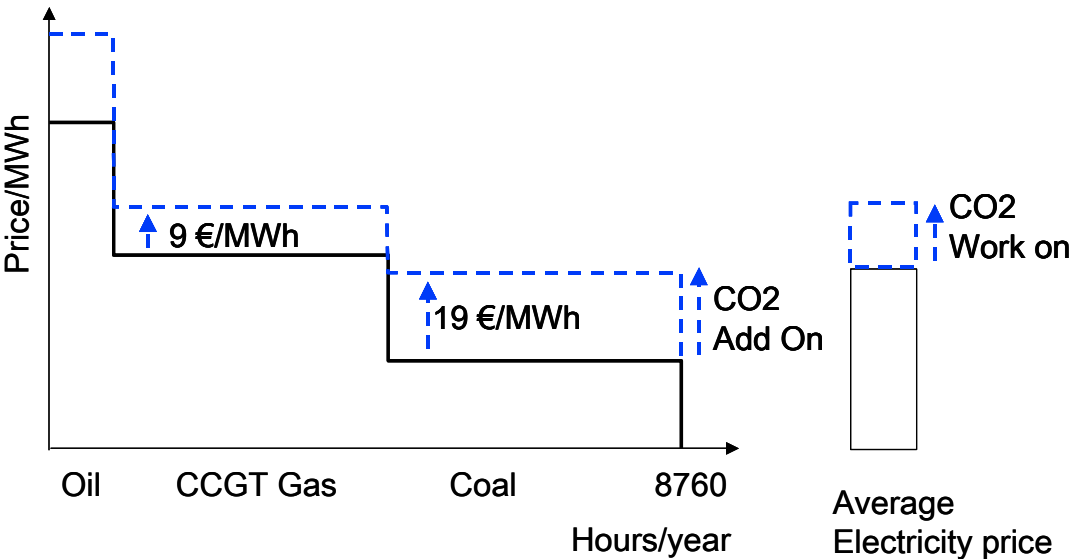


Figure 1 Pass through of CO₂ opportunity costs for different load periods (at a price of 20 €/tCO₂)

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 CO₂ allowances to the power price. The increase of the bid of the marginal unit will then determine how much of the CO₂ allowance prices are ‘worked-on’ the electricity price. However, in a liberalised 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 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 100 percent, the work-on rate will be lower than 100

percent. However, price response is typically rather low for households and other small-scale consumers of electricity, but may be more significant for major end-users such as the power-intensive industries. Power-intensive industry would substitute electricity purchases with 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 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 depends also on changes in the merit order of the supply curve due to emissions trading. This can be illustrated by Figure 2, where the supply curve is characterised by a step function with two types of technologies - A and B. The vertical dash line indicates the fixed demand. In the left part of Figure 2, when there is no change in the merit order, the change in the power price (Δp_2) will always be equal to the marginal CO₂ allowances 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 the right part of Figure 2, the situation becomes different. In this case, the marginal technology is A with CO₂ 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 percent, the work-on rate $\Delta p_4 / \Delta p_3$, will be less than 1 since $\Delta p_4 < \Delta p_3$.² In markets with surplus capacity, competitive pressures from excess generation capacity also impact the merit order and in turn, the work-on rate (Reinaud, 2003).

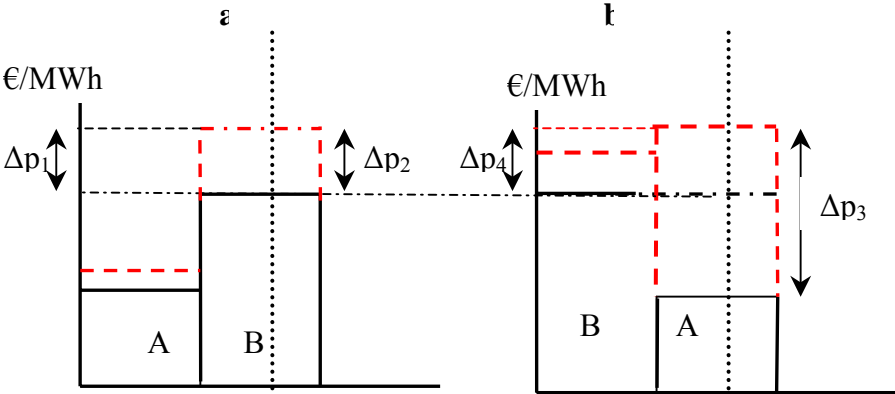


Figure 2 Pass-through rates under changes in the merit order

² Model analyses show that when CO₂ costs exceeds 20 €/tonne, emissions trading would induce substantial changes in the production merit order (Sijm et al., 2005).

In addition, there may be several reasons why generators do not add on the full CO₂ costs to their power bid prices:³

- 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 induces generators to not 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.

The impact on generators' profits

An important question is how the pass through of CO₂ opportunity costs affects the profitability of power stations. The main purpose of free allocation of emissions allowances under the US cap and trade programmes for SO₂ and NO_x as well as under the EU ETS for CO₂ 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 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. This figure illustrates the implications of emissions trading for generators profits in case the supply curve consists of different types of technology. In case emissions trading does not lead to a change in the merit order of the supply curve (and in total demand; see left hand side of Figure 2), the change in the power price (Δp_2) is just equal to the CO₂ costs per MWh of the marginal production unit (B). For this unit, this implies that profits do not change in case all the allowances have to be bought, while it results in windfall profits in 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

³ For a full discussion and illustration of these reasons, see Chapter 4 of Sijm et al. (2005).

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 the right part of Figure 2), the change in the power price (Δp_4) is lower than the change in the CO₂ costs per MWh of the marginal production unit (A). For this unit, emissions trading results in a windfall profit per MWh (equal to Δp_4) in case of free allocation, but in a windfall loss (equal to $\Delta p_3 - \Delta p_4$) if all the allowances have to be bought. Therefore, for this situation/unit, some grandfathering may be justified to break even.⁴ For the infra-marginal unit (B), the increase in power price is higher than the increase in CO₂ 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 a windfall profit and, hence, there is no need for any grandfathering to this unit to break-even.⁵

If 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 CO₂ costs

This section presents some empirically estimated rates of passing through CO₂ 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 CO₂ allowances. Secondly, we study the spot market, notably the German power exchange (EEX), by comparing hourly spot electricity prices for the period January 2005 till March 2006 with the corresponding hourly electricity prices in the year 2004. More specifically, we look to what extent a change in the spot power price, for example at 9am on the first Monday

⁴ 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.

⁵ 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.

in January 2006 relative to the first Monday in January 2004, can be explained by a change in the price of a CO₂ allowance on the EUA market.

First of all, however, some background information will be provided on trends in prices, fuel/CO₂ costs and dark/spark spreads in the power sector of Germany and the Netherlands during the years 2004-2005.

Trends in forward prices and costs

For the years 2004-05, Figures 3 and 4 present power prices versus fuel/CO₂ costs to generate a MWh of power (assuming a fuel efficiency of 40 percent for coal and 42 percent for gas, a related emission factor of 0.85 and 0.48 tCO₂/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.⁶

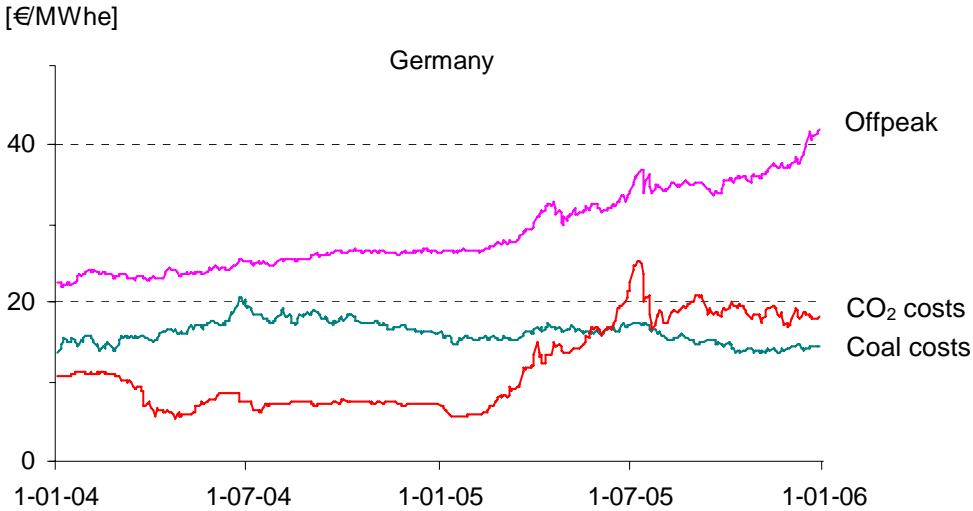


Figure 3 Off-peak power prices versus fuel/CO₂ costs in Germany (year ahead, 2004-2005)

⁶ 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 (35,17) from the Dutch Gas Union Trade & Supply (GUTS). Moreover, prices for power, fuels and CO₂ refer to forward markets (i.e. year-ahead prices).

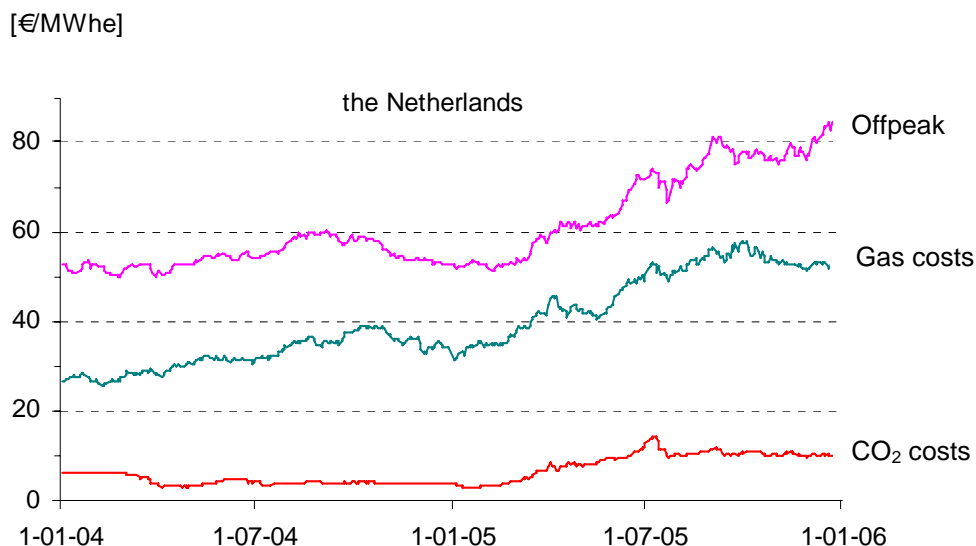


Figure 4 Peak power prices versus fuel/CO₂ costs in the Netherlands (year ahead, 2004-2005)

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, CO₂ costs of coal-generated power have been stable during the second part of 2004 but have approximately trebled during the first part of 2005 from about 6 €/MWh in January to some 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 CO₂ prices (and not by higher fuel prices). However, during the second part of 2005 (August-December 2005) CO₂ costs per coal-generated MWh have been rather stable while off-peak prices have continued to rise. This indicates factors other than fuel and CO₂ costs influence power prices.

The Dutch case illustrates that the fuel (i.e. gas) costs to produce electricity have risen substantially from some 33 €/MWh in early January 2005 to about 56 €/MWh in early September 2005. CO₂ 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, hence, that besides the CO₂ 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, whereas both gas and CO₂ costs have been more or less stable during the last quarter of 2005 (or even declined a bit as far as gas costs are concerned), peak power prices continued to increase to 84 €/MWh in late December 2005.

Trends in dark and spark spreads on forward markets

Figures 5 and 6 present trends in dark/spark spreads and CO₂ 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 CO₂ 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 a MWh of electricity, while a *spark spread* refers to the difference between the power price and the costs of *gas* to produce a MWh of electricity. If the costs of CO₂ are included, these indicators are called ‘*clean dark/spark spreads*’ or ‘*carbon compensated dark/spark spreads*’.⁷

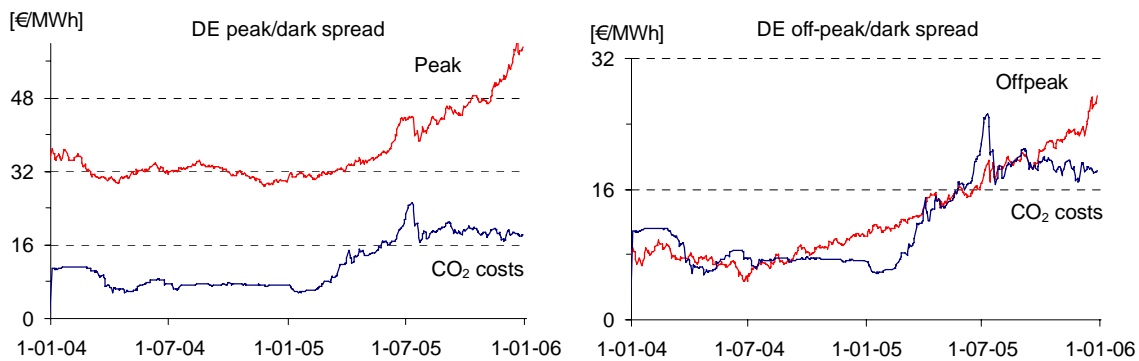


Figure 5 Trends in dark spreads and CO₂ costs per coal-generated MWh in Germany during peak and off-peak hours (year ahead, 2004-2005)

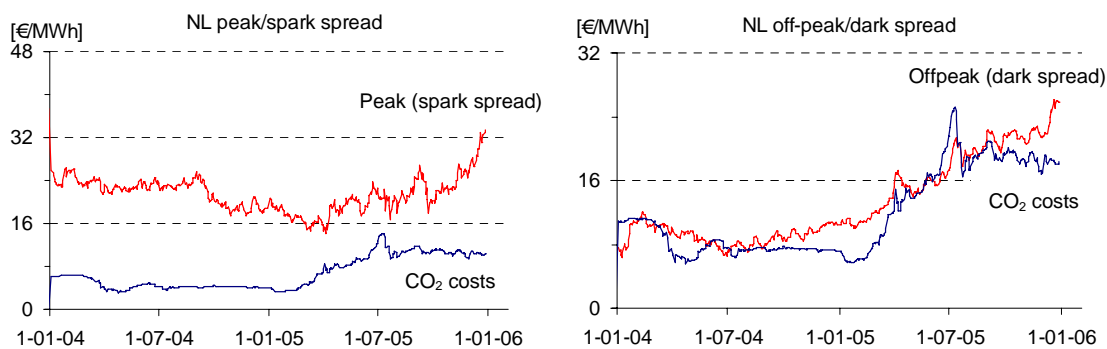


Figure 6 Trends in spark/dark spreads and CO₂ costs per gas/coal-generated MWh in the Netherlands during peak and off-peak hours (year ahead, 2004-2005)

For Germany, Figure 5 depicts trends in dark spreads in both peak and off-peak hours, based

⁷ These spreads are indicators for the coverage of other (non-fuel/CO₂) 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.

on the assumption that a coal generator is the price-setting unit during these periods.⁸ In addition, it shows the costs of CO₂ allowances required to cover the emissions per MWh generated by a coal-fired power plant (with an emission factor of 0.85 tCO₂/MWh). The figure suggests that up to July 2005 changes in the dark spread can be largely explained by changes in the CO₂ costs per MWh. Since August 2005, however, this relationship is less clear as the CO₂ 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 CO₂ 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 tCO₂/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 CO₂ costs per MWh, but that afterwards this relationship is less clear.

Statistical estimates of CO₂ cost pass through rates on forward markets

Below, we provide empirical estimates of pass through rates of CO₂ emissions trading costs to forward power prices in Germany and the Netherlands for the period January-December 2005. The basic assumption of estimating CO₂ 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 CO₂ 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 can not 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 CO₂ costs is expressed by equation (1), where superscripts *c* and *g* indicate coal and gas, respectively. Likewise, the term $CO_{2,t}$ is the CO₂ cost associated with coal and gas at time *t*. Thus, it is equal to the product of the CO₂ allowances price at time *t* and the time-invariant CO₂ emission rate of coal or gas generators. In our analysis, fuel costs are assumed to be fully passed on to power prices.⁹ This is equivalent to fixing the coefficient β_2 at unity.

⁸ 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.

⁹ In Sijm et al. (2006), this assumption was dropped, but it turned out that the estimated pass through rates for fuel and CO₂ costs were unreliable due to the observation that fuel and CO₂ costs are highly correlated.

$$P_t = \alpha + \beta_1 CO2_t^{c,g} + \beta_2 F_t^{c,g} + \varepsilon_t \quad (1)$$

By defining Y_t as the difference between power price and fuel cost, equation (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.

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

Like most price series, power price data exhibit serial correlation. Hence, the error term ε_t is characterised by a so-called I(0) process (integrated of order zero).¹⁰

$$\varepsilon_t = \rho \varepsilon_{t-1} + u_t, \quad (3)$$

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., $\text{Var}(u_t) = \sigma^2$.

In 2005, electricity forward contracts were traded at the German power exchange EEX 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 in commensurate with CO₂ prices. Since the different protocols used by various companies 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. 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 are estimating a non-cointegrated process based on (3) using other

¹⁰ 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 equation (3)) (Stewart and Wallis, 1981). It indicates a process of correlation frequently experienced in every day's 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 a case, the temperature today provides a prior belief from which tomorrow's temperature can be inferred. Statistically, when assuming ε_t an I(0) process (i.e., $|\rho| < 1$) in equation (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 CO₂ costs – follow an I(1) process based on Dickey-Fuller Test. Thus, in this paper, we intend to provide a preliminary assessment of the empirical CO₂ pass through rates.

approaches that iteratively determine both β_1 and ρ . 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 CO₂ pass through. We are somewhat concerned about the fact that price series are typically auto-correlated. In fact, both power prices and CO₂ costs series are I(1) processes. Thus, if CO₂ 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 CO₂ prices are bounded, it 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 appropriately 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 by bootstrapping samples from a window of a two-month period (e.g., January-February). Then, we run our regression based on the combined data from the bootstrapped subset data and from the remaining months (e.g., March-December). We repeat this process by sliding the two-month window (e.g., March-April, May-June, etc.), resulting in a total of six regressions with bootstrapped data.

Table 1 summarizes the estimated CO₂ pass through rates in Germany and the Netherlands and also gives the maximum and minimum of the OLS estimator associated with various bootstrapping estimations. With confidence of about 80 percent, we can say that these rates are within the interval of 60 and 117 percent in Germany, and between 64 and 81 percent in the Netherlands. In light of the aforementioned methodological difficulties, the results presented in Table 1 need to be interpreted and treated with caution. In particular, we offer some explanations of possible complexities and discuss the potential direction of bias:

Table 1 Empirical estimates of CO₂ pass through rates in Germany and the Netherlands for the period January-December 2005, based on year ahead prices for 2006 (in %)

Country	Load period	Fuel (efficiency)	OLS	Bootstrap (2 months)	
				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

First, the very high pass through rate for Germany might partially be explained by increasing gas prices during 2005. Given that gas generators (instead of coal generators) set the marginal

price in Germany markets during some peak hours, this could contribute to power prices increase in peak forward contracts. As coal generators benefit from this gas cost-induced increase in power prices, it leads to an overestimate of the pass through rate of CO₂ costs for coal-generated power.

Finally, Sijm et al. (2005 and 2006) present and discuss a wide variety of further estimations of CO₂ 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 percent for the period January-July 2005, while it is estimated at 78 percent for 2005 as a whole. This difference in estimated pass through rates between the period January-July and 2005 as a whole could possibly be caused by some delays in the market internalising the CO₂ 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 liberalised wholesale markets.

Empirical estimate using the hourly spot markets in Germany

Another approach to assess the impact of the CO₂ 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 CO₂ and fuel costs remain unchanged during these two years. According to equation (4), the difference in the electricity price during a certain 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 CO₂ price on the EUA market and by an error term.

$$P_{2005,t} - P_{2004,t} = P_{2005,t}^{coal} - P_{2004,t}^{coal} + \beta P_{2005,t}^{co2} + \varepsilon_t \quad (4)$$

We set P_{t}^{co2} to reflect the costs of CO₂ emissions at the daily allowance price for a coal power station with an emission rate of 0.9 tCO₂/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 in 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.

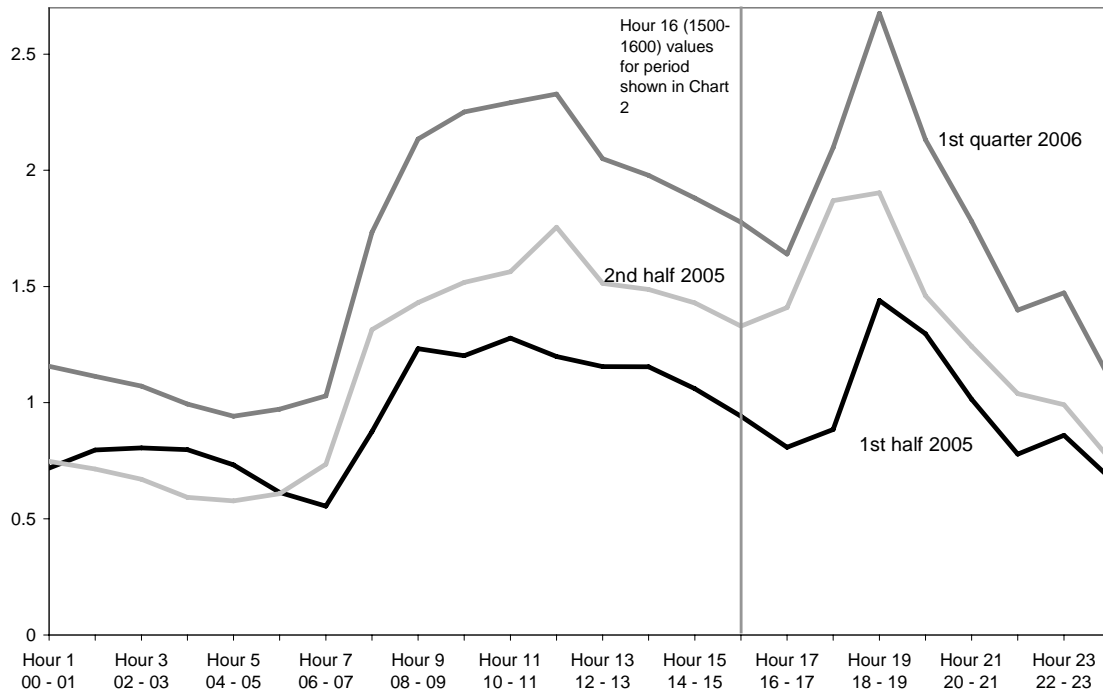


Figure 7 Work-on rate of CO₂ costs on the German spot power market for different time periods, assuming coal generators are at the margin

The figure invites three observations. First, during off-peak periods the work-on rate seems to be lower than one. This could be partially explained by intertemporal constraints of power stations – they prefer to operate during off-peak periods if this saves start up costs. As CO₂ costs increase the start up costs, they also create additional incentives to lower prices during off-peak periods to retain 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 of gas prices during the year 2005-2006 is likely to also explain some of the price increase during peak periods. As spinning cycle gas turbines might be called 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 pm 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 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 pm relative to the pre-ETS year 2004. The curves are again corrected for coal prices and therefore de facto depict: $p_{2005,t} - p_{2004,t} - (p_{2005,t}^{coal} - p_{2004,5}^{coal})$.

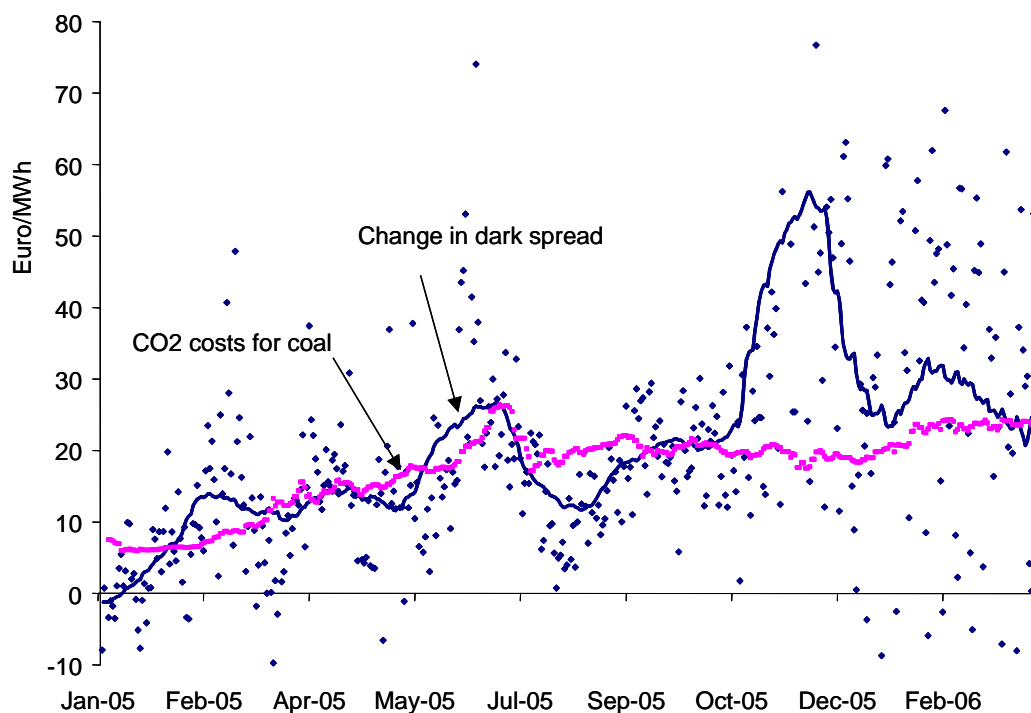


Figure 8 Coal price corrected price increase for electricity (3-4 pm) depicted as dots and their 40day moving average (volatile line) and the evolution of the CO₂ price

As can be noted in Figure 8, during January not the entire CO₂ price was passed through, but subsequently a close link seems to exist between the increase of the CO₂ cost and the increase of the electricity price relative to 2004. In September the public debate in Germany evolved about whether the inclusion of CO₂ opportunity costs into the electricity price is appropriate, and induced generation companies to exercise with some caution. It seems that eventually power firms' management took the position that any other behaviour than profit maximisation is inappropriate, and publicly acknowledged such behaviour, thus allowing traders to return to the habit of fully internalising the CO₂ 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 CO₂ allowances in the spot market.

4. Model estimates of CO₂ cost pass through

In addition to the empirical estimates, CO₂ cost pass through rates have been estimated for some EU countries by means of the model COMPETES.¹¹ COMPETES is basically a model to simulate and analyse the impact of 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 CO₂ emissions trading for power prices, firm profits and other issues related to the wholesale power market in four countries of continental North-western Europe (i.e. Belgium, France, Germany and the Netherlands).

The major findings of the COMPETES model with regard to CO₂ cost pass through are summarised in Table 2. They are compared to model results from the Investment Planning Model (IPM), which are described in more detail in Neuhoff et al. (2006). 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 both models results for the Netherlands.

Under all scenarios considered, power prices turn out to increase significantly due to CO₂ emissions trading. In case of a CO₂ 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.

Table 2 Model estimates of electricity price increases (in €/MWh) due to CO₂ costs at 20 €/t

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

Differences in absolute amounts of CO₂ 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

¹¹ 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, Maryland, USA). For more details on this model, see Sijm et al. (2005) and references cited there, as well as website <http://www.electricitymarkets.info>.

generator (with a high CO₂ emission factor). On the other hand, in France they are often determined by a nuclear plant (with zero CO₂ emissions), while the Netherlands take an intermediate position - in terms of average CO₂ 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 in case the power price is set by a nuclear plant), most of them vary between 60 and 80 percent, depending on the country, market structure, demand elasticity, load period and CO₂ price considered. In general, these model estimates of CO₂ cost pass through are higher than the empirical estimates for the forward power markets in Germany and the Netherlands, as discussed above (but lower than the empirical estimate for the German spot market).

In addition, Table 2 provides the results of simulation runs by the Integrated Planning Model (IPM), a detailed power sector model for the EU developed by ICF Consulting. At a price of 20 €/tCO₂, the average amount of CO₂ 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.¹²

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 to understand the qualitative impact, but the numbers should only be taken as an indication of the order of magnitude involved. We will further discuss this aspect at the end of the section.

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

¹² 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.

estimation of this category of profit changes is based on the assumption that all companies have to buy their allowances and, hence, that CO₂ costs are ‘real’ costs.

2. Changes in profits due to the free allocation of emission allowances. Actually, 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.

Table 3 Changes in aggregated power firms’ profits due to CO₂ emissions trading in Belgium, France, Germany and the Netherlands, based on COMPETES model scenarios

Scenario ^a	Price elasticity	Total profits	Change in profits due to:		Total change in profits due to emissions trading	
			price effects	free allocation	[M€]	[%]
(1)	(2)	[M€] (3)	[M€] (4)	[M€] (5)	[M€] (6)	[%] (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 (CO₂ price is 0) versus a scenario with emissions trading (at a price of 20 €/tCO₂). 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

We start with the analysis of the impact of a perfectly competitive environment. In the fourth column of Table 3, it is assumed that all firms have to buy all their emissions allowances on the market, i.e. there are no windfall profits due to grandfathering. Even under this condition, total firm 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 0.2.¹³ 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

¹³ This implies an increase of the wholesale price level from 20 €/MWh to 30 €/MWh, and hence of the retail price level (including transmission, distribution and marketing costs) from lets say 70 €/MWh to 90 €/MWh, would result in a reduction of demand by 10 percent.

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 is illustrated in column (6).

The model provides additional insights into the impact of strategic behaviour of power generators. If we assume power generators act strategically, then they will push up prices and, therefore, their profits already double in the reference case that ignores emission trading. It would be subject to further empirical work to assess to what extent this level of profits corresponds to the situation before the introduction of emission trading. If we now introduce emission 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 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 realise 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 CO₂ emissions and the assumption that power companies receive, on average, 90 percent of the allowances to cover their emissions for free. At a price of an emission allowance of € 20/tCO₂, 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).

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		Change in profits due to:		Total change in profits
	PC0	PC20-ze	price effects	free allocation	
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
E.ON	2007	4575	1517	1051	2568
Electrabel	1722	2883	625	536	1161
Electricité de France (EdF)	4405	6807	2178	225	2402
ENBW	768	1890	748	373	1122
ESSENT	319	535	-42	257	216
NUON	204	261	-90	148	57
RWE Power	1861	4565	802	1902	2704
Soc. Production d'Elec (SPE)	52	92	13	27	41
STEAG AG	217	438	-25	245	220
Vattenfall Europe	962	2329	-69	1436	1367
Total	13919	27487	5902	7666	13567

Oligopolistic competition (ST)	Total profits		Change in profits due to:		Total change in profits
	ST0	ST20	price effects	free allocation	
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
E.ON	3269	4226	757	199	956
Electrabel	2775	3220	245	199	445
Electricité de France (EdF)	12287	12709	323	98	422
ENBW	1646	2182	330	205	536
ESSENT	775	923	-99	247	147
NUON	650	620	-195	166	-29
RWE POWER	2896	3245	-119	468	349
Soc. Production d'Elec (SPE)	339	348	-51	60	9
STEAG AG	658	1001	-196	539	343
Vattenfall Europe	2103	2718	-636	1251	615
Total	32015	36782	-542	5308	4767

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 (CO₂ price is 0) versus a scenario with emissions trading (at a price of 20 €/tCO₂). 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

There are major differences, however, in profit performance due to emissions trading at the individual firm level, as can be noticed 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.¹⁴ In general, when excluding windfall profits due to grandfathering, 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 particularly 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 hardly benefit from ET-induced price increases in the Dutch market as these are matched by similar increases in CO₂ costs of gas-fired, price-setting power stations. 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 electricity price setting coal. This unbalanced portfolio is reflected in profit losses in the absence of free allowance allocation.

Once the windfall profits due to grandfathering are accounted for, however, all companies realise additional profits due to emissions trading under both scenarios mentioned in Table 4. As coal- and other carbon-intensive companies (such as RWE, STEAG AG and Vattenfall Europe) receive relatively large amounts of CO₂ emission allowances for free, they benefit relatively most from this effect of emissions trading on firms' profits.

Although the above-mentioned quantitative estimates of changes in windfall profits are helpful 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 entry of a new generator. This model therefore provides insights into the profitability during the transition period when emission trading is implemented, but the structure of generation assets has not adjusted to

¹⁴ 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).

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, the model scenarios of strategic behaviour tend to capture qualitative effects, but the quantification typically requires stronger assumptions. For example market design of transmission or balancing markets can have 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 CO₂ cost pass through relative to the competitive model scenarios. Analytic work shows that this result is inverted if we instead assume a constant elasticity of demand function. In this case strategic firms increase the CO₂ pass through rate relative to a competitive scenario. But, we believe 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 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 linear demand cases in general.

Estimates of windfall profits in the Netherlands

Recently, Frontier Economics (2006) has estimated windfall profits due to the EU ETS for the four largest power companies operating in the Netherlands (i.e. ESSENT, NUON, E.ON and Electrabel). For the year 2005, these profits are estimated at € 19 mln 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 percent of the power produced during 2005 was already sold in 2003 and 2004, when CO₂ prices and (assumed) pass through rates were low, resulting in additional revenues of power sales in 2005 of € 69 mln. 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 CO₂ prices were high, resulting in a total cost of € 50 mln.¹⁵ Overall, the net benefits or windfall profits for the four major power companies operating in the Netherlands is estimated at € 19 mln in 2005.

¹⁵ 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.

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 CO₂ 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 €/tCO₂, these changes vary between € 250 and 600 mln 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 substantial losses in 3 out of 4 scenarios. This is due to the fact that (i) 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 (ii) the share of gas-fired power generation - setting the power price - is relatively high in the Netherlands (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).

Table 5 Changes in aggregated profits due to CO₂ emissions trading for the four largest power firms in the Netherlands (E.ON, Electrabel, ESSENT and NUON), based on COMPETES model scenarios

Scenario	Price elasticity	Total profits [M€]	Change in profits due to:		Total change in profits due to emissions trading	
			price effects [M€]	free allocation [M€]	[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 (CO₂ price is 0) versus a scenario with emissions trading (at a price of 20 €/tCO₂). 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

On the other hand, when assuming that the power companies in the Netherlands receive 90 percent of their needed emission allowances for free, the grandfathering effect far outweighs

the price effect, resulting in major total windfall profits due to emissions trading based largely on free allocation. It can be estimated that if the share of grandfathering in total allowances needed by the four major power companies operating in the Netherlands would be reduced from 90 to 40 percent, they would still realize a windfall profit due to emissions trading in all scenarios considered in Table 5.

Secondly, following the methodology used by Frontier Economics for an average, ‘representative’ year, it may - for instance - be assumed that (i) total CO₂ emissions of the four major power companies in the Netherlands is about 37.5 MtCO₂ per year, while the amount of allowances grandfathered to these companies is 35 MtCO₂ per annum (hence, the allocation deficit is 2.5 MtCO₂ per year, i.e. about 7 percent of total emissions), (ii) the price of a CO₂ allowance bought is, on average, equal to the price of a CO₂ allowance passed through to power prices, and amounts to 20 €/tCO₂, and (iii) the average pass through rate is 50 percent. In that case, the total windfall profits of the four major power companies in the Netherlands amounts to € 325 mln.

Finally, the third approach to estimate windfall profits is based on ET-induced price increases of domestically produced power sales in the Netherlands. These sales amount to some 100 TWh per year. Assuming that (i) 75 percent of this volume is sold during peak hours and the remaining part during the off-peak, (ii) that during peak hours power prices are set by a gas-fired installation with an emission factor of 0.4 tCO₂/MWh and during the off-peak by a coal-fired plant with an emission factor of 0.8 tCO₂/MWh, (iii) the CO₂ price is, on average, 20 €/t, (iv) the average pass through rate is 40 percent during the peak and 50 percent during the off-peak, and (v) the allocation deficit for the power sector as a whole is equivalent to 4 mln tCO₂ per year. In that case, the total windfall profits amount to € 360 mln per year.¹⁶

To conclude, at a price of 20 €/tCO₂, estimates of windfall profits due to the EU ETS in the power sector of the Netherlands for an average, ‘representative’ year vary between € 300-500 mln. 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.¹⁷ 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 firm profits in the long run towards a new equilibrium.

¹⁶ 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 increased in the price of electricity.

¹⁷ 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.

6. Summary of major findings and policy implications

This paper shows that, 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 CO₂ costs per MWh generated by the marginal production unit. This is confirmed by empirical and model findings, showing estimates of CO₂ cost pass through rates varying between 40 and 100 percent for wholesale power markets in countries of North-western Europe. In absolute amounts, these rates imply that, at a CO₂ 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 CO₂ and the assumptions made. For instance, at a CO₂ price of 20 €/t, ETS-induced windfall profits in the power sector of the Netherlands are estimated at € 300-500 mln per year, i.e. about € 3-5 per MWh produced and sold in the Netherlands.

In order to reduce the windfall profits, an increasing part of the allowances available for the power sector should be auctioned, starting from the second phase of the EU ETS (2008-2012). While auctioning would raise power prices by the costs of the CO₂ allowances, it would have several beneficial effects, including (i) avoiding windfall profits among producers, (ii) enhancing environmental-economic efficiencies by internalising the external costs of CO₂ emissions into the power price, (iii) raising public revenues that could be used to mitigate potential drawbacks of rising power prices, and (iv) treating incumbents and newcomers equally while avoiding potential distortions of new investment decisions.

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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 each chief trader is expected to submit daily an updated price prediction on 40 contract types, it is unlikely that she 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's assume that electricity prices are formed according to:

$$p_t = rc_t + e_t \text{ with } e_t \text{ iid,} \quad (1)$$

but we can only observe q_t with

$$q_t = \frac{p_t + p_{t-1}}{2}. \quad (2)$$

This reflects that trading volume is limited with only trades 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 through rate? We estimate:

$$q_t = bc_t + \eta_t \quad (3)$$

1. OLS estimation

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

$$\begin{aligned} \hat{b} &= \frac{\sum c_t q_t}{\sum c_t^2} \quad (\text{using def of } q_t) \\ &= \frac{\sum c_t \frac{p_t + p_{t-1}}{2}}{\sum c_t^2} \quad (\text{using def of } p_t) \end{aligned}$$

$$\begin{aligned}
&= r \frac{\sum c_t(c_t + c_{t-1})/2}{\sum c_t^2} + \text{error term (assume independence of } c \text{ and } e) \\
&= r - \frac{r}{2} \frac{\sum c_t(c_t - c_{t-1})}{\sum c_t^2} = \left\{ \begin{array}{ll} < r & \text{if } c_0 < c_T \\ > r & \text{if } c_0 > c_T \end{array} \right\} + \text{error}
\end{aligned}$$

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 iid.

We minimise

$$\begin{aligned}
\sum \gamma_t^2 &= \sum (\eta - p\eta_{t-1})^2 \\
&= \sum (q_t - bc_t - \rho(q_{t-1} - bc_{t-1}))^2 \\
&= \dots [\text{without } b] \dots - 2b \sum (c_t - \rho c_{t-1})(q_t - \rho q_{t-1}) + b^2 \sum (c_t - \rho c_{t-1})^2
\end{aligned}$$

Using like always the first order condition

$$\begin{aligned}
\hat{b} &= \frac{\sum (c_t - \rho c_{t-1})(q_t - \rho q_{t-1})}{\sum (c_t - \rho c_{t-1})^2} \quad (\text{using def of } q_t) \\
&= \frac{\sum (c_t - \rho c_{t-1}) \frac{p_t - \rho p_{t-1} + p_{t-1} - \rho p_{t-2}}{2}}{\sum (c_t - \rho c_{t-1})^2} \quad \text{using def of } p_t \\
&= r \frac{\sum (c_t - \rho c_{t-1}) \frac{c_t - \rho c_{t-1} + c_{t-1} - \rho c_{t-2}}{2}}{\sum (c_t - \rho c_{t-1})^2} + \text{error term} \\
&\hspace{15em} (\text{assume independence of } c \text{ and } e) \\
&= \frac{r}{2} + \frac{r}{2} \frac{\sum (c_t - \rho c_{t-1})(c_{t-1} - \rho c_{t-2})}{\sum (c_t - \rho c_{t-1})^2} + \text{error}
\end{aligned}$$

3. Quantification of bias

We use the CO₂ 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 1 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.

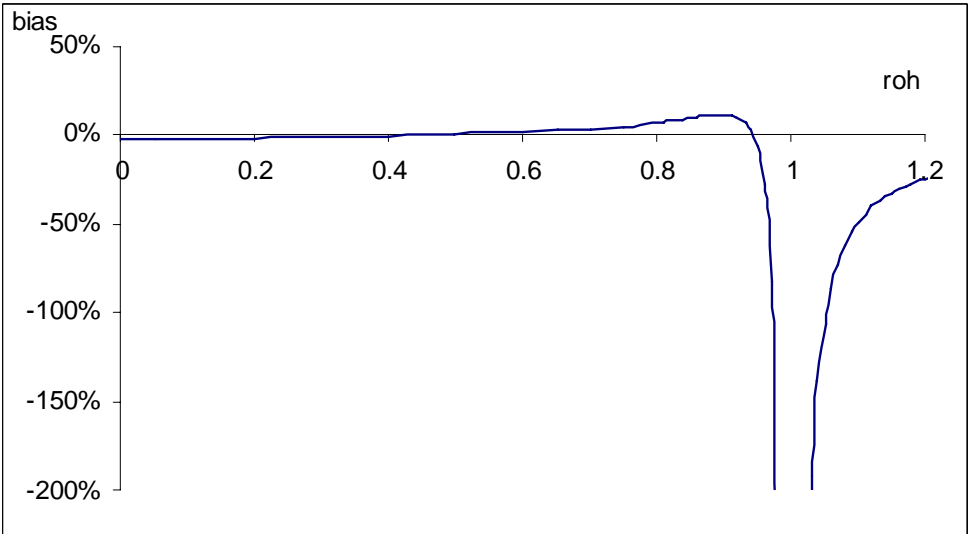


Figure A.1 Bias in estimated pass through rate

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 CO₂ 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 not cointegrated AR(1) processes (but does not have the quick convergence properties that otherwise characterise estimations using levels).

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

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

$$\begin{aligned}
&= \frac{\sum dc_t \frac{dp_t + dp_{t-1}}{2}}{\sum dc_t^2} \text{ (using def of } p_t) \\
&= r \frac{\sum dc_t (dc_t + dc_{t-1})/2}{\sum dc_t^2} + \text{error term} \\
&\hspace{15em} \text{(assume independence of } c \text{ and } e)
\end{aligned}$$

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

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