The impact of the EU ETS on electricity prices

Final report to DG Environment of the European Commission

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This project is registered at ECN under number 7.7848. For information on the project you can contact Jos Sijm by email (sijm@ecn.nl) or by telephone (+31 224 568255).

Second, revised edition

On February 2, 2009, a revised edition of the report has been released, including some adjustments and editorial corrections particularly in Section 2.2 and Appendix A.

Abstract

The present study analyses the impact of the EU Emissions Trading Scheme (ETS) on electricity prices, in particular on wholesale power markets across the EU. To study this impact, it uses a variety of methodological approaches, including theoretical, empirical, model, literature and policy analyses. The study shows that a significant part of the costs of freely allocated CO_2 emission allowances is passed through to power prices, resulting in higher electricity prices for consumers and additional ('windfall') profits for power producers. In addition, it discusses some policy implications of the pass-through of these costs. It concludes that the pass-through of CO_2 costs to electricity prices is a rational, carbon-efficient policy, while the issue of windfall profits can be addressed by either taxing these profits or auctioning - rather than free allocations - of the emission allowances.

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Summary

Power prices in EU countries have increased significantly since the EU emissions trading scheme (ETS) became effective on the 1st of January 2005. Besides other factors, these increases in power prices may - at least in part - be due to this scheme, in particular due the pass-through of the costs of EU allowances (EUAs) to cover the CO_2 emissions of eligible installations. In the power sector, however, eligible installations have usually received most of their needed allowances for free during the first phase of the EU ETS (2005-2007).

In several EU countries, the coincidence of the increases in power prices and the implementation of the EU ETS has raised questions on whether power producers have indeed passed through the costs of freely allocated CO_2 allowances to (wholesale) electricity prices, and to what extent the increase in these prices can be attributed to this pass-through or to other factors. In addition, it has raised questions on whether - and to what extent - the supposed passing through of these costs has led to additional profits for power producers, i.e., the so-called 'windfall profits'. Finally, the supposed ETS-induced increases in power prices and generators' profits have raised questions and concerns regarding its impact on the international competitiveness of some power-intensive industries, the purchasing power of electricity end-users such as small households or, more generally, the distribution of economic surplus among power producers and consumers. As a result, in several countries policy makers and stakeholders of industrial or other interest groups have suggested a variety of options to address these concerns, including improving the EU ETS allocation system (notably increasing the share of auctioning), taxing windfall profits or controlling market prices of either EU carbon allowances, electricity or both.

Against this background, the Energy research Centre of the Netherlands (ECN) has conducted a study on the impact of the EU ETS on electricity prices. More specifically, the major objectives of the present study include:

- To analyse empirically the trends in electricity prices during the period 2004-2006 for a variety of power markets across the EU ETS, and to assess whether and to what extent changes in these prices can be attributed to the pass-through of the costs of freely allocated EU carbon allowances or to other factors.
- To analyse the factors affecting the pass-through of emissions trading costs to power prices, using economic theory and models.
- To discuss whether the supposed EU ETS-induced increases in power prices and generators' profits are issues for concern and, if yes, to evaluate policy options to address these issues.

In order to achieve these objectives, the present study has applied a variety of analytical approaches:

- *Theoretical analyses,* in particular with regard to the impact of allocation of carbon allowances as well as other factors affecting the pass-through of carbon costs to power prices, such as the structure of the power market.
- *Empirical and statistical analyses* of trends in prices of fuels, CO_2 and electricity on both spot and forward markets in several EU countries during 2005-2006, including the assessment of passing through CO_2 opportunity costs in the price of electricity.
- *Model analyses*, in particular by means of the COMPETES model, of the implications of emissions trading on wholesale power prices and generators' profits in EU ETS countries
- *Literature analyses,* i.e., a survey of the literature*,* notably of empirical and modelling studies on the impact of the EU ETS on power prices.
- *Policy analyses,* in particular of the policy options and implications to address some of the concerns related to the EU ETS-induced increases in power prices and generators' profits.

The major results of these analytical approaches and their policy implications are discussed below.

Theoretical analyses

Basically, the extent to which costs of emissions trading are passed through to electricity prices depends on two sets of factors, namely (i) those related to the allocation of the emission allowances, and (ii) those related to the structure of the power market.

The impact of allocation on power prices

According to economic theory, power producers pass through the opportunity costs of emissions trading to electricity prices regardless of whether the allowances have been auctioned or allocated for free. In the ideal or reference cases of auctioning versus perfect free allocation, the impact of emissions trading on abatement efficiency and power prices is similar in both cases. In practice, however, emissions trading schemes may contain some specific free allocation provisions which distort the outcomes of these ideal cases in terms of carbon efficiency and power prices. These provisions include in particular (i) updating baselines of free allocation to incumbents, based on their output, (ii) contingent free allocation to plant closures (i.e., loosing freely obtained allowances if plants close), and (iii) free allocation to new entrants.

The main effect of these specific free allocation provisions is that they reduce the carbon efficiency of the ETS, i.e., they result in less CO_2 emission reduction - if the carbon budget of the system is not fixed - and/or in higher abatement costs. This applies in particular for so-called protected industries, such as the power sector, which do not face competition from outside the scheme. In addition, the specific provisions may reduce the ETS-induced increases in power prices in the medium or long term, depending on whether the carbon budget is fixed or not.[1]

The impact of market structure on power prices

The second category of factors affecting the impact of emissions trading on electricity prices is the structure of the power market. This structure refers primarily to the interaction of three elements:

- The number of firms active in the market, indicating the level of market competitiveness or market concentration.
- The shape of the demand curve, notably whether this curve is linear or not.
- The shape of the supply curve, particularly whether the marginal costs are constant or not.

The major theoretical findings and implications regarding the impact of market structure on cost pass-through include:

- If demand is perfectly elastic, i.e., the price is given, the pass-through rate (PTR) of carbon costs to power prices is zero (where carbon costs refer to the marginal CO_2 emissions trading costs of the marginal technology setting the power price at a certain demand level).[2]
- If demand is perfectly inelastic, i.e., demand is fixed and unresponsive to price changes, the PTR is always 100% (in the case of competitive markets), regardless of the shape of the sup-

[1] The carbon budget of an ETS refers to the total amount of carbon allowances allocated to eligible installations (i.e., the cap) and, if allowed, the use of offset credits – such as JI or CDM credits – to cover the emissions of these installations. According to the January 2008 proposals of the European Commission, the cap of the EU ETS is fixed far beyond 2020 while the use of JI/CDM is limited up to 2020. Therefore, the carbon budget of the EU ETS is fixed at least up to 2020 (although it is not certain whether in all cases the available JI/CDM limit will be fully used). More importantly, according to these proposals, carbon allowances will be auctioned to the power sector starting from 2013, implying that the impact of free allocation provisions on power prices – if any – will be eliminated.

[2] Pass-through rates in this study are calculated by comparing the price of electricity with and without emissions trading. Even if the power producers include the full carbon cost is their prices, this may not lead to a PTR equal to one, for instance due to a lower increase of the electricity price resulting from an induced lower power demand.

ply function, assuming no change in the dispatch or merit order of the generation plants (i.e. the ranking of these plants according to their output costs).
- If supply is perfectly elastic, i.e., marginal costs are constant, the PTR always tends towards 100% when the number of firms becomes large and, hence, markets approach the case of full competition, regardless of the shape of the demand function. When markets are not competitive, however, the PTR may be either significantly lower or higher than 1.0, depending on whether the demand curve is linear or not.
- If supply is not perfectly elastic, i.e., marginal costs are variable, one has to distinguish two definitions of the PTR. Whereas, in the first definition, the change in power price is related to the change in carbon costs only, in the second definition, it is related to ETS-induced changes in both carbon costs and other (marginal) costs of power generation.

The distinction between the two, alternative definitions of the pass-through rate is also relevant in the case of ETS-induced changes in the merit order of the power supply curve. For instance, if the PTR is defined as dP/dMC (where dMC refers to the difference between the marginal costs of the price-setting production technology after and before emissions trading), its value is and remains 100% in competitive markets facing perfectly inelastic demand, regardless of whether the merit order changes or not. However, if the PTR is defined as dP/dCC (where dCC refers to the carbon costs of the marginal production unit after emissions trading), the PTR can deviate substantially from 100% (either >1.0, or <1.0) if the merit order changes, even under competitive markets with perfectly inelastic demand and perfectly elastic supply, depending on the carbon intensity of the marginal generation technology after emissions trading.

In addition, there are some other factors related to the power market which influence the pass-through of carbon costs to power prices, including:
- *Market strategy.* Besides profit maximisation (as generally assumed), firms may pursue other objectives such as maximising market shares or sales revenues. These differences in market strategy affect the PTR, regardless of whether carbon costs are opportunity or actual costs.
- *Market regulation.* In the case of market regulation (or 'regulatory threat') public authorities (or firms) may treat the actual, real costs of purchased allowances differently than the opportunity costs of freely obtained allowances, resulting in different levels of cost pass-through to power prices.
- *Market imperfections.* The pass-through of carbon costs to power prices may be affected by the incidence of market imperfections such as (i) risks, uncertainties or lack of information, and (ii) other production constraints, including 'must run' limitations, high adjustment costs of changing generation technologies, lack of flexible fuel markets, etc. Moreover, related to market strategy, rather than exhibiting maximising behaviour, firms may pursue non-optimal strategies, for instance by applying simple rules of thumb for retail power pricing in order to achieve a satisfying level of profits or market shares.

Empirical and statistical analyses

Trends on power, fuel and carbon markets
The present study has conducted detailed empirical analyses of the trends on power, fuel and carbon markets in nine major EU ETS countries (France, Germany, Italy, Poland, Spain, Sweden, the Czech Republic, the Netherlands and the United Kingdom). The major findings of these analyses include:
- In general, forward power prices in the countries analysed have increased significantly between early 2005 and mid-2006, in particular for peak products. However, these prices have stabilised - or even declined - during the second part of 2006, especially for off-peak products. Similar trends can be observed on the spot markets, although less clear due to the high volatility of the power prices on these markets. On average, however, power spreads have generally increased considerably on both forward and spot markets over 2004-2006.

- The significant increases in forward power prices in 2005 can be largely attributed to higher fuel prices in those cases where gas-fired plants set the price, and to a lesser extent to the pass-through of carbon costs. On the other hand, in those cases where coal-fired stations determine the price, increases in this price can be largely attributed to the pass-through of carbon costs (and hardly to higher fuel prices as the price of coal has hardly increased in 2005). On the spot markets, it is more difficult to find a clear correlation between changes in the power prices on the one hand and changes in the fuel and/or carbon costs on the other hand, mainly due to the incidence of other factors affecting the power price on these markets, such as extreme or rapidly changing weather patterns, plant outages or other factors causing major fluctuations in market scarcity in the short term.
- Over a relatively short period, the link between CO_2 prices and power prices is sometimes very clear, notably on forward markets. This applies particularly for the period March-July 2005 - when CO_2 prices on the EU ETS market increased steadily from about 10 to 30 €/tCO_2 - and in April-May 2006, when CO_2 prices collapsed suddenly from approximately 30 to 10-15 €/tCO_2. Over longer time periods, however, the relationship between carbon and power prices is less clear, most likely because over longer time periods power prices are affected by other factors besides fuel and carbon costs, such as changes in market structure or generation capacities.
- Moreover, after the collapse of the carbon price in April/May 2006 and, particularly, during the latter part of 2006 (when both carbon and gas prices declined steadily), the link between power prices and fuel/carbon costs is far less clear, suggesting that other factors - such as growing capacity scarcities or market power - have become more important in affecting power prices.

By means of regression analyses, pass-through rates (PTRs) of CO_2 emission costs to power prices in 2005 and 2006 have been estimated for the nine EU ETS countries mentioned above. These estimates cover the peak and off-peak periods of these countries separately in order to account for differences in power demand between these periods and, hence, for possible differences in price-setting units to meet varying levels of demand. Moreover, PTRs have been estimated for both spot and - if present - forward power markets of these countries.[3]

Forward market analyses

Table S.1 provides a summary of the estimated pass-through rates of carbon costs on the forward market during the peak and off-peak periods in 2005 and 2006 for five selected EU ETS countries, i.e., Germany (DE), France (FR), the Netherlands (NL), Sweden (SE) and the United Kingdom (UK). Based on these results, the major findings and conclusions are:

- All of 22 estimates were found to be statistically significant at the 1% level with, in general, small confidence intervals. However, the indicator for the 'goodness of fit' of the estimated regression equation (R^2) is generally low (although far from bad for a single variable equation), implying that only a small part - usually less than a third - of the changes in power prices/spreads can be attributed to changes in carbon costs.
- Most of the estimates of pass-through rates show levels between 0 and 1, which is consistent with the expectation that the carbon (opportunity) costs of the EU ETS are passed-through. Actually, 17 out of 22 estimates range between 38 to 83%, 4 estimates are slightly above 1 (i.e., varying between 103 and 134%), and only one estimate is significantly larger than 1 (i.e., 182%).
- For France and Germany, the estimated PTRs are remarkably similar, ranging from 40 to 66% during 2005-2006 for the forward peak and off-peak markets. For Sweden, the estimated PTRs in 2005-2006 are about 50-60% on the forward baseload market. For the Netherlands, the estimated PTRs are relatively low for the off-peak period when coal is assumed to set the power price, whereas they are relatively high for the peak period when gas is the

3 During the observation period as a whole (i.e., 2004-2006), there were as yet no forward power markets in Italy, Poland, Spain and the Czech Republic. Hence, for these countries, carbon cost pass-through has been analysed only on the spot markets.

assumed marginal technology. Finally, the estimated PTRs on the forward markets in the UK are rather similar in 2006 (i.e., ranging only from 0.58 to 0.66) while they vary widely in 2005, ranging from 0.83 to 1.82.

Table S.1 *Estimates of carbon costs pass-through rates on forward power markets in EU ETS countries during the peak and off-peak period in 2005-2006*

	Load period and marginal unit	2005 PTR[b]	2005 StE	2005 R^2	2006 PTR	2006 StE	2006 R^2
DE[a]	Peak_coal	0.60	0.06	0.32	0.57	0.05	0.38
	Off-peak_coal	0.41	0.04	0.35	0.64	0.04	0.58
FR	Peak_coal	0.66	0.08	0.23	0.58	0.07	0.26
	Off-peak_coal	0.40	0.05	0.22	0.59	0.04	0.47
NL	Peak_gas	1.34	0.14	0.28	1.10	0.14	0.20
	Off-peak_coal	0.40	0.04	0.34	0.38	0.03	0.38
SE[c]	Base_coal	0.53	0.04	0.42	0.62	0.05	0.38
UK-S[d]	Peak_ccgt	0.83	0.17	0.09	0.58	0.06	0.31
	Off-peak_coal	1.03	0.18	0.12	0.60	0.06	0.29
UK-W[d]	Peak_ccgt	1.18	0.17	0.15	0.59	0.11	0.10
	Off-peak_coal	1.82	0.19	0.29	0.66	0.11	0.12

a) The nine EU ETS countries analysed in the present report include France (FR), Germany (DE), Italy (IT), Poland (PL), Spain (ES), Sweden (SE), the Czech Republic (CZ), the Netherlands (NL) and the United Kingdom (UK). In Italy, Poland, Spain and the Czech Republic, however, there was no forward power market present during the whole observation period 2004-2006.

b) These estimates are based on the following (standard) fuel efficiency assumptions: coal: 0.35; gas: 0.40, and Combined Cycle Gas Turbine (CCGT): 0.55. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at the 1% level. R^2 is an indicator for the 'goodness of fit' of the regression equation, varying from 0 ('bad') to 1 ('very good'). A white R^2 indicates a value below 0,5, light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75.

c) In Sweden, only baseload products are traded on the forward market.

d) In the UK, the most liquid forward markets involve seasonal forward products, i.e., winter-ahead and summer-ahead. Two forward products are evaluated, therefore, relating to the summer forward market and the winter forward market, respectively.

The above findings, however, have to be interpreted with due care as they depend on the data, methodology and assumptions used. These include the assumptions that over a certain observation period - for instance, during peak demand in 2005 or the off-peak period in 2006 - (i) power prices are set by a single (marginal) technology with a fixed, generic fuel efficiency, or (ii) changes in power prices are predominantly caused by changes in the underlying costs of fuels and CO_2 emission allowances, and that all other generation costs and factors affecting power prices are more or less fixed.

Spot market analyses

Table S.2 presents a summary of the statistical results of estimating carbon costs PTRs on the spot power markets of the selected EU ETS countries during the peak and off-peak periods in 2005 and 2006. Compared to the outcomes of the forward market estimated discussed above, these results are less straightforward. Overall, the major findings regarding the estimates of the PTRs on the spot markets include:

- Out of 36 PTR estimates, 21 prove to be statistically significant at the 10% level. For 2005, two-thirds of the estimates (i.e., 12 out of 18) are statistically significant, while for 2006 the score is one-half (i.e., 9 out of 18).
- Out of the 21 statistically significant estimates, 17 PTRs have a positive value between 0 and 2. In particular the estimates for the off-peak hours in countries such as Germany, France, Spain, Sweden and the UK seem fairly consistent with the hypothesis that CO_2 costs are passed through, with most PTR estimates ranging from 0.4 and 1.0. In addition, the esti-

mated PTRs are usually higher for the peak than off-peak period.

- Two out of 21 statistically significant estimates have a negative value. Both concern Italy in 2006 during the peak (-0.67) and the off-peak (-2.98). From an economic point of view, a negative PTR does not make sense as it implies that either prices go up when costs go down or vice versa. From a statistical perspective, a negative PTR may be explained by either a misspecification of the price-setting unit or, more likely, the coincidence of decreasing (increasing) carbon costs and increasing (decreasing) power prices due to factors other than fuel/carbon costs such as more (less) scarcity on the spot market. In 2006, for instance, power prices on the Italian spot market have been extremely volatile, with some major price hikes, due to weather-related events such as a cold spell in early 2006, a heat wave in mid-2006 and, at the same time, a drop in wind generation. Hence, rather than by (small) changes in carbon costs, power prices on the Italian spot market in 2006 seem to have been affected predominantly by these weather-related events or other factors affecting market scarcity.

Table S.2 *Estimates of carbon costs pass-through rates on spot power markets in EU ETS countries during the peak and off-peak period in 2005-2006*

	Load period and marginal unit	2005 PTR	2005 StE	2005 R^2	2006 PTR	2006 StE	2006 R^2
CZ	Peak_coal	1.50	0.39	0.49	-0.71	0.84	0.65
	Off-peak_coal	0.44	0.22	0.28	-0.27	0.26	0.46
DE	Peak_coal	1.76	0.88	0.69	0.92	0.72	0.22
	Off-peak_coal	0.82	0.23	0.75	0.68	0.17	0.76
ES	Peak_oil	0.50	0.67	0.65	1.11	0.49	0.76
	Off-peak_coal	0.64	0.23	0.74	0.52	0.28	0.90
FR	Peak_coal	1.96	0.97	0.75	1.18	0.96	0.64
	Off-peak_coal	0.98	0.33	0.72	0.76	0.17	0.80
IT	Peak_oil	-0.97	0.62	0.69	-0.67	0.23	0.79
	Off-peak_CCGT	0.39	0.70	0.58	-2.98	0.68	0.84
NL	Peak_gas	4.17	0.84	0.37	0.69	1.16	0.45
	Off-peak_coal	0.19	0.17	0.72	1.21	0.16	0.68
PL	Peak_coal	0.09	0.07	0.58	-0.04	0.03	0.72
	Off-peak_coal	0.09	0.06	0.82	0.00	0.06	0.61
SE	Peak_coal	0.48	0.12	0.60	0.44	0.31	0.75
	Off-peak_coal	0.35	0.12	0.85	0.82	0.21	0.92
UK	Peak_CCGT	3.70	0.75	0.28	0.89	1.31	0.14
	Off-peak_coal	0.70	0.40	0.84	1.53	0.25	0.66
	Scores	15	12		12	9	

Note: PTR stands for the pass-through rate of carbon costs to power prices and SE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at 10% level. R^2 is an indicator for the 'goodness of fit' of the regression equation, varying from 0 ('bad') to 1 ('very good'). A white R^2 indicates a value below 0,5, light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75. The last row indicates the number of PTR values between 0 and 2 (column PTR) and the number of statistically significant estimates (column StE).

- Two out of 21 statistically significant estimates have a relatively high value. Both estimates refer to gas-generated power during the peak period of 2005. One estimate concerns Open Cycle Gas Turbine (OCGT)-generated power in the Netherlands (with an estimated PTR of 4.2) and the other Combined Cycle Gas Turbine (CCGT)-generated power in the UK (i.e., 3.7). From a theoretical point of view, a PTR > 1.0 can be explained by either a change in the merit order or the incidence of non-competitive markets facing non-linear demand. From an empirical or statistical point of view, however, it is more likely that the high values of the PTRs are due to a misspecification of the marginal unit setting the price and/or the incidence of other factors besides carbon/fuel costs affecting spot prices, resulting in an overestimation of the PTR value. For instance, depending on the actual fuel/carbon costs for gas versus coal, either a coal-fired plant or a CCGT may be the price-setting unit during peak demand in the UK. Assuming CCGT to be the single, marginal unit during the peak, while actually both CCGT and coal are, alternately, setting the price may lead to an overestimate of the PTR value.

- All four estimates for Poland are statistically insignificant. Apart from statistical misspecifications (or data shortcomings), this may be due to the fact that power prices in Poland was heavily regulated up to mid-2007 and, hence, there was little room for passing through the (opportunity) costs of freely allocated emission allowances.
- Overall, there is statistical evidence to support the conclusion that there is a significant rate of carbon cost pass-through on spot markets in several cases, in particular during (i) the off-peak period of both 2005 and 2006 for countries such as Germany, France, Spain, Sweden and the UK, (ii) the peak period of 2005 for countries such as the Czech Republic, Germany, France, the Netherlands, Sweden and the UK, (iii) the off-peak period of 2005 in the Czech Republic, (iv) the peak period of 2006 in Spain, and (v) the off-peak period of 2006 in the Netherlands. In general, however, such evidence is lacking or inconclusive for the peak period in 2006 or for some specific countries, notably Italy and Poland.

It is important to emphasize, however, that the statistical estimates of the PTRs for the spot markets have to be treated with even greater care than those for the forward markets. In addition to the qualifications made above with regard to the forward estimates, this results particularly from the fact that spot power prices have a more market-balancing character and, hence, are more volatile as they are often less driven by costs (for fuels or carbon) than events such as extreme or rapidly changing weather patterns, plant outages or other factors causing major fluctuations in market scarcity. Due to a lack of data, analytical tools or other resources, however, it is often not possible to account for these events and factors in an adequate, quantitative way when conducting statistical analyses to estimate the pass-through of carbon costs to power prices on a variety of sport markets across the EU ETS. Therefore, due to the incidence of these events or other factors affecting spot power prices, the estimates of the carbon costs PTRs on spot markets may be not significant and, hence, inconclusive.

Retail market analyses

Power prices on retail markets for either households or industrial users in EU ETS countries have also increased significantly over 2004-2006. However, the empirical evidence on the carbon costs pass-through on these markets is still scarce and ambiguous, depending on the assumptions made. If it is assumed that over the period 2004-2006 changes in the retail power spreads - defined as retail power prices excluding taxes and fuel costs - are solely due to carbon costs passed through, the impact of the EU ETS on (changes in) retail power prices was still relatively low in 2005 due to relatively low year-ahead carbon prices in 2004 and, perhaps, some time-lags or other (marketing) constraints in passing through these costs to retail prices. In 2006, however, this impact seems to be already more significant due to relatively higher forward carbon prices in 2005 and, presumably, an increasing share of carbon costs passed through. Moreover, if it is assumed that the carbon costs passed through on the retail market are similar to the carbon costs passed through on the wholesale market, the impact of these costs - and, hence, of the EU ETS - on retail power prices becomes generally even more significant.

In general, however, it can be concluded that, proportionally, retail power prices are less affected by the pass-through of carbon costs as, notably for households, they are usually 2-4 times higher than wholesale power prices due to high energy taxes, and high distribution or other marketing costs which largely determine retail power prices.

COMPETES model analyses

COMPETES is basically a model to simulate and analyse the impact of strategic behaviour of large producers on the wholesale power market under different market structure scenarios (varying from perfect competition to oligopolistic or monopolistic market conditions, with different levels of demand responsiveness to price changes). As part of the present study, it has been used to analyse the implications of emissions trading at different carbon prices for power prices, sector emissions and generators' profits in 20 European countries.

The major findings of the COMPETES model analyses include:

- Wholesale power prices increase significantly due to CO_2 emissions trading under all scenarios considered. In the case of a CO_2 price of 20 €/tonne, these increases are generally highest in Poland (19 €/MWh, assuming that carbon costs are indeed passed-through) and lowest in Sweden (3-11 €/MWh. For the EU-20 countries, on average, the increase in wholesale power prices is estimated at 10-13 €/MWh, i.e., an increase of about 10-30% compared to the power prices before emissions trading.
- Estimates of the PTRs are generally high. Most of these rates vary between 70 and 90%, depending on the country, market structure, and demand elasticity considered. In general, the PTR is lower in scenarios with a higher price elasticity and higher in scenarios characterised by perfect competition (thereby confirming economic theory as COMPETES is based on market structures facing linear demand).
- A striking result of the COMPETES model analyses is that emissions trading and the resulting pass-through of carbon cost to electricity prices may reduce CO_2 emissions significantly by affecting not only producers decisions - through a re-dispatch or change in the merit order of generation technologies - but also consumer decisions, i.e. through reducing power demand in response to ETS-induced increases in electricity prices. For instance, under perfect competition and a price elasticity of demand of 0.2, a carbon price of 20 €/tCO_2 leads to an emission reduction of more than 210 MtCO_2, of which more than 80 MtCO_2 is due to demand response and the rest to re-dispatch. At a carbon price of 40 €/tCO_2, total abatement amounts even to 360 MtCO_2 of which almost 200 MtCO_2 is attributed to demand-induced less power production. Therefore, if power demand is price responsive (notably in the medium or long run), the pass-through of carbon costs to higher electricity prices for end-users is a major element in a policy regime of reducing CO_2 emissions in the medium or long term.
- In all scenarios with emissions trading - either including or excluding free allocations - operational profits of power generators in the EU-20 as a whole increase significantly compared to comparable scenarios without emissions trading. Individual power companies, however, may face a decline in their operational profits and/or sales volumes in the case of full auctioning, depending on the carbon intensity of their production (compared to other, price-setting competitors) and the responsiveness of power demand to higher electricity prices.

Literature analyses

A survey of the literature, including empirical and modelling studies on the impact of the EU ETS on power prices, confirms largely the empirical and model findings outlined above. Empirical studies have usually estimated PTRs varying from (less than) 0 to more than 1.0. This variety of outcomes results mainly from differences in (i) definitions of the PTR or regression variable estimated, (ii) coverage of the countries, power markets and observation periods analysed, and (iii) data and methodologies used. Due to these differences, it is hard to compare - or to draw firm, general conclusions from - these empirical studies. Nevertheless, most of these studies do seem to indicate that even in the early days of the EU ETS a major part of the scheme-induced carbon costs was passed through to power prices, notably in the more liberalised power markets of West-European countries.

Modelling studies have usually estimated the ETS-induced increase in power prices in absolute terms, varying between 1 and 19 €/MWh (at a carbon price of, in general, 20 €/tCO_2). Apart from differences in model specifications (such as differences in assumed market structures or price elasticities of power demand), these differences in ETS-induced increased in power prices result largely from differences in the carbon intensity of the power generation technology mix among countries, including dynamic changes in this mix over time.

Policy analyses

As supported by economic theory and empirical evidence, power producers in competitive, unregulated electricity markets pass through (part of) the opportunity cost of CO_2 emissions trading, even if they receive carbon allowances for free. From a climate policy perspective, passing-through the costs of CO_2 emissions is a rational and intended effect, enhancing the efficiency of emissions trading by giving incentives to end-users to reduce their consumption of carbon-intensive goods. For instance, the COMPETES model simulations show that price-induced reductions in power demand can potentially account for a large fraction of emission reductions. Hence, the pass-through of emissions trading costs should be supported and promoted rather than discouraged - even if the allowances are granted for free - by creating conditions for competitive power markets and avoiding measures to regulate price formation or carbon cost pass-through on these markets.

Nevertheless, the pass-through of CO_2 emission costs - notably in the case of free allocations - may raise certain questions or concerns affecting the socio-political acceptability of the EU ETS. In particular, these questions or concerns refer to the windfall profits for power producers and, to a lesser extent, to ETS-induced increases in power prices for certain end-users, notably power-intensive industries which may not be able to pass on their additional electricity costs to their outlet prices.

In order to address the (either putative or real) concerns mentioned above, policy makers, analysts, industrial stakeholders or other interest groups have suggested a wide variety of policy options. These include, among others, (i) auctioning of emission allowances, (ii) reducing carbon prices, (iii) regulating power prices, (iv) encouraging competitive power markets, and (v) taxing windfall profits.

An evaluation of these options shows that, in general, the effectiveness of options to control or reduce carbon/power prices - either directly or indirectly - is low to medium, partly depending on the means to achieve these objectives, in the first place because they reduce the efficiency to achieve the emission reduction target for which the system has been designed. Moreover, in general they largely fail to address the ETS-related concerns mentioned above or they have certain disadvantages or other side-effects which make these options not attractive or acceptable to policy makers.

On the other hand, the overall performance of auctioning allowances to power producers is considered to be high as it enhances the carbon efficiency of the EU ETS and eliminates the windfall profits due to free allocations. Moreover, it raises revenues that can be used to (i) finance public expenditures on carbon abatement or other useful, social objectives, (ii) invest in improving competitiveness or reduce taxation and related efficiency distortions (the so-called 'double dividend'), or (iii) address potential social concerns of poorer electricity consumers.

However, auctioning does not reduce generators' windfall profits due to ETS-induced increases in power prices - in particular for infra-marginal, less carbon-intensive plant operators - and may even lead to an increase in such profits. As far as such profits are a major point of concern in some EU countries, these profits can be taxed by these countries, while the revenues can be used for other purposes.

1. Introduction

Background
Power prices in EU countries have increased significantly since the EU emissions trading scheme (ETS) became effective on the 1st of January 2005. Besides other factors, these increases in power prices may - at least in part - be due to this scheme, in particular due the pass-through of the costs of EU allowances (EUAs) to cover the CO_2 emissions of eligible installations. In the power sector, however, eligible installations have usually received most of their needed allowances for free during the first phase of the EU ETS (2005-2007).

In several EU countries, the coincidence of the increases in power prices and the implementation of the EU ETS has raised questions on whether power producers have indeed passed through the costs of freely allocated CO_2 allowances to electricity prices, and to what extent the increase in these prices can be attributed to this pass-through or to other factors. In addition, it has raised questions on whether - and to what extent - the supposed passing through of these costs has led to additional profits for power producers, i.e., the so-called 'windfall profits'. Finally, the supposed ETS-induced increases in power prices and generators' profits have raised questions and concerns regarding its impact on the international competitiveness of some power-intensive industries, the purchasing power of electricity end-users such as small households or, more generally, the distribution of economic surplus among power producers and consumers. As a result, in several countries policy makers and stakeholders of industrial or other interest groups have suggested a variety of options to address these concerns, including improving the EU ETS allocation system (notably increasing the share of auctioning), taxing windfall profits or controlling market prices of either EU carbon allowances, electricity or both.

Objectives
Against this background, the Energy research Centre of the Netherlands (ECN) has conducted a study on the impact of the EU ETS on electricity prices. More specifically, the major objectives of the present study include:

- To analyse empirically the trends in electricity prices during the period 2004-2006 for a variety of power markets across the EU ETS, and to assess whether and to what extent changes in these prices can be attributed to the pass-through of the costs of freely allocated EU carbon allowances or to other factors.
- To analyse the factors affecting the pass-through of emissions trading costs to power prices, using economic theory and models.
- To discuss whether the supposed EU ETS-induced increases in power prices and generators' profits are issues for concern and, if yes, to evaluate policy options to address these issues.

Analytical approaches
In order to achieve these objectives, the present study has applied a variety of analytical approaches:

- *Theoretical analyses,* in particular with regard to the impact of allocation of carbon allowances as well as other factors affecting the pass-through of carbon costs to power prices, such as the structure of the power market.
- *Empirical and statistical analyses* of trends in prices of fuels, CO_2 and electricity on both spot and forward markets in several EU countries during 2005-2006, including the assessment of passing through CO_2 opportunity costs in the price of electricity.
- *Model analyses*, in particular by means of the COMPETES model, of the implications of emissions trading on wholesale power prices and generators' profits in EU ETS countries
- *Literature analyses,* i.e., a survey of the literature, notably of empirical and modelling studies on the impact of the EU ETS on power prices.

- *Policy analyses,* in particular of the policy options and implications to address some of the concerns related to the EU ETS-induced increases in power prices and generators' profits.

Report structure
The structure of the present report is as follows:
- Chapter 2 provides a theoretical approach for analysing the factors affecting the pass through of carbon opportunity cost to power prices, including the impact of the allocation of CO_2 emission allowances on the price of electricity as well as the impact of the structure of the power market on the pass through of carbon costs to power prices.
- Chapter 3 presents the major findings of the literature review, notably of the empirical and modelling studies on the impact of the EU ETS on power prices.
- Chapter 4 discusses the major results of the empirical and statistical analyses of the trends in power prices and costs (including fuel and CO_2 costs), as well as of the pass-through of CO_2 costs into power prices on spot and forward markets in several EU countries.
- Chapter 5 presents the major results of the COMPETES model analyses of the implications of EU emissions trading for the performance of the wholesale markets in European countries in general and the impact on power prices in particular
- Finally, Chapter 6 discusses the options and implications to address possible concerns regarding the EU ETS-induced increases in electricity prices and generators' profits.

2. The pass-through of carbon costs to power prices - a theoretical approach

The impact of emissions trading on the power sector in general and electricity prices in particular depends on the price of a CO_2 emission allowance and the carbon intensity of the power sector, especially of the generation technologies setting the electricity price at different levels of power demand. These two factors determine the so-called '*carbon costs of power generation*'.[4]

However, in addition to the carbon costs of power generation, the impact of emissions trading on electricity prices depends also on the rate or extent to which these costs are passed through to these prices. In turn, this so-called '*pass-through rate'* (PTR) depends mainly on two factors: (i) the method of allocating CO_2 emission allowances, and (ii) the structure of the power market. These factors are extensively discussed below in Section 2.1 and Section 2.2, respectively. Whereas the present chapter analyses these factors mainly from a theoretical perspective, PTRs and their underlying determinants are further analysed empirically in Chapter 4 and by means of power market model in Chapter 5.

2.1 The impact of allocation on passing through CO_2 costs

2.1.1 The opportunity costs of CO_2 emission allowances

In an emissions trading system, a CO_2 allowance is a scarce and, therefore, valuable commodity that can be traded on the market at a certain price. A producer, such as a power generator, who owns a certain amount of carbon allowances can either use these allowances to cover the CO_2 emissions resulting from the production of electricity or sell them on the market to other participants who need additional allowances. Hence, for a producer, using emission allowances represents a so-called 'opportunity cost' - i.e. the cost of *not* selling the allowance - regardless of whether the allowances have been allocated for free or purchased at an auction or market. Therefore, in line with economic theory on optimal market behaviour and the efficiency of emissions trading, power generators who aim at profit maximization are expected to include the opportunity costs of a CO_2 allowance into their operational decisions and to pass-through these costs into their price bids on the electricity wholesale market, even if the allowances are granted for free.[5]

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4 Note that the price of an EU allowance (EUA) is similar throughout the EU ETS at a certain moment, but fluctuates over time. The carbon intensity of power, however, varies widely among the countries of the EU ETS, depending on the technology of the generation capacity. In addition, it varies both in the short term - even within one day - depending on the level of power demand and relative fuel prices - as well as in the long run, depending on new investments in generation capacity. Therefore, the carbon costs of power generation vary not only across EU ETS countries but also over time. The determinants of the EUA price and the carbon intensity of power generation have been analysed in Sijm et al. (2005), notably Chapters 2 and 3. For other, more recent analyses of the EUA price see, among others, Kanen (2006), Mansanet-Bataller (2007) and Alberola et al. (2007, 2008a and 2008b). The implications of differences and changes in the carbon intensity of power production are analysed further in the present report, especially in Section 2.2 below, Chapter 4, Chapter 5 and Appendices B and C.

5 The concept of opportunity costs is fundamental to economics and not restricted to the analysis of using free emission allowances but also accepted in other respects. For instance, if a power company has acquired the right to use coal or gas at some contract prices, it is nevertheless expected that the current market price of fuels dictates the price setting of electricity, provided the company could otherwise sell the fuel to someone else at the current market price, including transaction costs (Radov and Klevnas, 2007). See also, Harrison and Radov (2002), Burtraw et al. (2002), Sorrell and Sijm (2003), Ecologic (2005), and Frontier Economics (2006b). It should be noted that the concept of opportunity costs applies not only to allowances obtained for free but also to allowances auctioned or bought. Hence, regardless of whether allowances have been obtained for free or bought on an auction or market, current operational decisions are based on the current opportunity cost - i.e. the current market price - while the difference between the current market price of an allowance and what has been paid for it in the past - if any - is accounted for as a loss or profit due to storage or other operational transactions.

Including the opportunity costs of carbon allowances to the other, variable costs of power generation and internalising these costs into the price setting of electricity is an important condition for achieving the environmental target of CO_2 emissions trading at least costs, notably by the following means:

- It provides an incentive to power producers - both incumbents and new entrants - to reduce their emissions by switching to or investing in technologies with lower emissions, including more efficient gas-fired plants, nuclear, renewables, carbon capture and storage or other abatement options.
- It provides an incentive to power consumers - both households and industrial users - to reduce their demand for carbon-generated electricity, notably in the medium and long term by means of increasing their energy efficiency - i.e. electricity saving - or switching to less CO_2 intensive generated electricity.

By equalizing the marginal abatement costs of all mitigation options throughout the system to the price of a CO_2 allowance, emissions trading results in the least costs to achieve its environmental target. However, if power prices do not internalise the opportunity costs of carbon allowances, least cost abatement options from low-emission generation and energy saving will not be encouraged. For a fixed emission target, abatement will therefore have to be achieved by other, more expensive options. This will increase the price of a CO_2 allowance and, hence, the overall costs of the trading scheme (Radov and Klevnas, 2007).

2.1.2 The reference cases: auctioning versus perfect free allocation

In order to illustrate the impact of allocation on passing through carbon costs in the power sector, two reference or base cases of allocating emission allowances will be considered, i.e. auctioning versus perfect free allocation. In an auctioning system, allowances are initially allocated by selling them at an auction (or market). On the other hand, the ideal (textbook) type of perfect free allocation is characterized by:

- A one-off initial allocation of free allowances to existing installations (incumbents), usually for a long time frame, based on (i) a fixed baseline or historic reference period of actual emissions at the installation level ('grandfathering'), or (ii) a standard emission factor multiplied by an ex-ante fixed quantity or activity level, for instance a certain input, output or capacity level ('benchmarking' with an absolute or fixed cap).[6]
- At closure, installations retain their allowances.
- New entrants do not receive allowances for free, but have to buy them on the market.

As the initial allocation of emission allowances in a perfect free allocation system is independent of operation, closure and investment decisions, it creates the same set of conditions for abatement efficiency as an auctioning system (Harrison et al., 2007). Hence, both allocation system result in the same level or choice of abatement, the same level of the allowance price, and the same (optimal) efficiency of emissions trading, including the same level of passing through of carbon allowance costs to power prices (as illustrated below).[7] The only difference between auctioning and perfect free allocation concerns the transfer of economic rent due to the initial allocation of emission allowances. Whereas this rent accrues to the government or public sector in the case of auctioning, it is transferred to the recipients of allowances in the case of perfect free allocation (Neuhoff et al., 2005b and 2006).

[6] If the quantity or activity level is determined ex-post - i.e. after the actual company's decisions or activity level realised - the allocation system is called benchmarking with a relative cap.

[7] It is important to note that, in addition to the conditions of the 'ideal' types of auctioning and perfect free allocation, these 'idealised' results hold only when certain other conditions hold as well, including negligible transaction costs, perfect competition in product and emissions markets, and a low cost of emissions relative to other costs and the overall value of economic activity (Harrison et al., 2007).

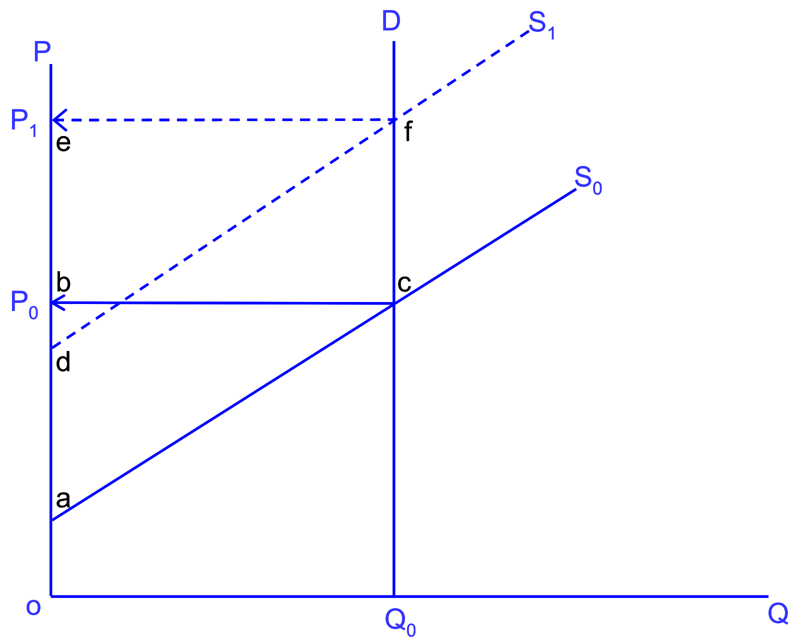

Figure 2.1 *Pass-through of carbon costs to power prices*
Note: S_0 is the supply curve excluding carbon costs, while S_1 includes carbon costs.

The pass-through of the opportunity costs of carbon allowances to power prices can be illustrated by means of Figure 2.1 representing the reference case of either auctioning or perfect free allocation, while assuming perfect competition, an inelastic demand curve (D), and a straight, upward sloping supply curve with constant carbon intensities of the generation technologies concerned (S_o). When emissions trading is introduced, the opportunity costs of carbon allowances are included to the other (variable) production costs, resulting in supply curve S_1. Under the conditions of the reference case, this results in the following implications:

- The power price increases from P_0 to P_1. Hence, the pass-through rate is 100% since the change in power price is equal to the change in marginal production costs.
- The producer surplus before emissions trading is equal to the triangle *abc*, i.e. the difference between total revenues (Q_o0bc) and total variable costs (Q_oOac). In a competitive situation, this surplus covers the fixed (investment) costs of power production, including some normal generators' profits. After emissions trading, in the case of auctioning, the producer surplus is equal to *def*. Since it can be shown that the size of *def* is equal to *abc*, it implies that in this case there is no change in the overall producer surplus due to emissions trading. The total emission costs are equal to the quadrangle *adfc*, which are fully passed on to the power consumers by means of higher electricity prices, resulting in a similar loss of their consumer surplus.[8] In the case of perfect free allocation, however, the producers get the allowances for free, while still passing on the opportunity costs of these allowances to the consumers, resulting in an increase in their producer surplus by the quadrangle *adfc*. This increase in producer surplus due to emissions trading is commonly defined as the 'windfall profits' resulting from grandfathering.

Due to a variety of reasons, however, the conditions or assumptions underlying the simple reference case outlined above may not be met, resulting in different rates of CO_2 cost pass-through and/or different changes in producer or consumer surpluses. These reasons will be discussed in the sections below.

[8] Note that the quadrangle *adfc* also represents the economic rent of allocating carbon allowances, which in the case of auctioning accrues to the public sector.

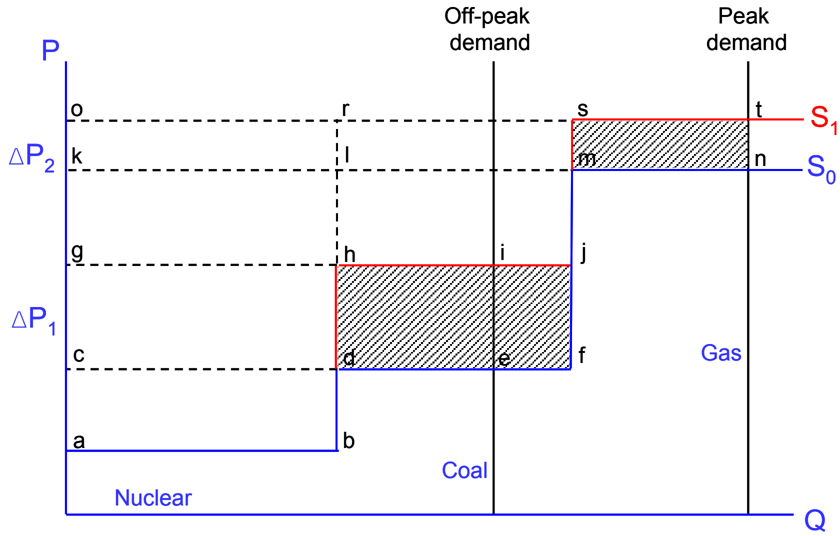

Figure 2.2 *Change in power prices and generators' profits due to emissions trading for different load periods and production technologies*

Note: The blue line S_0 represents the supply curve before emissions trading, while the red line S_1 includes the carbon costs due to emissions trading. The shaded areas represent the CO_2 opportunity costs of a fossil-fuel technology when it becomes the marginal unit (which in the case of free allocation implies a transfer of economic rent enhancing generators' profits).

Table 2.1 *Change in profitability of power generation due to emissions trading for different technologies and load periods*

Technology	Load period	Profits before ET	Profits after ET		Change in profits	
			Auctioning	Perfect free allocation	Auctioning	Perfect free allocation
Nuclear	Off-peak	abcd	abgh	abgh	cdgh	cdgh
	Peak	abkl	abor	abor	klor	klor
Coal	Off-peak	0	0	dehi	0	dehi
	Peak	dflm	hjrs	dfrs	lmrs-dfhj	lmrs
Gas	Off-peak	0	0	0	0	0
	Peak	0	0	mnst	0	mnst

Note: The symbols in this table refer to Figure 2.2.

The reference cases: some alternative illustrations

A slightly more realistic (and more complicated) situation is depicted by Figure 2.2, which shows the change in power prices and generators' profits due to emissions trading for different load periods and production technologies with different emission rates. During the off-peak period, the power price is set by the marginal technology, i.e. coal, while during the peak period it is set by gas. Assuming no change in the merit order and power demand, emissions trading results in a change of power prices equal to ΔP1 during the off-peak and ΔP_2 during the peak period, where $\Delta P_1 > \Delta P_2$ since the emission factor per unit produced is significantly higher for coal than gas.[9]

Changes in generators' profits due to emissions trading can also be derived from Figure 2.2 (see also Table 2.1 for an overview of these changes in profits for different production technologies and load periods, distinguishing between auctioning and free allocation of carbon allowances). For instance, during the off-peak period, profits for the marginal technology (coal) are 0 before emissions trading (as the cost per unit is equal to the power price), while after passing through

[9] The implications of emissions trading for power prices and generators' profits under changes in the merit order and/or power demand are analysed in the sections below.

the costs of emissions trading they remain 0 in the case of auctioning but increase by the rectangle *dehi* if all allowances are granted for free. On the other hand, for an infra-marginal technology such as nuclear (which has no CO_2 emissions), the profitability of power generation during the off-peak period increases by the rectangle *cdgh*, regardless of whether the allowances are auctioned or allocated for free as in both cases nuclear benefits from the ET-induced increase in the off-peak price while its costs do not change.

During the peak period, Figure 2.2 shows that the price is set by the gas-fired technology. Due to emissions trading, the peak generators' profits for gas remain 0 in the case of auctioning while they increase by *mnst* in the case of free allocation. For an infra-marginal, non-CO_2 technology such as nuclear or hydro, these profits increase by *klor* in both cases. On the other hand, for an infra-marginal, fossil-fuel technology such as coal (which has an emission factor higher than gas), emissions trading during the peak period results in a loss of producer surplus ('windfall losses') in the case of auctioning as the increase in total costs (*dfhj*) is larger than the increase in total revenues (*lmrs*). However, when carbon allowances are allocated for free, coal-fired generation during the peak period benefits by the amount *lmrs*.

A major observation of Figure 2.2 and Table 2.1 is that the allocation method (i.e. auctioning versus perfect free allocation) does not affect the impact of passing through the CO_2 opportunity costs on power prices and, hence, on the price-induced changes in the profits of both fossil and non-fossil generators. In fact, the issue of auctioning versus perfect free allocation only affects the distribution of the economic rent of carbon allowances in the sense that in the case of perfect free allocation this rent is transferred to incumbents in the form of a lump-sum subsidy that enhances their producer surplus (compared to auctioning where this rent accrues to the authority allocating the allowances).

Another way of illustrating the pass-through of CO_2 opportunity costs to power prices for different load periods and generation technologies is provided by Figure 2.3, which presents a so-called marginal cost (price) duration curve. This curve depicts the number of hours in a year during which the price is at least p (t), as well as the number of hours at which a specific technology generator will be producing. On the *x*-axis the 8760 hours of a year are depicted, sorted in descending order of the corresponding marginal system costs. The *y*-axis gives the marginal cost of the marginal generation technology needed to meet power demand during a certain load period (i.e. number of hours per year). As the power price is affected by cost changes of the marginal unit, the amount at which the power price increases due to the passing through may differ per load period, depending on the marginal plant concerned. As a consequence, over a certain period, the weighted average increase in power prices due to emissions trading depends not only on the weighted average price of a carbon allowance but also on the weighted average emission factors of the marginal generation units during that period.[10]

Finally, Figure 2.3 can also be used to illustrate the impact of passing through the CO_2 opportunity cost on generators' profits. In each hour or load period in which a technology is operational, its producer surplus or profits before emissions trading is equal to the difference between the power price of that period and its costs per unit generated multiplied by its output during that period. Therefore, assuming no change in merit order or power demand, in the case of auctioning the change in generators' profits due to emissions trading is equal to the change in this price-cost differential multiplied by the output of its technology during each period considered. Moreover, in the case of perfect free allocation, the additional profits are equal to the emission cost per unit generated for each specific technology multiplied by its total output (see shaded areas of Figure 2.3).

[10] Note that the weighted average emission factor of the marginal generation units multiplied by the weighted average price of a carbon allowance results in the weighted average emission costs of these units, which - in a competitive setting - is equal to the weighted average increase in power prices due to emission trading. Weighing is based on the total output during each sub-period in which the price is set by a specific technology.

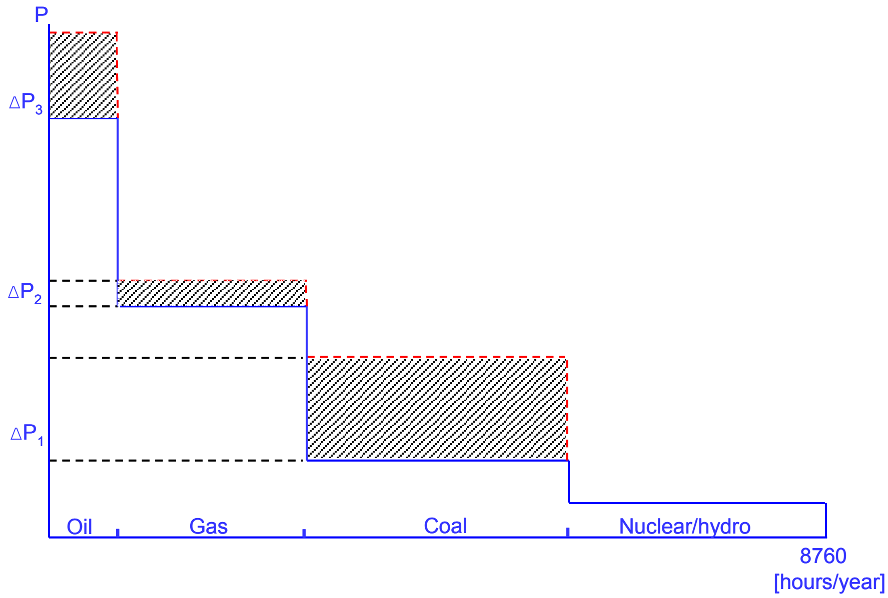

Figure 2.3 *Changes in power price due to the pass-through of CO_2 opportunity costs for different technologies along the price (marginal cost) duration curve*

Note: The blue line represent the price/marginal cost duration curve before emissions trading while the red line includes the opportunity costs of carbon allowances. The shaded areas represent the CO_2 opportunity costs of a fossil-fuel technology when it becomes the marginal unit (which in cases of free allocation implies a transfer of economic rent enhancing generators' profits).

2.1.3 Primary effects of free allocation provisions on power prices

During the first and second trading phases (2005-2012), the EU ETS is based primarily on a free allocation system of emissions allowances.[11] This system, however, does not meet the conditions of the ideal type of perfect free allocation mentioned above, but is rather characterised by the following free specific provisions or distortions of this ideal type:

1. Updating free allocation to incumbents.
2. Contingent allocation to plant closures.
3. Free allocation to new entrants.

This section discusses the main implications of these specific free allocation provisions, in particular their primary effects on power prices, while their potential secondary effects on CO_2 emissions, allowance prices, carbon costs pass-through and power prices are treated subsequently in Section 2.1.4 below.

Updating free allocation to incumbents

As noted above, a major characteristic of perfect free allocation is the one-off initial allocation of allowances to existing installations (incumbents), usually for a long time frame, based on either grandfathering or benchmarking,. The major implication of this feature is that operational decisions of incumbents are affected by the CO_2 price (or carbon opportunity costs) of emission allowances but not by the allocation of these allowances at the installation level as the latter is fixed ex-ante, i.e. before these decisions are made. In contrast, however, the baseline or reference period of free allocations to incumbents can also be regularly updated, for instance allocation in the next trading period can depend on their emissions, production or other activity level

[11] The share of auctioning in total allowances allocated is less than 1% during the first phase of the EU ETS and about 3% during its second phase. Many Member States, however, have made a distinction between power generators and other installations, putting most of the reduction effort on the first. Moreover, the quantities to be auctioned have usually been related to lower allocations for free to power generators rather than industrial installations.

of the current period and, hence, decisions on current activity levels are affected by the prospects or expectations of future allocations.[12]

The major reason for updating the baseline or reference period for allocating allowances is that in a dynamic economy with major future uncertainties and large (unknown) differences in growth patterns among sectors and installations - including plant closures and new entrants - it may be hard to allocate allowances for a long time frame based on a fixed reference period. Hence, updating can serve to avoid a lot of special provisions and maintain the allocation provisions of the ETS as simple as possible (Matthes et al., 2005).[13]

The major implication of updating is that the operational decisions of incumbents are affected by the allocation system as their current production or emission level influences their future allocations. As a result, incumbents will incorporate the value of these allocations in their production decisions, implying a lowering of their internal opportunity costs of emission allowances, a lower level of carbon cost pass-through and, hence, a lower increase in power prices (compared to perfect free allocation).[14]

Actually, whereas emission trading acts as a tax on CO_2 based production - increasing its variable (marginal) costs - updating essentially provides an output subsidy that reduces (the increase in) these costs and, hence, creates an incentive to increase current output (Fischer, 2001; Keats and Neuhoff, 2005).

Although the allocation periods for the EU ETS have been relatively short, it is unclear to what extent updating is a relevant factor for the EU ETS. Up to now, there have only been two allocation rounds, i.e. the first period (2005-2007) and the second period (2008-2012). Allocation to incumbents over the periods has varied significantly among the Member States with varying, often moving allocation reference years from the first to the second allocation plans. Consequently, companies might have expected or assumed a kind of updating for the third period (or beyond) and may, therefore, have incorporated this in their operational decisions, in particular passing through lower opportunity costs to their output prices. However, the European Commission's proposal of 23 January 2008 to amend the EU ETS provides that the (EU-wide harmonised) allocation rules shall not give incentives to increase emissions.[15] This clearly argues against updating. In addition, the Commission rejects extreme versions of updating such as ex-post allocation or relative target systems in which allocation is based on current production.

The implications of updating for carbon cost pass-through and power prices can be clarified by means of a mathematical expression and numerical example (Keats and Neuhoff, 2005; Neuhoff et al., 2005a). In a system of perfect free allocation the opportunity cost of a carbon allowance (C_t) is equal to its current market price (P_t), i.e.

$$C_t = P_t \tag{4.1}$$

In an updating system, the allowances allocated to incumbents in period t+1 are an assumed (or expected) fraction *u* of emissions generated in the first period, t. Then the (net or internal) carbon opportunity cost of an allowance are reduced by the value of the allowances allocated in fu-

[12] Allocation in the current trading period can even be based on current production or emissions at the installation level. This kind of 'extreme updating' (or ex-post allocation) results in a trading system with a flexible cap during the current period (rather than a fixed cap in an ex-ante allocation system).
[13] In addition, updating could provide an option for addressing the problem of free allocation to plant closures (Ahman et al., 2006). Moreover, if allowances are freely allocated to new entrants (based on expected or updated activity levels) it becomes increasingly harder in equity terms to justify free allocations to incumbents on emissions or activity levels in the remote past.
[14] Updating also results in less generators' profits during the current period but this is offset by the prospect of additional profits by future (higher) allocations (NERA, 2005).
[15] See EC (2008), notably COM (2008) 16 final, Article 10a (1).

ture periods, discounted by the time value of money (β), which is derived from the interest rate (r) according to $\beta = 1/(1+r)$:

$$C_t = P_t - \beta u \cdot P_{t+1} \quad (4.2)$$

To illustrate, if the emission factor of power production is 0.5 tCO_2/MWh and the allowance price in 2006 amounted to 20 €/tCO_2, then the carbon opportunity costs for generating power were equal to 10 €/MWh in a perfect free allocation system. However, if companies in 2006 assumed that allocations in 2010 would be updated by a factor u = 0.8 with 0.5 probability, an annual discount factor of β = 0.9 over 4 years, and expected an allowance price of 25 €/tCO_2 in 2010, then the opportunity costs would be 13.4 €/tCO_2, for a carbon allowance and, consequently, 6.7 €/MWh for generating power (i.e. the carbon opportunity costs and the pass-through to power prices are about one-third lower in the present example of updating compared to perfect free allocation).[16]

The impact of updating on power prices depends on the expected (net present) value of the allowance obtained for free in future allocations due to the present production or emissions of electricity. If allocation in the next trading (5-year) period is based on the production or emissions of the present (5-year) period, this value (or implicit subsidy to power output) is equal to the term $\beta u \cdot P_{t+1}$ of equation 4.1 mentioned above, where P_{t+1} is the (expected) price of an allowance in the next trading period, β the discount factor over the number of years concerned, and u the fraction (or benchmark) of allowances allocated in the next trading period related to the emissions or production of the present period. Hence, the impact of updating on power prices depends on these factors, i.e. its impact is higher if (i) the (expected) future allowance price is higher, (ii) the (expected) allocation benchmark of fraction u is higher, or (iii) the discount factor is smaller (i.e. the annual interest rate is lower and/or the number of years between the reference period and the allocation period is shorter)[17].

Contingent allocation to plant closures

Another feature of perfect free allocation is that, at closure, installations retain their allowances (allocated one-off for a long-time frame). As evidenced during the first and second trading periods of the EU ETS, however, allocation to installations in almost all Member States is contingent on their operational status in the sense that the allocation of allowances during the next period requires that the installation remains open or active for a minimum number of hours during the present period.

The main reason for such closure provisions is that authorities want to avoid that plants close - or even move to other countries - because their operations become unprofitable due to emissions trading (carbon leakage), while the operators benefit from selling large amounts of allowances allocated for free. Other reasons for closure rules refer to reaching other objectives besides abatement efficiency such as national energy security or industrial policy aims (e.g., to protect a diversity of key energy resources and industries) or just to maintain a level playing field for domestic industries as neighbouring, competitive countries are applying similar closure rules.

Compared to perfect free allocation, allocation to incumbent installations contingent on their operational status distorts the closure decisions of these installations. If power operators forgo free allowances when they close, they regard the value of these allowances as an annual or peri-

[16] In the example of updating, C_t is equal to $(20 - 0.8 * 0.5 * 0.9^4 * 25) = 13.4$ €/tCO_2. For similar examples, see Keats and Neuhoff (2005) and Neuhoff et al. (2005a).

[17] In a trading scheme with banking and borrowing, and in upward sloping curve of present and future allowance prices, the allowance price in the present trading period is equal to the future allowance price multiplied by the discount factor between these periods. Hence, in such a situation, the impact of updating on the price of electricity depends actually on the present allowance price multiplied by the benchmark u. This applies also to a situation of 'extreme updating' in which present allocation is based (ex-post) on present production indicators multiplied by the benchmark u.

odical subsidy covering the fixed costs or losses of upholding production capacity. While the opportunity costs of emissions trading are passed through to power prices, the subsidy provides an incentive to keep more capacity operational compared to an ETS with perfect free allocation or auctioning. This implies that older, carbon-inefficient power stations will stay on line. As a result, there is more power supply, particularly during the peak period, putting initially a downward pressure on electricity prices during this period (thereby eroding the ETS-induced upward pressure on power prices due to the pass-through if the carbon opportunity costs).

The impact of contingent allocation on power prices depends on the expected (net present) value of the free allowances forgone if the operator fails to meet the conditions of the plant closure rule. This value or subsidy to keep power capacity open, is equal to the value of the (expected) amount of allowances involved multiplied by the (expected, net present) price of an allowance. If this value is large enough to cover at least the losses of keeping inefficient capacity operational it acts to reduce power prices by preventing these prices to increase in markets with scarce capacity. While the amount of inefficient generation depends on the specific, minimum conditions of the closure rule, this amount is most likely produced during the peak hours when prices are highest and, hence, the output losses are minimised. To the extent that (peak) power prices depend on the margin of capacity, contingent allocation to incumbents can offset some of the impact of emissions trading on plant's variable costs, thereby limiting the overall implications of emissions trading on (average) power prices (Green, 2007).

Free allocation to new entrants

A final characteristic of perfect free allocation is that emission allowances are allocated for free to incumbents, but not to new entrants. In the EU ETS, however, the first and second set of National Allocation Plans (NAPs I and II) of all Member States included provisions for a so-called New Entrants Reserve (NER) in order to allocate allowances for free to new installations.

The major reasons for these new entrants provisions include (i) to mitigate distortions due to closure conditions (notably delaying the shift towards new efficient investments), (ii) to create 'fairness' among existing and new facilities (if incumbents receive allowances for free, so should new facilities) and (iii) to reduce carbon leakage and other adverse competitiveness effects (in the case of CO_2 emitting competitors in third countries not subject to similar carbon costs), (iv) to encourage new investments in cert ain technologies or, more precisely, to compensate the disincentive effects of emissions trading on investments in certain technologies, and (v) to reduce market power and, hence, increase competition by reducing barriers to entry for new operators, notably by improving their liquidity or access to capital as free allocations to new entrants avoid or compensate the additional costs of emissions trading (Neuhoff et al., 2006; Ahman et al., 2006; Ahman and Holmgren, 2006; Harrison et al., 2007).

Compared to emissions trading based on perfect free allocation (or auctioning), free allocation to new entrants distorts the investment decisions of power operators and, hence, can have important effects on the performance of the power sector, including electricity prices. Free allocation to new installations can be regarded as a subsidy towards the investors' fixed costs, coupled with a tax on their variable costs. While the tax is passed through to power prices, the subsidy gives an incentive to invest in additional capacity. Normally, the electricity price in an underinvested market increases until it reaches the long-run marginal costs (LRMC) of a new power plant (where the LRMC includes both variable and fixed costs). Since free allocation to new entrants lowers the LRMC of the next power plant, investments in additional capacity are moved forward in time at a lower electricity price. To the extent that (peak) power prices depend on the margin of capacity, this effect can offset some of the impact of emissions trading on a plant's variable costs, thereby limiting the overall implications of emissions trading on (average) power prices in the long run (Green, 2007; Lindboe et al., 2007, Schulkin et al., 2007). Therefore, free allocation to new entrants can mitigate the ETS-induced increase in power prices resulting from the pass-through of carbon opportunity costs.[18]

The impact of free allocation to new entrants on power prices depends on the expected, net present value of the number of allowances allocated to the operator of a new plant during the present and future trading periods. This value, or subsidy to fixed costs, is equal to the (expected) number of present and future allowances received for free multiplied by the (expected) price of present and future allowances. However, in a trading scheme with banking and an upward sloping curve of present and future allowance prices (where the slope represents the time value of money), the allowance price of the present period is equal to the allowance price of the future period multiplied by the discount factor accounting for the time interval between these periods. Hence, in such a scheme, the expected (net present) value of the allowances allocated for free is simply equal to the (expected) number of allowances allocated to a new entrant times the present allowance price.

For instance, suppose that an investor in a new coal plant - with a capacity of 500 MW, 5000 operational hours, on average, per year and an emission factor of 0.8 tCO_2/MWh - expects to receive the necessary emission allowances (i.e. per year, 2 million allowances of 1 tCO_2 each) the first ten years of the plant's operation (with 100% certainty) and 2 million allowances per annum during the remaining 30 years of the plant's lifetime (with a probability of 0.5), while the present allowance price is 20 €/tCO_2. Then the expected value or lump-sum subsidy of the allowances allocated for free is equal to (10 * 2 million * 0.8 + 30 *2 million * 0.5) * € 20 = € 1 billion. If the net present value of the investment costs of this plant is € 2 billion, then the investment costs, without the lump-sum subsidy, translate in a fixed cost of 20 €/MWh (€ 2 million / (40 * 5000h * 500 MWh)), while the subsidy rate due to free allocation to new entrants amounts to 50%. The opportunity costs passed on to power prices amounts to 16 €/MWh (0.8 * 20 €/tCO_2), while the subsidy of the fixed costs amounts to 10 €/MWh (50% of 20 €/MWh), which leads to a similar reduction in power prices.[19]

Some qualifications

It is important, however, to make some qualifications to the primary, output price-reducing effect of the specific free allocation provisions, in particular to the free allocation to new entrants (which seems to be the most relevant of these provisions for the EU ETS in the long run).

First, and most importantly, although the specific free allocation provisions may have some advantages or further some objectives (such as lower power prices for end-users, lower windfall profits for power producers, or less carbon leakage and other adverse competitiveness effects for exposed, power-intensive industries), compared to auctioning or perfect free allocation they erode the abatement efficiency of the ETS by (i) encouraging production of carbon-intensive output, (ii) discouraging investments in more expensive, but less carbon-intensive technologies such as renewables, (iii) stimulating price-responsive demand for carbon-intensive products, and (iv) maintaining capacity or even promoting new investments in carbon-intensive technologies, in particular when free allocations are fuel- or technology specific (see also Section 2.1.4 below). Notably free, technology-specific allocations to new entrants imply a serious erosion of the incentive framework of an ETS towards investments in less carbon-intensive technologies in

[18] Or, to put it slightly different, in an underinvested market, the electricity price includes a scarcity rent or margin ('mark-up') to cover the fixed cost of power generation and to induce new investments. If allocation is free to existing and new installations, it acts as a subsidy to their fixed costs which, in a competitive situation, reduces this margin and, hence, mitigates the increase in power prices due to emissions trading (Mannaerts and Mulder, 2003; Sijm et al. 2005).

[19] Note that if the coal plant operator has 100% certainty that he will receive all necessary allowances for free during the plant's 40-year lifetime, the subsidy rate would be 80%, while it would become 100% if, in addition, the CO_2 price would rise to 25 € tCO_2 (implying that the increase in power prices due to the pass-through of the carbon opportunity costs - i.e. 20 €/MWh - would be fully nullified by the decrease in power price due to the subsidy of the investment costs per MWh.

the long run (Sijm et al., 2005; Matthes et al., 2005; Neuhoff et al., 2006; Harrison et al., 2007, Linboe et al., 2007, and Schulkin et al., 2007).

Second, in addition to the abatement inefficiencies mentioned above, the specific free allocation provisions result in other inefficiencies or distortions at the inter-sectoral, international or inter-temporal level if they are not applied in a uniform, harmonised way but differentiated among sectors, countries or trading periods (Neuhoff et al., 2005a and 2005b). For instance, if one Member State of an ETS applies a stringent closure provision while the other does not (or if free allocation to new entrants is more favourable in the former than latter Member State), it results in relatively lower power prices in the former than the latter Member State. If power trade is possible between these countries, this leads to competitive distortions in the sense that the latter Member State closes its inefficient plants, produces less and imports more (or exports less), while the former Member State maintains its (perhaps even more) inefficient plants, generates more and imports less (or exports more). Moreover, in the case of power trade among countries, price differences between these countries will be reduced implying that the impact of specific free allocation provisions on lowering power prices in the former Member State will be less while part of this impact will be transformed to lower power prices in the latter Member State having no such provisions.

Third, the effectiveness of reducing power prices by means of free allocations to new entrants in the power sector is limited by several factors, notably:

a) Free allocation to new entrants is only effective in reducing power prices if generation capacity is indeed scarce and if, subsequently, the capacity scarcity is actually relieved by the implementation of new investments becoming operational (in the power sector it may at least take 4-5 years before new capacity investments are implemented and become productive).
b) It is only effective if the New Entrants Reserve is large enough to cover the needs for allowances of all new entrants, in the particular the last, marginal new entrant setting power price in the long run.
c) The effectiveness of free allocations to new entrants in reducing power prices is limited by (i) policy uncertainties or risks about future allocations of free allowances, and (ii) higher investment costs due to the increased demand for new generation capacity resulting from the subsidy effect of free allocations.
d) Free allocation to new entrants encourages inefficient investments, which increases power prices in the long run (Schulkin et al., 2007).
e) As a rational, profit-maximising producer will not sell power at a price below the opportunity costs of the allowances and fuels used, free allocations to new entrants is only effective in reducing power prices up to the point where the investment subsidy rate becomes 100%. Beyond that point, free allocations to new entrants result in additional (perverse) investments in new capacity but producers will not use this capacity to generate extra power - and, hence, further reduce power prices - but rather sell freely allocated allowances on the market (unless closure rules, i.e. minimum production conditions induce some additional output to meet these conditions). In the numerical example of free allocations to new entrants outlined above, the lump-sum subsidy rate (i.e. 50%) depends on the allowance price and the share or amount of needed allowances that is expected to be obtained for free. Assuming this share to be fixed, this implies that the point where the investment rate becomes 100% corresponds to an allowance price of 40 €/tCO_2.[20] If the allowance price increases above this level, the pass-through of carbon opportunity costs to power prices increases proportionally but the reduction of the power price due to the (full) subsidy of the investment costs is fixed at 20 €/MWh. Therefore, free allocations to new entrants are only able to nullify the increase in

[20] As explained in a previous note, if coal plant operators would have 100% certainty that they would receive all necessary allowances for free during the plant's 40-year lifetime, this point would be reached at a significant lower carbon price, i.e. 25 €/tCO_2.

power prices due to the pass-through of carbon opportunity costs up to a certain CO_2 allowance price.[21]

Fourth, free allocations to new entrants are sometimes proposed or justified by the argument that they result in more power producers actively supplying on the market, leading to less market concentration, i.e. more competition and, therefore, lower electricity prices. Due to a variety of technical, economic and other constraints, however, investments in new generation capacity are usually conducted by existing firms rather than truly newcomers. It is most likely hardly efficient to overcome these constraints for truly newcomers by free allocations to all new entrants. If one is indeed interested in increasing generation capacity or power market competition, there are most likely more socially efficient measures than free allocations to all new entrants, such as introducing capacity markets or direct capacity payments to power producers, including truly newcomers, or separating power network structures from production and marketing activities.

Last, but not least, the primary effects of the specific free allocation provisions - i.e. reducing power prices - may be offset by their secondary effects, in particular their possible upward pressure on carbon prices. These secondary effects are discussed in the next section.

2.1.4 Secondary effects of free allocation provisions on carbon and power prices

In addition to the primary, price-reducing effects of the specific free allocation provisions on the power market, these provisions may also have other effects, in particular on the price of carbon on the (EU) allowance market, which - in turn - may have additional, secondary effects on power prices. As noted, compared to perfect free allocation (or auctioning), the free allocation provisions exert an upward pressure on total emissions of eligible installations as they tend to enhance the (price-responsive) demand for carbon-intensive products and to encourage output supply by maintaining or even expanding generation capacity of CO_2 inefficient plants, in particular if free allocations are fuel-specific or biased towards more carbon-intensive technologies.[22] Extra emissions imply an additional demand for CO_2 allowances which, in the case of a fixed supply, result in higher carbon prices on the allowance market and, subsequently, in a pass-through of higher carbon opportunity costs and, finally, in higher power prices. Therefore, the primary effects of the specific free allocation provisions - i.e. decreasing power prices - may be either partially or fully offset by their secondary effects, i.e. increasing CO_2 allowance prices, resulting in increasing carbon costs passed through and, hence, increasing power prices.[23]
More specifically, the incidence or extent to which the secondary effects of the free allocation provisions may take place depends in particular on the following three factors:

- The price responsiveness of power demand.
- The technology bias of free allocations.
- The flexibility of the CO_2 budget.

These factors are discussed briefly below.

[21] Note that above this carbon allowance price, windfall profits to power producers continue to occur even in a fully competitive situation with free allocation to both incumbents and new entrants.

[22] Ellerman (2006) notes that the effect of free allocation to new entrants on emissions is ambiguous, in particular if demand is inelastic and free allocations are technology neutral, as the effect depends on the extent to which production from other units is displaced and on the emission characteristics of the units displacing and being displaced. However, if demand is price-responsive or free allocations are technology biased (i.e. higher emitters get more allowances for free while non-emitters get nothing), free allocations to new entrants results most likely in an upward pressure on emissions. Moreover, the effect of the other two specific free allocation provisions on emissions seems to less ambiguous, i.e. they usually increase emissions.

[23] Under specific conditions, the primary effects of the specific free allocation provisions may be fully or exactly nullified by their secondary effects, resulting in similar power prices as under the reference cases of auctioning and perfect free allocation. These conditions include in particular a fixed CO_2 budget of emission allowances and offset credits, as well as a uniform application of the free allocation provisions throughout all sectors, countries and trading periods of the scheme (Keats and Neuhoff, 2005; and Neuhoff et al., 2005a).

The price responsiveness of power demand
In general, power demand is rather price-inelastic in the short run, but more responsive to price changes in the medium and long term. This implies that if the specific free allocation provision indeed result in lower power prices (compared to the reference cases of auctioning and perfect free allocations), they also lead to a higher power demand and, hence, an upward pressure on CO_2 emissions, notably in the medium and long run.

The technology bias of free allocations
Free allocations can be either technology neutral or technology specific. If free allocations are technology neutral, the same benchmark or emission standard is applied to all power generating technologies, including non-CO_2 technologies such as nuclear or renewables. On the other hand, if free allocations are technology (or fuel) specific, high-emitting plants receive more free allowances than low-emitting stations while non-emitting installations get nothing. Although more carbon-intensive plants also need more allowances to cover their emissions (similar to a system based on auctioning or perfect free allocation), technology-specific free allocation provisions reduce the incentive to switch producer decisions towards cleaner technologies and, hence, affect the choice of technology in favour of higher emitting plants (Green, 2007; Schulkin et al., 2007). Hence, the secondary effects of the free allocation provisions - on emissions, etc. - are more significant if these provisions are more technology specific.

The flexibility of the CO_2 budget
The CO_2 budget of an ETS refers to the total amount of carbon allowances allocated to eligible installations (i.e. the cap) including, if allowed, offset credits - such as JI or CDM credits - to cover the emissions of these installations. This budget can be either fixed or variable, i.e. the cap of the total allowances allocated can be either fixed or variable, while the use of offset credits can be either fully forbidden, fully free or allowed under certain quantitative or qualitative restrictions.[24] If the CO_2 budget is fixed, additional emissions due to free allocation provisions result in increasing carbon prices and, hence, the primary effects of these provisions on power prices are compensated by these secondary effects, including the pass-through of higher carbon costs to power prices. On the other hand, if the CO_2 budget is variable, additional emissions of eligible installations are covered by extra allowances or credits and, hence, the carbon price hardly changes, implying that the secondary, price-increasing effects of the free allocation provisions on the power market are negligible (while the primary, price-decreasing effects may be substantial). Therefore, these secondary effects depend ultimately on the flexibility of the CO_2 budget of the ETS.

The EU ETS is characterised by a fixed cap of carbon allowances, but in order to cover their emissions eligible installations are also allowed to use JI/CDM credits to a certain limit. This implies that the secondary, power price-increasing effects of the free allocation provisions of this system depends on whether these installations have already reached their limit of JI/CDM credits and, if not, whether the additional demand for JI/CDM credits results in higher prices for these credits and, subsequently, higher (related) prices for EU carbon allowances. This situation in unlikely to arise, however, as the price of JI/CDM credits is expected to remain below the

[24] In addition, the inter-temporal allocation of the CO_2 budget, i.e. between different trading periods, depends on the incidence of banking and borrowing of emission allowances and offset credits (if allowed). If the specific free allocation provisions are applied uniformly across different trading periods, they do not change the structure of relative emission costs over time and, hence, do not change the inter-temporal allocation of the CO_2 budget. However, if these provisions are applied differently over time, they change relative emission costs over different trading periods and, hence, result in inter-temporal changes in CO_2 budgets, carbon prices and, therefore, power prices. For instance, if free allocation provisions are applied only the first trading period but not in subsequent trading periods, they lead to more emissions during the first period, resulting in less banking (if any) during this period (or, if allowed, more borrowing from subsequent periods) and, hence, to relatively lower carbon and power prices in the first period. For a detailed discussion of the inter-temporal implications of free allocation provisions, notably updating, either with or without banking (or borrowing), see Keats and Neuhoff (2005) and Neuhoff et al. (2005a, 2005b and 2006).

EUA price and the limit on these credits to remain rather restrictive. Hence, EU ETS installations are expected to use this limit anyway, i.e. regardless the potential impact of the free allocation provisions on ETS emissions and EUA prices. Therefore, as the overall CO_2 budget of the EU ETS thus seems to be rather fixed (at least up to 2020), the net impact of the free allocation provisions on power prices is probably small (or even nearly absent) as their primary, power price-reducing effects are likely largely offset by their secondary, EUA price-increasing effects.

2.1.5 Summary and conclusion

According to economic theory, power producers pass through the opportunity costs of emissions trading to electricity prices regardless of whether the allowances have been auctioned or allocated for free. In the ideal or reference cases of auctioning versus perfect free allocation, the impact of emissions trading on abatement efficiency and power prices is similar in both cases. In practice, however, emissions trading schemes are often characterised by some specific free allocation provisions which distort the outcomes of these ideal cases in terms of carbon efficiency and power prices. These provisions include in particular (i) updating baselines of free allocation to incumbents, (ii) contingent free allocation to plant closures, and (iii) free allocation to new entrants. Although the mechanisms and significance of these provisions may differ, they all have a similar primary effect on power prices, i.e. they may mitigate the ETS-induced increase in power prices resulting from the pass-through of carbon costs.

In addition, however, free allocation provisions erode the overall abatement efficiency of an ETS, while they lead to additional inefficiencies and distortions if they are applied differently across sectors, countries or trading periods. Moreover, the effectiveness of these provisions - in particular the free allocation to new entrants - is often limited in actually offsetting the ETS-induced increase in power prices. Finally, the primary, price-decreasing effects of these provisions on the power market may be either partially or fully offset by their secondary effects on CO_2 emissions of eligible installations, the price of these emissions and, hence, the pass-through of resulting carbon costs of power generation to electricity prices. The size or strength of these second, price-increasing effects on the power market depends particularly on (i) the price responsiveness of power demand, (ii) the technology bias of free allocation and, above all, (iii) the flexibility of the CO_2 budget of an ETS, including the potential use of JI/CDM or other offset credits to cover emissions of eligible installations.

A major policy implication is that if one moves from a perfect free allocation system to auctioning, there is no specific allocation effect on power prices. However, if the free allocation system is not perfect, for instance due to free allocations to new entrants, moving towards auctioning may exert an upward pressure on power prices in the long run, depending on whether the carbon budget of an ETS is fixed or not.

2.2 Market structure

Another major factor affecting the impact of emissions trading on electricity prices is the structure of the power market.[25] With regard to the pass-through of carbon costs to these prices, this structure refers to the interaction of the following three elements:

1. The number of firms active in the market (N), indicating the level of *market concentration* or *market competitiveness*. Depending on this number of firms, the market structure is called either monopolistic (N = 1), duopolistic (N = 2), oligopolistic (N = small) or competitive (N = large).

[25] The authors would like to thank Yihsu Chen (University of California, Merced, USA) who has been largely responsible for the results of Sections 2.2.1 up to 2.2.5 (including Appendix A). In addition, the authors would like to thank Prof. Ben Hobbs (The Johns Hopkins University, Baltimore, USA) for his valuable inputs and comments to Section 2.2 (including Appendix A.).

2. The shape of the demand curve, notably whether the (inverse) demand curve is linear or iso-elastic.[26]
3. The shape of the supply (or marginal cost) curve, in particular whether the marginal costs are constant – i.e., a flat, horizontal line of perfectly elastic supply – or variable, i.e., sloping upward in either a linear or iso-elastic way.[27]

The remainder of Section 2.2 is structured as follows. Sections 2.2.1 through 2.2.5 discuss the PTR of carbon costs to electricity prices under different power market structures, in particular under different levels of market competitiveness and different combinations of shapes for power demand and supply curves. Subsequently, Section 2.2.6 analyses the implications of ETS-induced changes in the merit order of power generation technologies for the PTR of carbon costs to prices. Next, Section 2.2.7 discusses the implications of other, market-related factors for the pass-through of emissions trading costs to power prices. Finally, Section 2.2.8 summarizes our major findings.

2.2.1 Constant marginal costs and linear demand

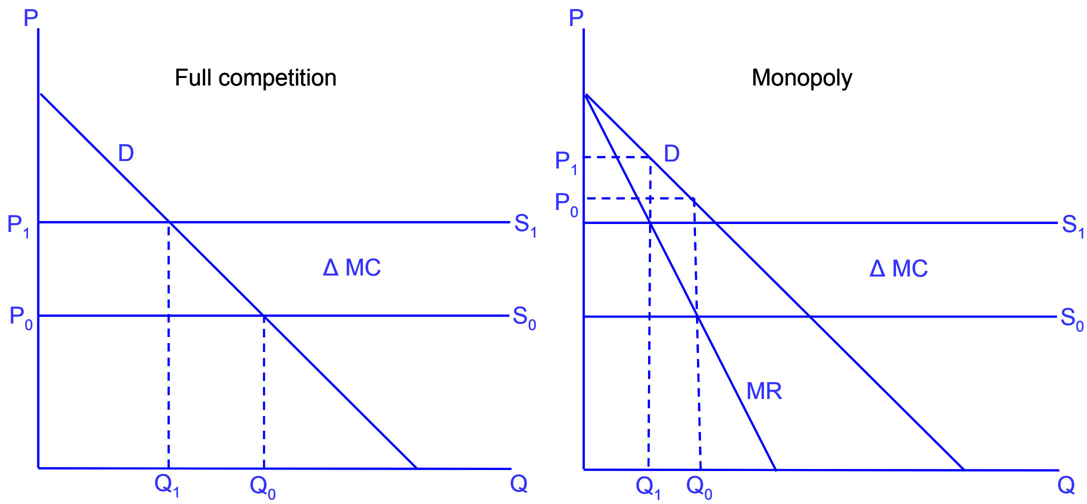

Figure 2.4 *Pass-through of carbon costs under full competition versus monopoly, facing constant marginal costs and linear demand*

Note: S_0 is the supply (i.e. marginal cost) curve excluding carbon costs, while S_1 includes carbon costs. D is the demand curve, while MR is the marginal revenue curve.

Figure 2.4 illustrates the pass-through of carbon costs for two polar cases, monopoly ($N = 1$) versus full competition ($N = \infty$), both characterised by linear demand and a constant marginal cost curve (i.e., perfectly elastic supply). Under these conditions, the extent to which carbon costs are passed through to power prices, i.e., the pass-through rate (PTR), is given by the formula:

$$\text{PTR} = dP/dMC = N/(N+1) \tag{2.3}$$

[26] A linear demand function can be expressed as $Q = r - sP$, and an iso-elastic demand function as $Q = tP^{-\varepsilon}$ ($\varepsilon > 0$), where Q is quantity, P is price, s is the slope of the linear demand curve, ε is the constant demand elasticity, while r and t are constants. On the other hand, the so-called *inverse* demand curves can be expressed as $P = w - vQ$ and $P = zQ^{-1/\varepsilon}$, respectively, where w and z are constants, while v $(=1/s)$ is the slope of the inverse linear demand curve.

[27] The inverse supply curve can be expressed as $MC = a + uQ$ if it is linear, or as $MC = kQ^b$ if it is iso-elastic, where MC is marginal costs, Q is quantity, a is a constant, u is the slope of the linear supply curve, k is a scaling factor, and $1/b$ (> 0) is the constant supply elasticity of the (non-inverse) iso-elastic supply curve.

where dP/dMC is the rate of change of price with respect to marginal cost, and N is the number of firms active in the market (the proof is provided in Appendix A.6). Note that under these conditions the change in power price due to emissions trading depends only on the number of firms active in the market, but not on the elasticities of power demand or supply.[28]

The implications of this formula are somewhat counterintuitive: a monopoly ($N = 1$) passes through only 50% of any increase in carbon costs. However, if a sector is more competitive (i.e., the number of firms increases), the pass-through rate rises until it is close to 100%. Hence, under linear demand and constant marginal cost, the more competitive the industry, the greater the PTR. Or, in other words, the greater the degree of market concentration, the smaller the proportion of carbon costs passed through (see Varian, 2003; Oxera, 2004; ten Kate and Niels, 2005; Sijm et al., 2005; Chen et al., 2008).[29]

This apparently counterintuitive result can be explained by the fact that as an industry becomes more competitive, prices become more aligned with marginal costs. In competitive markets, where producers are assumed to maximise their profits, marginal costs equal marginal revenues which, in turn, equal market prices by definition (i.e., $MC = MR = P$). Hence, *ceteris paribus*, carbon costs will be fully transmitted into higher prices. On the other hand, in less competitive markets – where prices are higher than marginal cost due to a so-called 'mark-up' – less than 100% of the change in carbon costs is expected to transmit into power prices as (profit-maximising) producers in such markets still equate marginal costs and marginal revenues. That is, as these producers can influence market prices by changing their output, their marginal revenues – and, hence, their marginal costs – deviate from their output prices (see Figure 2.4 where the slope of the *MR* curve of a monopolist is twice the magnitude of the slope of the demand curve *D*, resulting in a cost PTR of 50%).[30]

2.2.2 Constant marginal costs and iso-elastic demand

Figure 2.5 shows the pass-through of carbon costs for the cases of monopoly versus perfect competition, both characterised by constant marginal costs of power production and an iso-elastic demand curve, i.e., demand is related to price with a constant elasticity ($-\varepsilon$, with $\varepsilon>0$). Under these conditions, the PTR of carbon costs to power prices is given by the formula:

$$\text{PTR} = dP/dMC = N\varepsilon/(N\varepsilon - 1) \quad (2.4)$$

where ε ($\varepsilon > 0$) is the price elasticity of demand, and $N\varepsilon$ is assumed > 1 (see Appendix A.3). The formula implies that under less competitive market structures the pass-through rate is determined by the demand elasticity and that this rate is higher than 100%. For a monopolist facing constant marginal costs and an iso-elastic demand curve, the PTR formula corresponds to $\varepsilon/(\varepsilon - 1)$. Since a monopolist operates only where the marginal revenue is positive and, hence, the demand curve is elastic ($\varepsilon > 1$), this implies that under these market conditions changes in (power) prices are larger than changes in marginal (carbon) costs (Varian, 2003; Smale et al., 2006). For instance, in Figure 2.5, ε is 2, implying that in the case of a monopoly the PTR is 200%. This

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[28] The formula is based on the assumption that the companies operating in the market are all affected by the cost change (which in the case of the power sector affected by the EU ETS is a reasonable assumption as all major companies operating in EU power markets are covered by the scheme). However, in the case of significant competition in the form of imports by external companies not covered by the scheme, the formula for the cost PTR becomes $X/(N + 1)$, where X is the number of companies affected by the cost change and N the number of companies operating in the market (Oxera, 2004; Sijm et al., 2005; and Smale et al., 2006).

[29] These findings apply generally and symmetrically to cost increases and cost savings, i.e., under linear demand and constant marginal costs the PTR in monopolistic markets is 50% for both cost increases and cost reductions, while in perfect competitive markets it is 100% for both cases.

[30] In an oligopolistic or more competitive market structure, the slope of the *MR* curve is relatively less steep, i.e., it approaches the slope of the demand curve, implying that under linear demand, the PTR falls somewhere between the polar cases of monopoly (50%) and perfect competition (100%), and that it increases up to 100% if the degree of market concentration decreases.

rate, however, declines towards 100% when demand is more price-responsive and/or markets become more competitive. Thus, the PTR depends strongly on whether demand is assumed to be linear or iso-elastic.

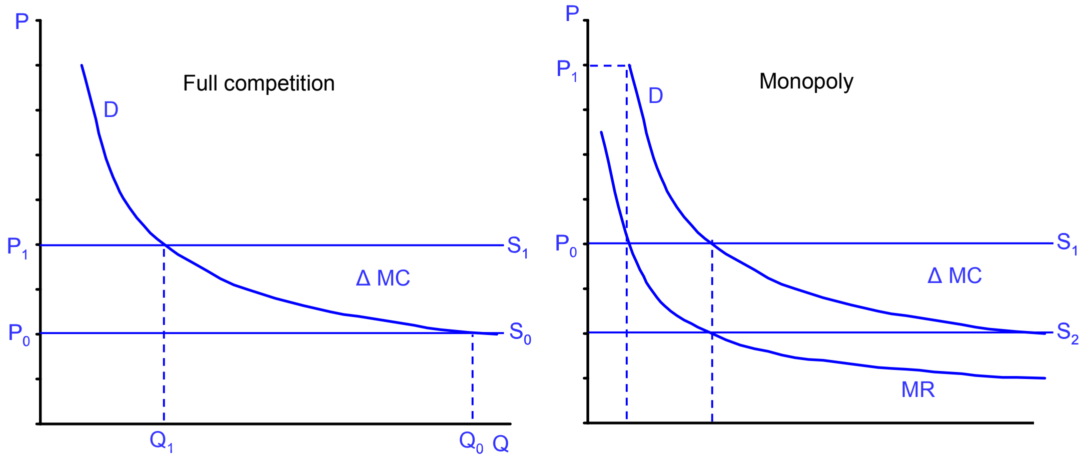


Figure 2.5 *Pass-through of carbon costs under full competition versus monopoly, facing constant marginal costs and iso-elastic demand*

2.2.3 Variable marginal costs and linear demand

In the previous sections, the marginal costs of power generation before emissions trading were assumed to be constant, regardless of the level of output production, and hence a change in marginal costs due to emissions trading is equal to the (change in) carbon costs concerned. However, if the marginal costs of power generation excluding carbon costs vary, and demand is price responsive, this equality between a change in marginal costs due to emissions trading and carbon costs no longer holds and, hence, the numerator of the PTR has to be clearly defined when discussing or estimating the pass-through of carbon costs.

This issue can be illustrated by Figure 2.6 which presents the pass-through of carbon costs for the cases of monopoly versus full competition, both characterised by linear demand and a variable, i.e., upward-sloping marginal cost curve.[31] Due to emissions trading, the supply or marginal cost curve increases from S_0 to S_1 by the amount c of carbon costs (assuming the same emission factor or carbon costs per unit production). Under perfect competition, prices are equal to marginal costs. Hence, if marginal costs increase due to emissions trading, prices in perfectly competitive markets increase proportionally. However, if demand is price responsive, demand decreases when prices increase. Less demand implies less supply, but also lower marginal costs as these costs are variable, depending on the output level. Therefore, in the case of variable marginal cost and linear (elastic) demand, the increase in (net) marginal costs due to emissions trading is lower than the increase in carbon costs and, hence, the pass-through to output prices is also lower (as part of the increase in carbon costs is compensated for by a decrease in the other components of marginal cost).[32]

In the left panel of Figure 2.6, this difference between the increase in (net) marginal costs and carbon costs is illustrated for the case of full competition. The carbon cost of emissions trading equals c, the increase in (net) marginal costs due to emissions trading is designated by f, while the difference in increase between these carbon and marginal costs equals $g = c - f$. Under full

[31] In Figure 2.6, the sloping supply curve is linear. The same discussion would apply, however, if this curve would slope upwards in an iso-elastic or other non-linear manner.

[32] See also ten Kate and Niels (2005) who make a similar distinction between gross and net cost changes in the case of variable marginal costs and elastic demand.

competition and linear demand, the ETS-induced increase in competitive power prices ($P_0 – P_1$) equals the increase in (net) marginal costs. Since the increase in these marginal costs is lower than the carbon costs of emissions trading, the increase in power prices due to emissions trading – i.e., the cost pass-through – is also lower (compared to the case of perfectly elastic or constant marginal costs).

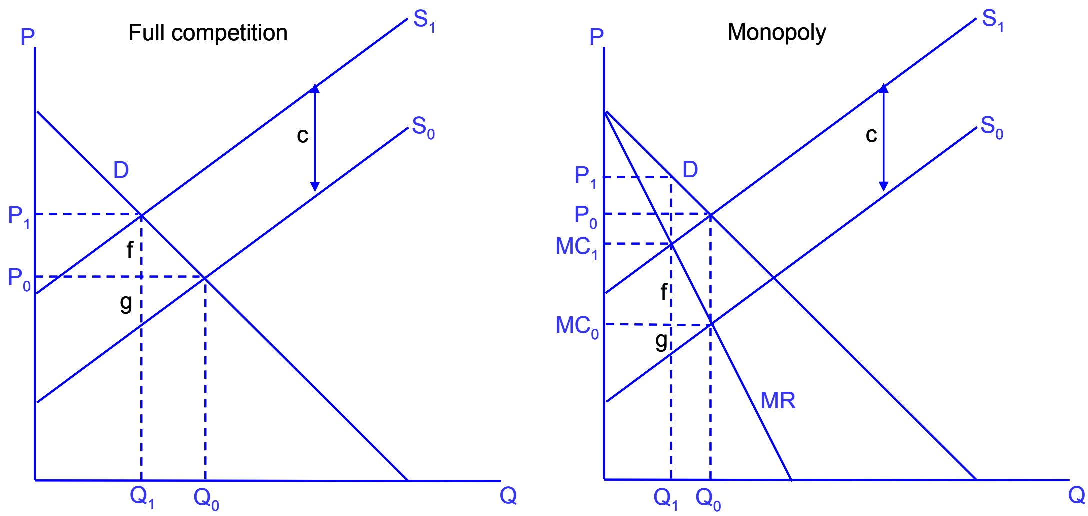


Figure 2.6 *Pass-through of carbon costs under full competition versus monopoly, facing variable marginal costs and linear demand*

It can be shown that in the case of variable marginal costs and linear demand, the pass-through of carbon cost to power prices is lower if demand is more price-responsive, or if supply is less elastic, i.e., less responsive to price or cost changes (see also Appendix A.4 and A.5). In the case of variable marginal costs, however, the value of the PTR depends upon the specific definition of this rate. If the PTR is defined as dP/dCC (where dCC is the change in carbon costs), it is, *ceteris paribus*, lower in the case of linear demand and increasing (rather than constant) marginal costs as power price increases are lower under increasing marginal costs. On the other hand, if the PTR is defined as dP/dMC – where $dMC = dCC + (dMC_o/dQ)(dQ/dCC)$ refers to the change in (net) marginal costs due to emissions trading, including changes in the non-carbon marginal cost MC_0 due to reduced demand – it is 100% in the case of perfect competition and linear demand, regardless of whether the marginal costs are variable or constant. As the term $(dMC_o/dQ)(dQ/dCC)$ is always negative, dP/dCC is always lower than dp/dMC.

Similarly, it can be shown that in the case of monopoly and linear demand, the PTR defined as dP/dCC is, *ceteris paribus*, always lower if the marginal costs are variable rather than constant, while the difference in PTR under variable versus constant marginal costs depends on the slopes of the demand and supply curves (compare, for instance the right panels of Figure 2.6 and Figure 2.4, respectively). However, if the PTR is defined as dP/dMC (as in the previous paragraph), it is 50% for a monopolist facing linear demand in the case of both variable and constant marginal costs, regardless of the slopes of the demand and supply curves, as the slope of the marginal revenues curve is always twice as steep as the slope of the demand curve.

More generally, in a market structure characterised by linear demand and N firms, the PTR defined as dP/dCC is always lower if the marginal costs are variable (rather than constant), while the difference in PTR under variable versus constant marginal costs depends on the slopes of the demand and supply curves. On the other hand, if the PTR is defined as dP/dMC, it is equal to $N/(N + 1)$ for all market structures characterised by linear demand, regardless of the slopes of the demand and supply curves, and regardless of whether the marginal costs are constant or variable. Moreover, these findings also hold regardless of whether the variable marginal costs are sloping upwards in a linear or non-linear way.

Turning to a case of variable and nonlinear supply, Appendix A.4 provides the derivation of the pass-through rate for market structures characterised by *N* firms facing linear demand and iso-elastic supply. Under these conditions, the PTR, defined as *dP/dCC*, is given by the formula:

$$PTR = \frac{dP}{dCC} = \frac{1}{1 + \frac{1}{N} + \varepsilon^b \left(\frac{Q}{Q_0}\right)^{b-1}} \qquad (2.5)$$

where *N* is the number of firms active in the market, ε is the demand elasticity at the competitive equilibrium before emissions trading (Q_0, P_0), *b* is the constant elasticity of the supply function, while Q_0 and *Q* are equilibrium output levels before and after emissions trading, respectively. In general, as supply elasticity increases, the PTR increases, if demand elasticity $\varepsilon < 1$.

2.2.4 Variable marginal costs and iso-elastic demand

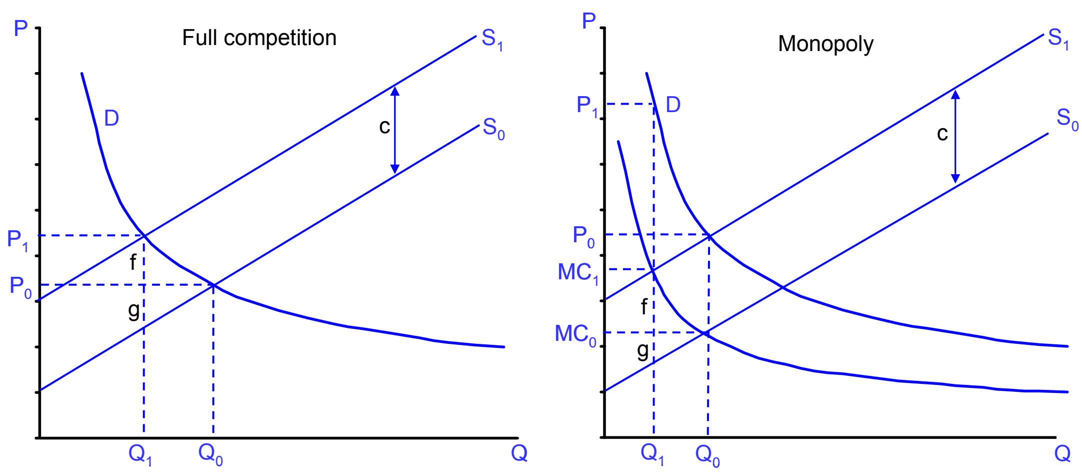


Figure 2.7 *Pass-through of carbon costs under full competition versus monopoly, facing variable marginal costs and iso-elastic demand*

Figure 2.7 presents the pass-through of carbon costs for the two polar cases monopoly versus perfect competition, both characterised by variable marginal costs and iso-elastic demand. Similar to the reasoning in the previous section, it can be shown that in a market structure characterised by iso-elastic demand and *N* active firms, the PTR defined as *dP/dCC* is always lower than *dp/dMC* if the marginal costs are upward sloping (rather than constant) as the increase in prices is lower in the case of variable marginal costs. This difference in PTR under variable versus constant marginal costs depends on the slopes of the demand and supply curves: it is larger – i.e., the PTR under variable marginal costs is lower – if demand is more elastic or supply is less elastic.

On the other hand, if the PTR is defined as *dP/dMC*, it is similar to the formula for the case of constant marginal costs and iso-elastic demand (i.e., PTR = $N\varepsilon/(N\varepsilon - 1)$), where ε is the constant demand elasticity ($\varepsilon > 0$). This formula applies to all market structures characterised by linear demand, regardless of the slopes of the demand and supply curves, and regardless of whether the marginal costs are constant or variable. Moreover, these findings also hold regardless of whether the variable marginal costs are sloping upwards in a linear or non-linear way.

Appendix A.1 presents the mathematical proof of the PTR for market structures characterised by N firms facing iso-elastic demand and iso-elastic supply. Under these conditions, the PTR formula, defined as dP/dCC, is given by the formula:

$$PTR = \frac{dP}{dCC} = \frac{1}{\left(1 - \frac{1}{N\varepsilon}\right)(1 + b\varepsilon)} \qquad (2.6)$$

with all notation having been defined earlier. For example, in the cases of full competition ($N = \infty$) and monopoly, with $\varepsilon = 1.5$ and $b = 1.2$, the PTR is 36% under full competition and 107% under monopoly. Note that under these conditions the PTR is higher if (i) demand is less price responsive, (ii) supply is more elastic, or (iii) markets are less competitive.[33]

2.2.5 Two bounding cases of linear demand and supply under competition

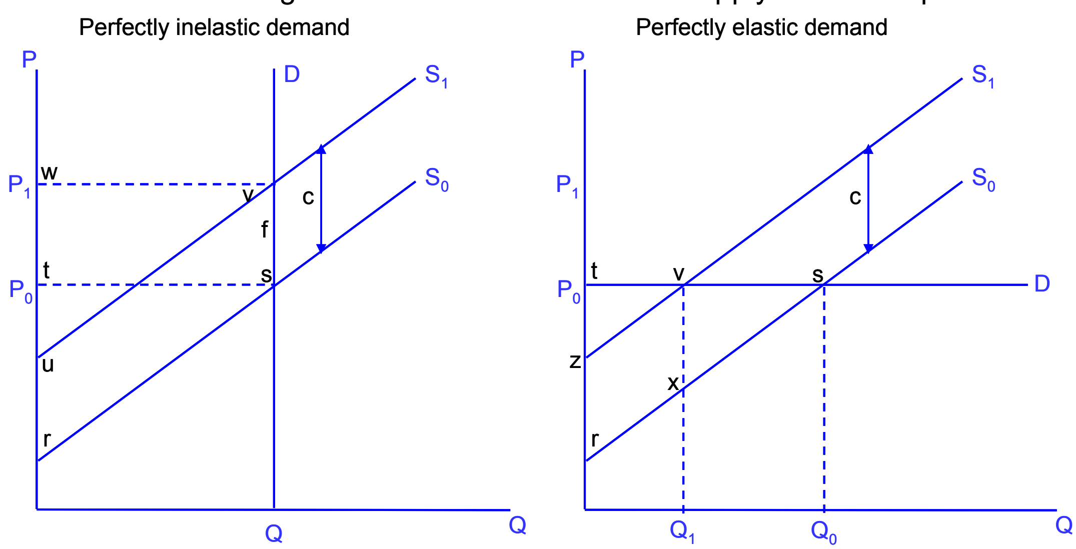


Figure 2.8 *Pass-through of carbon costs under full competition facing perfectly inelastic versus perfectly elastic demand*

Figure 2.8 presents two specific cases of carbon costs pass-through under competitive markets facing linear demand, where the left and right panels show the case of perfectly inelastic and perfectly elastic demand, respectively. Note that the right panel of Figure 2.8 represents not only the case of perfectly elastic demand but also other cases of fixed output prices to producers facing emissions trading, including cases of stringent price regulation or outside competition setting the price.

In the case of competitive markets and perfectly inelastic demand, the increase in power prices due to emissions trading is equivalent to the increase in marginal generation costs, i.e., the opportunity costs of carbon allowances needed to cover the CO_2 emissions of the production of an additional unit of power. Hence, the PTR under these conditions is 100%, not only regardless of the method of allocation but also regardless of the shape of the supply curve, i.e., no matter whether the marginal generation costs, excluding carbon costs, are constant or variable.

Moreover, since under perfectly inelastic demand, the level of demand and supply does not change while the carbon costs are fully passed through to electricity prices, the producer surplus

[33] More specifically, under monopoly ($\varepsilon > 1$), the PTR is $\varepsilon/(\varepsilon - 1)$ times higher than under full competition.

of power generators does not change, assuming that producers must buy all their allowances at an auction. As indicated by the left panel of Figure 2.8, before emissions trading the producer surplus is equal to the triangle *rst*. After emissions trading, in the case of auctioning, the producer surplus amounts to the triangle *tvw*. The areas *tvw* and *rst* are equal, and there is no change in producer surplus. In the case of perfect free allocation and perfectly inelastic demand, however, the new producer surplus amounts to *rsvw* i.e., it increases exactly by the full market value – or economic rent – of the free allowances represented by the quadrangle *rsvu*.

On the other hand, in the case of perfectly elastic demand, the pass-through rate is by definition 0 (as prices are fixed), regardless of the shape of the supply curve (provided this curve is not also perfectly elastic, i.e., marginal costs should be upward sloping so that supply and demand intersect). However, both the supply response and the producer surplus of power generators depend on the slope of the supply curve and the method of allocation. In the case of auctioning and perfect free allocation, profit-maximising producers adjust their output level until marginal revenues (i.e., fixed prices) are equal to marginal costs, including the opportunity costs of emissions trading. In the right panel of Figure 2.8, this situation is indicated by a reduction in output from Q_0 before emissions trading to Q_1 after emissions trading. As a result, the producer surplus decreases from *rst* before emissions trading to *rxvt* in the case of free allocation and even to *zvt* in the case of auctioning.

Therefore, even if the pass-through of carbon cost is zero (for instance, when prices are given due to perfect elastic demand, price regulation or outside competition), producers still include the full opportunity costs of emissions trading in their output decisions, i.e., when maximising profit, they adjust their production until price equals marginal cost, including the opportunity costs of CO_2 allowances. Compared to the situation before emissions trading, this yields a reduction of output and producer surplus in the case of auctioning. In the case of perfect free allocation, the reduction in output is similar to the case of auctioning while – depending on the slope of the supply curve and the share of allowances allocated for free – the reduction in producer surplus may be either partially, fully or more than fully compensated by the lump-sum subsidy of the free allowances.[34]

However, in the case of less perfect free allocations – such as updating or benchmarking based on realised output – the *net* opportunity costs of emissions trading are lower compared to auctioning (due to the implicit output subsidy). Hence, the reductions in output and producer surplus are also lower. In the right panel of Figure 2.8, this case can be illustrated by shifting the supply curve S_1 downwards to S_0.[35]

2.2.6 Changes in the merit order

In the previous sections, the supply function in the power sector was graphically illustrated by means of a line or smooth curve. However, for power systems with multiple generators having fixed capacities and differing marginal costs, this function is better represented by an increasing, step-wise line where each step represents a specific technology, with the width of each step showing the capacity or output of the technology and the height of each step indicating its marginal cost of power generation. In the short term, these costs are largely determined by the fuel costs, including the fuel efficiencies and – in the case of emissions trading – the carbon emissions of the technologies concerned. In the power sector, this ranking of the cheapest to the more expensive technologies is called the *merit order*.

[34] The implications of auctioning versus (perfect/imperfect) free allocation for electricity prices and power generators' profits are discussed in Section 2.1, while implications for long run generation mix are explored in Schulkin et al. (2008).

[35] Moreover, it can be shown in the right panel of Figure 2.8 that in the case of free allocations of enough allowances to new entrants to cover their entire output, investments in additional capacity take place when *P* covers at least the variable and fixed costs (excluding carbon costs), while in the case of auctioning or perfect free allocation these investments are only implemented if *P* covers at least all long run costs (including carbon costs).

Moreover, in the previous sections, the emissions rate – and, hence, the carbon costs – per unit production was assumed to be similar for each technology or level of output. In practice, however, these costs generally vary significantly among plants with different generation technologies and fuel efficiencies. In addition, these costs may change substantially over time depending on the evolution of the actual carbon price of an emission allowance. As a result, the merit order of power generation technologies may shift over time, depending on the dynamics and interaction of the actual carbon and fuel costs of the plants. Assuming that electricity prices are set by the marginal generation technology, this implies that the pass-through of carbon costs – and, hence, the impact of these costs on electricity prices – can change if the merit order of power production changes.

The impact of a change in the merit order on carbon cost pass-through to power prices is illustrated in Figure 2.9 for the case of a competitive market facing perfectly inelastic demand.[36]

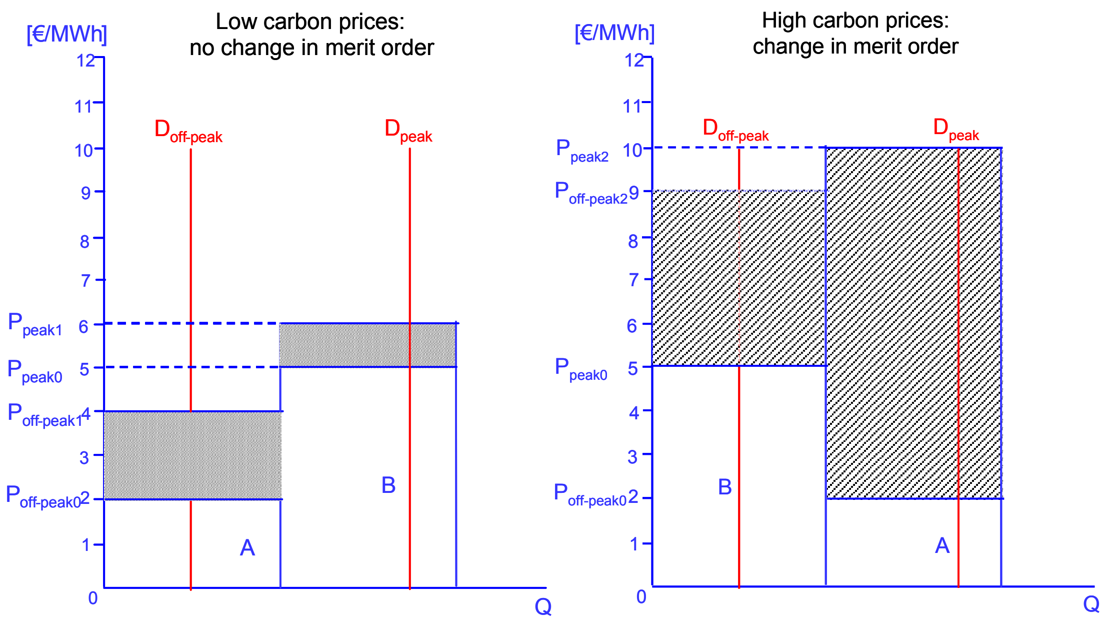


Figure 2.9 *Pass-through of carbon costs in a competitive market facing perfectly inelastic demand during peak and off-peak hours, including a change in the merit order*

Note: Technology A is characterised by low marginal (fuel) costs before emissions trading and a high emission factor, while technology B has opposite characteristics, i.e. high marginal costs before emissions trading and a low emissions factor. The shaded areas represent carbon costs per technology, depending on their emission factor and the actual carbon price.

The figure presents a simple merit order for only two technologies with different characteristics. Technology A is characterised by low marginal (fuel) costs before emissions trading and a high emission factor, while technology B has opposite characteristics, i.e., high fuel costs and a low emission factor. Hence, before emissions trading, technology A is the cheapest technology (in terms of variable costs), setting the price during the off-peak period ($P_{offpeak0}$), while the more expensive technology B determines the price during the peak (P_{peak0}).

After emissions trading, the merit order and the carbon cost pass-through depend on the carbon price. As long as the carbon price is relatively low, the order does not change (left side of Figure

[36] Based on the findings of the previous sections, a similar reasoning can be followed for other, less competitive markets and, other, more elastic demand curves in order to illustrate the impact of a change in the merit order on carbon cost pass-through to power prices for these cases.

2.9). Under these conditions, as discussed in the previous section, the PTR is 100%, resulting in power prices P_{peak1} and $P_{off\text{-}peak1}$ during the peak and off-peak period, respectively.

If the carbon price becomes relatively high, however, the merit order of generation technologies changes, as illustrated in the right panel of Figure 2.9. This implies that the magnitude of the PTR depends on its definition. On the one hand, the (marginal) PTR can be defined as the impact of emissions trading on the power price, *dP*, divided by the difference between the marginal costs of the price-setting production technology after and before emissions trading, *dMC*, i.e., PTR = *dP/dMC*.[37] Defined this way, the PTR is and remains 100% under the conditions of competitive markets facing perfectly inelastic demand (as in Section 2.2.5 above).[38]

Alternatively, the (marginal) PTR can be defined as the impact of emissions trading on the power price, *dP*, divided by the carbon costs of the marginal production unit after emissions trading, *dCC*, i.e., PTR = *dP/dCC*.[39] Defined this way, the PTR can deviate substantially from 100% if the merit order changes due to emissions trading, even under competitive markets with perfectly inelastic demand and perfectly elastic supply, depending on the carbon intensity of the marginal production unit after emissions trading.

For instance, as illustrated by Figure 2.9, the off-peak power price before emissions trading ($P_{off\text{-}peak0}$) is set by technology A at 2 €/MWh, while after emissions trading – when carbon prices are relatively high – the off-peak power price ($P_{off\text{-}peak}2$) is determined by technology B at 9 €/MWh. Hence, the increase in power prices due to emissions trading, *dP*, is 7 €/MWh. As the carbon costs (*dCC*) of technology B are 4 €/MWh, this results in a PTR – defined as *dP/dCC* – of 175%. Similarly, under emissions trading with relatively high carbon prices, the peak power price increases from P_{peak0} to P_{peak2} (*dP* = 10 – 5 = 5 €/MWh), while carbon costs of the marginal technology setting the peak price after emissions trading (i.e., A) amounts to 8 €/MWh. Hence, in this case, the PTR – defined as *dP/dCC* – is 5/8 or 63%. Therefore, in the case of a change in the generation merit order due to emissions trading, the resulting pass-through may vary significantly from 100% even under competitive markets and perfectly elastic demand, depending on the definition of the pass-through rate and the carbon intensity of the marginal production technology after emissions trading.[40]

2.2.7 Other market factors affecting carbon cost pass-through

In addition to the factors outlined in the previous sections, there are some other, market-related factors which influence the pass-through of emission costs to power prices, in particular:

- Market strategy
- Market regulation
- Market imperfections

These factors are briefly discussed below

[37] This way of defining the (marginal) PTR seems to be more appealing from a theoretical point of view as long as one intends to consider the overall change in marginal costs due to emissions trading and its impact on power prices (Sijm et al., 2005; Bonacina and Gulli, 2007).

[38] For example, before emissions trading the power price during the peak period (P_{peakO}) is equal to the marginal costs of technology A (excluding carbon costs) while after emissions trading this price (P_{peak2}) is set by the marginal costs of technology B (including carbon costs). The difference between the marginal costs after and before emission's trading, *dMC*, is just equal to the difference in power price, d*P*, i.e., the PTR is 100%.

[39] This way of defining the (marginal) PTR follows the more conventional notion of carbon cost pass-through to power prices and seems to be more appropriate from an empirical point of view as, in practice, it may be rather complicated to determine empirically the difference between the (total) marginal costs of the marginal production unit after and before emissions trading (or after and before a certain change in carbon prices), in particular if the merit order of the generation technologies changes due to emissions trading or a change in carbon prices.

[40] The effects of merit order changes in an actual power system are quantified in Chen et al. (2008).

Market strategy
The above results are based on the assumption that power companies pursue profit maximisation. This assumption may be largely valid for analysing short-term operations in the wholesale power market, or it may adequately reflect the objectives of private company shareholders in the short or medium run. In practice, however, there may be trade-offs between maximising profits and other company objectives in the short versus medium or long run. Further, the objectives of firm's shareholders may diverge to some extent from the objectives of firm's managers, or company objectives may differ between private versus public utilities.

Moreover, it may not be possible for managers to determine the profit-maximising strategy in bulk or retail power markets, due to a lack of information on the exact shape of the demand curve in the short, medium and long-term for different categories of electricity end-users (including power-intensive industries, small and medium firms, public institutions and private households characterised by different income levels or other factors determining consumption patterns). Therefore, in practice, companies' managers may pursue other short- or medium-term strategies besides profit maximisation (such as maximising market shares or sales revenues) or operate by simple rules of thumb, particularly for retail market transactions. An example of such a rule is cost-plus or mark-up pricing in which a mark-up is added to the average unit cost of production in order to meet a satisfying level of producer surplus (Smale et al., 2006).

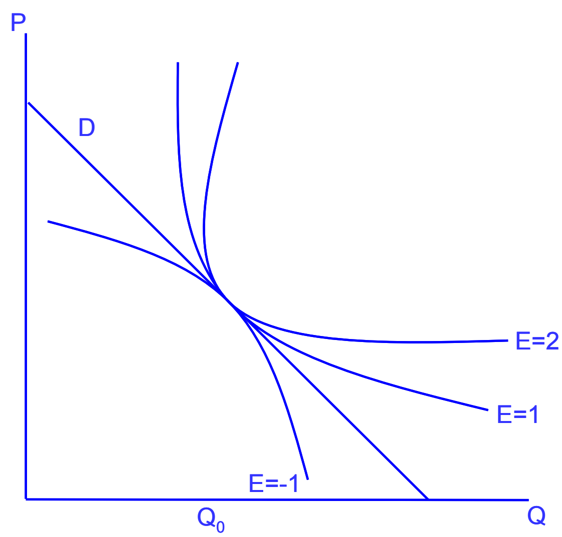


Figure 2.10 *Demand curves and the parameter E*
Source: Vivid Economics (2007).

Recently, Vivid Economics (2007) has analysed the implications of different firm strategies for cost pass-through to output prices.[41] In order to derive the cost pass-through formula under these strategies, they introduce the so-called 'demand curvature' parameter E. This parameter does not represent the elasticity of demand (ε), but the elasticity of the *slope* of the demand curve. Hence, it measures the percentage change in the slope of the (inverse) demand curve for a small change in total output.[42] Demand curvature is constant for most well-known demand curves, including linear demand, log-linear demand and constant elasticity demand. It is always 0 for linear demand curves, always negative for concave demand curves and positive for convex demand curves (see Figure 2.10, where the value of the parameter E is indicated for different shapes of the demand curve). It can be shown that the parameter E is closely related to the de-

[41] Vivid Economics (2007) used this analysis for a study to estimate ticket price changes when, as proposed, the aviation sector is introduced in the EU ETS, but it can be applied also to other sectors such as the power industry. It is based on recent work by Hepburn et al. (2006) and Ritz (2007).
[42] Or, in symbols: $E = -P''(Q)/P'(Q)Q$, where $P(Q)$ is the inverse demand curve.

mand elasticity of a curve (-ε, with $\varepsilon > 0$), i.e., $E \approx 1/\varepsilon$ or $\varepsilon \approx 1/(E - 1)$ (Hepburn et al., 2006). Hence, the formula for the pass-through rate (PTR, defined as *dP/dMC*) derived in Sections 2.2.2 and 2.2.4 for market structures with linear costs of production (see equation 2.4), assuming profit maximisation, can be rewritten as (Vivid Economics, 2007):

$$PTR = dP / dMC = \frac{N}{N+1-E} > 0 \qquad (2.7)$$

Cost pass-through thus depends on the number of firms (N) and the demand curvature parameter (E). For linear demand curves ($E = 0$), the formula mentioned above becomes similar to the PTR formula derived in Sections 2.2.1 and 2.2.3 for market structures with linear demand and linear costs of production, i.e., PTR = $dP/dMC = N/(N + 1)$.

Equation 2.7 for cost pass-through, assuming profit maximisation, does not depend on the distribution of the firms' market shares, i.e., it holds equally for cases where firms are all the same size (symmetric) as well as for cases where firms are different sizes (asymmetric). In addition, some implications can be drawn from this equation (Vivid Economics, 2007):

- The PTR is increasing in demand curvature E (i.e., decreasing in demand elasticity).
- If the demand curve is log-linear ($E = 1$), the PTR is equal to 100% regardless of the number of firms active in the market.
- If the demand curve is sufficiently convex ($E > 1$), the PTR > 100% regardless of the number of firms.
- If, conversely, the demand curve satisfies $E < 1$ (e.g., linear demand, where $E = 1$), the PTR < 100% regardless of the number of firms.
- If N becomes large, i.e., approaching the case of full competition, the PTR tends towards 100%.

In addition to profit maximisation, Vivid Economics (2007) also considers cost pass-through under other firms' strategies, in particular under strategic delegation with objectives of either maximizing sales revenue (PQ_i for firm i) or market share (Q_i/Q_{tot}; see also Ritz, 2007).[43] For the case of strategic delegation with sales revenue as the objective, the PTR satisfies:

$$PTR = dP / dMC = \frac{N(N-E)+E}{N(N-E)+1} > 1/2 \qquad (2.8)$$

For the case of strategic delegation with a market share objective, the analogous inequality is:

$$PTR = dP / dMC = \frac{N}{N+(1-E)(1+R)} > 1/3 \qquad (2.9)$$

where R (-1,0) solves the quadratic defined by:

[43] Strategic delegation refers to the case where a firm's shareholders delegate decision-making to managers whose compensation is based on, for instance, a combination of firm profits and sales revenue (or a combination of firm profits and market share). As a result, these managers do not solely maximise profits but trade off between maximising profits and sales revenues (or between maximising profits and market shares). Intuitively, placing some weight on sales revenue (market share) leads to a manager acting as if his/her firm's (marginal) costs are lower than they actually are, and thus favouring a relatively higher output level. In acting as if marginal costs are lower, it results in setting lower prices, selling higher volumes and achieving a higher market share (Vivid Economics, 2007).

$$R = \frac{\left[-(N-1) + \frac{(N-1)E}{N} + \frac{(N-2)R}{N} \right]}{\left[N - \frac{(N-1)E}{N} - \frac{(2(N-1)R)}{N} \right]} \tag{2.10}$$

These formulas for cost pass-through under strategic delegation assume a symmetric industry structure, i.e., all firms are assumed to have identical market shares of $1/N$. As under profit maximisation, the PTR is larger than (smaller than, equal to) 100% whenever $E > 1$ ($E < 1$, $E = 1$), regardless of the number of firms in the industry. Also, when N becomes large, the PTR tends towards 100% (Vivid Economics, 2007).

A remarkable feature of the cost pass-through rate under strategic delegation is that it has a lower bound, i.e., regardless of the shape of the demand curve, the PTR is always higher than 50% in cases with sales revenue objectives and higher than 33% in cases with market share objectives. More generally, for any value of the parameter E, the PTR under delegation is closer to 100% than it is under profit maximisation.

According to Vivid Economics (2007), the intuition for these results is that firms under strategic delegation act as if they face more rivals than they actually do, thus pushing cost pass-through towards 100%, the level under perfect competition. It is important to note, however, that the difference is not due to managers' treatment of opportunity costs under free allocation (rather than actual costs from buying allowances). Although it is possible that firms under strategic delegation are more likely to treat opportunity costs of freely allocated allowances as 'soft costs' that they absorb to undercut their competitors, the authors of Vivid Economics (2007) are not aware of any evidence that this is the case. Hence, they retain the assumption that all firms exhibit maximising behaviour regardless of whether carbon costs are actual or opportunity costs.

Market regulation

The extent to which carbon costs are passed-through to power prices may be affected by the presence of market regulation, including regulation of wholesale or retail power prices. Although firms exhibit maximising behaviour regardless of whether carbon costs are actual or opportunity costs, regulators may treat the pass-through of these costs differently depending on whether they are opportunity costs (in the case of free allocations) or cash outlays (in the case of auctioning or market purchases of allowances).

If regulators forbid and can indeed prevent any cost pass-through on retail power markets in the case of free allocations, the PTR is by definition zero. However, as discussed in Section 2.2.5 even if the pass-through of carbon costs is zero, optimising power producers still include the opportunity costs of carbon allowances in their price bidding and other operational decisions, resulting in less output, depending on the specifics of the free allocations and the slope of their marginal cost curves. Moreover, less output implies more scarcity, leading to higher power prices in the spot market (or serious risks of other ways of demand rationing). In addition, price regulation in some Member States of an ETS holds prices to below marginal cost, leading to more (price-responsive) power consumption in these countries and, hence, to more emissions and an upward pressure on carbon prices, resulting in higher power prices in other Member States. Hence, as a policy option to avoid the pass-through of the opportunity costs of carbon allowances, the regulation of power prices may be ineffective or have negative side effects.

While the incidence of power price regulation is decreasing or even absent in a growing number of power markets in the EU, the pass-through of the opportunity costs of freely allocated allowances may still be affected by so-called 'regulatory threats', including the threat of reinstating price controls, of taxing windfall profits resulting from the pass-through of carbon opportunity costs, or of other less favourable energy policies. These threats may be implicit or explicit. As a result, power companies may be reluctant to pass through such costs. This applies particularly for companies in countries characterised by either a monopoly, a dominant firm or a small oligopoly of power producers, as such companies run the risk of being accused of 'abusing their market position'.

Market imperfections other than market power
A final category of factors affecting carbon cost pass-through refers to the incidence of market imperfections other than the existence of market power. While we addressed the impact of imperfect competition on carbon cost pass-through above, we have assumed other market conditions to be more or less perfect, including full and free information of energy and carbon market performance, no risks or uncertainties, low adjustment costs, insignificant time lags, etc. In practice, however, power production, trading, pricing and other generators' decisions are affected by all kinds of market imperfections, including the incidence of (i) risks, uncertainties or lack of information and (ii) other production constraints, such as the presence of 'must-run' constraints on operation, high costs of starting up or closing down coal plants, or a lack of liquid and flexible fuel (gas) markets, resulting in a lack of production flexibility and high costs of short-term production adjustments. Although it may be difficult to estimate the size (or even, occasionally, the direction) of the impact of these market imperfections on the carbon cost PTR, it is obvious that they could affect this rate.

2.2.8 Summary and conclusion

A major factor affecting the impact of emissions trading on electricity prices is the structure of the power market. This structure refers primarily to the interaction of three elements:

- The number of firms active in the market (*N*), indicating the level of market competitiveness or market concentration.
- The shape of the demand curve, notably whether this curve is linear or iso-elastic.
- The shape of the supply curve, particularly whether the marginal costs before emissions trading are constant – i.e., a flat, horizontal line – or variable, i.e., sloping upward in either a linear or iso-elastic way.

Table 2.2 gives an overview of the cost pass-through formulas for different market structures, assuming profit maximisation among producers. The table makes a distinction between two definitions of the pass-through rate (PTR), i.e., $PTR_1 = dP/dMC$ (where *dP* is the change in price and *dMC* the total change in marginal costs, including carbon costs) and $PTR_2 = dP/dCC$ (where *dCC* refers to the change in carbon costs only). If the supply function is perfectly elastic (i.e., marginal costs are constant) PTR_1 is similar to PTR_2. However, if the marginal costs are variable (i.e., sloping upwards linearly or iso-elastically), the two rates are no longer similar, with $PTR_1 > PTR_2$.
Based on Table 2.2, our findings regarding the impact of market structure on cost pass-through include:
- If demand is perfectly elastic, i.e., the price is given, then PTR is zero. This outcome applies also to cases of outside competition – when prices are set by competitors outside the ETS – or price regulation, in particular when the cost pass-through of freely allocated allowances is not accepted.
- If demand is perfectly inelastic, i.e., demand is fixed and unresponsive to price changes, then PTR is always 100% (in the case of competitive markets), regardless of the shape of the supply function, assuming no change in the merit order of generating plants.

Table 2.2 *Overview of cost pass-through formulas for different market structures, assuming profit maximisation among producers, and different definitions of the pass-through rate*

Definition of PTR/Supply function	Demand function: Perfect elastic	Perfect inelastic	Linear	Iso-elastic
$PTR_1 = \dfrac{dP}{dMC}$				
All supply functions	0	1.0	$\dfrac{N}{N+1}$	$\dfrac{N\varepsilon}{N\varepsilon - 1}$
$PTR_2 = \dfrac{dP}{dCC}$				
Perfect elastic	N.A.	1.0	$\dfrac{N}{N+1}$	$\dfrac{N\varepsilon}{N\varepsilon - 1}$
Linear	0	1.0	$\dfrac{v}{u+v+v/N}$	$\dfrac{1}{\left(1-\dfrac{1}{N\varepsilon}\right)+uP^{-\varepsilon-1}}$
Iso-elastic	0	1.0	$\dfrac{1}{1+\dfrac{1}{N}+\varepsilon b\left(\dfrac{Q}{Q_0}\right)^{b-1}}$	$\dfrac{1}{\left(1-\dfrac{1}{N\varepsilon}\right)(1+b\varepsilon)}$

Note: PTR is pass-through rate, *dP* is the change in price, *dMC* is the change in marginal costs, *dCC* is the change in carbon costs, *N* is the number of firms active in the market, $1/b$ is the price elasticity of supply ($b > 0$), $-\varepsilon$ is the price elasticity of demand ($\varepsilon > 0$), v is the slope of the inverse, linear demand function, and u is the slope of the inverse, linear supply function.

- If supply is perfectly elastic, i.e., marginal costs are constant, the PTR depends on the shape of the demand curve and the number of firms active in the market (*N*). If demand is linear, the PTR is significantly lower than 100% when *N* is small (for instance, it is 50% in the case of monopoly, i.e., $N = 1$) but increases when markets become more competitive (it approaches 100% in the case of perfect competition, when $N = \infty$). If demand is iso-elastic, however, the PTR may be substantially higher than 100% when *N* is small (and demand is less elastic), but decreases towards 100% when markets become more competitive (or demand becomes more price-responsive). Therefore, if supply is perfectly elastic, the PTR always tends towards 100% when the number of firms becomes large and, hence, markets approach the case of full competition, regardless of the shape of the demand function.
- If supply is not perfectly elastic, i.e., marginal costs are variable, the PTR should be carefully defined, distinguishing between $PTR_1 = dP/dMC$ and $PTR_2 = dP/dCC$. When using the first definition, the pass-through rate (i.e., PTR_1) under variable marginal costs is similar to the PTR under constant marginal costs (as discussed above). However, when applying the second definition, the pass-through rate (i.e., PTR_2) under variable marginal costs is always lower than the PTR under constant marginal costs. Moreover, the PTR_2 under variable costs decreases when supply becomes less elastic or demand becomes more elastic.

The distinction between the two definitions of the pass-through rate is also relevant in the case of ETS-induced changes in the merit order of the power supply curve (i.e., changes in the ranking of generation technologies according to their marginal costs, including carbon costs). For instance, if the PTR is defined as *dP/dMC* (where *dMC* refers to the difference between the marginal costs of the price-setting production technology after and before emissions trading), its value is and remains 100% in competitive markets facing perfectly inelastic demand, regardless of whether the merit order changes or not. However, if the PTR is defined as *dP/dCC* (where *dCC* refers to the carbon costs of the production unit that becomes marginal after emissions trading), the PTR can deviate substantially from 100% (either > 1.0, or < 1.0) if the merit order changes, even under competitive markets with perfectly inelastic demand and perfectly elastic supply, depending on the carbon intensity of the marginal generation technology after emissions trading.

In addition, there are additional factors related to the power market that influence the pass-through of carbon costs to power prices, including:

- *Market strategy.* Besides profit maximisation (as assumed above), firms may pursue other objectives such as maximising market shares or sales revenues. These differences in market strategy affect the PTR, regardless of whether carbon costs are actual cash outlays or opportunity costs.
- *Market regulation.* However, in the case of market regulation (or 'regulatory threat') public authorities (or firms) may treat the actual, real costs of purchased allowances differently than the opportunity costs of freely obtained allowances, resulting in different levels of cost pass-through to power prices.
- *Market imperfections.* The pass-through of carbon costs to power prices may be affected by the incidence of market imperfections such as (i) risks, uncertainties or lack of information, and (ii) other production constraints, including 'must run' limits, highly non-convex operating cost functions (such as high start-up costs), lack of flexible fuel markets, and time lags.

3. The impact of the EU ETS on power prices - a review of the literature

This chapter provides a review of the literature on the impact of the EU ETS on power prices. First of all Section 3.1 discusses some empirical studies, i.e. studies which have used actual, empirical data on carbon and energy prices during the first years of the EU ETS in order to assess the effect of this scheme on power prices in specific Member States. Subsequently, Section 3.2 reviews some modelling studies, i.e. studies which have applied a power market/sector model to simulate or assess the implications of the EU ETS on the performance of the power sector in specific countries, including its impact on electricity prices. Finally Section 3.3 provides a comparative summary of both the empirical and modelling studies reviewed in this chapter.

3.1 Empirical studies

Bauer and Zink (2005)

In order to address the correlation between the prices of CO_2 allowances and electricity in Germany. Bauer and Zink (2005) use a combination of empirical approaches, i.e. graphical analyses, the comparison of trends in actual versus estimated power prices, and regression analyses of power and CO_2 prices. They start their analyses from a simple equation:

$$\text{Power price} = \text{Constant} + (X_1 * CO_2 \text{ price} + X_2 * \text{oil price} + X_3 * \text{coal price} + X_4 * \text{gas price})$$

Subsequently, they launch four hypotheses:

1. The trend of the power price is determined by the trends in fuel prices only, assuming 100% pass-through of all fuel costs.
2. The trend of the power price is determined by the trends in prices for both fuels and CO_2. However, whereas the pass-through of fuel costs is assumed to be 100%, the impact of the CO_2 price is supposed to be limited to the extent that power producers - besides the allocations for free - have to buy additional allowances on the market (i.e. estimated at 7.5% of the allowances needed to cover total CO_2 emission by the power sector).
3. The trend of the power price is determined by the trends in prices for both fuels and CO_2. In this case, however, the pass-through of the CO_2 price is assumed to be 100%, regardless of the fact that generators receive almost all of their necessary allowances for free.
4. The trend of the power price is determined by the trends in CO_2 prices only, assuming 100% pass through of the (opportunity) costs of CO_2.

Based on data of the fuel generation mix and year-ahead (Cal06) price for fuels, carbon and baseload power, Bauer and Zink test these hypotheses for the period January-June 2005. They found that hypothesis 1 offered the worst fit between actual and calculated power prices, while hypothesis 4 resulted in the best fit. Based on this finding, they estimated the parameters of a simple linear equation:

$$\text{Power price} = a + b \times \text{allowance price}$$

For the period January-June 2005, the value of the parameters a and b was estimated at 29.8 €/MWh and 0.52 tCO_2/MWh, respectively. This implies that an allowance price of 20 €/t results in an increase in the power price by 10.4 €/MWh.

According to Bauer and Zink, the estimated value for the parameter b corresponds highly with the average emission factor of the fuel mix for power generation in 2004, i.e. about 0.53

tCO_2/MWh. This suggests that the average CO_2 cost pass-through in the first half of 2005 was nearly 100%. However, assuming that the baseload prices are largely set by coal-fired generators with a marginal emission factor of approximately 0.95 tCO_2/MWh, the marginal pass-through rate of carbon costs would be approximately 55% (i.e. 0.52/0.95).

Bunn and Fezzi (2007)
The paper of Bunn and Fezzi (2007) addresses the impact of the EU ETS on wholesale electricity and gas prices (see also Fezzi, 2006). In particular, it analyses econometrically the mutual relationships between electricity, gas and carbon prices in the daily spot markets of the UK from April 2005 to May 2006 by using a so-called Structural Vector Autoregressive (SVAR) model.

Bunn and Fezzi show that carbon prices react significantly and quickly to a shock on gas prices, but - in turn - the dynamic pass-through of carbon to electricity is only after some days. In particular, they estimate that eventually a 1% change in carbon prices translate on average into a 0.42% change in UK power prices. Similarly, with regard to the impact of gas on electricity, they estimate a coefficient of 0.63, implying that a gas price rise of 1% would, in equilibrium, be associated with an electricity price rise of 0.63%.

Essentially, Bunn and Fezzi observe that "gas drives carbon, whilst both carbon and gas drive electricity prices. Evidently one of the indirect effects of carbon trading has been to strengthen the link between gas and power, and to the extent that global gas prices are acquiring the geopolitical risk characteristics of oil, that may not be a welcome outcome". Clearly the carbon prices are responding to gas in terms of seeking to motivate the substitution of coal generators at the margin by gas. Altogether the effect of carbon trading on power prices is not just a simple increase in prices to reflect the extra costs of carbon abatement, it is perhaps more seriously the increased short-term volatility and increased gas price exposure with the consequent risk management and investment aversion costs that follow (Bunn and Fezzi, 2007).

Chernyavs'ka and Gulli (2007)
In a paper, Chernyavs'ka and Gulli (2007) estimate empirically the marginal pass-through rate (MPTR) on the Italian spot market for 2005-2006.[44] Their approach consists of the following steps:[45]

- Load duration curves of power prices, fuel costs and CO_2 cost are designed by ordering these prices and costs according to decreasing levels of demand.[46]
- The spread curve, obtained by subtracting the fuel cost curve form the power price curve, is compared to the CO_2 cost curve.
- Since the Italian power market is a combination of (almost) separated sub-markets (with different features in terms of market power and available capacity), a distinction is made between the North and South sub-market. The North sub-market is characterised by excess generation capacity, a relatively lower level of market concentration, and a so-called 'trade-off in the plant mix' (i.e. the technology with lower variable costs is not also the lower CO_2 emission technology). In the South sub-market, on the other hand, there is scarcity of generation capacity, a high level of market power, but no 'trade-off in the plant mix' (i.e. the technology with lower variable costs is also the cleaner technology, such as in the case of gas-fired versus oil-fired steam cycle plants).
- The fuel and CO_2 costs are calculated by accounting for the real plant mix in each sub-market, i.e. by estimating which kind of technology is able to set prices in each hour. In particular, in the North sub-market it is very likely that hydro plants (in Italy, mainly storage

[44] Chernyavs'ka and Gulli (2007) define the marginal pass-through rate (MPTR) as the change in power prices divided by the change in marginal production costs of the marginal unit due to the EU ETS.
[45] In addition, Chernyavs'ka and Gulli compare their empirical results to the predictions of a theoretical model (see also Bonacina and Gulli, 2007).
[46] A load duration curve presents the power price (or fuel/carbon costs) during the hours of a certain period (either on an absolute or percentage basis), according to decreasing levels of demand (i.e. from super peak to very off-peak hours).

and pumped storage hydro plants) could be the marginal units in the peak hours, the CCGT plants in the peak and mid-merit hours and the cogeneration plants (based on the CCGT technology) in the (very) off-peak hours. In the South sub-market, instead, oil-fired and gas-fired steam cycle plants set prices in almost all hours in the year.

The approach of Chernyavs'ka and Gulli results in some interesting findings on the marginal pass-through rate (MPTR) in Italy for different time periods, sub-markets and levels of power demand (i.e. different load periods). By comparing the hourly data on the Italian sport market for 2005 versus 2004, they note that in both the North and South sub-markets the change in power spreads is almost always negative. This legitimises them to say that it is unlikely that power prices included CO_2 costs in 2005. They explain this result by the fact that in Italy the CO_2 emission allowances have been allocated only at the beginning of 2006. Consequently, they presume that power firms began to pass-through CO_2 costs only in that year, i.e. these firms decided to not pass-through CO_2 costs during 2005 (before the allocation), also - perhaps - in order to avoid more restrictive regulation (including less free allocations) during the first phase of the EU ETS.

Subsequently, Chernyavs'ka and Gulli compare the hourly spot data for 2006 to 2005.[47] In the North sub-market, the change in spread (2006 vs. 2005) is much higher than the CO_2 cost (close to the carbon cost of a typical peaking technology, i.e. a gas turbine plant or an oil-fired plant) in a relatively limited number of hours of the peak period (up to 1700 hours, i.e. up to 20% on a percentage basis). Hence, the level of the MPTR curve during these hours is significantly higher than 1.0 (i.e. fluctuating between 1.5 and 2.5). In the remaining hours, the change in spread is more or less equal to the CO_2 cost for a CCGT (mid-merit hours) and a CHP-CCGT (off-peak hours), except for the interval between 2200 and 4000 hours (between 25 and 45% on a percentage basis). Therefore, whereas during this interval the MPTR curve is significantly below 1.0 (i.e. fluctuating around a level of 0.5), it is close to one beyond 4000 hours.

In the South sub-market, the change in spread in 2006 is much lower than the CO_2 cost (and, occasionally, even negative) in a large number of hours (up to 4000 hours, i.e. around 40% on a percentage basis). Instead, between 45 and 60% of the total annual hours, it is sensibly more than the CO_2 costs for gas-fired steam cycle plants while it is close to these costs for the remaining hours of the year. Therefore, the level of the empirical MPTR curve is substantially below 1.0 during the peak hours (occasionally even negative, but mostly fluctuating between 0 and 0.5), significantly above 1.0 during the mid-merit and off-peak hours, while close to one during the very off-peak period.

According to Chernyavs'ka and Gulli (2007), deviations form the 'full pass-through' rule can be determined by market power (see also Bonacina and Gulli, 2007). The sign of this deviation, however, cannot be known *a priori,* i.e. without before carefully taking into account the structural features of the power markets such as the degree of market concentration, the available capacity (whether there is excess capacity or not), the power plant mix in the market, the allowance price and the power demand level (peak versus off-peak hours).

Frontier Economics (2006a and 2006b)

On behalf of the energy regulator in the Netherlands (DTe), Frontier Economics has gathered factual information about the impact of the EU ETS on the performance of the Dutch wholesale electricity market, in particular to estimate the extent of windfall profits in 2005 that generators may have realised as a consequence of the EU ETS.[48] To meet this objective, Frontier Econom-

[47] In theory, to estimate the incidence of CO_2 cost pass-through, one should compare a year with emissions trading (for instance, 2005 or 2006) with a year preceding emissions trading (e.g., 2004). However, since Chernyavs'ka and Gulli did not find any pass-through in 2005, they have compared 2006 versus 2005 (personal communication Gulli, April 2007).

[48] Actually, this information was requested by the Dutch Ministry of Economic Affairs as a supplement to - and independent check-up - of the empirical work by Sijm et al. (2005 and 2006a, as discussed below).

ics has statistically estimated the link between CO_2 and fuel prices on the one hand and electricity prices in the Netherlands on the other hand, based on the following assumptions:

- In the peak, Dutch power prices are set by a gas-fired plant with a fuel efficiency of 35%.
- In the off-peak hours, Dutch power prices are set by a coal-fired plant with a fuel efficiency of 40%.

In order to estimate the links between CO_2, fuel and power prices, Frontier Economics (2006a) has used year-ahead data from 2005 (i.e. Cal 06). Given the distortions that time trends can create, regression variables have been expressed in first differences rather than absolute values.[49] Moreover, two kinds of specifying regressions have been used, i.e. regressing power prices to both fuel and CO_2 prices and, secondly, regressing power spreads to CO_2 prices only. Finally, regressions have been conducted for 2005 as a whole, as well as for two sub-periods, i.e. January-July 2005 and August-December 2005.

The key results of the regressions by Frontier Economics are summarised in Table 3.1. Although a relationship between power and carbon prices appears to exist, the nature of the relationship is sometimes uncertain, in particular between CO_2 and peak electricity prices. For the period January-July 2005, the electricity price regression shows a CO_2 pass-through of 47%. However, the confidence interval for this rate is rather broad, 25-70%. Moreover, the same regression implies that only 20% of changes in gas prices are passed through in electricity peak prices during the same period. Furthermore, applying the same specification to the rest of the year leads to a pass through estimate for CO_2 of 108%, while the pass-through rate for gas falls to 17%. Following a different specification in which the peak spark spread is regressed against the CO_2 price, Frontier Economics estimates pass-through rates of 4 and 66% for the two periods, but with very wide confidence intervals for both estimates.

Table 3.1 *Summary of regression results for 2005 for the effect of CO_2 prices on year-ahead electricity prices/spreads in the Netherlands for different periods of 2005*

Period 2005	Regression (Variables in first differences)	Pass through rate [in%] (95% confidence interval)		Adj. R^2
		CO_2 price	Fuel price	
All 2005	Peak price v. CO_2 price and gas price	61 (40 - 83)	20 (8 - 32)	.19
January-July		47(25 - 70)	20 (7 - 33)	.20
August-December		108 (57 - 160)	17 (-7 - +42)	.20
All 2005	Spark spread v. CO_2 price	18 (-9 - +46	NA	.00
January-July		4 (-26 - +35)	NA	.01
August-December		66 (46 - 128)	NA	.03
All 2005	Off-peak price v. CO_2 price and coal price	34 (22 - 46)	-1 (-12 - +9)	.11
January-July		32 (18 - 45)	-2 (-16 - +12)	.12
August-December		39 (13 - 65)	-1 (-19 - +17)	.07
All 2005	Dark spread v. CO_2 price	34 (15 - 53)	NA	.10
January-July		33 (11 - 55	NA	.10
August-December		40 (0 - 80)	NA	.06

Source: Frontier Economics (2006a).

According to Frontier Economics (2006a), the overall findings do not provide persuasive evidence as to how CO_2 prices in 2005 affect year-ahead power prices and spreads in the Netherlands. There is *prima facie* evidence that pass-through rates in the latter part of 2005 are higher

[49] Time trends can lead to a spurious apparent correlation between variables which are in fact unrelated. Use of first differences is a standard technique to help eliminate spurious correlation.

than in the earlier part of the year. However, it is also plausible that as the real delivery time approaches, there are other important factors that start to influence electricity prices, for example longer term weather forecasts or more specific knowledge about the availability of plant. For the same reason that spot prices are more volatile than forward prices, forward prices close to delivery are more volatile than longer term forwards. Causal factors not represented in the model may play a more important role and bias the results. Hence, caution should be exercised in regarding these results as truly representative of the change in pass-through rates.

In a paper published later on, Frontier Economics (2006b) has conducted similar regressions on CO_2 power prices/spreads for a broader set of countries, including Scandinavia, the Netherlands and the UK. The results are summarised in Table 3.2. As can be seen, the correlation between carbon prices and electricity prices/spreads during 2005 is very high for all countries considered.

Frontier Economics notes, however, that during the fourth quarter of 2005 power prices are sometimes less well explained by CO_2 allowance prices. The reason is that in Q4-2005, the delivery period of the electricity forward contract is nearing. In this case, short term market developments start to have an impact on the forward price. For example, in Q4 international meteorological offices started developing forecasts of a cold winter. The market inferred high electricity demand and consequently higher electricity prices. This could also have affected the forward price for Cal06 (Frontier Economics, 2006b). Therefore, regressing carbon versus power prices for 2005 without Q4 data results in even higher correlation coefficients, as shown in the last column of Table 3.2.

Table 3.2 *Summary of correlation between forward electricity and carbon prices*

Correlations Cal06	Whole year [%]	W/o 4th quarter [%]
UK: Peak prices vs. allowance prices	91	97
UK: Off-peak prices vs. allowance prices	97	98
UK: Spark spreads vs. allowance prices (for peak hours)	89	95
UK: Dark spreads vs. allowance prices (for off-peak hours)	93	95
NL: Peak prices vs. allowance prices	91	92
NL: Off-peak prices vs. allowance prices	95	96
Scandinavia: Baseload prices vs. allowance prices	97	98

Source: Frontier Economics (2006b).

Honkatukia et al. (2006) and Perrels et al. (2006)

In a study for the Finnish Ministry of Trade and Industry, the Government Institute for Economic Research (VATT, Helsinki) has analysed the impact of the EU ETS on Finnish wholesale electricity prices (Honkatukia et al., 2006; see also Perrels et al., 2006). Based on hourly, daily and monthly data of the Finnish part of the Nord Pool sport market over the period February 2005 to May 2006, the authors have estimated CO_2 pass-through rates by means of three econometric models.[50]

[50] The three econometric models include: (i) a vector error correction model (VECM), i.e. a model which is convenient for the simultaneous analysis of long-run relationships between variables as well as for their deviations form these equilibriums in the short run, (ii) an autoregressive integrated moving average (ARIMA) model, i.e. a different version of an error correction model which is purely expressed in terms of first differences, and (iii) an autoregression-generalised autoregressive conditional heteroskedasticiy (AR-GARCH) model, i.e. a model in which (natural logarithms of the) absolute levels of the variables is used (Honkatukia et al., 2006; Fezzi, 2006; and Reinaud, 2007).

In summary, the major findings of the three econometric exercises include:

- During the period analysed, on average about 75-95% of the price change in the EU carbon market was passed through to the Finnish Nord Pool spot market.
- The state of the power system, as characterised in particular by the utilisation level of domestic generation capacity and in addition by other features such as the filling of the hydro reserve, influences the sensitivity of the spot price with respect to input costs, including the CO_2 allowance costs on the EU ETS market.

The authors also simulate to what extent the pass-through of the price of an EU allowance (EUA) varies when the state of the power system varies (and, hence, the wholesale price level). The key results are summarised in Table 3.3 for increases in EUA prices of 15, 25 and 50%, assuming a baseline level of 21.30 €/tCO_2 (the average EUA price during the period considered). For example, if the EUA price increases by 25% (in one day) during a typical medium load period, the Finnish spot price is expected to rice by 0.94 x 0.25 x 21.30 = 5 €/MWh.

According to Table 3.3, lower loads imply lower shares of EUA prices passed on to spot prices. At low loads, non-fossil fuel technologies can compete with fossil fuel technologies more effectively. This implies that the tendency to pass on 100% of the CO_2 costs is less since fossil-fuel technologies may risk losing all or part of the market, if they do so (Honkatukia et al., 2006; Reinaud, 2007).

Table 3.3 *Shares of the rise in the EUA carbon price passed immediately on to the spot price for different single day ETS price increases for different typical load levels*

Increase in EUA price	Share of EUA price increase passed on		
[%]	Low loads	Medium loads	High loads
12	0.47	0.97	1.11
25	0.45	0.94	1.07
50	0.43	0.89	1.02

Source: Honkatukiu et al. (2006).

On the other hand, higher loads generally imply an increased use of more fossil-fuelled, higher CO_2 emitting capacity and, hence, an increased need for allowances to cover the higher emissions. Moreover, higher load levels also correspond to lower competition levels and, consequently, greater possibilities to increase prices (implying that the share of variation in EUA price passed on to spot prices will be high, as indicated by Table 3.3). The results also show that the larger the price change of an EUA (in one day) the smaller the share is passed on (Honkatukia et al., 2006; Perrels et al., 2006).

Levy (2005)

In a case study of the impact of the EU ETS on power prices in five Member States (France, Germany, Italy, Spain and the UK), Levy (2005) has run a series of regressions on CO_2 prices versus wholesale baseload prices on spot and forward markets during the first semester of 2005. The results are summarised in Table 3.4. In general, the correlation coefficient (R^2) of the regression variable between CO_2 prices and baseload prices on the spot market is very low for all countries analysed during the first three months of the EU ETS (January-March 2005), but higher during the second quarter of 2005 (April-June).

On the forward market, however, the correlation between carbon and power prices during the first semester of 2005 as a whole is strong for Germany and France, but weak for the UK. The low R^2 of the estimates may be due to the relatively short periods used for the analyses, the fact that the EU ETS was still immature (and, hence, power producers were not yet used to factor in allowance costs in their bid prices) and/or the volatile, rising gas prices (which is transmitted to volatile, increasing power prices, notably in the UK). The cases with a higher R^2, on the other hand, may be due to the longer period analysed (in particular, the estimates covering the first semester), the fact that carbon costs were increasingly passed on to wholesale power prices, and/or less volatile fuel prices for countries such as France of Germany (which rely less on gas for their power generation).

Table 3.4 *Summary of regressions of CO_2 prices and baseload prices on spot and forward markets in EU countries during the first semester of 2005*

		France	Germany	Italy	Spain	UK
Spot						
January-March 2005	RC	1.32	0.96	-1.82	1.08	1.58
	R^2	0.02	0.02	0.22	0.04	0.05
April-June 2005	RC	2.21	3.33	2.04	3.53	2.19
	R^2	0.42	0.40	0.29	0.62	0.58
Forward						
January-June 2005	RC	0.56	0.48	n.a	n.a.	1.84
	R^2	0.96	0.95	n.a.	n.a.	0.33

Note: RC is regression coefficient between the power price (dependent variable) and the carbon price (independent variable). This coefficient shows whether there is a correlation between the variables, but is not similar to the so-called pass-through rate of carbon costs to power prices.
Source: Levy (2005)

Sijm et al. (2005, 2006a and 2006b)

In addition to model analyses (see previous chapter), Sijm et al have conducted a series of statistical and empirical analyses of the impact of the EU ETS on power prices. In particular, Sijm et al. (2005) have estimated rates of passing through CO_2 costs into power prices on year-ahead markets in Germany and the Netherlands over the period January-July 2005 for both peak and off-peak hours. To estimate these pass-through rates, three methods have been used, including two statistical regression approaches called Ordinary Least Squares (OLS) and the Prais-Winston (PW) method, and a simple regression-line approach developed by ECN.[51]

Table 3.5 *Comparison of estimated pass-through rates in Germany and the Netherlands over the period January-July 2005, based on year ahead prices for 2006*

	Load period	Fuel (efficiency)	OLS[a] [%]	PW[a] [%]	ECN [%]	ECN [€/MWh]
Germany	Peak load	Coal (40%)	72	69	73	9.5
	Off-peak	Coal (40%)	42	42	46	5.9
NL	Peak load	Gas (42%)	40	44	39	2.8
	Off-peak	Coal (40%)	53	47	55	7.2

a) All regression estimates are statistically significant at the 1% level.

The major results of Sijm et al. (2005) are summarised in Table 3.5. The estimated pass-through rates vary between 40 and 70%, depending on the cases considered (including the assumptions made on the marginal generation technology and fuel efficiency). In addition, the authors have estimated the absolute amounts of CO_2 costs passed through to power prices, based on an average price on the EU ETS market of 15.3 €/MWh over the period January-July 2005. For Germany, these amounts vary from 5.9 €/MWh during the off-peak period to 9.5 €/MWh during the peak load hours (both coal-based cases). For the Netherlands, these amounts vary from 2.8 €/MWh during the peak load period (gas-based case) to 7.2 €/MWh during the off-peak

51 OLS and PW are both linear regression methods to analyse associations between a dependent variable and independent variables. The difference between these methods concerns the incidence of autocorrelation between the data used. The incidence of such autocorrelation could bias the estimated results. While the PW method corrects for this incidence/bias, the OLS does not. The method developed by ECN (i.e. Sijm et al.) is based on an analysis of power spreads over a certain period, assuming that the trend line of these spreads should be flat when including the CO_2 costs, assuming in effect that all remaining variations of these spreads can be attributed to random variables with an expected value of zero. The method consists in solving for the pass-through rates that will meet this condition.

hours (coal-based case). The amount for the gas-based case in the Netherlands is relatively low because the carbon intensity of gas-generated power is much lower (about half) than coal-generated power, while the passing-through rate for gas is relatively low (probably because of the volatile and rapidly increasing gas prices during the period analysed, it was harder to pass on CO_2 costs to power prices, assuming that changes in fuel prices are always fully and directly passed on to higher power prices).

Sijm et al. (2006a and 2006b) have updated the empirical and statistical analyses discussed above for 2005 as a whole, including some additional methodological variations and approaches to test the consistency and accuracy of their estimates. The major updated results are summarised in Table 3.6, including the minimum and maximum values of the OLS estimator with bootstrapping.[52] In general, the estimated pass-through rates for 2005 as a whole are substantially higher (60-120%) than for the period January-July 2005 (40-70%). During the period August-December 2005, power prices and spreads in Germany and the Netherlands have increased significantly, which may to some extent be attributed to a catching up of the CO_2 pass-through rates up to 100%. However, the high pass-through rate for the peak hours in Germany (i.e. 117%) might be partially explained by increasing gas prices during 2005. Given that gas generators (instead of coal genitors set the marginal price in German markets during some peak hours, this could contribute to power prices 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.

Table 3.6 *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 [%]*

	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

More generally, estimates of CO_2 cost pass-through rates for the latter part of 2005 seem to be overestimated due to the incidence of other factors causing increases in power prices - such as growing market power or scarcity - especially during the peak hours. In addition, differences 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 CO_2 price (i.e. market learning), rapidly rising gas prices (notably during February-July 2005), higher power prices due to increasing scarcity and/or market power (particularly during September-December 2005), or by various other factors affecting power prices in liberalised wholesale markets.

Besides the above-mentioned analyses of the forward markets, Sijm et al. (2006b) have also studied the impact of the EU ETS on 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 2004. More specifically, the authors look to what extent a change in the spot power price, for example at 9 a.m. on the first Monday in January 2006 relative to the first Monday in January 2004, can be explained by the introduction of EU emissions trading, assuming that factors other than CO_2 and fuel costs remain unchanged.

Figure 3.1 presents the estimated PTR for different hours of the day, assuming that coal generators are at the margin and, hence, set the price. The picture shows clearly that the pass-through rate is significantly higher during the (very) peak hours than the (very) off-peak hours. The pass-through rate during the (very) peak hours, however, may be overestimated as it is assumed

[52] Bootstrapping implies the estimation of a regression coefficient, such as a pass-through rate, for a sequence of sub-sets of the total observed dataset in order to test the reliability and robustness of the estimation.

that coal is at the margin, while during certain (very) peak hours the price is set by a gas-fired plant which faced increasing fuel costs pushing up the power price.

To examine whether the daily pattern of the pass-through rate is consistent over time, the authors have split the observation into three sections. Figure 3.1 shows that, while this pattern did not change during the day, the level of the pass-through rate increased for each subsequent period considered. To some extent, however, this increase in pass-through rates over time may be overestimated as increases in power prices may also result from other factors such as growing market power or scarcity.

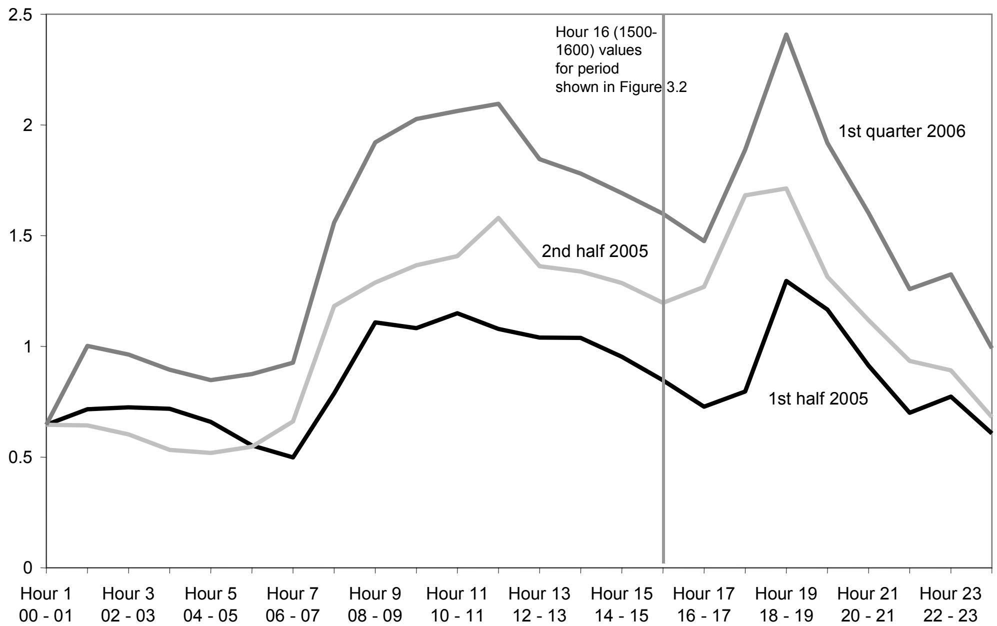


Figure 3.1 *Pass-through rate of CO_2 costs on the German spot power market for different time periods, assuming coal generators are at the margin*
Source: Sijm et al. (2006b).

A final result by Sijm et al. (2006b) is presented by Figure 3.2, which depicts for each day over the period January 2005 - March 2006 the change in dark spread on the German spot market in the hour 3-4 p.m. relative to the pre-ETS year 2004. As can be seen from Figure 3.2, during January 2005 hardly any CO_2 costs were passed through, but subsequently - up to October 2005 - a rather close link seems to exist between the increase in the CO_2 costs and the increase in the dark spread relative to 2004. By the end of 2005, the dark spread on the German spot market increased rapidly, while the CO_2 costs hardly changed. The increase in the dark spread can be attributed to (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. Overall, the authors conclude that market participants in Germany seem to have fully passed through the opportunity costs of CO_2 allowances on the spot market.

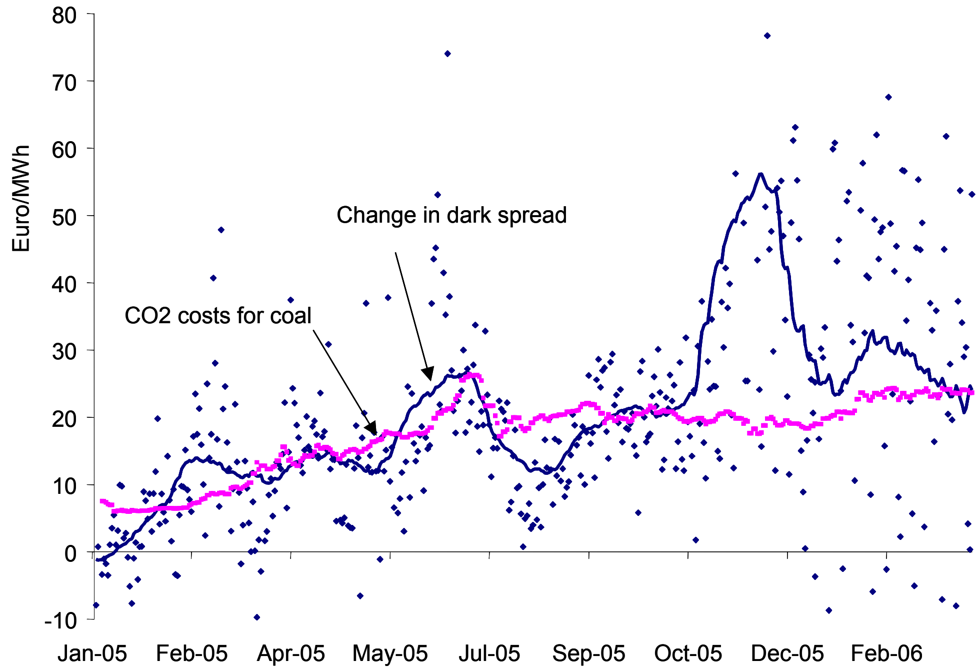


Figure 3.2 *Coal price corrected price increase for electricity (3-4 pm) depicted as dots and their 40 day moving average (volatile (dark) line) and the evolution of the CO_2 price (grey line)*

Source: Sijm et al. (2006b).

3.2 Modelling studies

IPA (2005)

On behalf of the UK Department of Trade and Industry (DTI), IPA Energy Consulting has analysed the implications of the EU ETS for the UK power generation sector by applying a model called ECLIPSE. This proprietary power system model simulates the complex interactions in the UK market, including the interface with policy instruments such as renewables obligations, environmental regulations and emissions trading. It is able to analyse the impact of these instruments by generating consistent forecasts of significant market parameters, in particular of system costs, power prices, plant profits and capacity investments (with and without free allocations of carbon allowances).

In addition, IPA has used its European Power System Model (EPSYM) in order to compare the impact of the EU ETS on wholesale power prices in Great Britain (GB) and Northern Ireland (NI) to the impact on similar prices in France, Germany, Italy, and Spain.[53] EPSYM simulates the main power markets in Western Europe, including their interconnections. It yields annual baseload and peak prices by undertaking an economic dispatch of the different generation technologies across Europe, accounting for all commodity costs - including carbon and other variable costs - average plant availabilities, and average load factors for renewable sources.

IPA (2005) uses the models ECLIPSE and EPSYM to estimate the impact of the EU ETS on power prices over 2005-2020 according to three scenarios, i.e. a Base Case, a Low Case and a High Case. In the Base Case, carbon prices are assumed to be 15 €/tCO_2 during Phase I of the EU ETS (2005-2007), 20 €/t during Phase II (2008-2012), and 25 €/t during the period 2012-

[53] For a brief description of IPA's power market models ECLIPSE and EPSYM, see Appendix A of IPA (2005).

2020. Compared to the Base Case, the carbon prices are assumed to be lower in the Low Case and higher in the High Case.[54]

Based on these scenarios, including the assumption of full pass-through of carbon costs into wholesale power prices at the carbon intensity of the marginal plant, IPA's major findings with regard to the impact - or *uplift* - of the EU ETS on wholesale power prices across Europe include:[55]

- The cost of carbon is expected to add a direct uplift of 5-16 €/MWh to wholesale power prices in Great Britain over the forecast period to 2020, assuming Base Case carbon prices of €15, €20 and €25/tCO_2 in Phases I, II and beyond. In addition, the incorporation of carbon into wholesale prices will drive capacity changes. The sensitivity of wholesale prices to carbon is expected to increase over Phase II as coal plant increasingly runs at the margin, but to reduce after around 2014 as lower intensity plant takes its place.
- Under all the scenarios, Great Britain starts with the lowest carbon uplift in wholesale power prices, relative to the other major EU markets, while France and Italy tend to have lower uplifts later in the forecast period. This reflects the gradual switch of the marginal generation units from gas to coal. However, it also reflects the fact that the retirement of much of the nuclear fleet means that Great Britain is still reliant on coal generation later in the forecast horizon, despite a significant capacity expansion of Combined Cycle Gas Turbines (CCGTs).
- For all countries the carbon uplift of the wholesale price is broadly correlated with carbon price, so the uplift is highest in the High Case scenario, and lowest in the Low Case scenario. However, the level of uplift varies across countries, depending on the carbon intensity of the generation mix, and changes through time, depending upon the rate of evolution of the capacity mix.
- Under all three scenarios and across all countries, the carbon uplift associated with the wholesale price increases to 2015. This reflects the underlying increases in carbon price (under the Base and High Case scenarios), as well as the decreasing competitiveness of coal which typically serves to increase the carbon intensity of the marginal plant. However, beyond 2015, the carbon uplift typically decreases, reflecting the evolution of the power sectors to a lower carbon intensity capacity mix, primarily through the construction of CCGT and renewable capacity.
- Germany typically has the highest wholesale price uplift due to carbon, reflecting their relatively high dependence on coal and lignite for power generation. The uplift does not decrease in later years to the same extent as in other countries. This is due to the planned nuclear closures over the period, which ensures that despite significant renewable and CCGT build, they still are reliant on coal plants.
- Italy also shows a relatively high uplift, initially due to a reliance on coal and oil plants. Despite significant CCGT build within Italy over the forecast horizon, there is also significant demand growth. This means that the older, more carbon intensive generation has to be maintained to provide system security, increasing the carbon intensity of the generation mix.
- The sensitivity of wholesale prices to carbon prices increases with higher carbon prices. The competitiveness of coal plant relative to CCGT is eroded with higher carbon prices and coal therefore increasingly replaces gas plant as the marginal technology, which leads to a higher marginal carbon intensity and hence a greater impact on power prices.

In addition, IPA (2005) has estimated the impact of the EU ETS on generators' profits in the UK. In that respect, IPA's major findings include:

- The combination of free allocations with full pass-through of marginal costs is estimated to result in increased profitability for the UK power generation sector of approximately €1200

[54] For more details on the assumptions regarding carbon prices (and other variables) in the three scenarios, see Section 3.2 of IPA (2005).

[55] According to IPA (2005), *'uplift'* simply means the additional cost of carbon, calculated as the average carbon intensity of the marginal plant multiplied by the assumed carbon price for the period considered. For a more extensive discussion and executive summary of IPA's pricing analysis, see Chapters 1 and 8 of IPA (2005).

million per year over Phase I (based on the current annual free allocation of 130 $MtCO_2$). The overall impact on sector profitability would have been neutral with an annual free allocation of around 45 $MtCO_2$ (assuming a constant carbon price of 15 €/tCO_2).
- However, sector profitability is expected to decline over Phase II, as the impact of carbon prices and new entry CCGT plant reduces the profitability of coal plant, and lower power prices reduce the profitability of nuclear plant. The profitability of the sector is expected to flatten out in Phase III and beyond, as the sector becomes increasingly dominated by a single technology (CCGT). Free allocations would continue to boost sector profitability if applied beyond Phase II.

Kara et al. (2007)
On behalf of the Finnish Ministry of Trade and Industry, Kara et al. (2007) have analysed the likely impacts of the EU ETS on power plant operators, energy-intensive industries and other consumer groups, specifically in Finland as well as, more generally, in the other countries of the common Nordic electricity system (i.e. Norway, Sweden and Denmark). These impacts were studied in particular with the so-called VTT electricity market model, based on physical demand and production of electricity in the Nordic market area and trade between neighbouring countries such as Russia or Central Europe.[56] The model balances the generation of electricity between thermal power, hydro power and other power sources so that the total variable costs are minimised.

Due to EU emissions trading, the annual average electricity price in the Nordic area is estimated to rise by 0.74 €/MWh for every 1 €/tCO_2 allowance costs (depending on the periods that each marginal generation mode is setting the price, while assuming that the marginal costs are fully passed on to the power price).[57] As a result, Kara et al. have estimated large windfall profits to incur to power producers in the Nordic area, notably to hydro and nuclear generators in Norway and Sweden. In Finland, on the other hand, metal industry and private consumers are estimated to be most affected by the EU ETS-induced increases in power prices, whereas the pulp and paper industry is relatively protected from these increases as it owns most of its electricity and heat supply (CHP), either directly or through shareholdings in the industry-owned production companies in Finland.

Linares et al. (2006)
In order to assess the impact of the EU ETS on the Spanish electricity sector, Linares et al. (2006) apply a model called ESPAM. This is a technology-detailed, oligopolistic market model of the Spanish power system which simulates expansion of generation capacity and endogenously determines CO_2 allowance prices (based on some stringent supply and demand assumptions). While assuming full cost pass-through of carbon costs, the study estimates that the EU ETS will result in a steady increase in carbon allowance costs and, hence, of power prices over the considered period 2005-2014. For instance, in 2010 the allowance price is estimated at 7.3 €/tCO_2, leading to an increase in the electricity price by 2.6 €/MWh (i.e. +10%), while in 2014 the carbon price amounts to 15.2 €/tCO_2, resulting in a power price increase of 5.4 €/MWh (i.e. +20%).

To some extent, the rise in power prices is mitigated by the EU ETS-induced fuel switch and expansion of generation capacity towards Combined Cycle Gas Turbines (CCGTs). Nevertheless, due to the pass-through of CO_2 costs to power prices, large windfall profits are estimated to incur to power generators, especially to those producers with a large share of low-carbon tech-

[56] VTT is the Technical Research Centre of Finland. For a description of the VTT electricity market model, see Kara et al. (2007) and references cited therein.
[57] By using an additional, long-term dynamic energy system model (i.e. TIMES), Kara et al. show that the price impact of the EU ETS in Finland is substantially limited to about one-third if it is accompanied by the installation of a new (sixth) nuclear power plant.

nologies (provided the Spanish regulator allows for the estimated, ETS-induced increase in power prices under the regulated tariff system).

Lindboe et al. (2007)

On behalf of the Danish Environmental Protection Agency, Ea Energy Analyses examined the consequences of allocating free CO_2 emission allowances to new entrants in the EU ETS (Lindboe et al., 2007). To achieve this objective, they used the Balmorel model, which covers the electricity and district heat sector of Germany and the Nordic countries (Denmark, Finland, Norway and Sweden). Balmorel is a dynamic partial equilibrium model which simulates welfare-economic optimal dispatch of generation capacity, consumption, transmission as well as performing investments in generation technology endogenously.[58]

The Balmorel reference scenario refers to a situation of emissions trading at an allowance price of 20 €/tCO_2, excluding free allocation to new entrants, while the alternative scenario includes this provision. By comparing the outcomes of the reference and alternative scenarios, the major findings and conclusions with regard to the impact of free allocations to new entrants include (Lindboe et al., 2007):[59]

- Allocation to new entrants is a substantial investment subsidy. At 20 €/tCO_2, the income from the sale of allowances is able to cover a considerable part of the total capital costs of a new plant. In Germany, this amounts to more than 60%. As a result, total investments in new power capacity increase significantly. The additional capacity reduces the number of hours where expensive peak-load facilities need to be in operation.
- Due to free allocation to new entrants, investments in new capacity will shift from a combination of coal, gas and wind power to almost exclusively coal power. As a result, CO_2 emissions increase by 40 MtCO_2 per year in the long term (i.e. a 6% increase).
- In the medium term, i.e. starting from about 2010, electricity prices decrease - particularly in Germany - because allocation to new entrant stimulates investments in new power capacity with low short-term marginal costs. Consumers benefit from this whereas existing electricity producers lose.[60]
- Distortions in the market will lead to a welfare-economic loss of almost € 5 billion (net present value) at an allowance price of 20 €/tCO_2. The welfare-economic loss increases with increasing carbon prices. At an allowance price of 30 €/tCO_2, the total welfare-economic loss increases to € 15 billon.
- Carbon prices rise and, hence, exacerbate the welfare-economic loss mentioned above. If carbon prices reach 40 €/tCO_2, this may endanger the functioning of the EU ETS as the subsidy for fossil-fuel plants exceeds the investment costs of new power plants.
- The costs of achieving a renewable energy target may be increased significantly due to new entrant allocation. According to the model simulations by almost 60% from approximately 14 €/MWh in a situation without new entrant allocation to 22.5 €/MWh.

Oranen (2006)

As part of a research project called 'Market analysis and risk management of EU emissions trading' (conducted jointly by the University of Helsinki and the Helsinki University of Technology), the master's thesis of Oranen (2006) aims to find out how dominant firms in Nord Pool - i.e. the relatively highly integrated and liberalised Nordic power market - will react to the EU ETS and how this will affect the price of electricity in the Nordic countries. To achieve this ob-

[58] Balmorel stands for Baltic Model of Regional Electricity Liberalisation. A more detail description o f this model is provided by Lindboe et al. (2007), notably in Appendix A of their study.

[59] At a more abstract level, comparable model simulation results were found by Schulkin et al. (2007). See also Hobbs (2007 and 2008).

[60] For instance, electricity prices in Germany decline from a level of almost 50 €/MWh to 40 €/MWh, driving down the profits of existing power operators. It is not clear, however, whether this decrease in power prices due to the free allocation to new entrants also includes the impact of this provision on carbon prices I.e. whether the increase in carbon prices due to the free allocation to new entrants is included in the pass-through to power prices; see Section 2.2 for a theoretical discussion of the impact of free allocation to new entrants on power and carbon prices).

jective, she uses a Cournot oligopolistic market model based on a Nordic merit order supply curve and a constant elasticity demand function.

Oranen's model estimates with regard to the impact of the EU ETS on Nordic electricity prices are summarised in Table 3.7. In particular, it shows the marginal generation technology, the equilibrium price and the pass-through rate for (i) two demand levels, i.e. winter and summer (with demand/production being some 40-60% higher in the winter compared to the summer), (ii) two market structures, i.e. perfect competition (PC) and Cournot competition (CC), (iii) four levels of demand elasticities, i.e. 0.05, 0.1, 0.4 and 1.0, and (iv) two ETS cases, i.e. one without ETS (where the CO_2 price is 0) and one with ETS (where the number 20 indicates at an allowance price of 20 €/tCO_2).

Table 3.7 *Summary of model estimates regarding the impact of the EU ETS on electricity prices in the Nordic area*

		Winter[a]				Summer			
Elasticity 0.05		PC	PC20	CC	CC20	PC	PC20	CC	CC20
Marginal technology		CHP biofuel	Gas	CHP biofuel	Gas	CHP coal	CHP coal	CHP coal	CHP coal
Power price	[€/MWh]	39	43.3	56.68	98.93	15	22.82	15	22.82
Pass-through	[%]		59		578		100		100
Elasticity 0.1									
Marginal technology		CHP biofuel	Gas	CHP biofuel	Gas	CHP coal	CHP coal	CHP coal	CHP coal
Power price	[€/MWh]	39	43.3	46.19	62.43	15	22.82	15	22.82
Pass-through	[%]		59		223		100		100
Elasticity 0.4									
Marginal technology		CHP biofuel	Gas	CHP biofuel	Gas	CHP coal	CHP coal	CHP coal	CHP coal
Power price	[€/MWh]	39	43.3	40.29	44.04	18.96	22.82	18.96	22.82
Pass-through	[%]		59		51		49		49
Elasticity 1.0									
Marginal technology		CHP biofuel	Peat	CHP biofuel	Peat	Peat	CHP coal	Peat	CHP coal
Power price	[€/MWh]	39.2	40.91	39.44	42.58	22.56	24.32	22.39	24.45
Pass-through	[%]		8		16		26		26

a) PC stands for perfect competition and CC for Cournot competition, while the number 20 indicates that CO_2 costs are incorporated at a level of 20 €/tCO_2.
Source: Oranen (2006).

The results show that the demand level and the price elasticity of demand significantly affect the dominant firms' possibilities for exercising market power and passing through carbon costs. The level of demand determines whether distorting the prices away from competitive levels is possible. In the summer when demand is low the equilibrium prices and quantities are exactly identical under perfect and imperfect competition for elasticities 0.05, 0.1 and 0.4, but differ slightly for the most price elastic demand. In all cases the pass-through rate is the same for both market structures, which results from the fact that the dominant firms are unable to increase power prices above their competitive levels. The pass-through rate is thus only affected by possible merit order changes and the level of demand elasticity. As theory suggests, the pass-through rate decreases as demand becomes more elastic going from 100% in the case of very inelastic demand to 26% for the most elastic demand case.

The winter situation is quite different. Capacity is tight and already almost at its limit under perfect competition. In such a case even a slight reduction in produced amounts quickly leads to large price increases, especially if demand is very inelastic. This is exactly what happens when price elasticity is 0.05. The dominant firms are able to raise the price from the competitive level of 39 to 57 €/MWh when carbon costs are not included. Once emissions trading is introduced at a CO_2 cost of 20 €/t, this difference becomes even greater with the Cournot equilibrium price settling at 99 €/MWh, implying a pass-through rate of 578%. This rather exaggerated price increase is made possible by limited capacity and the assumption of a price-insensitive, constant-elasticity demand function.

Increasing demand elasticity importantly reduces the dominant firms' possibilities for affecting price. With demand elasticity of 0.4, the Cournot equilibrium prices are only slightly above competitive prices, and interestingly, the pass-through rate is lower under imperfect competition. This is due to the fact that, because of imperfect competition, the power price was already on a higher level compared to the competitive price before carbon costs. Yet, because of a more responsive demand, the firms are not able to increase price significantly once carbon costs are included. The change between the two price levels is therefore smaller than under perfect competition.

Once price elasticity of demand is increased to 1, the pass-through rates become very low. This is due to merit order changes. The pass-through rate indicates how big a proportion of the cost increase the *new* marginal producer manages to pass on to the price. The marginal technology under the new cost structure is peat, which faces a cost increase of 19 €/MWh when CO_2 is priced at 20 €/t. Before the change in production costs peat features low in the merit order, and the equilibrium price is well above its marginal costs. In the new equilibrium, it does cover its new costs which are 40 €/MWh but the price increase from the equilibrium excluding carbon is only a small fraction of the increase in production costs faced by the new marginal producer. The power price rises by far less than the increase in carbon costs, hence the low pass-through rate of only 8%.

Table 3.7 shows that in the winter season, when capacity is tight, an inverse relationship prevails between demand elasticity and pass-through rate (PTR). When the demand elasticity is low, imperfect competition enables firms to overstate the impact of carbon costs on the price of electricity (PTR>1), whereas the PTR is low (<1) when the demand elasticity is high.

Finally, it can be noted from Table 3.7 that a situation of tight capacity leads to more extreme results with the power prices ranging from 39 to 99 €/MWh and the pass-through rates ranging between 8 and 578% depending on demand elasticity. Also, dominant firms succeed in raising the price even under the most price-responsive demand. A lower level of demand does not permit this. Overall, it is seen that the inclusion of costs due to emissions trading does increase price levels, and this increase can be severely exacerbated by the exercise of market power when demand is unresponsive to price changes (Oranen, 2006).

Sijm et al. (2005); Chen et al. (2008)

In order to analyse the implications of EU emissions trading for the price of electricity, Sijm et al. (2005) have applied a variety of methodological approaches, including the use of the model COMPETES (see also Chen et al., 2008).[61] 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, with different levels of price elasticities of power demand ranging from 0.0 to 0.2). The model has been used to analyse the impact of CO_2 emissions trading on 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). Under all scenarios considered, power prices increase significantly due to CO_2 emissions trading. In the case of a CO_2 price of 20 €/tonne, these increases are generally highest in Germany (13-19 €/MWh) and lowest in France (1-5 €/MWh), with an intermediate position for Belgium

[61] For a description of the COMPETES model as well as a discussion of the results of an updated and extended version of this model, covering 20 European countries, see Chapter 5 of the present study.

(2-14 €/MWh) and the Netherlands (9-11 €/MWh). For these EU4 countries, on average, the increase in power prices is estimated at 6-12 €/MWh, i.e. an increase of about 13-39% compared to the power prices before emissions trading.

Differences in absolute amounts of CO_2 cost pass-through between the individual countries 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 proportional 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%, depending on the country, market structure, demand elasticity, load period and CO_2 price considered. In contrast to the absolute amounts of CO_2 cost pass-through, in proportional terms the pass-through rates are generally highest in France (>1.0) and lowest in Germany (about 0.75), with an intermediate position for Belgium and the Netherlands (approximately 0.9). In addition, although there are some exceptions and outliers among the large variety of scenarios and cases considered, the pass-through rates are usually a bit lower under non-competitive scenarios (compared to the competitive cases), whereas they are generally higher under the less demand responsive scenarios (compared to the more price elastic cases).

3.3 Summary and conclusion

Table 3.8 presents a comparative overview of the empirical studies on the impact of the EU ETS on power prices, as reviewed in Section 3.1. It shows that the estimated 'pass-through rates' - or, more precisely, the estimated regression coefficients between the power price and the allowance costs - vary widely between -1.8 and 2.5.[62] This variety of outcomes results mainly from the following factors:

- Differences in definitions of the 'pass-through rate' or regression variable estimated. Most authors (Chernyavs'ka and Gulli, Frontier Economics, Honkatukia et al., and Sijm et al.) have estimated pass-through rates defined broadly as the ETS induced change in power prices divided by the ETS induced change in marginal production costs of the marginal unit. Other authors, however, have used different concepts or definitions of the coefficients estimated. For instance, Levy (2005) has estimated the regression coefficient between the carbon price (independent variable) and the power price (dependent variable), whereas Bunn and Fezzi (2007) have actually estimated elasticity between these variables (as their estimated regression equation is based on natural logarithms).
- Differences in coverage with regard to the observation periods, power markets and countries studied (see Table 3.8).[63]
- Differences in data and methodologies used. Even those authors who have estimated more or less the same regression variable (PTR) have often applied different regression equations - including other, different variables - as well as different regression methods, varying from simple Ordinary Least Squares (OLS) methods to more sophisticated econometric models.

[62] The term 'pass-through rates' is put between quotation marks in order to indicate that the estimates recorded in Table 5.8 actually refer to different concepts, as explained in the main text.

[63] Differences in power markets refer not only to differences between spot and forward markets but also to differences between more or less competitive markets.

Table 3.8 *Overview of empirical studies on the impact of the EU ETS on power prices*

Study	Country	Market	Period	'Pass-through rate'
Bauer and Zink (2005)	Germany	Forward	Jan.-June 2005	1.0
Bunn and Fezzi (2007)	UK	Spot	2005	0.42
Chernyavs'ka and Gulli (2007)	Italy	Spot	2005	0
			2006	-0.5 to 2.0
Frontier Economics (2006a)	Netherlands	Forward	2005	0.04 to 1.08
Frontier Economics (2006b)	UK,	Forward	2005	0.89-0.98
	Netherlands			0.91-0.96
	Scandinavian countries			0.97-098
Honkatukia et al. (2006)	Finland	Spot	Feb. 2005 - May 2006	0.75 to 0.95
Levy (2005)	France	Forward	January-June 2005	0.56
	Germany			0.48
	UK			1.84
	France	Spot	April-June 2005	2.21
	Germany			3.33
	Italy			2.04
	Spain			3.53
	UK			2.19
Sijm et al.	Germany	Forward	2005	0.60-1.17
(2005, 2006a and 2006b)	Netherlands			0.78-0.80
	Germany	Spot		0.50-2.50

Due to these differences, it is hard to compare - or to draw firm, general conclusions from - the empirical studies mentioned in Table 3.8. Nevertheless, most of these studies do seem to indicate that even in the early days of the EU ETS a major part of the scheme-induced carbon costs was passed through to power prices. Most of the studies reviewed, however, refer mainly to liberalised, rather competitive power markets in West-European countries, but not to more regulated or less competitive markets in other parts of the EU ETS, in particular in East-European countries. Therefore, the potential implications of these differences in regulation or competitive structure of power markets across the EU ETS have to be considered before drawing firm, general conclusions on the carbon cost pass-through on these markets.[64]

Table 3.9 presents a comparative overview of the modelling studies on the impact of the EU ETS on power prices, as reviewed in Section 3.2.[65] More specifically, these studies have all estimated the ETS-induced increase in power prices in absolute terms (i.e. in €/MWh). Table 3.9 shows that the estimates of this increase vary between 1 and 19 €/MWh (at a carbon price of, in general, 20 €/tCO_2).[66] These differences result mainly from differences in the technology mix between countries or, more specifically, from differences between countries in the carbon efficiency - or carbon costs - of the marginal generation technology setting the power price.

[64] See also the empirical findings on the PTRs in a large variety of EU ETS countries - including Poland and the Czech Republic - discussed in Chapter 4 of the present study.

[65] Table 5.9 does not include Lindboe et al. (2007) as this study does not analyse the impact of the EU ETS on power prices as such, but focuses on the effects of free allocation to new entrants on a variety of power sector variables, including electricity prices. Note that all modelling studies mentioned in Table 5.9 do not include the impact of this free allocation provision in their analyses.

[66] Note that only Linares et al. (2007) uses a substantial lower carbon price and that, for comparative reasons, Table 5.9 includes only the perfect competition scenario results of Oranen (2006) and Sijm et al. (2005).

Table 3.9 *Overview of modelling studies on the impact of the EU ETS on power prices*

Study	Country	Model	CO_2 price	ETS-induced increase in power price [€/MWh]
IPA (2005)	UK	Dynamic	15-25	5-16
Kara et al. (2007)	Finland	Static	20	15
Linares et al. (2006)	Spain	Dynamic	7-15	3-5
Oranen (2006)[a]	Nordic area	Static	20	1-8
Sijm et al. (2005)[a]	Belgium	Static	20	7-4
	France			2-5
	Germany			10-19
	The Netherlands			5-11

a) For comparative reasons, only the perfect competitive scenario results of these studies have been included in this table.

In addition, the differences in ETS-induced increases in power prices result to some extent from differences in model specifications such as differences in assumed price elasticities of power demand or whether the studies concerned have used a static or dynamic model. For instance, if power demand is more price responsive, the pass-through of carbon costs to electricity prices is generally lower. Moreover, in the long run, this pass-through depends also on dynamic (ETS-induced) changes in the fuel mix, i.e. an (ETS-induced) expansion or change of generation capacity towards carbon saving technologies results in a lower pass-through in the long run.

Therefore, the major conclusion from the modelling studies included in Table 3.9 seems to be that differences in ETS-induced increased in power prices result largely from differences in the carbon intensity of the power generation technology mix among countries, including dynamic changes in this mix over time.

4. Empirical and statistical analyses of carbon cost pass-through on EU power markets

This chapter discusses the major results of the empirical and statistical analyses of carbon cost pass-through on EU power markets over 2004-2006. The analyses cover both forward and spot wholesale markets as well as retail markets for electricity end-users in nine selected EU ETS countries. These countries include France (FR), Germany (DE), Italy (IT), Poland (PL), Spain (ES), Sweden (SE), the Czech Republic (CZ), the Netherlands (NL) and the United Kingdom (UK). Together these countries (i.e. EU9) cover a wide variety of power generation and market structures, accounting for some 80% of total electricity output and power-related CO_2 emission of the EU27.

The structure of the present chapter runs as follows. First, Section 4.1 analyses some trends in electricity prices, cost drivers and power spreads on wholesale markets in selected EU countries over the period 2004-2006. Subsequently, Section 4.2 presents and discusses statistical estimates of carbon cost pass-through rates on wholesale power markets in the selected EU9 countries for 2005 and 2006. Finally, Section 4.3 addresses the issue whether and to what extent retail electricity prices in these countries have been affected by the EU ETS or other factors in 2005-2006.

It is important to note that the present chapter discusses only some general findings as well as a few selected cases to analyse the interaction between power, fuel and carbon markets in EU ETS countries, including a brief indication of the methodology used. Appendices B and C provide a more detailed discussion and graphical presentation of all countries and cases analysed, including an explanation of the methodology and data used.

4.1 Trends in wholesale electricity prices, cost drivers and power spreads in 2004-2006

This section aims (i) to illustrate and analyse the diversity in interlinkages between power, fuel and carbon markets for different load periods and countries across the EU ETS and (ii) to provide the necessary background information for Sections 4.2 and 4.3, which estimate and analyse the pass-through of carbon costs on EU wholesale and retail power markets, respectively. In order to achieve these aims, this section analyses in particular some trends in electricity prices, cost drivers and power spreads on both forward and spot wholesale markets for some specific cases over the whole period 2004-2006 (while the whole set of selected EU countries and load periods is discussed in Appendix B).

More specifically, this section runs as follows. First of all, Section 4.1.1 provides a brief explanation of the methodology and data used to analyse the trends in electricity prices, cost drivers and power spreads on EU wholesale markets. Subsequently, Section 4.1.2 presents (changes in) average annual power prices and generation costs in EU countries during the period 2004-2006.

Next, Section 4.1.3 and 4.1.4 discuss some specific cases in order to illustrate the diversity in interlinkages between power, fuel and carbon markets across the EU in general and to analyse the trend in electricity prices, cost drivers and power spreads on some specific EU wholesale markets in particular. These cases include:

- Forward, off-peak markets in Germany
- Forward, peak markets in the Netherlands
- Spot, off-peak markets in Spain and Poland
- Spot, peak markets in Italy and the UK

These cases have been selected as they represent or, at least, illustrate a wide variety of experiences and differences in power market structures and performances across the EU. While the forward market cases are discussed in some detail in Section 4.1.3, the spot market cases are treated more briefly in Section 4.1.4. Finally, Section 4.1.5 provides some general findings and conclusions.

4.1.1 Methodology and data used

In order to analyse empirically the impact of the EU ETS on electricity prices, a large amount of data has been gathered and processed, including daily data on carbon and fuel prices as well as daily and hourly data on power prices for a large variety of wholesale markets in nine EU countries over 2004-2006. Data on wholesale power prices refer to both spot (i.e. day-ahead) markets and, if present, forward (i.e. year-ahead) markets. These data have been transformed to daily power prices for peak and off-peak products, based on the country-specific definition of peak versus off-peak hours per day or week (for details, see Appendix B). Major exceptions include (i) Italy, Poland, Spain and the Czech Republic, which did not have a forward power market during the whole period 2004-2006, (ii) Sweden, which trades only baseload products on the year-ahead market, but no separate peak or off-peak products, and (iii) the United Kingdom, where the seasonal-ahead markets for winter and summer products have been used as they are more liquid than the year-ahead market.

To analyse the interaction between power, fuel and carbon markets, prices for fuels and CO_2 emission allowance (EUAs) have been transformed and expressed in the same unit as power prices (i.e. in €/MWh) by using the standard energy conversion and emission factors, assuming generic thermal efficiency rates in all selected countries for four different types of fossil-fuel generation technologies (see Table 4.1). For instance, for coal and natural gas (open cycle turbines), generic efficiency rates of 35 and 40%, respectively, have been assumed regardless of the country in which these technologies are operated.

Table 4.1 *Marginal unit during peak and off-peak* in *EU ETS countries*

	CZ	DE	ES	FR	IT	NL	PL	SE	UK
Peak	Coal	Coal (Gas)[a]	Oil (Gas)	Coal (Gas)	Oil	Gas	Coal	Coal	CCGT
Off-peak	Coal	Coal	Coal (CCGT)	Coal	CCGT (Gas)	Coal (CCGT)	Coal	Coal	Coal

a) Technologies between brackets indicate alternative marginal (i.e. price-setting) unit. Gas refers to an open cycle gas turbine (OCGT) while a combined cycle gas turbine is indicated by its acronym CCGT.

Finally, for each country and each load period, a specific fossil-fuel technology has been determined as the marginal, price-setting unit in order to asses the relationship - i.e. the pass-through rate - between the carbon costs of this technology and the power price assumed to be set by this technology (see Table 4.2). For instance, coal is generally regarded as the marginal unit during the off-peak period in Poland, while gas is usually considered to be the price-setting technology during the peak period in the Netherlands.[67]

[67] Unless stated otherwise 'gas' refers to an open cycle gas turbine (OCGT), while a combined cycle gas turbine is indicted by its acronym 'CCGT'.

Table 4.2 *The thermal efficiencies and emission factors assumed with respect to the four main fossil fuel technologies*

Fuel	Thermal efficiency [%]	IPCC [kg CO_2/GJ]	Emission factor [tCO_2/MWh]
Oil	35	73.3	0.754
Natural gas (OC)[a]	40	56.1	0.505
Natural gas (CC)[b]	55	56.1	0.367
Coal	35	94.6	0.973

a) The thermal efficiency of open cycle gas turbines.
b) The thermal efficiency of combined cycle gas turbines.

It is assumed that a single technology is dominant in setting the power price for a certain country and load period. In some cases, however, it is hard to determine such a single, dominant technology as two or more technologies may alternately set the power price in a specific country and load period. In those cases, an alternative marginal technology has been selected as well. In Table 4.2 the first mentioned technology in each cell is regarded as the most likely marginal unit, while the second indicated technology (between brackets) is a possible alternative, price-setting unit (for more details, See Appendix C).

4.1.2 Trends in power prices and cost drivers: general findings

Figure 4.1 and Figure 4.2 present average annual power prices on forward and spot wholesale markets respectively, for peak and off-peak products in selected EU ETS countries over 2004-2006, while Table 4.3 and Table 4.4 provide further data on the changes in these prices. It can be noticed that in almost all cases considered power prices have increased significantly in 2005 and 2006, compared to 2004, although there are major differences among the countries and load periods analysed. On the year-ahead markets, for instance, off-peak power prices in France and Germany increased by some 15-16 €/MWh between 2004 and 2006 (+ 60-65%), while peak prices in the Netherlands and the UK rose by some 40 €/MWh (+70-85%). On the spot wholesale market, these differences in power price increases are even more outspoken (see Table 4.4). For instance, whereas average annual peak spot prices between 2004 and 2006 increased by less than 6 €/MWh in Poland (+22%), they rose by more than 30 €/MWh in countries such as Germany, France, the Netherlands and the UK (+85-95%).[68]

[68] Note that in Italy the average spot power price also increased by more than 30 €/MWh between 2004 and 2006, but since Italy had already the highest power prices in 2004 among the selected countries in an absolute sense, the percentage increase over this period was relatively low, i.e. 41%.

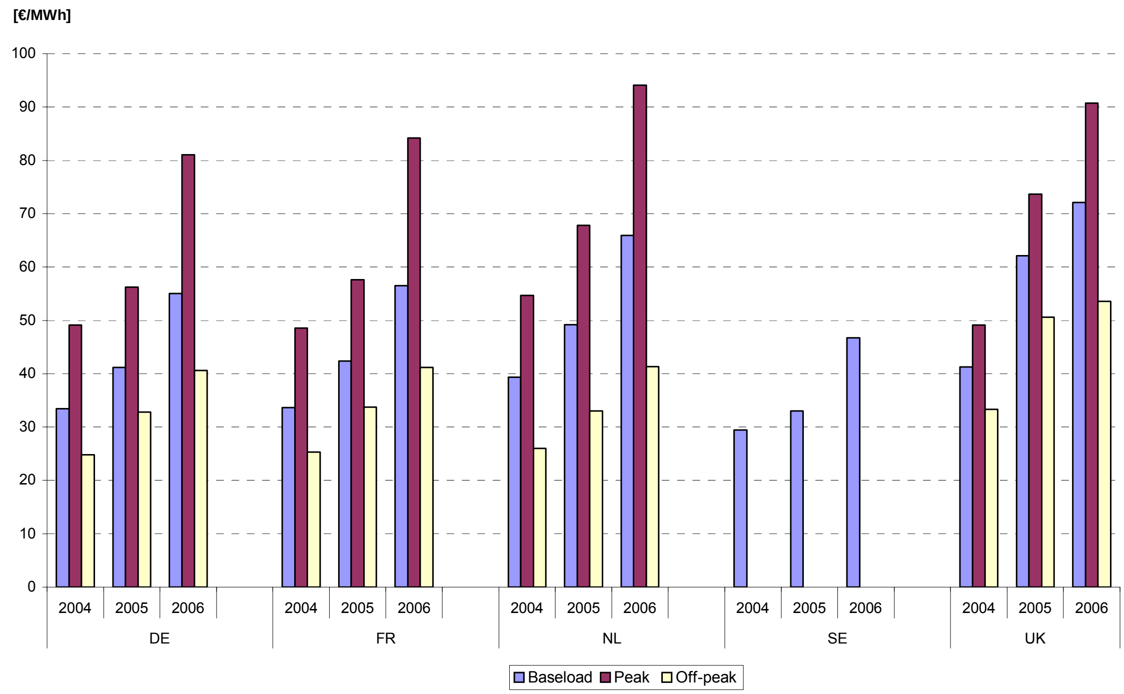


Figure 4.1 *Average annual power prices on year-ahead forward markets during baseload, peak and off-peak periods in selected EU ETS countries, 2004-2006*

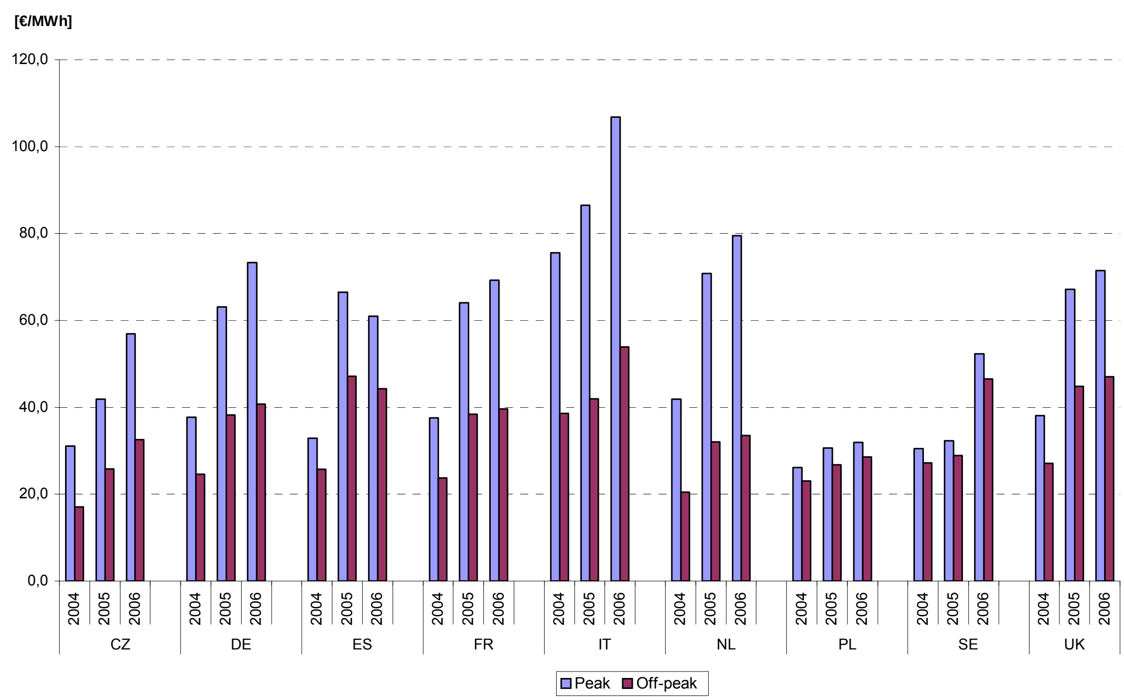


Figure 4.2 *Average annual power prices on spot markets during peak and off-peak periods in selected EU ETS countries, 2004-2006*

Table 4.3 *Changes in power prices on year-ahead markets in selected EU ETS countries, 2004-2006*

	Average annual power prices			Changes in prices (compared to 2004)			
	[€/MWh]			[€/MWh]		[%]	
Cases[a]	2004	2005	2006	Δ2005	Δ2006	Δ2005	Δ2006
DE baseload	33.5	41.2	55.0	7.7	21.5	23	64
DE peak	49.1	56.2	81.0	7.1	31.9	14	65
DE off-peak	24.8	32.8	40.6	8.0	15.8	32	64
FR baseload	33.6	42.4	56.5	8.7	22.8	26	68
FR peak	48.6	57.6	84.2	9.0	35.6	19	73
FR off-peak	25.3	33.8	41.2	8.4	15.9	33	63
NL baseload	39.4	49.2	65.9	9.9	26.5	25	67
NL peak	54.7	67.8	94.1	13.1	39.4	24	72
NL off-peak	26.0	33.0	41.3	7.0	15.3	27	59
SE baseload[b]	29.4	33.0	46.7	3.6	17.3	12	59
UK baseload	41.2	62.1	72.1	20.9	30.9	51	75
UK peak[c]	49.1	73.7	90.7	24.5	41.6	50	85
UK off-peak	33.3	50.6	53.5	17.3	20.2	52	61

a) Countries include Germany (DE), France (FR), the Netherlands (NL), Sweden (SE) and the United Kingdom (UK).
b) For the year-ahead market of Sweden, only prices of baseload products are available.
c) Annual average of seasonal-ahead prices, including both winter and summer prices for peak and off-peak products.

Table 4.4 *Changes in power prices on spot markets in selected EU ETS countries, 2004-2006*

	Average annual power prices			Changes in prices (compared to 2004)			
	[€/MWh]			[€/MWh]		[%]	
Cases[a]	2004	2005	2006	Δ2005	Δ2006	Δ2005	Δ2006
CZ peak	31.1	41.9	56.9	10.8	25.8	35	83
CZ off-peak	17.1	25.8	32.5	8.7	15.4	51	90
DE peak	37.7	63.1	73.3	25.3	35.6	67	94
DE off-peak	24.6	38.2	40.7	13.6	16.1	55	65
ES peak	32.9	66.5	60.9	33.6	28.0	102	85
ES off-peak	25.7	47.2	44.3	21.4	18.6	83	72
FR peak	37.5	64.0	69.3	26.5	31.7	71	85
FR off-peak	23.8	38.4	39.6	14.6	15.8	62	67
IT peak	75.5	86.5	106.8	11.0	31.3	15	41
IT off-peak	38.6	41.9	53.9	3.3	15.3	9	40
NL peak	41.9	70.8	79.6	28.9	37.7	69	90
NL off-peak	20.5	32.0	33.5	11.5	13.0	56	63
PL peak	26.2	30.6	32.0	4.5	5.8	17	22
PL off-peak	23.1	26.8	28.6	3.7	5.5	16	24
SE peak	30.4	32.3	52.3	1.9	21.9	6	72
SE off-peak	27.2	28.9	46.6	1.7	19.3	6	71
UK peak	38.0	67.2	71.4	29.2	33.4	77	88
UK off-peak	27.1	44.8	47.0	17.7	19.9	65	74

a) Countries include the Czech Republic (CZ), Germany (DE), Spain (ES), France (FR), Italy (IT), the Netherlands (NL), Poland (PL), Sweden (SE) and the United Kingdom (UK).

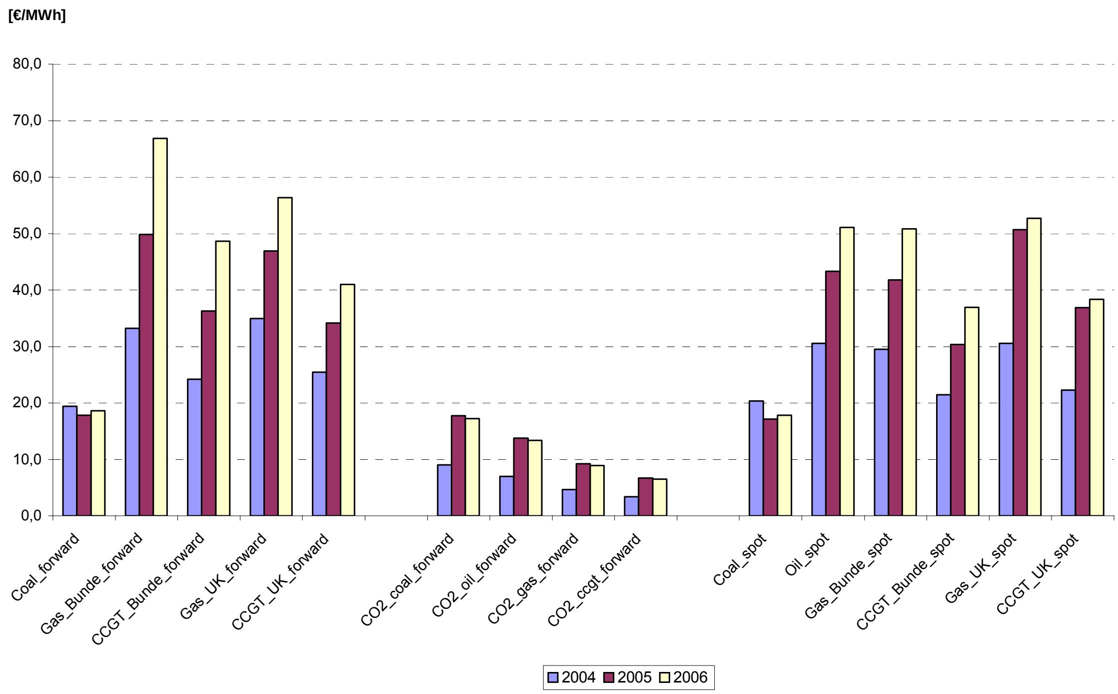


Figure 4.3 *Average annual fuel and carbon costs on EU spot and forward markets, 2004-2006*

Table 4.5 *Changes in fuel and carbon costs on EU spot and forward markets, 2004-2006*

	Fuel and carbon costs [€/MWh]			Changes in costs (compared to 2004) [€/MWh]		[%]	
	2004	2005	2006	Δ2005	Δ2006	Δ2005	Δ2006
Forward							
Coal	19.4	17.8	18.6	-1.6	-0.8	-8	-4
Gas Bunde	33.2	49.9	66.8	16.6	33.6	50	101
CCGT Bunde	24.2	36.3	48.6	12.1	24.5	50	101
Gas UK	35.0	46.9	56.3	12.0	21.4	34	61
CCGT UK	25.4	34.1	41.0	8.7	15.5	34	61
CO_2 coal[a]	9.0	17.8	17.2	8.8	8.2	97	91
CO_2 oil	7.0	13.8	13.3	6.8	6.3	97	91
CO_2 gas	4.7	9.2	8.9	4.5	4.2	97	91
CO_2 CCGT	3.4	6.7	6.5	3.3	3.1	97	91
Spot							
Coal	20.3	17.1	17.8	-3.2	-2.5	-16	-12
Oil	30.6	43.4	51.1	12.8	20.5	42	67
Gas Bunde	29.5	41.8	50.8	12.3	21.4	42	72
CCGT Bunde	21.4	30.4	37.0	9.0	15.5	42	72
Gas UK	30.6	50.7	52.7	20.1	22.1	66	72
CCGT UK	22.2	36.8	38.3	14.6	16.1	66	72

a) Carbon costs on the EUA spot market for 2005 and 2006 are, on average, similar to the costs on the EUA forward market for these years.

In addition, Figure 4.3 presents the average annual fuel and carbon costs (in €/MWh) on some selected EU spot and forward markets over 2004-2006, while Table 4.5 proved further data on the changes in these prices. It can be observed that whereas generation costs per MWh declined slightly over this period for coal, they increased substantially for oil and gas, thereby further widening the cost differential between these fuels. On the forward markets, for instance, the power production costs by coal declined from 19.4 €/MWh in 2004 to 18.6 €/MWh in 2006, while the costs to generate electricity by a CCGT fired by gas traded at the Bunde hub more than doubled from 24 to 49 €/MWh over this period.

In the Sections 4.1.3 and 4.1.4 below, the links between the above-mentioned changes in average annual power prices versus costs are further assessed by analyzing in some detail the trends in daily electricity prices, cost drivers and power spreads during 2004-2006 for some specific cases on the forward and spot markets, respectively.

4.1.3 Trends in forward power prices, costs and spreads

This section illustrates and analyses trends in power prices, costs and spreads on *forward* (i.e. year-ahead) markets in 2004-2006 for two specific cases.[69] These cases refer to the forward markets in Germany during the off-peak hours of power demand, and in the Netherlands during the peak period.

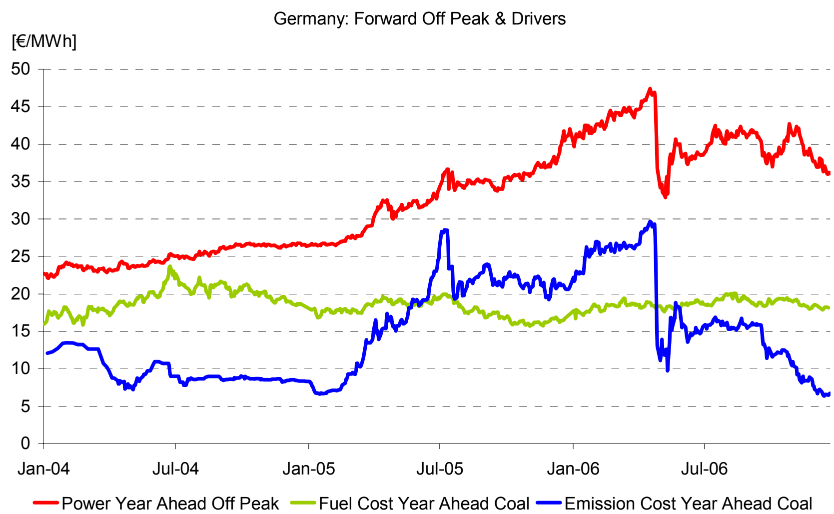


Figure 4.4 *Trends in power prices and cost drivers on forward markets in Germany during off-peak hours in 2004-2006*

For 2004-2006, Figure 4.4 presents trends in forward power prices versus fuel and CO_2 emission costs to generate one MWh of electricity during the off-peak period in Germany, while Figure 4.5 shows similar trends during the peak hours in the Netherlands. These figures provide a first impression of the changes in power prices over 2004-2006 and the potential link with underlying fuel and carbon costs, depending on the assumed price-setting technology in the countries and load periods considered as well as the emission factors and fuel efficiencies mentioned in Tables 6.1 and 6.2, respectively. For instance, off-peak power prices in Germany are assumed to be set by a coal-fired installation. As can be observed from Figure 4.4, these prices increased substantially from less than 30 €/MWh in early 2005 to almost 50 €/MWh in April 2006. After a sudden collapse by some 15 €/MWh in late April-early May, off-peak prices in Germany started to rise again up to the summer of 2006 but, subsequently, stabilised at a level of 30-35 €/MWh in late 2006. These significant changes in power prices cannot be explained by changes in coal prices since the costs of this fuel have been rather stable at the level of 20 €/MWh over the period considered.

[69] Unless stated otherwise, the forward market refers to the year-ahead market where, for instance, electricity or fuel delivered in 2006 is traded during every day of 2005.

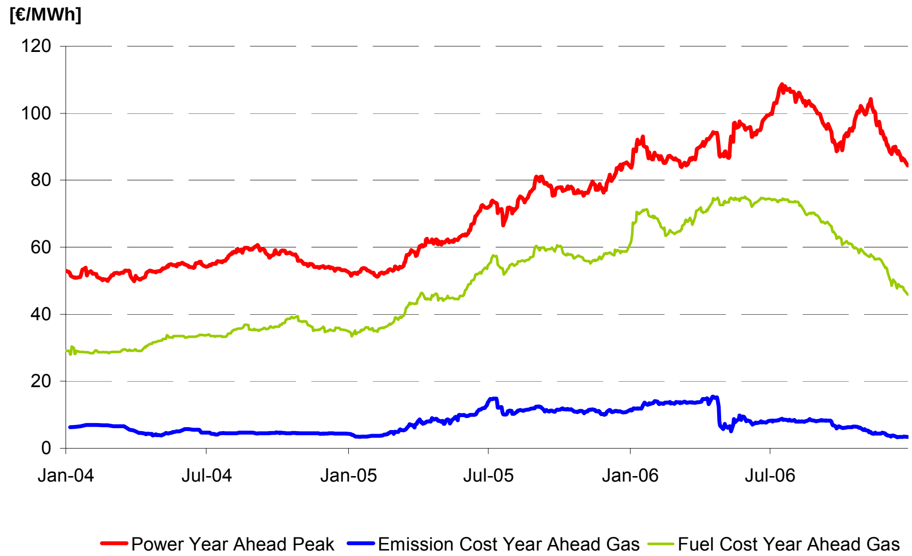


Figure 4.5 *Trends in power prices and cost drivers on forward markets in the Netherlands during peak hours in 2004-2006*

However, in the case of the forward off-peak power market in Germany there seems to be a close (causal) link between the prices of carbon and electricity as the changes in CO_2 emission allowance costs of coal-fired generation are more or less similar to the changes in power prices, notably during periods of major changes in the price of an EU emission allowance (EUA) such as April-May 2006 (see Figure 4.4). In other cases where coal is assumed to be price-setting, similar links and changes in power prices versus cost drivers in 2005-2006 can be found, for instance in the case of forward off-peak power markets in France, Sweden, the Netherlands and the United Kingdom or, although less significant, in the case of forward peak power markets in these countries (including Germany; see Appendix B).[70] Note, however, that the link between power prices and fuel/CO_2 cost drivers is less clear or even absent/contrary in the second half of 2006, suggesting that in this period changes in power prices have been largely affected by other factors than changes in fuel/CO_2 costs.

On the other hand, Figure 4.5 shows the trends in power prices and cost drivers on forward markets in the Netherlands during the peak period of 2004-2006. For this case, power prices are assumed to be set by an open cycle gas turbine with a fuel efficiency of 40%. These prices were more or less stable during 2004, but increased rapidly from 50-55 €/MWh in early 2005 to 100-105 €/MWh in mid-2006. This increase in power prices can be largely related to rising gas prices (which, in turn, are usually related to oil-indexed prices), resulting in an increase in gas costs from 35-40 €/MWh in early 2005 to 70-75 €/MWh in mid-2006. The potential impact of gas-related CO_2 costs, however, is less substantial - rising from about 5 to 15 €/MWh between early 2005 and mid-2006 - partly due to the fact that the emission factor for gas is significantly lower than for coal.

Trends in forward power spreads

In order to have a closer look and a better assessment of the potential impact of CO_2 emissions trading on forward power prices, fuel costs have been subtracted from these prices, resulting in the so-called ‘power spreads’. For the present analysis, a *dark* spread is simply defined as the

[70] It should be noted, however, that in the case of forward peak markets in countries such as France or Germany power prices are not solely set by coal-fired generators but during a substantial number of peak hours also by gas-fired installations. Hence, the increase in (average) peak prices in France or Germany over the period 2004-2006 can to some extent be explained by rising gas costs.

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 costs of *gas* to produce 1 MWh of electricity. If, subsequently, the carbon costs of power production are also subtracted, these indicators are called *'clean dark/spark spreads'*, respectively.[71]

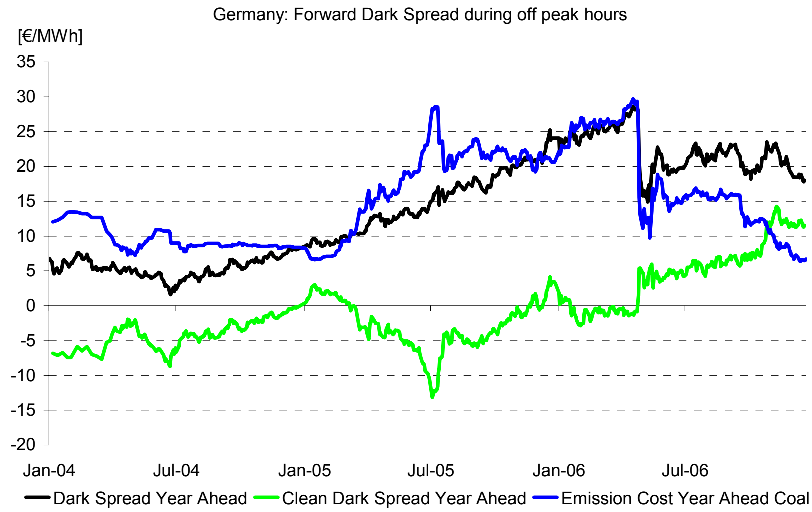


Figure 4.6 *Trends in power spreads and carbon costs on forward markets in Germany during off-peak hours in 2004-2006*

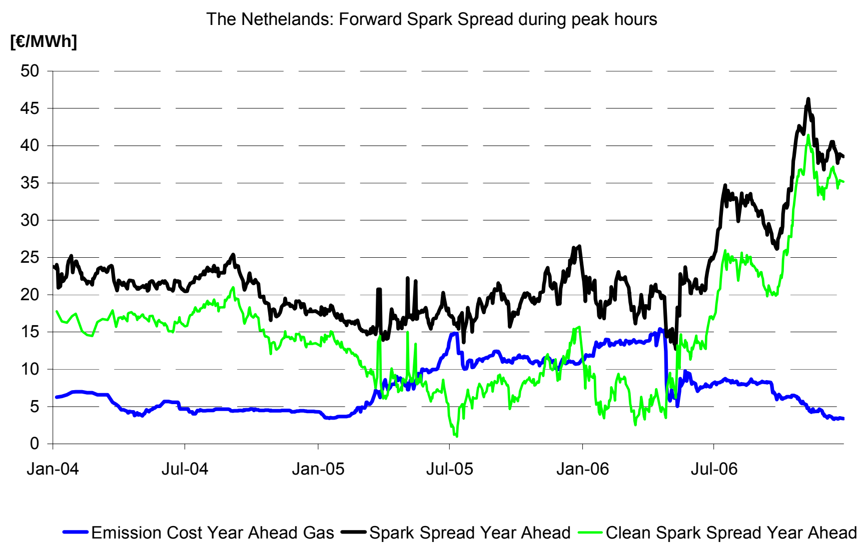


Figure 4.7 *Trends in power spreads and carbon costs on forward markets in the Netherlands during peak hours in 2004-2006*

Figures 4.6 and 4.7 present trends in year-ahead power spreads over 2004-2006 in Germany and the Netherlands, respectively, based on the forward market trends in power prices and fuel/carbon costs discussed above. Whereas Figure 4.6 depicts trends in (clean) dark spreads for

[71] These spreads are indicators for the coverage of other (non-fuel/carbon) costs of generating electricity, including profits. For the present analysis, however, these other costs - for instance, maintenance or capital costs - are ignored as they are assumed to be constant for the period considered - although they may vary for the different country/load periods analysed - and, hence, they are assumed to not affect the pass-through rates of carbon costs estimated below in Section 4.2.

the off-peak period in Germany, Figure 4.7 shows similar trends in the (clean) spark spread during the peak hours in the Netherlands. In addition, these figures illustrate the opportunity costs of CO_2 allowances to cover the emissions per MWh produced by a coal- or gas-fired power plant, with an emission factor of 0.97 and 0.51 tCO_2/MWh, respectively.

For the off-peak hours in Germany, Figure 4.6 shows that there is a close relationship between the dark spread and the emission costs of a coal-fired power station, at least up to April-May 2006 when the year-ahead (Cal07) price of an EUA suddenly collapsed and - after a short recovery plus stabilisation phase - declined steadily during the latter part of 2006. The dark spread in Germany, however, fell less in April-May 2006, and more or less stabilised during the latter part of 2006, resulting in a growing disparity between the spark spread and the emission costs of coal-generated power per MWh. This suggests either that declining carbon costs are passed-through to a lesser extent (or less quickly) than rising carbon costs (i.e. asymmetric pass-through) or that changes in power prices/spreads are largely due to other factors than changes in fuel/carbon costs, for instance due to growing power market scarcities and related increasing market power of electricity suppliers to set sales prices.

A similar, but even stronger picture of the delinking between the trends of the power spreads and related carbon costs - particularly since Spring 2006 - can be observed in Figure 4.7, which presents these trends during the peak period of 2004-2006 in the Netherlands. While the gas-related carbon costs declined from about 15 €/MWh in April/May 2006 to approximately 5 €/MWh in late 2006, the clean spark spread improved substantially from about 30 to 45 €/MWh over this period.

In addition to the trends in power spreads, Figures 4.6 and 4.7 also provide trends in *clean* spreads over 2004-2006 in Germany and the Netherlands, respectively (by subtracting the full carbon emission costs from the 'normal' spreads). If it is assumed that (i) fuel and carbon costs are passed through more or less fully and directly to power prices, and (ii) other generation costs are more or less stable during the period considered, then the trend of the clean dark spread would be represented by a straight horizontal line at a certain level (say 10 or 20 €/MWh in order to cover the other generation costs, including profits).

Figures 4.6 and 4.7 show that, in general, clean spreads fluctuated significantly at a certain level in 2004-2005, while they increased substantially during 2006. For instance, the *clean spark* spread during the peak hours in the Netherlands (i) was rather stable in 2004, fluctuating at a level of about 18 €/MWh, (ii) declined during the first part of 2005 (due to rising fuel/carbon costs that were not fully passed through), (iii) fluctuated at a level of approximately 15 €/MWh between mid-2005 and Spring 2006, and (iv) increased rapidly from about 10 €/MWh in April 2006 to more than 35 €/MWh in late 2006, implying that trends in peak power prices have diverted by some 25 €/MWh over this period from trends in fuel/carbon costs.

During the off-peak period, a similar but far less striking increase in clean dark spreads can be observed since April/May 2006 on the year-ahead power markets of Germany. Note, however, that these spreads are generally low, even in 2006, and that they were actually negative during most of the time in 2004 and 2005 (see Figure 4.6). The latter is surprising as it raises the question why coal operators would generate power at prices which do not even cover the opportunity costs of fuel and carbon allowances and, hence, would earn more by selling the fuel and carbon allowance straight on the market rather than using them for generating power.

The incidence of negative clean dark spreads, as observed in Figure 4.6 during the off-peak period in Germany, could be due to several reasons. First, the calculation of these spreads is based on an assumed fuel efficiency of 35% for a coal station setting the price. However, if this efficiency is higher, both the fuel and carbon costs per MWh will be lower and, hence, the clean spread will be higher. Second, operators of coal stations may decide to continue power generation during off-peak hours at lower prices if it saves start-up costs for producing electricity during the peak period at more attractive prices.

Third, the calculation of the clean dark spreads is based on the assumption that off-peak prices in Germany are set by (domestic) coal plants. During certain off-peak hours, however, power prices in Germany are set by lignite plants which, overall, may have lower fuel and carbon costs (depending on the relative prices and efficiencies of the fuels and carbon used).

Finally, the observation that during certain off-peak periods the clean spreads are negative and, hence, that it would be more profitable to sell contracted fuels and (freely) obtained carbon allowances directly on the market rather than using them for generating power assumes that (i) fuel markets are liquid and, hence, contracted fuels can readily and without major costs be resold at the market, and (ii) power generators aim to maximise their profits. However, sometimes it is hardly possible or rather costly to resell contracted fuels at current market prices. Moreover, rather than maximizing profits, power generators may try to achieve other (short-term) objectives - for instance, to maintain certain market shares - or accept a certain satisfying profit margin, in particular if free allocation of carbon allowances results in a 'normal' spread that is already relatively high.

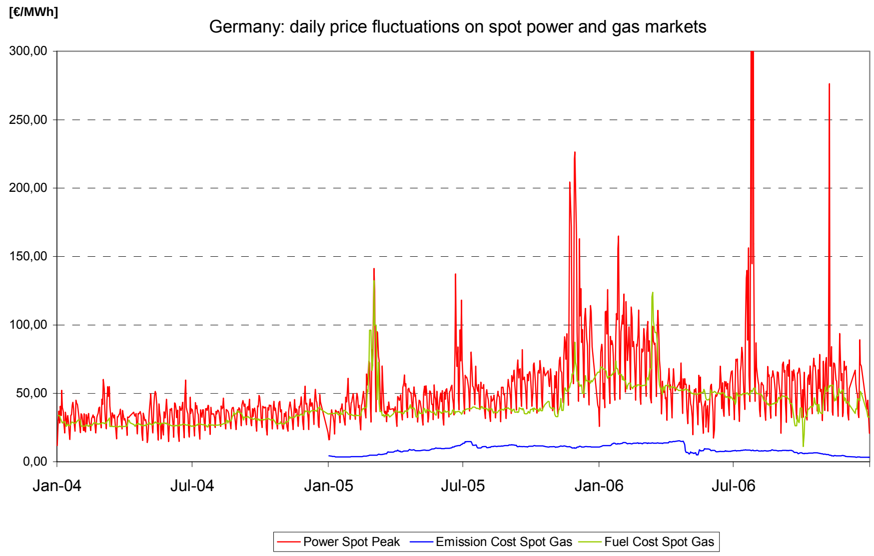
4.1.4 Trends in spot power prices, costs and spreads

This section illustrates and analyses briefly trends in power prices, costs and spreads on *spot* (i.e. day-ahead) markets in 2004-2006 for four specific cases.[72] These cases refer to the spot markets in Sweden and Poland during the off-peak hours of power demand, and in Italy and the UK in the peak period.

A major characteristic of energy spot market is the incidence of wide fluctuations of daily prices. For the spot power market, this high degree of price volatility corresponds to the increasing risks of defaulting due to the short period between trade and delivery. In other words, less and less opportunities are available to the trader to balance the portfolio of power demand and supply in the short run. The market is, therefore, strongly event-driven. Unexpected outages or demand hikes are strongly reflected in the prices of day-ahead markets. Hence, for the purpose of analysing graphically trends in the spot markets, a smoothing procedure was applied to the price data of energy spot markets (including both power and fuel markets), by calculating the 14-days-moving average of these data (see Figure 4.8 for an example showing the difference between daily price fluctuations and smooth price data of spot power and gas markets in Germany.[73]

For the four spot markets cases mentioned above, Figure 4.9 up to Figure 4.12 show smoothed data trends in power prices, costs and spreads over 2004-2006 in Sweden, Poland, Italy and the UK, respectively. These trends and, in particular, the possible links between fuel and carbon costs on the one hand and power prices and power spreads on the other hand are discussed briefly below (see Appendix B for a presentation of the full set of spot market cases analysed, including all selected EU ETS countries and differentiating between peak and off-peak periods in these countries).

[72] The spot market refers to the day-ahead market where electricity or fuel traded today is delivered tomorrow.
[73] Since prices on the spot EUA markets during 2005-2006 have been far less volatile than spot energy market prices (and, on average, similar to the prices on the forward EUA market), these prices have not been smoothed. In addition, it is important to note that the smoothing procedure has been applied just to facilitate the graphical analyses and presentations, but that for the statistical analyses the daily ('unsmoothed') data have been used.



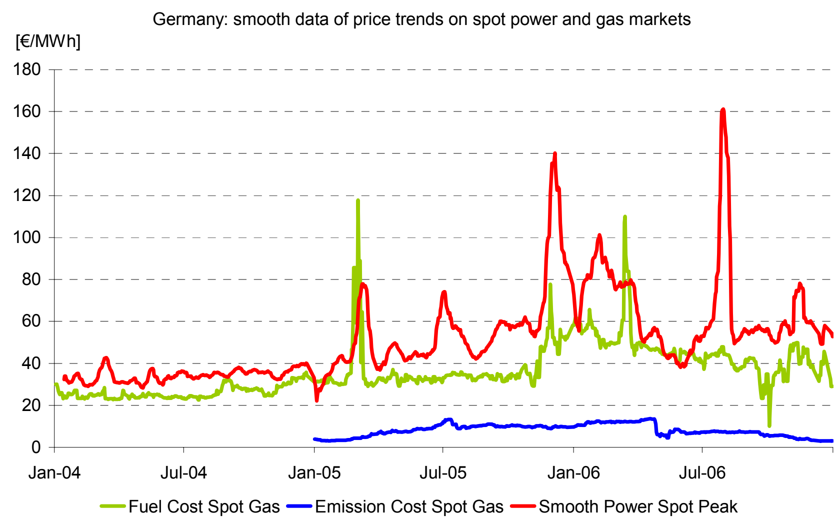
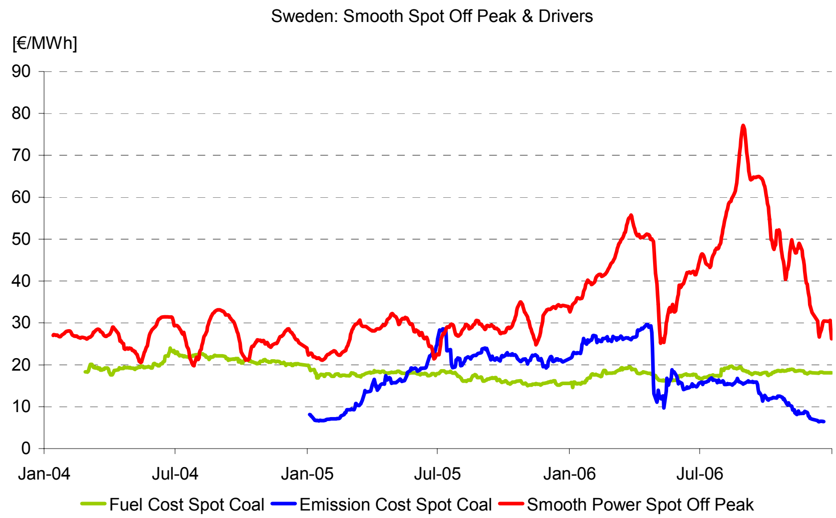


Figure 4.8 *Trends in power prices and cost drivers on spot markets in Germany during peak hours in 2004-2006: daily price fluctuations versus smooth price data based on 14-days moving averages*

Sweden: off-peak period

During the off-peak period, spot power prices in Sweden are assumed to be set basically by a coal-fired plant, although temporarily they are heavily influenced by water reservoir levels or other events. Similar to the stability of the coal costs per MWh since 2004, these power prices were rather stable during 2004-2005, despite rising carbon costs of coal-generated power during the first half of 2005. Since late 2005, however, spot prices started to increase steadily, but dropped suddenly in April-May 2006 corresponding to the collapse of the EUA carbon prices in this period (see Figure 4.9). In the second half of 2006, spot carbon prices - after some recovery - first stabilised and, subsequently, started to decline steadily since the last quarter of 2006. On the other hand, spot electricity prices showed a strong hike during the third quarter of 2006 as a consequence of relatively low water reservoir levels to generate hydro power. By September 2006, reservoir levels started to approach median levels again, implying that power prices and spreads on the Swedish spot markets declined accordingly. Therefore, although the close link between EUA and power prices in April-May 2006 suggests that carbon costs are passed through on the Swedish spot market, for the period 2005-2006 as a whole this relationship is less clear when based on a graphical empirical analysis of the trends in power prices, costs and spreads on this market.



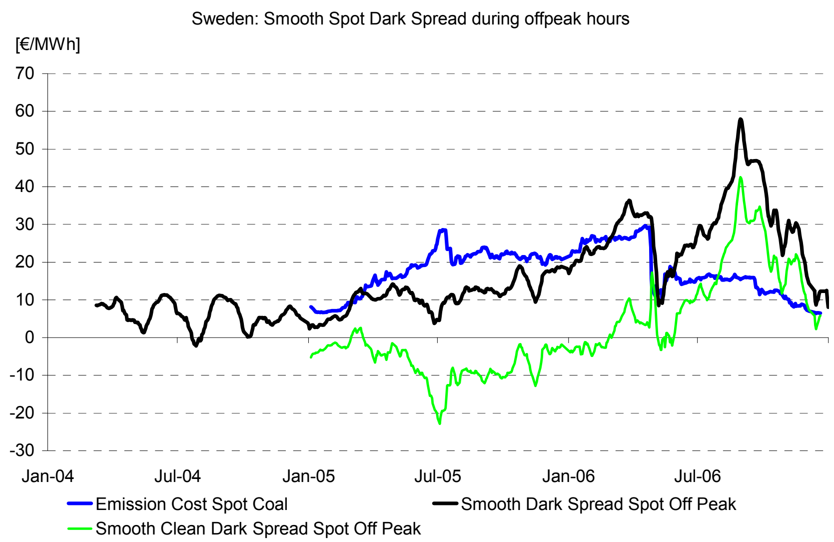


Figure 4.9 *Trends in power prices, costs and spreads on spot markets in Sweden during off-peak hours in 2004-2006*

Poland: off-peak period

During 2004-2006, spot power prices in Poland were not only amongst the lowest of the selected EU ETS countries, but also hardly changed, on average, over this period (see Table 4.4 and Figure 4.2 in Section 4.1.2). Although the costs of power production are predominantly determined by the vast majority of coal (and lignite) plants, electricity prices used to be regulated up to mid-2007.[74] As a result, end-user prices were set too low - perceived by the European Commission as prohibited state aid - which pushed wholesale power prices down as well (EC, 2006; see also Appendix B.6). This also largely explains why hardly any relationship can be observed between spot power prices and spreads in Poland over 2005-2006 on the one hand and EUA carbon prices on the other. For instance, Figure 4.10 shows that although the carbon costs of a coal-generated MWh increased rapidly during February-July 2005 and fell by some 20

[74] During 2007, the structure of the Polish energy market changed significantly as long term power purchase agreements were terminated and replaced by direct compensation.

€/MWh in April-May 2006, the spot prices during the off-peak period in Poland hardly changed during these periods.

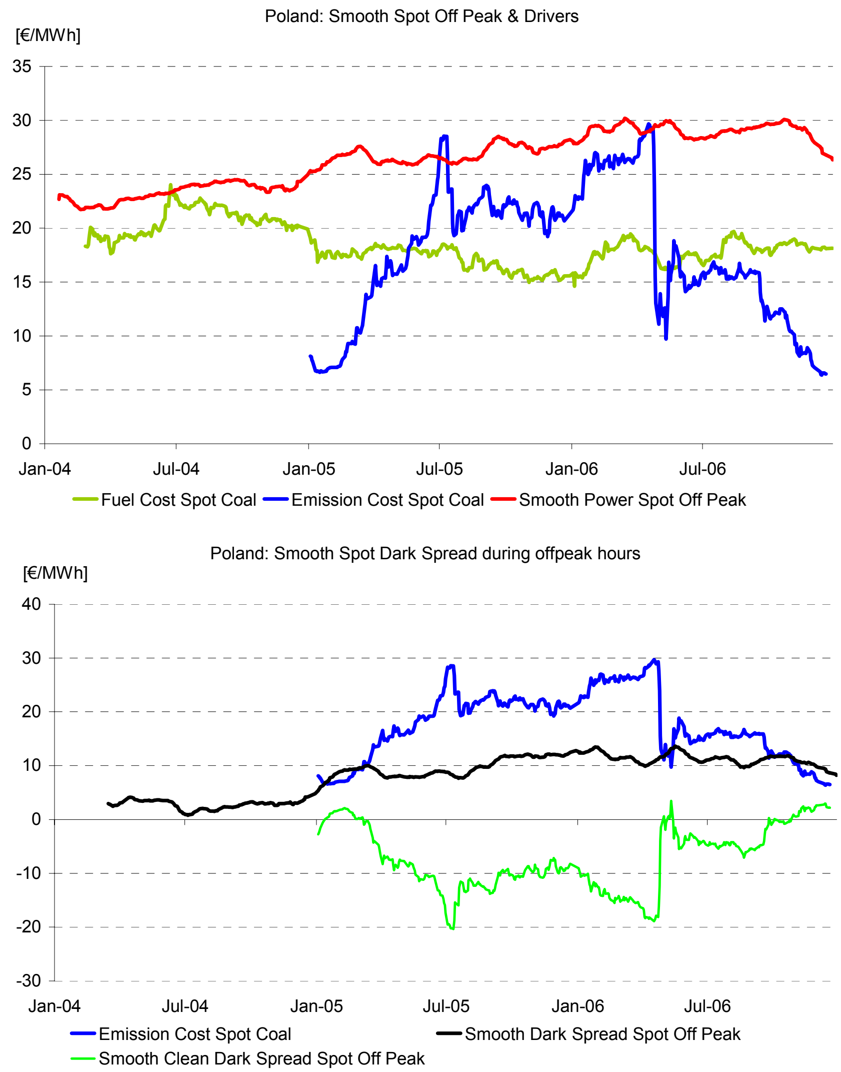


Figure 4.10 *Trends in power prices, costs and spreads on spot markets in Poland during off-peak hours in 2004-2006*

Italy: peak period

In contrast to Poland, over 2004-2006 Italy was characterised by the highest spot power prices and largest increases in these prices amongst all selected EU ETS countries, in particular during the peak hours (see Table 4.4 and Figure 4.2). To some extent, this can be attributed to the high and rising costs of oil-fired generation, which is assumed to set Italian spot prices during the peak period (see Table 4.1, Table 4.5 and Figure 4.3). In addition, peak prices on the Italian spot market are characterised by a large volatility even if they are smoothed by taking a 14-days moving average of these prices (see Figure 4.11). In 2006, for instance, price hikes were due to either a cold spell (early 2006) or a heat wave combined with a drop in wind generation (mid-2006). Compared to the volatility of the peak prices, the carbon costs of an oil-generated MWh were rather stable over 2005-2006. Therefore, due to this contrast in volatility and the likely impact of high and rising fuel oil costs, it is hard to derive any clear conclusion from Figure 4.11 on the relationship between EUA carbon costs and peak prices on the Italian spot market.

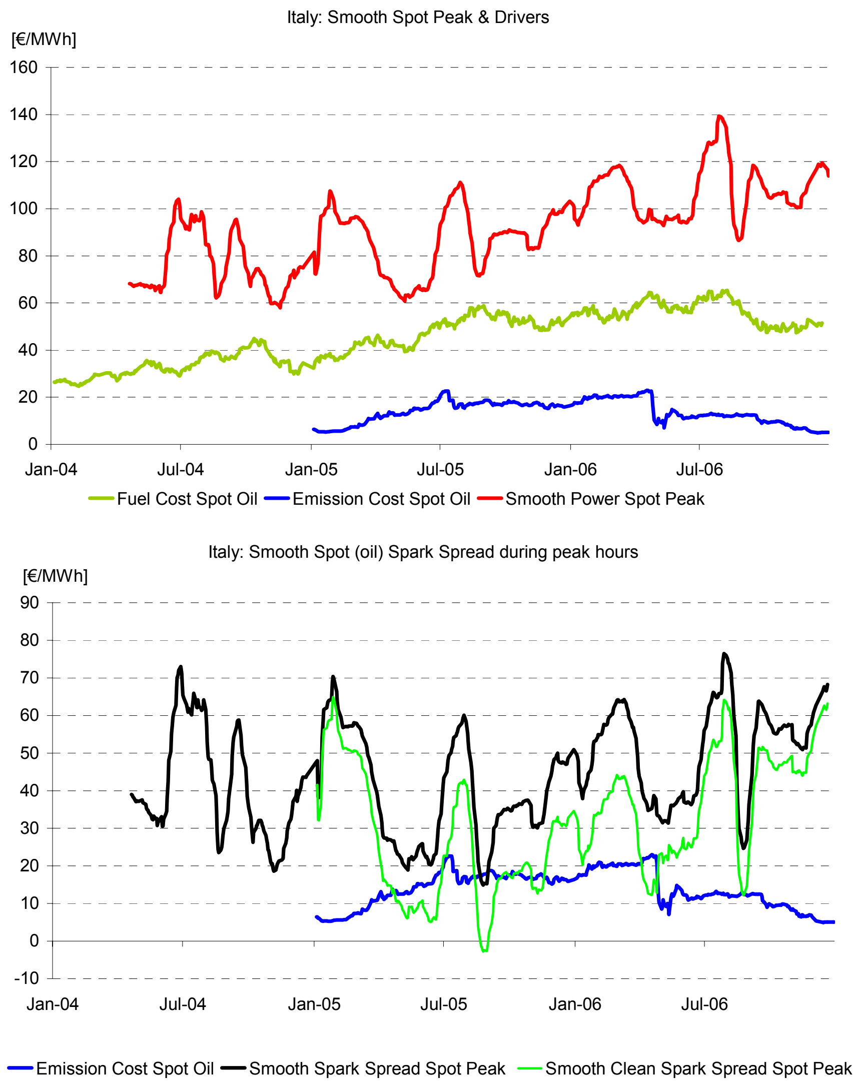
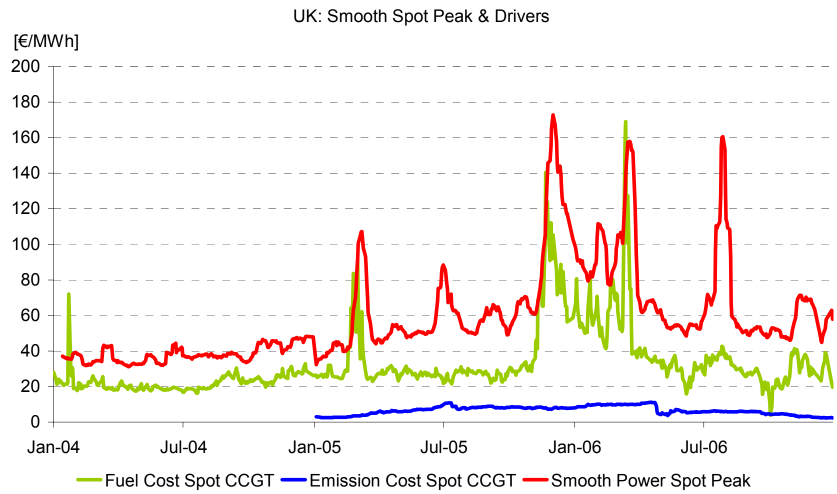


Figure 4.11 *Trends in power prices, costs and spreads on spot markets in Italy during -peak hours in 2004-2006*

The United Kingdom: peak

Spot prices during peak hours in the UK are assumed to be set by a combined cycle gas turbine (CCGT), which is characterised by the lowest carbon costs per MWh of the four main fossil fuel technologies due to its high thermal efficiency and the relatively low CO_2 emissions of generating power by natural gas (see Table 4.2, Table 4.5 and Figure 4.3). On the other hand, the spot price of UK gas has been relatively high and rather volatile during 2005-2006, in particular during the winter of 2005-2006, which to some extent explains the relatively high and rather volatile power prices on the UK spot market during the peak hours of 2005-2006 (see Figure 4.12). In addition, UK spot power spread for CCGT have also been relatively high and volatile during 2005-2006, while the carbon costs of a CCGT-generated MWh have been relatively low and stable. As a result, the clean spreads for CCGT on the UK spot market have been relatively high and volatile as well in 2005-2006, indicating that - besides gas costs - other factors have also heavily influenced changes in UK spot power prices during the peak period of 2005-2006. Therefore, similar to the case of Italy outlined above, it is hard to derive a clear conclusion form Figure 4.12 on the link between EUA carbon costs and peak prices on the UK spot market due to the volatility of these prices, the impact of relatively high and volatile UK gas prices, the impact of other factors on UK spot power prices, and the fact that the carbon costs of a CCGT-generated MWh have been relatively low and stable during the peak period of 2005-2006.



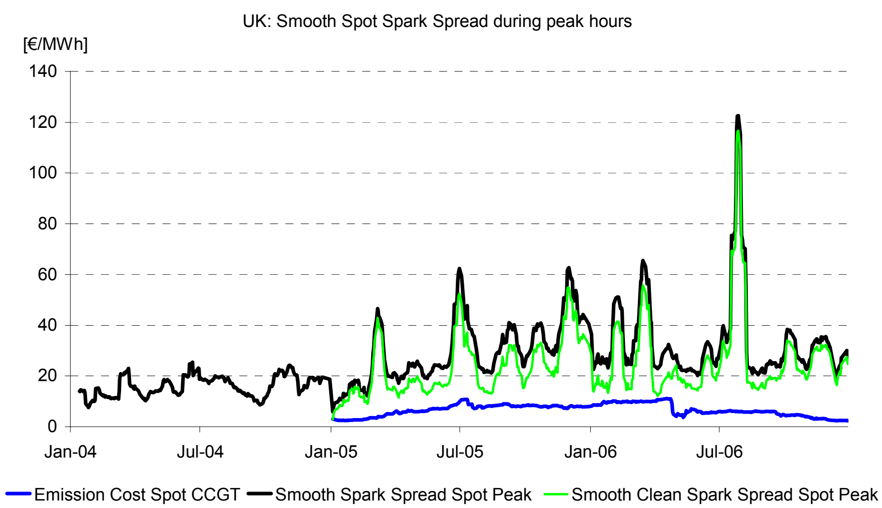


Figure 4.12 *Trends in power prices, costs and spreads on spot markets in the UK during peak hours in 2004-2006*

4.1.5 Summary of major findings

Based on the empirical analyses of the trends on power, fuel and carbon markets for nine major EU ETS countries (as outlined in the sections above as well as in Appendix B), the major findings include:

- In general, forward power prices in the countries analysed have increased significantly between early 2005 and mid-2006, in particular for peak products. However, these prices have stabilised - or even declined - during the second part of 2006, especially for off-peak products. Similar trends can be observed on the spot markets, although less clear due to the high volatility of the power prices on these markets. On average, however, power spreads have generally increased considerably on both forward and spot markets over 2004-2006.
- The significant increases in forward power prices in 2005 can be largely attributed to higher fuel prices in those cases where gas-fired plants set the price, and to a lesser extent to the pass-through of carbon costs. On the other hand, in those cases where coal-fired stations determine the price, increases in this price can be largely attributed to the pass-through of car-

bon costs (and hardly to higher fuel prices as the price of coal has hardly increased in 2005). On the spot markets, it is more difficult to find a clear correlation between changes in the power prices on the one hand and changes in the fuel and/or carbon costs on the other hand, mainly due to the incidence of other factors affecting the power price on these markets, such as extreme or rapidly changing weather patterns, plant outages or other factors causing major fluctuations in market scarcity in the short term.
- Over a relatively short period, the link between CO_2 prices and power prices is sometimes very clear, notably on forward markets. This applies particularly for the period March-July 2005 - when CO_2 prices on the EU ETS market increased steadily from about 10 to 30 €/tCO_2 - and in April-May 2006, when CO_2 prices collapsed suddenly from approximately 30 to 10-15 €/tCO_2. Over longer time periods, however, the relationship between carbon and power prices is less clear, most likely because over longer time periods power prices are affected by other factors besides fuel and carbon costs, such as changes in market structure or generation capacities.
- Moreover, after the collapse of the carbon price in April/May 2006 and, particularly, during the latter part of 2006 (when both carbon and gas prices declined steadily), the link between power prices and fuel/carbon costs is far less clear, suggesting that other factors - such as growing capacity scarcities or market power - have become more important in affecting power prices.

4.2 Statistical estimates of CO_2 cost pass-through rates

By means of regression analyses, pass-through rates (PTRs) of CO_2 emission costs to power prices have been estimated for the nine selected EU ETS countries in 2005 and 2006. These estimates cover the peak and off-peak periods of these countries separately in order to account for differences in power demand between these periods and, hence, for possible differences in price-setting units to meet varying levels of demand. Moreover, PTRs have been estimated for both spot and - if present - forward power markets of these countries.[75]

The sections below provide a brief, non-technical discussion of the methodology to estimate the carbon costs PTRs as well as the major results of the regression analyses. A more detailed presentation of the methodology used and the results obtained can be found in Appendix C.

4.2.1 Methodology

The basic assumption of the statistical analyses is that during the observation period (say 'peak 2005' or 'off-peak 2006') changes in power prices can be explained by variations in the fuel and carbon costs of the price-setting technology over this period. Hence, it is assumed that during this period other costs - for instance, capital, 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, generation capacity, risks or other factors). In addition, it is assumed that fuel costs are fully and directly passed on to power prices.

Based on these assumptions, the pass-through rate of carbon costs to power prices has been estimated by means of the following basic equation:

$$p^{power} - p^{fuel} = a + b_1 p^{EUA} + e \qquad (6.1)$$

The left hand side of the equation involves the spark spread in the case of gas-fired generators and the dark spread in the case of coal-fired generators. The first constant on the right hand side

[75] During the observation period as a whole (i.e. 2004-2006), there were no forward power markets in Italy, Poland, Spain and the Czech Republic, although in 2006 such markets have been opened in Spain and the Czech Republic, while Italy and Poland also intend to introduce such markets.

of the equation represents some fixed components of the fuel spread, including for example the fixed cost elements and the other, less quantifiable but stable, components. The second term on the right hand side represents the costs of the CO_2 emission allowances needed for the generation of a MWh multiplied by the pass-through rate (b_1). The last term, i.e. the error term (e), represents all other non-stable components in the fuel spread.

Depending on the availability and statistical tests of the forward and spot market data sets, equation 6.1 has been adjusted and differentiated for the forward versus spot market analyses (for details see Appendix C). Subsequently, the pass-through rates have been estimated by means of the Ordinary Least Squares (OLS) method and the data sets of daily observations for the countries, markets and load periods analysed.

4.2.2 Forward market analyses

Table 4.6 provides a summary of the estimated pass-through rates of carbon costs on the forward market during the peak and off-peak periods in 2005 and 2006 for five selected EU ETS countries, i.e. Germany (DE), France (FR), the Netherlands (NL), Sweden (SE) and the United Kingdom (UK). Based on these results, the major findings and conclusions are:

- All of 22 estimates were found to be statistically significant at the 1% level with, in general, small confidence intervals. However, the indicator for the 'goodness of fit' of the estimated regression equation (R^2) is generally low (although far from bad for a single variable equation), implying that only a small part - usually less than a third - of the changes in power prices/spreads can be attributed to changes in carbon costs.
- Most of the estimates of pass-through rates show levels between 0 and 1, which is consistent with the expectation that the carbon (opportunity) costs of the EU ETS are passed-through. Actually, 17 out of 22 estimates range between 38 to 83%, 4 estimates are slightly above 1 (i.e. varying between 103 and 134%), and only one estimate is significantly larger than 1 (i.e. 182%)
- For France and Germany, the estimated PTRs are remarkably similar, ranging from 40 to 66% during 2005-2006 for the forward peak and off-peak markets. For Sweden, the estimated PTRs in 2005-2006 are about 50-60% on the forward baseload market. For the Netherlands, the estimated PTRs are relatively low for the off-peak period when coal is assumed to set the power price, whereas they are relatively high for the peak period when gas is the assumed marginal technology. Finally, the estimated PTRs on the forward markets in the UK are rather similar in 2006 (i.e. ranging only form 0.58 to 0.66) while they vary widely in 2005, ranging from 0.83 to 1.82.

The above findings, however, have to be interpreted with some discretion due to the following considerations.

First, as noted, the estimated PTRs are based on the fundamental assumption that changes in power prices are predominantly caused by changes in the underlying costs of fuels and CO_2 emission allowances, and that all other generation costs and factors affecting power prices are more or less fixed during the observation period (i.e., for instance, the peak period in 2005 or the off-peak period in 2006). However, as observed in the previous, this assumption seems to hold for certain periods (e.g. the off peak 2005) but not for others (notably during the peak period of the second half of 2006). The other generation costs and factors refer not only to maintenance or fixed costs, but also to items such as changes in scarcity of generation capacity, market power, risks, etc. Due to a lack of data, however, it is not possible to account quantitatively for the impact of these other factors changes in power prices in an adequate way, which may lead to biased results of the estimated PTRs.

Second, the estimated PTRs are based on the assumption that during the observation period power prices are set by a single (marginal) technology with a fixed, generic fuel efficiency. In practice, however, peak or off-peak prices during a particular year (or even a particular month, week or day) may be set by a variety of technologies (with different or changing fuel efficiencies), depending on the specific load hour, the maintenance or outage schedule of the generation park, daily changes in relative fuel/carbon prices, etc. Due to a lack of data, it is not possible to account quantitatively for these technological factors, which may lead to (additional) biases in the estimated PTRs.

Third, the estimated PTR are based on the use of daily price data for fuels traded on (inter)national, rather liquid markets, assuming that these data reflect the changes in the opportunity costs of the fuels used by the marginal, price-setting technology in either Germany or the Netherlands. In practice, however, power generators may use another (or adjusted) fuel price indicator for their operational and bidding strategies as they usually rely on long-term fuel supply contracts with specific marketing and pricing conditions. Moreover, in particular the gas market is often less liquid and, hence, the 'opportunity costs' of gas becomes a dubious concept as power companies are less flexible in trading gas surpluses or shortages due to contract fines and other, high balancing costs of trading gas flexibly. Therefore, the estimated PTRs depend on the assumptions made with regard to the fuel price data.

Finally, the estimated PTRs depend on - i.e. are sensitive to - the assumed generic (fixed, average) fuel efficiency rates, which in all relevant cases amount to 35 and 40% for coal and gas, respectively. However, for specific cases, e.g. NL off-peak, these rates may be too low.

Table 4.6 *Estimates of carbon costs pass-through rates on forward markets in EU ETS countries during the peak and off-peak period in 2005-2006*[a]

			2005			2006	
		PTR[b]	StE	R^2	PTR	StE	R^2
DE	Peak_coal	0.60	0.06	0.32	0.57	0.05	0.38
	Off-peak_coal	0.41	0.04	0.35	0.64	0.04	0.58
FR	Peak_coal	0.66	0.08	0.23	0.58	0.07	0.26
	Off-peak_coal	0.40	0.05	0.22	0.59	0.04	0.47
NL	Peak_gas	1.34	0.14	0.28	1.10	0.14	0.20
	Off-peak_coal	0.40	0.04	0.34	0.38	0.03	0.38
SE[c]	Base_coal	0.53	0.04	0.42	0.62	0.05	0.38
UK-S[d]	Peak_ccgt	0.83	0.17	0.09	0.58	0.06	0.31
	Off-peak_coal	1.03	0.18	0.12	0.60	0.06	0.29
UK-W[d]	Peak_ccgt	1.18	0.17	0.15	0.59	0.11	0.10
	Off-peak_coal	1.82	0.19	0.29	0.66	0.11	0.12

a) The nine EU ETS countries analysed in the present report include France (FR), Germany (DE), Italy (IT), Poland (PL), Spain (ES), Sweden (SE), the Czech Republic (CZ), the Netherlands (NL) and the United Kingdom (UK). In Italy, Poland, Spain and the Czech Republic, however, there was no forward power market present during the whole observation period 2004-2006.

b) These estimates are based on the following (standard) fuel efficiency assumptions: coal: 0.35; gas: 0.40, and Combined Cycle Gas Turbine (CCGT): 0.55. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at the 1% level. R^2 is an indicator for the 'goodness of fit' of the regression equation, varying from 0 ('bad') to 1 ('very good'). A white R^2 indicates a value below 0.5, light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75.

c) In Sweden, only baseload products are traded on the forward market.

d) In the UK, the most liquid forward markets involve seasonal forward products, i.e. winter-ahead and summer-ahead. Two forward products are evaluated, therefore, relating to the summer forward market and the winter forward market, respectively.

Sensitivity analysis
In order to assess the impact of the assumed fuel efficiencies on the estimated PTRs, a sensitivity test has been conducted assuming different values for the thermal efficiency of coal, gas and CCGT of 0.40, 0.42 and 0.50, respectively (rather than the reference values of 0.35, 0.40 and 0.55, respectively). The results of this sensitivity analysis are recorded in Table 4.7. In general, the estimated PTRs are higher when the fuel efficiency is higher, although the difference is usually small. The major exception concerns the UK where the PTR for the peak period - when CCGT is assumed to set the price - is substantially higher when the fuel efficiency is lower.

Table 4.7 *Estimates of carbon costs pass-through rates on forward power markets in EU ETS countries during the peak and off-peak period in 2005-2006, sensitivity analyses*

			2005			2006	
		PTR[a]	StE	R^2	PTR	StE	R^2
DE	Peak_coal	0.69	0.06	0.32	0.65	0.06	0.38
	Off-peak_coal	0.46	0.04	0.34	0.73	0.04	0.58
FR	Peak_coal	0.75	0.09	0.23	0.66	0.07	0.26
	Off-peak_coal	0.46	0.06	0.22	0.68	0.05	0.47
NL	Peak_gas	1.40	0.15	0.28	1.15	0.15	0.20
	Off-peak_coal	0.45	0.04	0.34	0.44	0.04	0.38
SE	Base_coal	0.60	0.05	0.42	0.71	0.06	0.38
UK-S	Peak_ccgt	1.73	0.40	0.07	1.27	0.13	0.29
	Off-peak_coal	1.18	0.21	0.12	0.69	0.07	0.29
UK-W	Peak_ccgt	2.14	0.37	0.11	1.25	0.23	0.10
	Off-peak_coal	2.08	0.21	0.29	0.75	0.13	0.12

a) These estimates are based on the following (alternative) fuel efficiency assumptions: coal: 0.40; gas: 0.42, and CCGT: 0.50 (for other notes, see Table 4.6).

Table 4.8 *Estimates of carbon costs pass-through rates on forward power markets in EU ETS countries during the peak and off-peak period in 2005-2006: first-choice versus alternative marginal units*

			2005			2006	
		PTR	StE	R^2	PTR	StE	R^2
DE	Peak_coal	0.60	0.06	0.32	0.57	0.05	0.38
	Peak_gas	1.07	0.11	0.29	1.07	0.09	0.36
FR	Peak_coal	0.66	0.08	0.23	0.58	0.07	0.26
	Peak_gas	1.04	0.15	0.17	1.02	0.12	0.24
NL	Off-peak_coal	0.40	0.04	0.34	0.38	0.03	0.38
	Off-peak_ccgt	0.90	0.10	0.27	0.93	0.08	0.35
UK-S	Peak_ccgt	0.83	0.17	0.09	0.58	0.06	0.31
	Peak_coal	1.87	0.44	0.07	1.38	0.14	0.29
	Off-peak_coal	1.03	0.18	0.12	0.60	0.06	0.29
	Off-peak_ccgt	2.42	0.47	0.10	1.48	0.16	0.27

For notes, see Table 4.6. The alternative marginal units are marked in blue, just below the 'first-choice', price-setting technologies.

Alternative marginal units
In addition, PTRs have been estimated for a few cases in which it is hard to define a single, dominant marginal unit as, most likely, more than one technology sets alternately the price during a certain load period. For instance, it has been assumed that coal is the dominant marginal unit during the peak in Germany. However, during a major part of this period - in particular during the so-called 'super peak' - the power price is set by gas rather than coal. Table 4.8 presents the estimated PTRs for some cases assuming an alternative marginal unit (where the alternative, price-setting unit is marked in blue below the 'first-choice' marginal technology). The table shows that for all cases analysed the PTR is higher when gas (rather than coal) is assumed to be

price-setting. This implies that when both gas and coal alternately set the price during a certain load period, the PTR is overestimated if gas is selected as the single dominant technology and underestimated if coal is assumed to be solely price-setting.

4.2.3 Spot market analyses

Table 4.9 presents a summary of the statistical results of estimating carbon costs PTRs on the spot power markets of the nine selected EU ETS countries during the peak and off-peak periods in 2005 and 2006. Compared to the outcomes of the forward market estimated discussed above, these results are less straightforward. Overall, the major findings regarding the estimates of the PTRs on the spot markets include:

- Out of 36 PTR estimates, 21 prove to be statistically significant at the 10% level. For 2005, two-thirds of the estimates (i.e. 12 out of 18) are statistically significant, while for 2006 the score is one-half (i.e. 9 out of 18).
- Out of the 21 statistically significant estimates, 17 PTRs have a positive value between 0 and 2. In particular the estimates for the off-peak hours in countries such as Germany, France, Spain, Sweden and the UK seem fairly consistent with the hypothesis that CO_2 costs are passed through, with most PTR estimates ranging from 0.4 and 1.0. In addition, the estimated PTRs are usually higher for the peak than off-peak period.
- Two out of 21 statistically significant estimates have a negative value. Both concern Italy in 2006 during the peak (-0.67) and the off-peak (-2.98). From an economic point of view, a negative PTR does not make sense as it implies that either prices go up when costs go down or vice versa. From a statistical perspective, a negative PTR may be explained by either a misspecification of the price-setting unit or, more likely, the coincidence of decreasing (increasing) carbon costs and increasing (decreasing) power prices due to factors other than fuel/carbon costs such as more (less) scarcity on the spot market. In 2006, for instance, power prices on the Italian spot market have been extremely volatile, with some major price hikes, due to weather-related events such as a cold spell in early 2006, a heat wave in mid-2006 and, at the same time, a drop in wind generation (see Appendix B.5). Hence, rather than by (small) changes in carbon costs, power prices on the Italian spot market in 2006 seem to have been affected predominantly by these weather-related events or other factors affecting market scarcity.
- Two out of 21 statistically significant estimates have a relatively high value. Both estimates refer to gas-generated power during the peak period of 2005. One estimate concerns Open Cycle Gas Turbine (OCGT)-generated power in the Netherlands (with an estimated PTR of 4.2) and the other Combined Cycle Gas Turbine (CCGT)-generated power in the UK (i.e., 3.7). From a theoretical point of view, a PTR > 1.0 can be explained by either a change in the merit order or the incidence of non-competitive markets facing non-linear demand (see Section 2.2). From an empirical or statistical point of view, however, it is more likely that the high values of the PTRs are due to a misspecification of the marginal unit setting the price and/or the incidence of other factors besides carbon/fuel costs affecting spot prices, resulting in an overestimation of the PTR value. For instance, depending on the actual fuel/carbon costs for gas versus coal, either a coal-fired plant or a CCGT may be the price-setting unit during peak demand in the UK. Assuming CCGT to be the single, marginal unit during the peak, while actually both CCGT and coal are, alternately, setting the price may lead to an overestimate of the PTR value (as shown above in the case of the forward market estimates; see also Table 4.12 below).
- Most of the statistically insignificant estimates concern the peak period in 2006 (i.e. 7 out of 9 estimates for this period are not significant). This may be attributed to the coincidence of (i) highly volatile and, on average, rising power prices due to weather-related events or other factors such as growing market scarcities, and (ii) carbon prices which showed some wide fluctuations during the first period of 2006 (including a major collapse and trend break), and a declining trend during the latter part of 2006 towards such low levels to become relatively

insignificant to affect peak power prices or to compensate the impact of other factors inflating these prices.

- All four estimates for Poland are statistically insignificant. Apart from statistical misspecifications (or data shortcomings), this may be due to the fact that power prices in Poland was heavily regulated up to mid-2007 and, hence, there was little room for passing through the (opportunity) costs of freely allocated emission allowances.
- Overall, there is statistical evidence to support the conclusion that there is a significant rate of carbon cost pass-through on spot markets in several cases, in particular during (i) the off-peak period of both 2005 and 2006 for countries such as Germany, France, Spain, Sweden and the UK, (ii) the peak period of 2005 for countries such as the Czech Republic, Germany, France, the Netherlands, Sweden and the UK, (iii) the off-peak period of 2005 in the Czech Republic, (iv) the peak period of 2006 in Spain, and (v) the off-peak period of 2006 in the Netherlands. In general, however, such evidence is lacking or inconclusive for the peak period in 2006 or for some specific countries, notably Italy and Poland.

Table 4.9 *Estimates of carbon costs pass-through rates on spot power markets in EU ETS countries during the peak and off-peak period in 2005-2006*

		2005			2006		
		PTR	StE	R^2	PTR	StE	R^2
CZ	Peak_coal	1.50	0.39	0.49	-0.71	0.84	0.65
	Off-peak_coal	0.44	0.22	0.28	-0.27	0.26	0.46
DE	Peak_coal	1.76	0.88	0.69	0.92	0.72	0.22
	Off-peak_coal	0.82	0.23	0.75	0.68	0.17	0.76
ES	Peak_oil	0.50	0.67	0.65	1.11	0.49	0.76
	Off-peak_coal	0.64	0.23	0.74	0.52	0.28	0.90
FR	Peak_coal	1.96	0.97	0.75	1.18	0.96	0.64
	Off-peak_coal	0.98	0.33	0.72	0.76	0.17	0.80
IT	Peak_oil	-0.97	0.62	0.69	-0.67	0.23	0.79
	Off-peak_CCGT	0.39	0.70	0.58	-2.98	0.68	0.84
NL	Peak_gas	4.17	0.84	0.37	0.69	1.16	0.45
	Off-peak_coal	0.19	0.17	0.72	1.21	0.16	0.68
PL	Peak_coal	0.09	0.07	0.58	-0.04	0.03	0.72
	Off-peak_coal	0.09	0.06	0.82	0.00	0.06	0.61
SE	Peak_coal	0.48	0.12	0.60	0.44	0.31	0.75
	Off-peak_coal	0.35	0.12	0.85	0.82	0.21	0.92
UK	Peak_CCGT	3.70	0.75	0.28	0.89	1.31	0.14
	Off-peak_coal	0.70	0.40	0.84	1.53	0.25	0.66
		15	12		12	9	

Note: PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at 10% level. R^2 is an indicator for the 'goodness of fit' of the regression equation, varying from 0 ('bad') to 1 ('very good'). A white R^2 indicates a value below 0,5, light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75. The last row indicates the number of PTR values between 0 and 2 (column PTR) and the number of statistically significant estimates (column StE).

It is important to emphasize, however, that the statistical estimates of the PTRs for the spot markets have to be treated with even greater care than those for the forward markets. In addition to the qualifications made above with regard to the forward estimates, this results particularly from the fact that spot power prices have a more market-balancing character and, hence, are more volatile as they are often less driven by costs (for fuels or carbon) than events such as extreme or rapidly changing weather patterns, plant outages or other factors causing major fluctuations in market scarcity. Due to a lack of data, analytical tools or other resources, however, it is often not possible to account for these events and factors in an adequate, quantitative way when conducting statistical analyses to estimate the pass-through of carbon costs to power prices on a variety of sport markets across the EU ETS. Therefore, due to the incidence of these events or other factors affecting spot power prices, the estimates of the carbon costs PTRs on spot markets may be not significant and, hence, inconclusive.

An alternative approach: differentiating the size of the dataset
Since the impact of the above-mentioned events and other factors (besides fuel/carbon costs) affecting spot power prices could not be adequately addressed in a quantitative way within the limits of the study, an alternative approach has been applied to eliminate the most extreme cases of these events and factors and, hence, to assess their impact on estimating PTRs on spot markets. This approach implies simply eliminating observations from the database assumed to be related to such events and other factors distorting an adequate estimation of PTRs on spot markets.

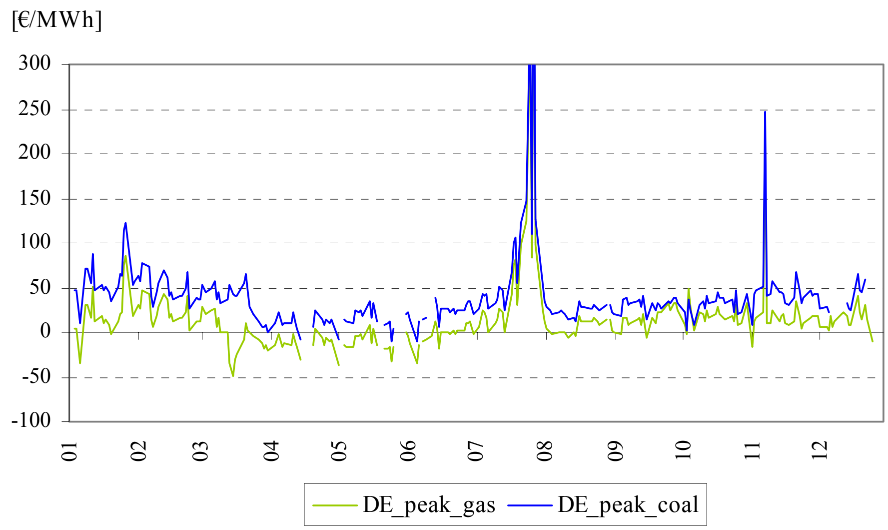


Figure 4.13 *Trend in clean power spreads for coal and gas during the peak period in Germany over 2006*

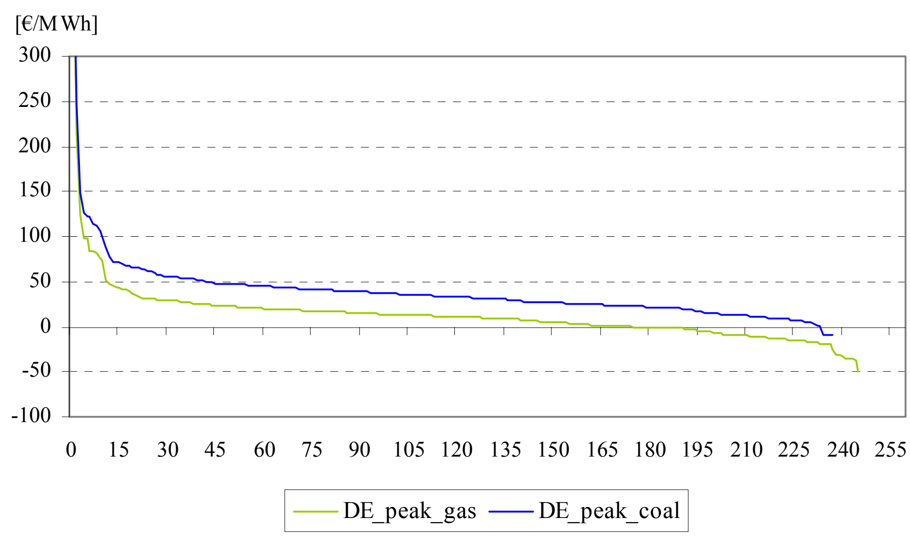


Figure 4.14 *Duration curve of clean power spreads for coal and gas during the peak period in Germany over 2006*

The approach can be explained and illustrated by means of Figure 4.13 and Figure 4.14. Figure 4.13 presents the trend in clean power spreads for coal and gas during peak demand in Germany over 2006. As noted, the clean power spread is the difference between the power price and the costs for both fuels and carbon allowances per unit output. Figure 4.13 shows that the spreads have been very volatile in 2006, indicating that spot power prices have been affected heavily be other factors than fuel/carbon costs (note that the trend in clean power spread would be represented by a flat, vertical line in case changes in power prices are solely due to changes in fuel/carbon costs). For instance, due to the heat wave of mid-2006, there was an extreme price hike on the German spot market in July 2006, resulting in extremely high values of the clean power spreads during this period. On the other hand, power spreads on the spot markets are occasionally very low (or even negative), for instance due to sudden price hikes for fuels - not fully or directly transmitted to power prices - or so-called ‘must-run’ conditions, i.e. the need to run co-generation plants to meet heat demand, or to reduce the costs of temporarily closing and, subsequently, restarting coal plants.

In order to eliminate the most extreme cases of these events or other factors causing very high or low (negative) clean spreads, the values of these spreads have been ranked from high to low along the so-called *duration curve* (see Figure 4.14 showing such a curve for the clean power spreads of coal and gas during peak demand in Germany over 2006). Note that the duration curve of Figure 4.14 has two tails, a big one on the left - representing the extreme high clean spreads of, for instance, July 2006 - and a small one on the right, including some negative spreads.[76] Over a large range in the middle of this curve, however, the variation in clean spread values is rather small, resulting in a flat, almost vertically slope of the clean spread duration curve (and supporting the view that over this range changes in power prices have been caused predominantly by changes in carbon/fuel costs).

In order to assess the impact of some extreme observations on estimating PTRs on spot markets, these observations have been eliminated from the database, in particular by eliminating a small percentage on the observations on both the upper left and bottom right of the clean spread duration curve. By eliminating either 5 or 10% of the observations on both sides of this curve, this results in either a so-called ‘middle 90%’ or ‘middle 80%’ of the database.

The results of this exercise are recorded in Table 4.10 which presents the estimates of the PTRs of the carbon costs on the spot markets in EU ETS countries during 2005-2006 using three different sizes of the annual data base denoted as ‘Full 100%’, ‘Middle 90%’ and ‘Middle 80%’ (where the result of the full dataset are similar to the results recorded in Table 4.9, as discussed above). The last row of Table 4.10 provides the performance for each dataset in terms of the number of statistically significant estimates (column SE) and the number of estimated PTR values between 0 and 2 (column PTR).

[76] See Appendix B for pictures showing the trends in clean spreads for the other countries and load periods analysed in this study. In several cases, these pictures even illustrate a far higher incidence of negative or extremely positive values of clean spreads).

Table 4.10 *Estimates of carbon costs pass-through rates on spot power markets in EU ETS countries during the peak and off-peak period in 2005-2006 using different data-sets*

	Full 100%				Middle 90%				Middle 80%			
	2005		2006		2005		2006		2005		2006	
	PTR	StE	PTR	StE	PTR	StE	PTR	StE	PTR	SE	PTR	StE
CZ Peak_coal	1.50	0.39	-0.71	0.84	1.54	0.26	-0.62	0.31	1.28	0.22	-0.16	0.28
Off-peak_coal	0.44	0.22	-0.27	0.26	0.77	0.18	0.21	0.13	0.71	0.16	0.44	0.12
DE Peak_coal	1.76	0.88	0.92	0.72	1.11	0.24	1.20	0.15	1.06	0.19	1.23	0.13
Off-peak_coal	0.82	0.23	0.68	0.17	0.83	0.12	0.70	0.11	0.88	0.11	0.90	0.09
ES Peak_oil	0.50	0.67	1.11	0.49	0.79	0.41	1.05	0.37	0.85	0.28	1.24	0.29
Off-peak_coal	0.64	0.23	0.52	0.28	0.79	0.14	0.91	0.19	0.93	0.10	0.98	0.14
FR Peak_coal	1.96	0.97	1.18	0.96	2.10	0.32	0.99	0.18	2.05	0.20	1.18	0.15
Off-peak_coal	0.98	0.33	0.76	0.17	0.94	0.15	0.72	0.14	0.84	0.15	0.79	0.12
IT Peak_oil	-0.97	0.62	-0.67	0.23	-0.37	0.44	-0.38	0.24	0.31	0.43	-0.24	0.23
Off-peak_CCGT	0.39	0.70	-2.98	0.68	0.30	0.27	-2.43	0.45	0.47	0.19	-1.74	0.40
NL Peak_gas	4.17	0.84	0.69	1.16	2.85	0.47	1.34	0.30	2.12	0.39	1.61	0.25
Off-peak_coal	0.19	0.17	1.21	0.16	0.40	0.11	1.24	0.11	0.53	0.08	1.17	0.08
PL Peak_coal	0.09	0.07	-0.04	0.03	0.25	0.06	-0.02	0.04	0.32	0.06	0.00	0.05
Off-peak_coal	0.09	0.06	0.00	0.06	0.21	0.05	0.01	0.06	0.30	0.04	0.02	0.07
SE Peak_coal	0.48	0.12	0.44	0.31	0.69	0.07	0.30	0.23	0.75	0.07	0.42	0.20
Off-peak_coal	0.35	0.12	0.82	0.21	0.59	0.09	0.65	0.18	0.67	0.09	0.72	0.18
UK Peak_CCGT	3.70	0.75	0.89	1.31	3.27	0.45	0.41	0.36	2.58	0.36	0.78	0.29
Off-peak_coal	0.70	0.40	1.53	0.25	1.06	0.19	0.99	0.09	1.08	0.13	0.90	0.06
	15	12	12	9	14	16	14	12	15	17	14	14

Note: PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at 10% level. The last row indicates the number of PTR values between 0 and 2 (column PTR) and the number of statistically significant estimates (column StE).

By comparing the results in Table 4.10, the major findings of differentiating the size of the database for estimating PTRs on spot markets include:

- The total number of statistically significant estimates increases from 21 (out of 36) in the full database to 28 and 31 in the middle 90 and 80% datasets, respectively, while the number of PTR values between 0 and 2 increases less remarkably from 27 to 28 and 29, respectively.
- The estimates of the smaller datasets confirm that there is statistical evidence for a significant rate of carbon cost pass-through on spot markets in a large variety of cases, notably during the off-peak in 2005 and 2006 as well as during the peak in 2005. The major exceptions concern (i) Italy, for which the estimated PTRs are either not statistically significant or negative, and (ii) Poland, notably in 2006). Moreover, even in the smaller datasets several estimates for the peak period in 2006 are either statistically not significant or relatively high (>2), most likely due to the high incidence of other factors besides fuel/carbon costs affecting peak power prices in 2006.

Once again, it is important to stress that the above findings and conclusions have to be interpreted prudently. Differentiating the size of the database is, of course, a questionable issue. Perhaps the most important contribution or insight of such differentiation is that it may confirm (or not) the cost pass-through in specific cases and that it questions the robustness or exactness of the estimated PTRs, even - or just - for the full database, as these estimates may be biased due to the incidence of other factors besides fuel/carbon costs affecting power prices.

Alternative marginal units
Table 4.11 presents the estimated PTRs for some cases assuming an alternative marginal technology (where the alternative, price-setting unit is marked in blue below the 'first-choice' marginal technology). In general the table shows that the performance of the estimated PTRs for the first-choice technology is better than for the alternative technology. This seems to confirm that the first-choice technology is indeed the best choice to estimate the PTRs in the cases concerned.

Table 4.11 *Estimates of carbon costs pass-through rates on spot power markets in EU ETS countries during the peak and off-peak period in 2005-2006 using different datasets: first-choice versus alternative marginal units*

		100%				Middle 90%				Middle 80%			
		2005		2006		2005		2006		2005		2006	
		PTR	StE	PTR	StE	PTR	StE	PTR	StE	PTR	StE	PTR	StE
DE	Peak_coal	1.76	0.88	0.92	0.72	1.11	0.24	1.20	0.15	1.06	0.19	1.23	0.13
	Peak_gas	3.24	1.02	-0.16	1.27	2.11	0.29	0.50	0.28	1.73	0.23	0.52	0.23
ES	Peak_oil	0.50	0.67	1.11	0.49	0.79	0.41	1.05	0.37	0.85	0.28	1.24	0.29
	Peak_gas	2.34	0.59	-1.70	0.73	1.54	0.36	-0.81	0.38	1.23	0.29	-0.31	0.27
	Off-peak_coal	0.64	0.23	0.52	0.28	0.79	0.14	0.91	0.19	0.93	0.10	0.98	0.14
	Off-peak_CCGT	1.56	0.46	-1.31	0.67	1.21	0.21	-0.45	0.44	1.28	0.17	0.31	0.36
FR	Peak_coal	1.96	0.97	1.18	0.96	2.10	0.32	0.99	0.18	2.05	0.20	1.18	0.15
	Peak_gas	4.27	1.15	-1.37	1.57	3.56	0.40	-1.52	0.34	3.10	0.27	-1.04	0.28
IT	Off-peak_CCGT	0.39	0.70	-2.98	0.68	0.30	0.27	-2.43	0.45	0.47	0.19	-1.74	0.40
	Off-peak_gas	0.19	0.70	-2.94	0.69	0.05	0.29	-2.32	0.46	0.35	0.18	-2.03	0.39
NL	Off-peak_coal	0.19	0.17	1.21	0.16	0.40	0.11	1.24	0.11	0.53	0.08	1.17	0.08
	Off-peak_CCGT	0.45	0.45	0.95	0.53	0.55	0.19	1.66	0.33	0.61	0.14	1.47	0.26
		18	16	13	13	18	21	16	17	20	23	17	18

Note: In addition to the assumed dominant price-setting technology for each country and load period, an alternative marginal technology has been indicated in blue for those cases where this technology presumably sets the price during a major part of the load period as well. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate at 10% level. The last row indicates the number of PTR values between 0 and 2 (column PTR) and the number of statistically significant estimates (column StE).

4.3 Carbon costs pass-through on retail power markets

In the previous sections, the analysis focused on the impact of CO_2 emissions trading on (year-ahead) *wholesale* power prices over the period 2005-2006. This raises the question whether and to what extent there is already some empirical evidence on the pass-through of carbon allowances costs to *retail* power prices during this period. In order to address this question, data have been gathered from Eurostat on average, semi-annual power prices for two categories of electricity end-users:

- Households, with an annual consumption of 3.5 MWh (of which 1.3 MWh at night).
- Industry, in particular large industrial end-users with an annual consumption of 24,000 MWh (maximum demand 4 MW and 6000 annual load hours).

Figure 4.15 presents the changes in the average, annual electricity prices for these two categories of power consumers over 2004-2006. A comparison of these prices leads to some interesting findings, including:

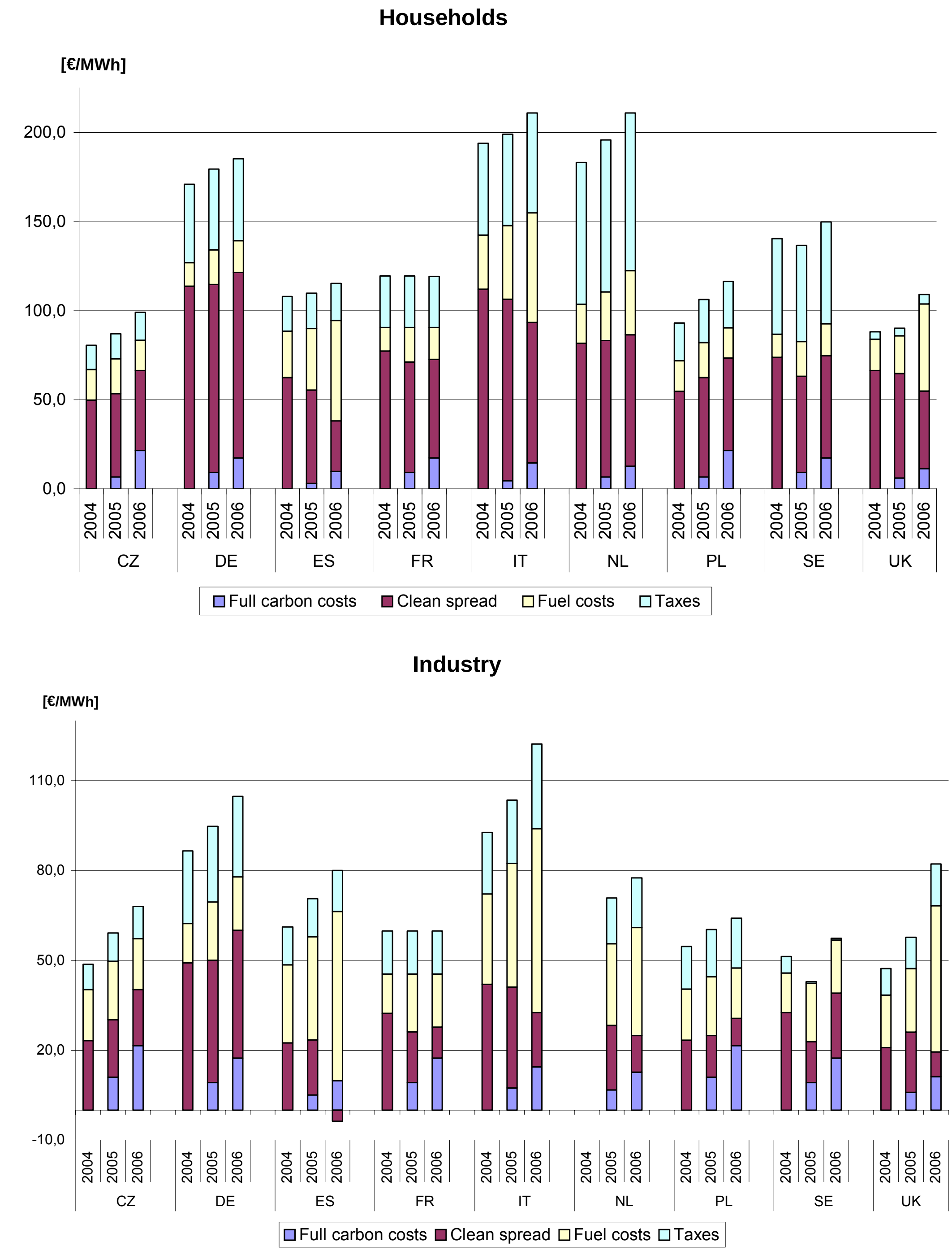


Figure 4.15 *Decomposition of retail power prices in EU countries for 2004-2006*

- Retail power prices are, as expected, substantially higher than wholesale power prices. This applies in particular for electricity prices charged to households with an annual consumption of 3.5 MWh. In 2005-2006, for instance, average, annual power prices on the (year-ahead) wholesale markets of Germany and the Netherlands amounted to approximately 40-50 €/MWh, while retail prices for households - including taxes - were, on average, about 180-185 €/MWh in Germany and even some 195-210 €/MWh in the Netherlands. The large differential between these wholesale and retail electricity prices can be attributed to the costs of power distribution and marketing as well as the (energy/value-added) taxes charged to household consumers in these countries.

- Retail power prices, however, are significantly lower for industrial end-users than for households. For instance, for the category of the largest power consumers (i.e. those industrial users with an annual consumption of 24,000 MWh), electricity prices in 2005-2006 were, on average, about 100 €/MWh in Germany and 75 €/MWh in the Netherlands (including taxes) while, as noted, household power prices in these countries amounted to approximately 180-185 €/MWh and 195-210 €/MWh, respectively. These significant differences in household versus industrial user prices can be explained by substantial differences in taxes as well as distribution and marketing costs for small versus large power consumers. Note that these factors, in particular differences in taxation, also largely account for differences in power prices for similar end-users between Germany and the Netherlands. For instance, due to these factors, power prices in 2004-2006 were generally higher for Dutch households (i.e. compared to German households), whereas they were lower for Dutch large industrial end-users, compared to their German competitors (see Figure 4.15).

In addition, Figure 4.15 shows that retail power prices in the countries considered have increased significantly for both households and industrial consumers over 2004-2006 (except in France where retail prices for both large and small end-users have been more or less the same during 2004-2006). For instance, including taxes, power prices for large industrial end-users in Germany rose from 86 €/MWh in 2004 to 105 €/MWh in 2006 (+21%), while household electricity prices in the Netherlands increased from 183 to 211 €/MWh over this period (+15%). To some extent, these changes in retail prices are affected by changes in energy taxes (including value added taxes). Between 2004 and 2006, for instance, taxes on industrial power prices in Germany were raised from 24 to 27 €/MWh, resulting in an increase in these prices, excluding taxes, from 62 to 78 €/MWh (+25%), while taxes on household power prices in the Netherlands were raised from 80 to 89 €/MWh, implying an increase in these prices, excluding taxes, from 103 to 122 €/MWh (+18%). Hence, whereas changes in energy taxes can explain a major part (about one-third) of the increase in household power prices in the Netherlands over 2004-2006, they are less important (about one-sixth) in accounting for differences in industrial power prices in Germany during this period.

In order to assess the possible impact of CO_2 emissions trading on (changes in) retail power prices during 2005-2006, the carbon costs passed through on the retail power markets have been estimated for two countries (Germany and the Netherlands) according to three different methodologies:

1. Estimation of the carbon costs passed through based on the change in the so-called 'retail power spread' (defined as the difference between the average annual power price, excluding taxes, and the average annual fuel costs of power generation per MWh). This approach assumes that changes in this spread can be solely attributed to changes in carbon costs passed through on the retail market (and, hence, that changes in retail power prices can be explained by changes in these carbon costs, fuel costs and taxes), while other costs or determinants of retail power prices are fixed over this period (2004-2006). According to this approach, the estimated carbon costs passed through are assumed to be equal to the difference in the average annual retail power spread during a certain year after emissions trading (2005 or 2006) and the year before emissions trading (i.e. 2004).[77]

[77] More precisely, in the first approach, the retail power spreads for 2005 and 2006 have been calculated by taking the average, annual power prices for a certain category of end-users (say, German households in 2005 or 2006) and subtracting the average, annual fuel costs of power generation per MWh. These costs have been calculated by means of daily prices on the year-ahead fuel market, i.e. prices during 2004 and 2005 for fuels delivered in 2005 and 2006, respectively, used by marginal technologies setting wholesale power prices during the peak and off-peak periods, based on the same fuel price data and assumptions regarding these technologies (including their fuel efficiencies) as applied for the empirical analyses of the power spreads on the wholesale markets (see previous sections). In the case of different marginal technologies during the peak and off-peak periods, a weighted average of the fuel costs of these technologies has been calculated, based on the share in total annual power sales during each period (for instance, 55% during the peak and 45% during the off-peak). For instance, the retail power spread

2. Estimation of the carbon costs passed through on retail markets based on the estimated PTRs on related wholesale power markets. This approach assumes that for a specific case (say the Netherlands in 2005) the same rate (or amount) of carbon costs is passed through on both the wholesale and retail power markets. According to this approach, the estimated carbon costs passed through on the retail market during a specific year (for instance, 2006) are assumed to be equal to the annual average of the estimated CO_2 costs passed through on the wholesale market during the peak and off-peak periods of the previous year (2005) weighted by the power sales volumes during these periods.[78]
3. Estimation of the carbon costs passed through on retail markets based on the so-called 'full carbon costs' of the marginal technologies setting the power price. This approach assumes that the costs of these technologies are fully passed through on the retail markets. According to this approach, for each specific case, the estimated carbon costs passed through on the retail market during a specific year (e.g., 2006) are assumed to be equal to the annual average of the CO_2 emission costs of the marginal technologies setting the power price on the wholesale market during the peak and off-peak periods of the previous year (2005) weighted by the power sales volumes of these periods.[79]

The results of the three methodologies outlined above are summarised in Table 4.12, where the three approaches are briefly denoted as 'Retail', 'Wholesale' and 'Full carbon costs', respectively.[80] First of all, the upper part of this table shows the estimated amounts of carbon costs passed through according to these three methodologies. For instance, following the first approach ('Retail'), the amounts of carbon costs passed through to households in Germany are estimated at 1.0 €/MWh in 2005 and 7.7 €/MWh in 2006, while for the large industrial users these costs amount to 0.9 and 11.0 €/MWh, respectively. However, according to the second methodology ('Wholesale'), the estimated amounts are significantly higher for both German households and industrial users, i.e. 4.8 and 9.0 €/MWh in 2005 and 2006, respectively. These amounts are even higher if it is assumed that the carbon costs of the price-setting technologies are fully passed on to these consumers (i.e. following the third, 'full carbon costs' approach). Note that, in general, the estimated amounts of carbon costs passed through to retail power prices are substantially higher in 2006 than in 2005. This is due to the fact that, while the estimates for 2005 are based on year-ahead prices of CO_2 emission allowances in 2004 (to be delivered in 2005) and estimates for 2006 on year-ahead carbon prices in 2005, these prices have been, on average, significantly higher in 2005 than in 2004.

on the retail market for households in the Netherlands amounted to 81.6 €/MWh in 2004 and 86.3 €/MWh in 2006, implying that the assumed carbon costs passed through on this market are equal to the change in the retail power spread over this period, i.e. 4.7 €/MWh.

78 More precisely, in the second approach, the carbon costs passed through on the retail market (D) are equal to the formula: $D = (A_p * B_p * C_p) + (A_o * B_o * C_o)$, where A refers to the estimated pass-through rate on the wholesale market, B to the shares in total annual power sales during the peak and off-peak periods, and C to the carbon costs of the marginal technology setting the price on the year-ahead wholesale market, while the subscripts p and o refer to the peak and off-peak periods, respectively. For instance, assume that for the Netherlands in 2006 (i) the pass-through rates on the wholesale markets during the peak and off-peak periods are estimated at 0.6 and 0.5, respectively, (ii) the shares in total annual power sales during these periods are 55 and 45%, respectively, and (iii) the carbon costs of the marginal technologies setting the price on the year-ahead wholesale market during these periods amount to 6 and 10 €/MWh, respectively, than the carbon costs passed through on the retail market of the Netherlands in 2006 are equal to D = (0.6 * 0.55 * 6 €/MWh) + (0.5 * 0.45 * 10 €/MWh) = 4.2 €/MWh.

79 More precisely, in the third approach, the carbon costs passed through on the retail market (E) are equal to the formula: $E = (B_p * C_p) + (B_o * C_o)$, where the symbols of the right hand of the equation have the same meaning as those mentioned above in the previous note. For example, when taking the same values for the variables as in the previous note, this results in an amount of carbon costs passed through on the retail market equal to E = (0.55 * 6 €/MWh) + (0.45 * 10 €/MWh) = 7.8 €/MWh.

80 See also Figure 4.15, which presents a decomposition of the retail power prices into (a) energy taxes, (b) fuel costs, (c) full carbon costs, and (d) clean spreads, defined as the difference between the 'normal' (or 'dirty') retail power spreads and the full carbon costs of the technologies setting power prices. Hence, by adding the full carbon costs to the clean spreads presented in Figure 4.15, one gets an indication of the absolute levels of these (normal/dirty) spreads in 2004-2006 and the changes of these spreads over this period.

Table 4.12 *Summary of estimated carbon cost pass-through on retail power markets in Germany and the Netherlands, 2005-2006*

	Households				Industry			
	Germany		The Netherlands		Germany		The Netherlands[a]	
	2005	2006	2005	2006	2005	2006	2005	2006
	Estimated amount of carbon costs passed-through [€/MWh]							
Approach:								
• Retail	1.0	7.7	1.6	4.8	0.9	11.0	N.A.	N.A.
• Wholesale	4.8	9.0	5.2	9.9	4.8	9.0	5.2	9.9
• Full carbon costs	9.2	17.4	6.7	12.6	9.2	17.4	6.7	12.6
	Pass-through rate [in% of full carbon costs]							
Approach:								
• Retail	11	44	24	38	10	63	N.A.	N.A.
• Wholesale	52	52	78	78	52	52	78	78
• Full carbon costs	100	100	100	100	100	100	100	100
	Share of carbon costs passed-through [% of retail power prices, including taxes]							
Approach:								
• Retail	1	4	1	2	1	10	N.A.	N.A.
• Wholesale	3	5	3	5	5	9	7	13
• Full carbon costs	5	9	3	6	10	17	9	16
	Share of carbon costs passed-through [% of change in retail power prices, including taxes, compared to 2004]							
Approach:								
• Retail	12	52	13	18	9	60	N.A.	N.A.
• Wholesale	58	62	42	35	63	49	N.A.	N.A.
• Full carbon costs	111	120	53	45	121	95	N.A.	N.A.

a) Some estimates for the Dutch industry are not available since Eurostat data on power prices for large industrial power consumers in the Netherlands are lacking up to 2004.

Subsequently, Table 4.12 presents the estimated PTRs according to the three different methodologies (where the PTR is defined as the estimated amount of carbon costs passed through divided by the full carbon costs of the price-setting technologies, as discussed above). Following the ‘retail’ approach, the PTRs are estimated at 11% in 2005 and 44% in 2006 in case of German households, at 24 and 38%, respectively, for German industry, and at 10 and 63%, respectively, for Dutch households (while similar estimates for Dutch industry are not available since data on power prices for large industrial end-users in the Netherlands are lacking up to 2004). On the other hand, assuming that the PTRs on the retail markets would be similar to the estimated PTRs on the wholesale markets, these rates amount to 52% in Germany and 78% in the Netherlands for both consumer groups in both 2005 and 2006.[81]

[81] Note that the estimated PTRs according to the ‘wholesale’ approach vary by country but are similar in both 2005 and 2006 for both consumer groups in each country. This is due to the assumptions of this approach, notably that (i) for each country, the estimated amount of carbon costs passed through on the wholesale market is equal to the amount of carbon costs passed through on the retail market, regardless whether the electricity is sold to households or industrial consumers, and (ii) the PTRs for the year-ahead wholesale markets in 2004 (i.e. power produced/consumed in 2005) are equal to the PTRs estimated for the forward markets in 2005 (as estimates of year-ahead PTRs for 2004 are lacking). In addition, note that the estimated PTRs according to the ‘wholesale’ approach for Germany and the Netherlands in 2006 (as recorded in Table 6.12) are actually the averages of the estimated PTRs of these countries on the year-ahead power markets during the peak and off-peak periods in 2005 (weighted by the shares of each period in total annual power sales), as recorded in Table 5.1 This follows from the assumption that the carbon costs passed through on the wholesale year-ahead markets in 2005 (with delivery in 2006) are subsequently passed through on the retail markets in 2006.

The results following from the 'retail' approach suggest that the pass-through of CO_2 emission costs on the retail markets in Germany and the Netherlands was rather low in 2005, but increased substantially in 2006. The low figures for 2005 may be due to time-lags in retail price setting or other (marketing) constraints in passing through carbon costs fully or immediately to retail power consumers. The estimated PTRs according to this approach, however, have to be interpreted with due care as they are based on the assumption that changes in retail power spreads result only from changes in carbon costs passed through - and, hence, both changes are equal - but not from changes in other price determinants (besides taxes, fuel costs and carbon costs) such as distribution or marketing costs or growing market scarcities.

Finally, in order to get an indication of the relevance of carbon costs passed through for both the absolute levels of the retail prices and the changes of these prices in Germany and the Netherlands during 2005-2006, the lower part of Table 4.12 presents these costs as a share or percentage of both these absolute levels and price changes. In general, the table shows:

- As the carbon costs passed through on the retail market according to the 'retail' approach are generally much lower compared to either the 'wholesale' approach or - even stronger - the 'full carbon costs' approach, the shares of these costs in (changes of) retail power prices are consequently much lower for the 'retail' approach than the other two methodologies.
- As the retail prices are usually much higher for households than for industrial power consumers, the shares of carbon costs passed through to these prices are consequently much lower for households than for industrial users.
- As the estimated carbon costs passed through on retail markets are generally much higher for 2006 than for 2005, the shares of these costs in (changes of) retail prices are consequently much higher in 2006 than in 2005.
- As short-term changes in retail power prices are usually a minor part of the total or absolute levels of these prices, the shares of carbon costs passed through on retail markets are consequently much higher when expressed as a percentage of the changes in retail prices rather than as a share of the absolute levels of these prices.[82]

More specifically, Table 4.12 shows that when the carbon costs passed through are estimated according to the 'retail' approach the share of these costs in total retail prices is relatively low in 2005-2006, i.e. in general less than 4%. The only exception concerns the case of German industry in 2006, where the carbon costs passed through account for about 10% of the retail power price concerned. Even if one assumes that the full carbon costs are passed through to retail power prices, these costs account generally for only a small part of these prices, although in case of the large industrial power users in both Germany and the Netherlands the share of the full carbon costs in the electricity prices for these consumers amounted to about 16-17% in 2006.

On the other hand, when the (estimated or assumed) carbon costs passed through are expressed as a percentage of the changes in retail power prices, these rates are generally much more significant. For instance, if it is assumed that the changes in the retail power spreads are solely due to the pass-through of carbon costs (i.e. the 'retail' approach), the shares of these costs in the changes of the retail prices in 2005-2006 (compared to 2004) range from 13-18% for Dutch households, 12-52% for German households, and 9-60% for German industry (where the first percentage mentioned refers to 2005 and the second to 2006, see Table 4.12). This implies that the remaining shares of the price changes in these cases can be attributed to changes in fuel costs and/or energy taxes.

[82] Note that in some cases of the 'full carbon costs' approach, the share of carbon costs passed through as a percentage of the changes in retail power price is more than 100%. This may be due to the fact that (i) the carbon costs passed through is actually overestimated by the 'full carbon costs' approach, and/or (ii) the net change in retail power prices is small compared to the carbon costs passed through because (the increase in) these costs are compensated by a decrease in fuel costs or energy taxes.

However, if it is assumed that the carbon costs passed through on the retail market are similar to either the carbon costs passed through on the wholesale market (i.e. the ‘wholesale’ approach) or the full carbon costs of the price-setting technologies (i.e. the ‘full carbon costs’ approach), Table 4.12 shows that the shares of these costs in the retail price changes are usually much higher.

To conclude, if it is assumed that over the period 2004-2006 changes in the retail power spreads - defined as retail power prices excluding taxes and fuel costs - are solely due to carbon costs passed through, the impact of the EU ETS on (changes in) retail power prices was still relatively low in 2005 due to relatively low year-ahead carbon prices in 2004 and, perhaps, some time-lags or other (marketing) constraints in passing through these costs to retail prices. In 2006, however, this impact seems to be already more significant, notably in Germany, due to relatively higher forward carbon prices in 2005 and, presumably, an increasing share of carbon costs passed through. Moreover, if it is assumed that the carbon costs passed through on the retail market are similar to either the carbon costs passed through on the wholesale market or the full carbon costs of the price-setting technologies, the impact of these costs - and, hence, of the EU ETS - on retail power prices becomes generally even more significant. These findings, however, have to be treated with due care as, to some extent, they depend on the assumptions made to estimate the carbon costs passed through, in particular the assumption that the changes in the retail power prices over the period 2004-2006 are solely due to changes in taxes, fuel costs and carbon costs and, therefore, that other determinants of these prices - such as distribution/marketing costs or the incidence of market scarcity/power - have been stable over this period.

5. Major results of the COMPETES model analyses

This chapter discusses the major results of the COMPETES model analyses of the implications of emissions trading for the performance of the wholesale power market in 20 European countries. First of all, Section 5.1 provides a brief description of the COMPETES model (whereas a more detailed description is included in Appendix D). Subsequently, Section 5.2 discusses the major characteristics of the COMPETES model scenarios distinguished for the present study. Finally, Section 5.3 presents the major results of the COMPETES model analyses with regard to the following topics:

- Power prices
- Carbon cost pass-through
- Power sales
- Power trade
- Carbon emissions
- Power generators' profits

5.1 Brief model description

In order to analyse the performance of wholesale electricity markets in European countries, ECN has developed the so-called COMPETES model.[83] The present version of the model covers twenty European countries, i.e. Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom.

In the COMPETES model, the representation of the electricity network is aggregated into one node per country, except for Germany and Luxembourg, which are joined into one nod, while Denmark is divided into two nods belonging to two different, non-synchronised networks (i.e. East and West Denmark). Virtually all individual power companies and generation units in the 20 countries - including combined heat and power (CHP) plants owned by industries or energy suppliers - are covered by the input data of the model and assigned to one of these nodes. The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e., the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe'.

The COMPETES model is able to simulate the effects of differences in producer behaviour and wholesale market structures, including perfect versus oligopolistic competition. The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of power sales (market prices multiplied by total sales) minus the costs of generation and - if sale is not at the node of generation - transmission. Costs of generation are calculated by using the short-run marginal cost (i.e., fuel and other variable costs). Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model.

The model considers 12 different periods or levels of power demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The 'super peak' period covers 240 hours per annum, con-

[83] 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. For a more extensive description of this model, see Appendix A of the present report.

sisting of the 120 hours with the highest sum of power loads for the 20 considered countries during spring/fall and 60 hours each in winter and summer. The other three periods represent the rest of the seasonal load duration curve covering equal numbers of hours during each period and season. Altogether, the 12 periods include all 8760 hours of a year. Power consumers are assumed to be price sensitive by using decreasing linear demand curves depending on the electricity price. The number and duration of periods and the price elasticity of power demand in different periods are user-specified parameters.

5.2 The COMPETES model scenarios

5.2.1 Major scenario definitions

In order to analyse the implications of CO_2 emissions trading for electricity prices under different assumptions regarding power market structure and price responsiveness of electricity demand, different scenarios have been assessed by means of the COMPETES model. The acronyms and assumptions of each scenario are summarised in Table 5.1.

Table 5.1 *Summary of COMPETES model scenarios*

Scenario acronym	CO_2 price [€/t]	Elasticity	Description
REF	20	0.0	Reference scenario: Perfect competition with fixed demand
OCe0.1c20	20	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c20	20	0.2	Oligopolistic competition with EdF price taker in France
PCe0c0	0	0.0	Perfect competition with fixed demand at REF level
PCe0.2c0	0	0.2	Perfect competition
OCe0.1c0	0	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c0	0	0.2	Oligopolistic competition with EdF price taker in France
PCe0c40	40	0.0	Perfect competition with fixed demand at REF level
PCe0.2c40	40	0.2	Perfect competition
OCe0.1c40	40	0.1	Oligopolistic competition with EdF price taker in France
OCe0.2c40	40	0.2	Oligopolistic competition with EdF price taker in France

The reference scenario (REF) concerns an assumed situation of perfect competition and fixed power demand on the wholesale markets of European countries. It is based on a carbon price of 20 €/tCO_2 (comparable to the average EUA price in 2005-2006). The reference scenario has been calibrated to the level of power demand in 2006, while model outcomes in terms of wholesale prices and carbon emissions are quite close to actual realisations in 2006.

To assess the influence of market structure on CO_2 cost pass-through, two stylistic ('extreme') cases are considered, namely perfect competition (indicated by the acronym PC) and oligopolistic competition (indicated by OC) where the French company Electricité de France (EdF) is assumed not to be able to exercise market power in France due to regulatory threat, whereas all other non-fringe firms fully exercise market power in all markets in which they operate.

To analyse the impact of demand response to the CO_2 cost-induced changes in power prices, different levels of demand elasticity have been assumed. For most scenarios, a price elasticity of

0.2 has been taken (indicated by e0.2 in the acronyms of the scenarios).[84] This may be justified as the demand response in the medium or long term.[85] For the short term, however, a price elasticity of 0.2 may be considered too high because it is usually hard to reduce power consumption in the short run. Hence, some scenarios with lower elasticities or zero elasticities have been considered as well, namely 0.1 for the oligopolistic competition scenarios (indicated by e0.1 in the acronyms of the scenarios) and 0 - i.e. fixed load demand - for the perfect competition scenarios (indicated by e0 in the acronyms of the scenarios).

To study the implications of emissions trading for power prices, an exogenously fixed CO_2 price has been considered at three different levels: 0, 20 and 40 €/tCO_2 (indicated by c0, c20 and c40 in the acronyms of the scenarios). The COMPETES model has not yet been extended to include CO_2 costs endogenously. This model feature of an exogenously fixed carbon price implies that power producers are assumed to be price takers on the EU CO_2 allowance market, i.e. they are assumed to be unable to influence the price of an EUA.

In addition, it is assumed that power producers regard the costs of CO_2 allowances as 'opportunity costs', regardless of whether they purchase the allowances or get them for free. Hence, they add these costs to their other marginal costs when making production or trading decisions (following economic theory and sound business principles). Therefore, the pass-through rate in the sense of the extent to which carbon costs are included to or added to the other marginal costs is by definition (or default) 100% in the COMPETES model. However, the extent to which CO_2 allowances costs ultimately affect power market prices may differ from 100% due to a variety of reasons such as a change in the merit order, demand response, market structure, etc.

Based on the REF scenario, four additional perfect competition (PC) scenarios are derived by setting the carbon costs at 0 and 40 €/tCO_2 and by assuming either fixed demand or a demand elasticity of 0.2. In addition, six oligopolistic (OC) scenarios are derived by assuming a carbon cost of 0, 20, and 40 €/tCO_2, combined with a demand elasticity of either 0.1 or 0.2.

The results of the COMPETES model analyses are presented not only in an absolute sense for each scenario separately but also by providing the difference between two scenarios. More specifically, to gain insight in the effect of the CO_2 allowance costs on power market performance, the difference in outcome between the scenario with and without CO_2 allowance cost is studied for the same market structure (perfect or oligopolistic competition) and price elasticity of power demand. These differences between these scenarios are indicated by acronyms such as PCe0Δ20 or OCe0.2Δ40, where - for instance - PCe0Δ20 refers to the difference in outcome between the perfect competition scenarios with and without a carbon price of 20 €/tCO_2, assuming fixed demand, i.e. a price elasticity of 0 in both scenarios.

The COMPETES analyses focus on the extent to which the opportunity costs of CO_2 allowances affect power prices (and related issues such as power demand and carbon emissions). By comparing the results of the scenarios, the impact of emissions trading on power prices (and related issues) has been analysed under different assumptions of market structure, demand response and CO_2 prices (including resulting changes in the merit order of the power supply curve). These results are discussed in Section 2.3 below.

5.2.2 The reference scenario

The reference scenario (REF) has been calibrated to the level of power demand in 2006. In order to judge the reality performance of the reference scenario (and, more generally, of the

[84] Although the sign of the price elasticity of power demand is usually negative (e.g. -0.1 or -0.2), for convenience we express them as absolute values (i.e. as 0.1 or 0.2).

[85] Note that COMPETES covers the wholesale power market only. In response to a price increase, certain power-intensive users may shift to self-production, which reduces demand/supply on the wholesale market.

COMPETES model as a whole), this section presents a comparison between actual realisations in 2006 and reference model scenario outcomes in terms of electricity prices and carbon emissions.

The electricity prices in the reference (perfect competition) scenario are assumed to be equal to the sum of the marginal (fuel and carbon) costs of generating power. Figure 5.1 compares these reference prices with the actual, average spot prices in 2006 for the nine EU countries analysed empirically in the previous chapter. These countries represent 80% of the total power sales in the 20 European countries covered by the COMPETES model and, hence, are quite representative to test the model calibration in terms of electricity prices.

Figure 5.1 indicates that in terms of power prices, the model reference outcomes compare generally well to the actual realisations in 2006. For five of the nine countries the difference is less than 5%, for France and the UK the REF prices are about 10 €/MWh lower than average spot prices, whereas for Poland and Spain the REF prices are about 10 €/MWh higher. An explanation for these deviations is that the model reference scenario assumes liberalised electricity markets with no market power, no regulation and free trade among countries within their transmission constraints. In reality, however, EU power markets in 2006 were to some extent still characterised by the incidence of market power, regulation and trade restrictions affecting power prices.

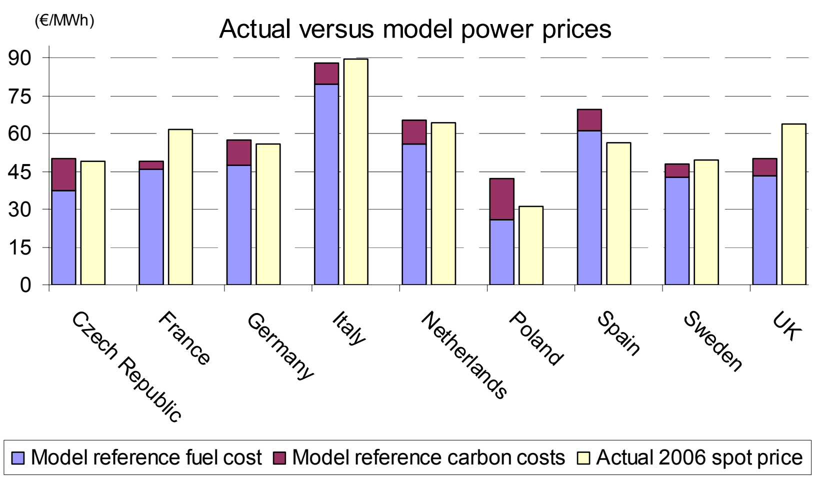


Figure 5.1 *A comparison of COMPETES model reference power prices with actual, average spot prices in 2006 for selected EU countries*

Figure 5.2 compares the estimated CO_2 emissions of the COMPETES reference scenario to the actual emissions of the power sector for 15 countries in 2005. These countries represent 82% of the total CO_2 emissions in the power sector of the 20 European countries covered by COMPETES and, hence, are quite representative to test the model calibration in terms of CO_2 emissions.

Figure 5.2 indicates that for most countries the COMPETES reference scenario emissions compare relatively well to the actual emissions in 2005. For Germany and the UK, the reference emissions are respectively 17% and 27% lower than the actual 2005 emissions, while in Italy the model emissions are about 19% higher.

The deviations between model estimates and actual emissions can be due to specific assumptions regarding the reference scenario such as the assumption of (fully) liberalised, competitive electricity markets across the EU (as discussed above). Another explanation for these deviations refers to the assumed (fixed, annual average) relative fuel prices affecting fuel switch and, hence, related emissions in the power sector, notably in a country where the opportunities for fuel switch are relatively large and depend critically on (daily) changes in these prices, such as in Germany or the UK.

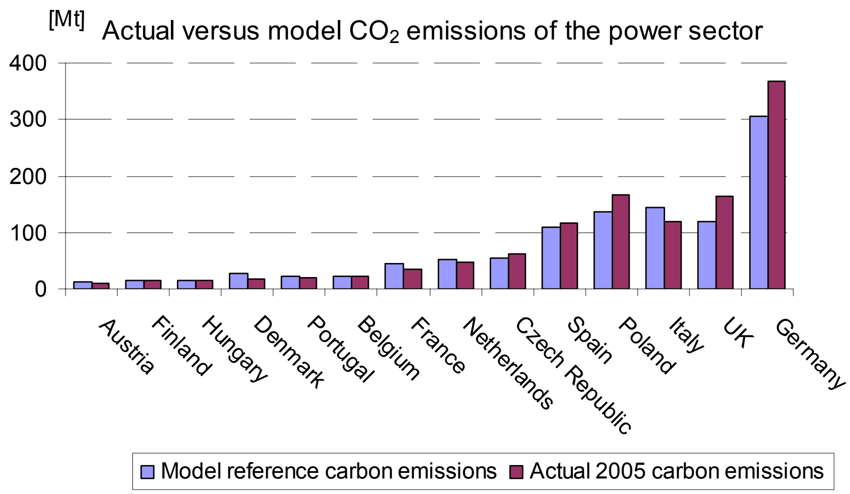


Figure 5.2 *A comparison of COMPETES model reference CO_2 emissions with actual 2005 emission in the power sector of selected EU countries*

5.3 Model results

In the sections below, the major results of the COMPETES model analyses of the implications of CO_2 emissions trading for the power sector are discussed, in particular the effects on whole-sale power prices, sales, trade, carbon emissions and generators' profits in the 20 European countries covered by the model (indicated as the 'EU-20').[86] These effects are assessed at two different EUA price levels, i.e. 20 and 40 €/tCO_2.[87]

Beforehand, however, some model characteristics should be mentioned (see also Appendix D). First, COMPETES is a static, medium-term model and hence, it is not able to assess dynamic changes - i.e. new investments - in generation capacity in the long run. Second, COMPETES is based on the assumption that power producers include the (full) opportunity costs of emissions trading in their bidding prices, regardless of the allocation method. Moreover, while COMPETES is able to assess quantitatively the implications of either auctioning or perfect free allocations at different EUA prices, it is not able to analyse the effects of specific free allocation provisions to incumbents, plant closures or new entrants. Therefore, at a certain carbon price level, the COMPETES model results are similar in terms of the impact of the EU ETS on the power sector, regardless of the allocation method. The major exception concerns the impact on generators' profits, as illustrated below.

5.3.1 Power prices

For all scenarios and countries considered, Table 5.2 presents estimates of the impact of CO_2 emissions trading on power prices, while Table 5.3 and Table 5.4 show the absolute and proportional changes in these prices (in €/MWh and%, respectively). By comparing these scenarios

[86] Although Norway and Switzerland are not part of the European Union (EU), for convenience the expression EU-20 is used to indicate the total of 20 countries included in the COMPETES model.

[87] The price level of 20 €/tCO_2 is representative for the average EUA price during the first years of the EU ETS (2005-2006), while the level of 40 €/tCO_2 is representative for the expected EUA price during the (end of) the third phase.

and countries, the most striking results recorded by these tables include (see also Figure 5.3, which shows ETS-induced increases in power prices in selected EU countries under two different COMPETES model scenarios):

Table 5.2 *Wholesale power prices in EU countries under various COMPETES model scenarios [€/MWh]*

	Perfect Competition (PC)				
CO_2 price [€/tCO_2]	0	0	20	40	40
Demand elasticity	0	0.2	n/a	0	0.2
Scenario acronym[a]	PCe0c0	PCe0.2c0	REF	PCe0c40	PCe0.2c40
Austria	50.9	54.7	65.9	80.5	78.0
Belgium	54.3	55.7	65.4	79.1	77.7
Czech Republic	35.3	37.1	50.3	67.7	66.6
Denmark	40.7	43.3	55.9	72.1	70.6
Finland	38.2	40.7	51.2	64.8	60.8
France	38.4	42.1	49.1	60.1	57.6
Germany	42.2	43.5	57.3	73.5	72.1
Hungary	55.5	55.8	64.7	74.8	72.9
Italy	70.2	75.8	88.3	100.8	98.3
Netherlands	54.2	55.4	65.5	79.4	78.0
Norway	32.6	35.7	42.6	53.7	49.1
Poland	23.1	23.1	42.0	60.9	60.9
Portugal	61.4	63.9	72.1	86.1	85.0
Slovakia	35.4	37.5	50.2	67.6	70.7
Slovenia	46.4	50.0	60.7	74.6	66.5
Spain	58.8	59.9	69.5	83.7	81.9
Sweden	36.0	39.2	47.8	60.6	56.5
Switzerland	48.2	51.0	63.7	79.5	76.8
UK	39.5	40.5	50.0	66.7	66.1
EU-20	45.6	47.9	58.8	73.0	71.1

	Oligopolistic competition (OC)					
CO_2 price [€/tCO_2]	0	0	20	20	40	40
Demand elasticity	0.1	0.2	0.1	0.2	0.1	0.2
Scenario acronym[a]	OCe0.1c0	OCe0.2c0	OCe0.1c20	OCe0.2c20	OCe0.1c40	OCe0.2c40
Austria	84.1	75.1	94.5	85.1	104.3	95.8
Belgium	220.9	132.8	225.1	138.6	227.2	141.5
Czech Republic	144.6	90.5	155.0	101.2	165.4	111.7
Denmark	92.3	70.5	100.3	79.9	109.6	90.2
Finland	52.8	45.8	58.5	53.9	68.1	64.3
France	42.3	40.8	51.0	48.4	58.4	55.9
Germany	87.4	66.1	100.8	78.8	114.4	91.5
Hungary	69.5	65.0	79.6	74.5	90.6	85.1
Italy	152.2	115.6	164.3	128.0	176.0	138.0
Netherlands	126.6	92.3	136.2	101.1	145.4	109.7
Norway	53.3	39.5	54.4	41.5	56.0	44.4
Poland	23.1	23.1	42.0	42.0	60.9	60.9
Portugal	147.3	101.5	159.2	112.0	169.6	122.6
Slovakia	140.7	87.8	151.0	100.7	162.1	110.9
Slovenia	47.1	44.5	57.4	52.8	68.9	63.8
Spain	113.2	83.6	123.8	93.4	133.9	103.5
Sweden	72.5	53.6	75.5	59.1	79.7	65.6
Switzerland	100.8	76.1	111.8	86.1	123.2	96.7
UK	51.0	43.2	61.4	53.2	72.2	68.3
EU-20	85.6	65.8	95.9	75.9	106.1	86.4

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cX to the CO_2 price.

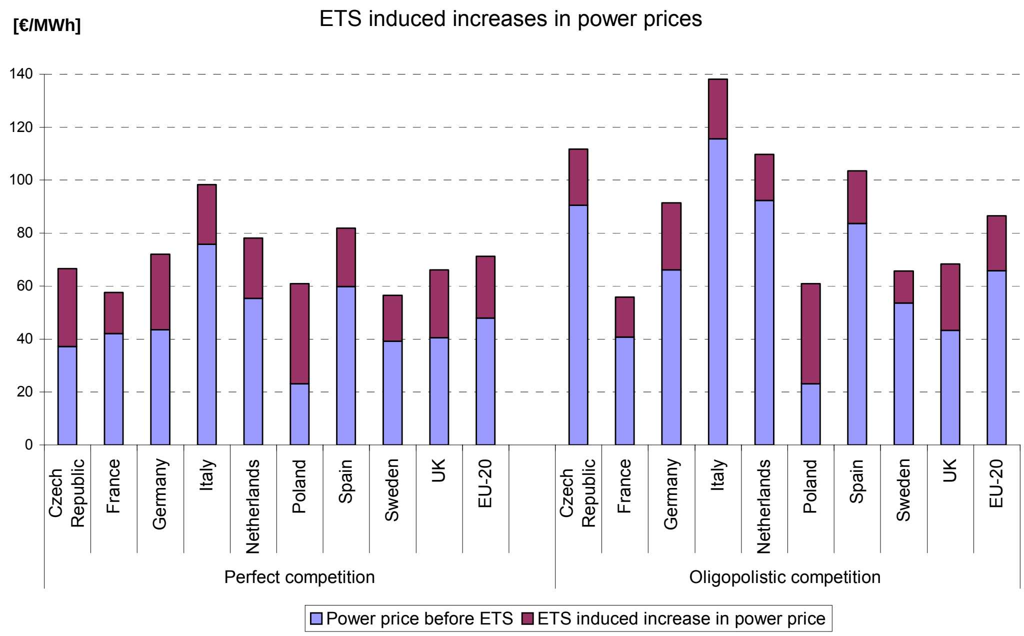


Figure 5.3 *ETS-induced increases in power prices in EU countries under two COMPETES model scenarios*

Note: Both scenarios are based on a carbon price of 40 €/tCO_2 and a price elasticity of power demand of 0.2.

- For a given carbon price and demand elasticity, electricity prices are significantly higher under the oligopolistic competition (OC) scenarios than under the perfect competition (PC) scenarios. The major exception concerns France for which it is assumed that in the OC scenarios, the dominant company - Electricité de France (EdF) - is a price taker in its home country, i.e. due to regulatory threat it is not able to exercise market power in order to raise electricity prices in France.
- For a given carbon price and power market structure, electricity prices are substantially higher under lower demand elasticity scenarios, notably in the case of oligopolistic competition, demonstrating the relation between price elasticity of power demand and the ability to exercise market power to increase electricity prices.
- In the perfect competition scenarios before emissions trading (PCc0), electricity prices are generally lowest in Poland while highest in Italy. Since prices in these scenarios are set by marginal (fuel) costs, this is due to differences in fuel mix in these countries. Whereas electricity prices are set largely by coal in Poland, they are set by gas in Italy during a major part of the year, in particular during the peak period.[88]
- In the oligopolistic competition scenarios before emissions trading (OCc0), electricity prices are generally lowest in Poland and highest in Belgium. Since prices in these scenarios are determined largely by the incidence of market power, this is due to differences in market structure and (assumed) producer behaviour in these countries. Whereas the level of market concentration - i.e. the potential to exercise market power - is relatively high in Belgium (where one company - i.e. Electrabel - owns about 85% of total generation capacity), it is relatively low in Poland due to the relatively high share of the competitive fringe in Poland.[89]

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[88] See Appendix D, notably Figure D.3, for the differences in technology mix of power generation in the EU-20 countries of the COMPETES model.

[89] See Appendix D, particularly Table D.1, for an overview of the generation capacity and market shares of the major power companies and competitive fringes in the EU-20. Note that although the level of market concentration in France is very high (due to the dominance of EdF), French power prices are relatively low in the OC scenarios. This results from the modelling assumption that in France, due to regulatory threat, EdF is not able to raise electricity prices by exerting market power.

Table 5.3 *ETS-induced changes in wholesale power prices in EU countries under various COMPETES model scenarios [€/MWh or%]*

	Perfect Competition (PC)				Oligopolistic Competition (OC)			
ΔCO_2 price [€/tCO_2]	20	20	40	40	20	20	40	40
Demand elasticity	0	0.1	0	0.1	0.1	0.2	0.1	0.2
Acronym[a]	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40	OCe0.1Δ20	OCe0.2Δ20	OCe0.1Δ40	OCe0.2Δ40
Austria	15.1	11.2	29.6	23.3	10.4	10.0	20.3	20.8
Belgium	11.1	9.8	24.9	22.1	4.2	5.8	6.3	8.8
Czech Republic	14.9	13.1	32.4	29.5	10.4	10.7	20.9	21.2
Denmark	15.3	12.7	31.5	27.4	8.0	9.4	17.3	19.7
Finland	13.0	10.5	26.6	20.1	5.8	8.1	15.3	18.6
France	10.7	7.0	21.7	15.5	8.7	7.6	16.1	15.1
Germany	15.1	13.9	31.3	28.6	13.4	12.7	27.1	25.3
Hungary	9.3	8.9	19.4	17.1	10.1	9.6	21.1	20.1
Italy	18.1	12.5	30.6	22.5	12.1	12.4	23.8	22.5
Netherlands	11.3	10.1	25.2	22.7	9.6	8.8	18.9	17.4
Norway	10.1	6.9	21.1	13.4	1.1	1.9	2.6	4.8
Poland	18.9	18.9	37.8	37.8	18.9	18.9	37.8	37.8
Portugal	10.7	8.2	24.7	21.1	11.8	10.5	22.2	21.1
Slovakia	14.8	12.7	32.2	33.1	10.3	12.9	21.4	23.1
Slovenia	14.3	10.7	28.2	16.5	10.4	8.3	21.9	19.3
Spain	10.8	9.6	24.9	22.0	10.6	9.7	20.7	19.9
Sweden	11.8	8.7	24.6	17.3	3.0	5.6	7.1	12.1
Switzerland	15.5	12.7	31.4	25.9	11.0	10.0	22.4	20.6
UK	10.5	9.5	27.2	25.6	10.4	10.0	21.2	25.1
EU-20	13.2	10.9	27.4	23.3	10.3	10.1	20.5	20.7

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

- In all comparable scenarios - i.e. those with a similar demand elasticity and market structure - power prices increase significantly due to emissions trading. Under perfect competition (PC), the price increases in absolute terms - i.e. in €/MWh - are generally highest in Poland and lowest in France/Hungary. For instance, depending on the assumed demand elasticity, the increase in power prices due to an EUA price of 20 €/tCO_2 amounts to about 19 €/MWh in Poland and to some 9 €/MWh in Hungary (Table 5.3). These differences in ETS-induced price increases among countries are due to (i) differences in carbon intensity of the (existing) price-setting generation units in these countries, and/or (ETS-induced shifts in the merit order of the power generation technologies.
- Under oligopolistic scenarios, however, the absolute increases in power prices due to emissions trading are generally lower than comparable perfect competition scenarios, notably in Belgium and Scandinavian countries such as Finland, Norway or Sweden(see Table 5.3). Given the COMPETES model assumption of linear, downward sloping demand curves, this results from the (expected) lower pass-through rate of carbon costs to power prices under these market conditions, i.e. oligopolistic competition with linear, elastic demand (see also next section as well as Section 2.2).[90] Note, however, that despite generally higher price increases due to emissions trading under PC, power prices affected by emissions trading are still far lower in absolute terms under PC than OC (Table 5.2).

[90] In addition, it may result from the fact that power demand is generally lower under OC than PC due to the responsiveness to higher prices under OC. This lower demand may be met by either a higher or a lower carbon intensive plant setting the power price (compared to a situation of PC). Therefore, the resulting difference in carbon cost pass-through due to this factor may either enhance or (over)compensate the effect of the lower pass-through rate under OC discussed in the main text.

Table 5.4 ETS-induced changes in wholesale power prices in EU countries under various COMPETES model scenarios [%]

	Perfect Competition (PC)				Oligopolistic Competition (OC)			
ΔCO_2 price [€/tCO_2]	20	20	40	40	20	20	40	40
Demand elasticity	0	0.1	0	0.1	0.1	0.2	0.1	0.2
Acronym	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40	OCe0.1Δ20	OCe0.2Δ20	OCe0.1Δ40	OCe0.2Δ40
Austria	30	21	58	43	12	13	24	28
Belgium	21	18	46	40	2	4	3	7
Czech Republic	42	35	92	79	7	12	14	23
Denmark	38	29	77	63	9	13	19	28
Finland	34	26	70	49	11	18	29	41
France	28	17	56	37	21	19	38	37
Germany	36	32	74	66	15	19	31	38
Hungary	17	16	35	31	15	15	30	31
Italy	26	16	44	30	8	11	16	19
Netherlands	21	18	46	41	8	9	15	19
Norway	31	19	65	38	2	5	5	12
Poland	82	82	164	164	82	82	164	164
Portugal	17	13	40	33	8	10	15	21
Slovakia	42	34	91	88	7	15	15	26
Slovenia	31	21	61	33	22	19	46	43
Spain	18	16	42	37	9	12	18	24
Sweden	33	22	68	44	4	10	10	23
Switzerland	32	25	65	51	11	13	22	27
UK	27	24	69	63	20	23	42	58
EU-20	29	23	60	49	12	15	24	31

- In proportional terms, the differences in power price increases due to emissions trading are even larger between comparable PC and OC scenarios.[91] For instance, under PC and an EUA price of 40 €/tCO_2, these increases vary - depending on the assumed demand elasticity - between 31-35% for Hungary and between 66-74% for Germany, while they amount to 164% in Poland.[92] On the other hand, under OC and a similar carbon price, these ranges in proportional price increases amount to 3-7% for Belgium and 31-38% for Germany, while in Poland these increases are similarly high under OC than PC(i.e. 164%; see Table 5.4). These differences in proportional power price increases between PC and OC scenarios are partly due to the (slightly) lower absolute amounts of carbon costs passed through under OC market conditions (as discussed above) but mainly due to the higher absolute power prices under OC before emissions trading (to which the lower pass-through amounts are related).
- As expected, in all comparable scenarios - i.e. those with a similar carbon price and market structure - wholesale electricity prices are generally lower in scenarios with a higher price elasticity of power demand (Table 5.2). Moreover, in comparable PC scenarios with relatively higher demand elasticity, increases in power prices due to emissions trading are also lower in both absolute and proportional terms (Table 5.3 and Table 5.4). In comparable OC scenarios with relatively higher demand elasticity, however, these increases may be either higher or lower in absolute/proportional terms.[93]

[91] Note that these proportional changes refer to wholesale power prices. As retail power prices are generally 2-3 times higher than wholesale prices - while the amount of carbon cost passed through is assumed to be more or less similar in the long run - the relative increase in retail power prices is evidently proportionally lower.

[92] The reason why the proportional increase in power prices is so high in Poland is due to two factors: (i) the ETS-induced increase in power prices - i.e. the nominator of the equation - is relatively high due to the high carbon intensity of the marginal technology (coal), and (ii) the relatively low power prices before emissions trading (i.e. the denominator of the equation).

[93] The latter case is due to the fact that sometimes the ETS-induced increase in power prices - i.e. the numerator of the equation - in OC scenarios with higher demand elasticity are relatively larger than the related power price before emissions trading (i.e. the denominator of the equation). In addition, it is occasionally due to the fact that the ETS-induced increases in power prices are higher in OC scenarios with relatively higher demand elasticities (as explained in note 87).

Table 5.5 *ETS-induced changes in marginal CO_2 costs of power generation in EU countries under various COMPETES model scenarios [€/MWh]*

	Perfect Competition (PC)				Oligopolistic Competition (OC)			
ΔCO_2 price [€/tCO_2]	20	20	40	40	20	20	40	40
Demand elasticity	0	0.2	0	0.2	0.1	0.2	0.1	0.2
Acronym	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40	OCe0.1Δ20	OCe0.2Δ20	OCe0.1Δ40	OCe0.2Δ40
Austria	14.52	14.52	25.76	26.12	15.53	15.77	29.90	31.45
Belgium	10.60	10.60	28.73	30.86	9.50	12.86	7.13	12.72
Czech Republic	14.16	14.16	34.82	37.11	18.42	19.34	35.49	38.59
Denmark	15.88	15.88	31.85	32.08	16.78	17.18	36.99	36.81
Finland	13.35	13.35	27.63	22.17	11.00	16.31	25.41	27.38
France	12.56	12.56	22.83	23.28	16.99	16.81	20.97	19.98
Germany	16.03	16.03	33.50	34.62	20.04	16.47	40.00	38.46
Hungary	9.54	9.54	22.54	25.97	7.11	8.73	13.02	23.61
Italy	13.13	13.13	26.21	25.50	16.35	12.88	23.19	28.24
Netherlands	10.84	10.84	28.71	30.38	10.71	10.88	23.02	21.98
Norway	11.27	11.27	23.33	24.67	0.00	4.17	0.00	9.20
Poland	18.90	18.90	37.80	37.80	18.90	18.90	37.80	37.80
Portugal	11.99	11.99	29.46	30.13	17.55	18.18	34.14	33.02
Slovakia	13.34	13.34	34.94	37.19	15.75	14.52	32.12	25.28
Slovenia	12.90	12.90	24.31	25.25	16.36	17.13	32.67	32.55
Spain	12.14	12.14	29.88	29.89	16.05	13.61	32.29	30.80
Sweden	13.06	13.06	26.86	26.26	1.43	6.65	7.17	22.88
Switzerland	16.65	16.65	30.98	33.86	12.34	18.10	26.72	35.37
UK	17.50	17.50	35.01	33.45	4.70	9.50	12.16	30.12
EU-20	14.07	14.07	29.34	29.52	13.85	13.92	24.76	28.29

5.3.2 Carbon cost pass-through

Table 5.5 provides estimates of the marginal CO_2 costs of power generation due to emissions trading in the EU-20 countries under various COMPETES model scenarios. Three major observations can be noted:

- For the countries considered, the marginal carbon costs of power production are generally highest in Germany and Poland, while they are lowest in Belgium and Hungary. These differences between countries are due to differences in the carbon intensities of the generation units setting the price during the various load periods considered in COMPETES.
- For all countries considered, the marginal carbon costs of comparable cases - i.e. scenarios with similar market structures and demand elasticities - are higher if the allowance price per tonne CO_2 is higher. At first sight, this link between higher CO_2 prices and higher marginal carbon costs seems logic, but is not necessarily so: if the CO_2 price increases, power demand may decrease or the merit order of the supply curve may shift, resulting in another unit setting the price. If this unit is less carbon intensive, the marginal carbon costs may decrease - or even become 0 - if the CO_2 price rises.
- For a certain carbon price, however, the marginal carbon costs may be either higher or lower for comparable cases, i.e. cases with similar market structures or with similar demand elasticities (for instance, 0.2 under both PC and OC). This is due to ETS-induced changes in the merit order and/or differences in power demand under similar market structures.[94]

In addition, Table 5.6 presents estimates of the marginal carbon cost pass-through rate (PTR) under various COMPETES model scenarios. This rate is defined as the ETS-induced change in

[94] Note that for each country the marginal costs are similar in the cases PCe0.0cΔ20 and PCe0.0cΔ40 (see Table 5.5). This is due to the fact that in the reference scenario (PC with fixed demand and a carbon price of 20 €/tCO_2) the marginal units setting the price of electricity and, hence, the marginal costs of power generation are similar, while in the PC scenarios without emissions trading the carbon costs are also similar - i.e. equal to 0 - regardless of the units setting the price.

power price relative to the CO_2 allowance costs of the marginal generation unit setting the power price:

$$PTR = \Delta \text{ power price} / \Delta \text{ marginal } CO_2 \text{ allowance costs} \quad (7.1)$$

The numerator, Δ power price, is the power price differential between the scenarios with and without emissions trading. The denominator, on the other hand, refers to the change in CO_2 allowance costs per MWh of the marginal production unit setting the power price (where the allowance costs are zero in the case without emissions trading).

The absolute values of the numerator and denominator for the various scenarios and countries considered have been recorded in Table 5.3 and Table 5.5, respectively. Hence, the relative values or pass-through rates (PTRs) of Table 5.6 have been obtained by dividing these respective absolute values.

Table 5.6 *Estimates of pass-through rates of carbon costs to power prices in EU countries under various COMPETES model scenarios*

	Perfect Competition (PC)				Oligopolistic Competition (OC)			
ΔCO_2 price [€/tCO_2]	20	20	40	40	20	20	40	40
Demand elasticity	0	0.2	0	0.2	0.1	0.2	0.1	0.2
Acronym	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40	OCe0.1Δ20	OCe0.2Δ20	OCe0.1Δ40	OCe0.2Δ40
Austria	0.98	0.74	1.09	0.82	0.65	0.65	0.68	0.66
Belgium	1.18	0.99	0.89	0.71	0.54	0.51	1.09	0.80
Czech Republic	1.01	0.89	0.89	0.74	0.51	0.52	0.54	0.52
Denmark	0.89	0.64	0.94	0.75	0.47	0.53	0.45	0.51
Finland	0.94	0.62	0.95	0.83	0.63	0.49	0.61	0.66
France	0.97	0.65	1.07	0.73	0.58	0.46	0.87	0.78
Germany	0.87	0.75	0.89	0.77	0.67	0.76	0.68	0.65
Hungary	1.01	0.98	0.88	0.71	1.41	1.04	1.60	0.83
Italy	1.22	0.93	1.11	0.92	0.70	0.84	1.01	0.73
Netherlands	1.10	0.99	0.88	0.75	0.95	0.84	0.83	0.81
Norway	0.93	0.52	0.95	0.56	n.a.	0.57	n.a.	0.60
Poland	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Portugal	1.00	0.83	0.88	0.72	0.64	0.56	0.63	0.61
Slovakia	1.06	0.91	0.88	0.73	0.60	0.80	0.61	0.84
Slovenia	1.01	0.80	1.05	0.83	0.64	0.50	0.66	0.61
Spain	1.00	0.89	0.88	0.76	0.62	0.63	0.61	0.60
Sweden	0.93	0.57	0.95	0.66	2.16	0.87	1.06	0.52
Switzerland	0.90	0.67	1.01	0.69	0.88	0.48	0.84	0.52
UK	0.56	0.53	0.78	0.79	2.26	1.13	1.70	0.84
EU-20	0.93	0.75	0.94	0.78	0.75	0.71	0.83	0.71

Some of the major observations from Table 5.6 include:

- For all cases considered, most PTRs range between 0.5 and 1.0. The estimates of the PTRs are based on the assumption that the opportunity costs of emissions trading are included (fully) in the bidding prices - and other operational decisions - of power producers, regardless of the allocation method. Hence, differences in PTRs are due solely to differences in market structures, differences in demand elasticities and/or ETS-induced changes in the merit order of the marginal units setting the price in various load periods distinguished by COMPETES.
- According to economic theory, the PTR in the case of PC and fixed demand should be 1.0, while in the case of OC with linear responsive demand it should be lower than 1.0. Table 5.6, however, shows that in almost all PC cases with fixed demand, the PTR deviates from 1.0, while in some OC cases the PTR is (significantly) higher than 1.0. The reason for these de-

viations is that in the case of an ETS-induced change in the merit order the PTR may be either higher or lower than 1.0, even under PC with fixed demand, depending on whether the price setting technology shifts from either a high-CO_2 to a low-CO_2 marginal unit or vice versa (see Section 2.2.6). Hence, the deviations mentioned above indicate that at least during one of the load periods considered by COMPETES the merit order has shifted due to a change in the carbon price.[95]

- As predicted by basic economic theory, in the case of linear price responsive power demand, PTRs are usually lower under OC than PC scenarios with similar carbon prices and demand elasticities (Section 2.2). In addition, as predicted, under scenarios with similar carbon prices and market structures, PTRs are lower if demand elasticities are higher. Table 5.6, however, shows that there are some exceptions to these general, basic statements (e.g., for Belgium or France, the PTR is higher under OCe0.2cΔ40 than PCe0.2cΔ40, while for Germany the PTR is higher under OCe0.2cΔ20 than under OCe0.1cΔ20). The reason for these exceptions is a shift in the merit order during at least one of the load periods considered by COMPETES.

5.3.3 Power sales

Table 5.7 and Table 5.8 provide data on total power sales in EU countries under various COMPETES model scenarios. Under perfect competition (PC), total power sales remain fixed at the same level if the price elasticity of power demand is 0 (i.e. fixed demand), regardless of the level of the CO_2 price and its impact on electricity prices. On the other hand, if power demand responds to changes in electricity prices - under either PC or OC scenarios - total power sales decline when increases in the carbon price are passed through to electricity prices (see also Figure 5.4).

In addition, however, the following observations and qualifications can be made by comparing the results for individual scenarios and countries recorded in Table 5.7 and Table 5.8:

- As expected, under price responsive scenarios with similar market structures (i.e. either PC or OC), the decrease in power sales is higher if the carbon price is higher and/or the price elasticity of power demand is higher. Moreover, under price responsive scenarios with similar demand elasticities - e.g. 0.1 under both PC and OC - and similar carbon prices, i.e. either 20 or 40 €/tCO_2, the decline in power sales is usually higher under PC than OC. This is due to the fact that under linear, price-responsive demand, the pass-through of carbon costs to electricity prices is generally higher under PC - as explained above - while power prices before emissions trading are significantly lower under PC. This results in substantially higher proportional (%) increases in power prices due to emissions trading under PC - at similar carbon prices - and, hence, in significantly higher decreases in power sales under PC than OC (at similar demand elasticities).[96]

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[95] It should be noted, however, that although most PTRs in Table 4.6 meet the expected or predicted values, they may still be affected by an ETS-induced change in the merit order during at least one of the demand periods considered by COMPETES.

[96] Note that power prices under OC are generally significantly higher than under PC and, hence, that the absolute levels of total power sales are lower under OC than PC (at similar carbon prices and demand elasticities). In specific, individual cases, however, total power sales of a particular country may be higher under OC than PC at similar prices and demand elasticities. For instance, at a carbon prices of 40 €/tCO_2 and a demand elasticity of 0.2, total power sales in Germany are significantly lower under OC than PC, but slightly higher in France. This is to some extent due to the fact that it is assumed that in France EdF is not able to exercise market power (because of regulatory threat) and, hence, power prices under OC increase less in France than in de other countries considered and, therefore, power sales in France decline less. In addition, it is also due to the fact that power generation is, on average, less carbon intensive in France and, therefore, less carbon costs are passed through to power prices in France. This further improves the competitive position of power companies in France versus neighbouring, competing countries and, therefore enables these companies to maintain or even increase their power sales, including power trade to other countries (see also next bullet point in the main text, as well as the section below on power trade).

Table 5.7 *Total power sales in EU countries under various COMPETES model scenarios [TWh]*

	Perfect Competition (PC)				
CO_2 price [€/tCO_2]	0	0	20	40	40
Demand elasticity	0	0.2	n/a	0	0.2
Scenario acronym	PCe0c0	PCe0.2c0	REF	PCe0c40	PCe0.2c40
Austria	67	69	67	67	64
Belgium	90	93	90	90	86
Czech Republic	64	68	64	64	60
Denmark	36	38	36	36	34
Finland	81	85	81	81	78
France	478	490	478	478	463
Germany	566	594	566	566	535
Hungary	41	43	41	41	40
Italy	335	345	335	335	327
Netherlands	116	120	116	116	111
Norway	124	127	124	124	120
Poland	135	147	135	135	122
Portugal	51	52	51	51	49
Slovakia	29	30	29	29	27
Slovenia	7	8	7	7	7
Spain	262	269	262	262	251
Sweden	148	153	148	148	143
Switzerland	63	66	63	63	60
UK	323	335	323	323	302
EU-20	3016	3129	3016	3016	2881

	Oligopolistic competition (OC)					
CO_2 price [€/tCO_2]	0	0	20	20	40	40
Demand elasticity	0.1	0.2	0.1	0.2	0.1	0.2
Scenario acronym	OCe0.1c0	OCe0.2c0	OCe0.1c20	OCe0.2c20	OCe0.1c40	OCe0.2c40
Austria	65	64	63	62	62	60
Belgium	69	71	68	70	68	69
Czech Republic	52	54	51	51	50	49
Denmark	34	34	34	33	33	32
Finland	81	83	80	80	78	76
France	485	493	477	480	471	467
Germany	537	549	523	523	510	498
Hungary	41	41	40	40	40	39
Italy	312	315	307	305	302	297
Netherlands	105	107	104	104	102	100
Norway	120	123	119	122	119	121
Poland	141	147	135	135	128	122
Portugal	46	47	45	45	44	43
Slovakia	24	25	23	23	23	22
Slovenia	8	8	8	8	7	7
Spain	246	251	242	243	238	235
Sweden	140	144	139	140	138	136
Switzerland	60	61	58	59	57	56
UK	322	331	315	319	308	299
EU-20	2886	2948	2832	2842	2778	2730

Table 5.8 *ETS-induced changes in power sales in EU countries under various COMPETES model scenarios [%]*

	Perfect Competition (PC)				Oligopolistic Competition (OC)			
ΔCO_2 price [€/tCO_2]	20	20	40	40	20	20	40	40
Demand elasticity	0	0.1	0	0.1	0.1	0.2	0.1	0.2
Acronym	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40	OCe0.1Δ20	OCe0.2Δ20	OCe0.1Δ40	OCe0.2Δ40
Austria	0	-2.9	0	-7.2	-3.1	-3.1	-4.6	-6.3
Belgium	0	-3.2	0	-7.5	-1.4	-1.4	-1.4	-2.8
Czech Republic	0	-5.9	0	-11.8	-1.9	-5.6	-3.8	-9.3
Denmark	0	-5.3	0	-10.5	0.0	-2.9	-2.9	-5.9
Finland	0	-4.7	0	-8.2	-1.2	-3.6	-3.7	-8.4
France	0	-2.4	0	-5.5	-1.6	-2.6	-2.9	-5.3
Germany	0	-4.7	0	-9.9	-2.6	-4.7	-5.0	-9.3
Hungary	0	-4.7	0	-7.0	-2.4	-2.4	-2.4	-4.9
Italy	0	-2.9	0	-5.2	-1.6	-3.2	-3.2	-5.7
Netherlands	0	-3.3	0	-7.5	-1.0	-2.8	-2.9	-6.5
Norway	0	-2.4	0	-5.5	-0.8	-0.8	-0.8	-1.6
Poland	0	-8.2	0	-17.0	-4.3	-8.2	-9.2	-17.0
Portugal	0	-1.9	0	-5.8	-2.2	-4.3	-4.3	-8.5
Slovakia	0	-3.3	0	-10.0	-4.2	-8.0	-4.2	-12.0
Slovenia	0	-12.5	0	-12.5	0.0	0.0	-12.5	-12.5
Spain	0	-2.6	0	-6.7	-1.6	-3.2	-3.3	-6.4
Sweden	0	-3.3	0	-6.5	-0.7	-2.8	-1.4	-5.6
Switzerland	0	-4.5	0	-9.1	-3.3	-3.3	-5.0	-8.2
UK	0	-3.6	0	-9.9	-2.2	-3.6	-4.3	-9.7
EU-20	0	-3.6	0	-7.9	-1.9	-3.6	-3.7	-7.4

a) PC and OC refer to Perfect Competition and Oligopolistic Competition, respectively, e.0.X to the demand elasticity, and cΔX to the change in the CO_2 price (while the other parameters of the model scenario are constant).

- Under similar scenarios, there might be significant differences between countries in terms of changes in power sales due to (ETS-induced) changes in electricity prices. For instance, in the OC scenario with a carbon price of 40 €/tCO_2 and a demand elasticity of 0.2, the decline in power sales due to emissions trading amounts to 1.6% for Norway, 5.3% for France, 9.3% for Germany and 17% for Poland (Table 5.8). These differences are due to (i) differences in carbon intensity of power units setting the electricity prices in these countries, resulting in different *amounts* of carbon costs of power output, and (ii) differences in market concentration in these countries or, in particular in the case of France, different assumptions regarding producer behaviour, resulting in differences in exercising market power in these countries and, hence, in different *rates* of carbon costs passed through to electricity prices. Consequently, despite similar carbon prices and demand elasticities, electricity prices may increase faster in some countries than others. As a result, power sales decrease more in countries with higher ETS-induced increases in power prices due to both lower domestic power sales and a loss of trade competitiveness resulting in less power exports or more power imports. On the other hand, power sales decrease less - or may even increase - in countries with lower ETS-induced increases in power prices due to a smaller decline in domestic power sales and an improvement in trade competitiveness, leading to more exports or less imports of electricity (see also next section). Similarly, even within one country, power sales of individual companies (or units) may decline less than other companies - or even increase - depending on their carbon intensity and, hence, the change in their competitive position due to emissions trading (see also Section 5.3.6).

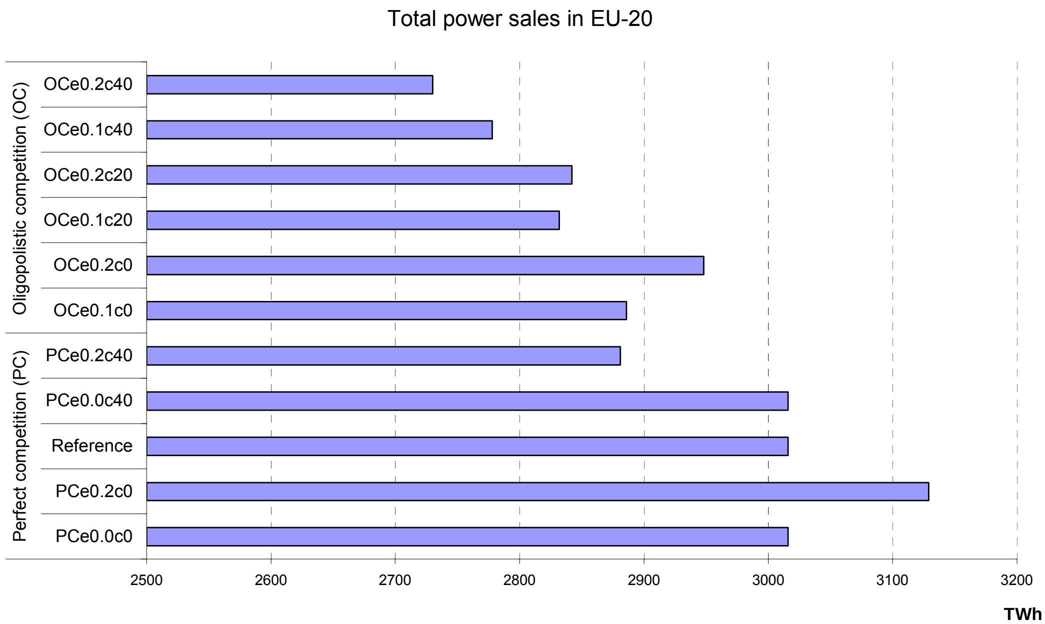


Figure 5.4 *Total power sales in the EU-20 under various COMPETES model scenarios*

Table 5.9 *Power generation, domestic sales, net trade flows and major trading partners of EU countries in the reference scenario [TWh]*

	Generation	Sales	Net trade	Major trading partner
Austria	51.6	66.5	-14.9	Germany, Switzerland
Belgium	75.2	89.9	-14.7	France, Netherlands
Czech Republic	81.4	64.3	17.1	Germany
Denmark	35.8	36.4	-0.6	Sweden, Germany
Finland	78.5	81.2	-2.7	Sweden, Norway
France	535.4	478.4	57.1	Switzerland, Italy
Germany	566.3	565.7	0.7	Netherlands, Czech Republic, France
Hungary	31.6	41.4	-9.8	Slovakia, Slovenia
Italy	300.0	335.2	-35.1	Switzerland, France
Netherlands	95.9	116.1	-20.2	Germany, Belgium (France)
Norway	135.6	123.6	12.0	Sweden, Denmark
Poland	143.3	134.6	8.7	Germany, Slovakia
Portugal	49.6	50.7	-1.1	Spain
Slovakia	30.4	28.8	1.6	Hungary, Czech Republic
Slovenia	15.6	7.5	8.1	Hungary, Austria
Spain	257.2	261.5	-4.3	France, Portugal
Sweden	150.4	148.3	2.1	Denmark, Finland
Switzerland	61.1	63.2	-2.1	France, Germany
UK	320.9	322.7	-1.7	France
EU-20	3016.0	3016.0	0.0	

5.3.4 Power trade

Table 5.9 shows the amounts of power generation, domestic sales, net trade flows and major trading partners of EU countries in the reference scenario of the COMPETES model. In this scenario, France and Germany are both the main power producers and the main power traders in terms of gross trade flows.[97] For instance, in the COMPETES reference scenario, France generates some 535 TWh of electricity. A major part of this production is sold and consumed at home (478 TWh), while the rest is exported to Switzerland, Italy or indirectly - i.e. via Belgium/Germany - to the Netherlands.

Similarly, in the reference scenario, Germany produces some 566 TWh of electricity, which is more or less equal to its domestic sales. In addition, however, Germany imports major amounts of power from countries such as France or the Czech Republic whereas it exports more or less similar amounts to the Netherlands, resulting in a net trade position of 0.7 TWh in the reference scenario.

On the other hand, in the reference scenario, the Netherlands is the second main net importer of power (after Italy). Whereas the domestic power consumption of the Netherlands amounts to 116 TWh, its domestic production reaches only 96 TWh, resulting in major power imports of more than 20 TWh (i.e. almost one-sixth of total domestic sales). These imports are obtained either directly or indirectly from Belgium, France and Germany.

Table 5.10 presents the net power trade position of some EU countries under various COMPETES model scenarios, including the reference scenario. It shows that in all scenarios considered, France remains a main net exporter of power while Belgium and Italy remain major net importers. However, in PC scenarios - notably when the demand elasticity is 0.2 - Germany shifts from a net power exporter if the carbon price is relatively low (i.e. 0-20 €/tCO_2) to a net power importer if this price becomes relatively high (i.e. 40 €/tCO_2 or higher), while in the OC scenarios Germany imports already a significant amount of power before emissions trading. This amount tends to increase once emissions trading is introduced and the carbon price starts to rise. On the other hand, in the PC scenarios, the Netherlands tends to decrease its substantial net power imports when the carbon price increases, while under OC its net imports hardly change at a rather low level.

These differences and changes in power trade positions among countries are due to differences and ETS-induced changes in power demand and competitive position - i.e. relative power prices - among countries, resulting from their market structure as well from their fuel mix and carbon intensity of their generation capacities.

5.3.5 Carbon emissions

Table 5.11 presents the total CO_2 emissions of the power sector in EU countries under various COMPETES model scenarios. It shows that, in general, these emissions go down if the carbon price goes up, notably in the scenarios where power demand is more responsive to ETS-induced changes in electricity prices. For instance, if the carbon price increases from 0 to 40 €/tCO_2, the carbon emissions of the EU-20 decreases from 1234 to 1069 MtCO_2 (-15%) in the PC scenario with fixed demand, while they decline from 1317 to 954 MtCO_2 (-33%) in the PC scenario with a demand responsiveness of 0.2 (see also Figure 5.5).

Note from Table 5.11 that if the carbon price increases (in scenarios with similar market structures and demand elasticities), the proportional decrease in CO_2 emissions may vary significantly between individual countries, and that in specific cases the CO_2 emissions of an individual country may even slightly rise if the carbon price goes up (see, for instance, Hungary or the Netherlands in the PC scenario with fixed demand: CO_2 emissions go up if the carbon price rises from 20 to 40 €/tCO_2). This is due to differences between these countries in the fuel mix or carbon intensity of their generation units, the opportunities for fuel switch or re-dispatch of the

[97] Gross trade flows refer to the sum of power exports and imports of an individual country, while net trade flows concern the balance of its power exports minus imports.

merit order, and the resulting ETS-induced changes in electricity prices, competitive (trade) positions and, hence, total power sales of individual countries.

Table 5.10 *Net power trade of EU countries under various COMPETES model scenarios [TWh]*

	Perfect Competition (PC)				
CO_2 price [€/tCO_2]	0	0	20	40	40
Demand elasticity	0	0.2	n/a	0	0.2
Scenario acronym	PCe0c0	PCe0.2c0	REF	PCe0c40	PCe0.2c40
Austria	16	17	15	15	16
Belgium	15	15	15	7	6
Czech Republic	-17	-17	-17	-17	-17
Denmark	0	-1	1	2	5
Finland	4	1	3	3	5
France	-57	-54	-57	-57	-59
Germany	-2	-11	-1	11	20
Hungary	10	9	10	8	9
Italy	34	34	35	35	35
Netherlands	20	19	20	14	12
Norway	-12	-9	-12	-12	-15
Poland	-9	-9	-9	-8	-8
Portugal	1	2	1	1	1
Slovakia	-2	-1	-2	-1	-2
Slovenia	-8	-8	-8	-8	-8
Spain	5	3	4	2	3
Sweden	-3	1	-2	-2	-7
Switzerland	2	5	2	4	1
UK	3	2	2	2	3
EU-20	0	0	0	0	0

	Oligopolistic competition (OC)					
CO_2 price [€/tCO_2]	0	0	20	20	40	40
Demand elasticity	0.1	0.2	0.1	0.2	0.1	0.2
Scenario acronym	OCe0.1c0	OCe0.2c0	OCe0.1c20	OCe0.2c20	OCe0.1c40	OCe0.2c40
Austria	9	9	9	9	8	9
Belgium	10	8	10	9	10	9
Czech Republic	0	0	0	0	0	0
Denmark	-2	0	0	3	3	6
Finland	1	3	2	4	3	5
France	-42	-41	-46	-44	-49	-52
Germany	8	7	11	10	16	19
Hungary	7	7	6	7	5	6
Italy	30	29	30	31	30	31
Netherlands	1	1	1	1	0	1
Norway	-6	-8	-7	-10	-9	-12
Poland	-5	-6	-5	-6	-5	-5
Portugal	-1	-1	-1	-1	-1	-1
Slovakia	-2	-3	-2	-2	-2	-3
Slovenia	-8	-7	-8	-8	-7	-8
Spain	5	6	5	6	6	6
Sweden	1	0	0	-5	-4	-9
Switzerland	-3	-1	-4	-3	-5	-5
UK	-3	-2	0	0	0	0
EU-20	0	0	0	0	0	0

Table 5.11 *Total CO_2 emissions of the power sector in EU countries under various COMPETES model scenarios [$MtCO_2$]*

	Perfect Competition (PC)				
CO_2 price [€/tCO_2]	0	0	20	40	40
Demand elasticity	0	0.2	n/a	0	0.2
Scenario acronym	PCe0c0	PCe0.2c0	REF	PCe0c40	PCe0.2c40
Austria	12.4	13.0	12.8	12.6	10.0
Belgium	23.8	25.1	22.6	22.6	21.1
Czech Republic	53.3	56.3	53.5	52.3	47.7
Denmark	27.0	29.4	26.5	23.7	19.4
Finland	16.1	21.0	15.0	14.4	9.8
France	45.6	52.7	44.5	43.2	32.2
Germany	327.8	357.1	306.1	294.5	258.6
Hungary	14.3	15.3	14.4	15.1	14.3
Italy	162.1	167.9	143.7	143.8	138.9
Netherlands	58.4	60.8	53.3	54.4	53.2
Norway	0.2	0.2	0.1	0.1	0.1
Poland	136.7	148.3	136.7	133.5	121.3
Portugal	21.9	22.2	21.9	21.6	20.0
Slovakia	9.0	9.6	8.8	8.0	6.9
Slovenia	6.6	6.7	6.6	6.6	6.4
Spain	109.8	114.3	110.1	100.4	91.4
Sweden	3.2	4.1	1.9	1.7	1.6
Switzerland	3.0	3.0	3.0	1.3	1.1
UK	202.9	209.5	120.0	119.6	99.5
EU-20	1234.2	1316.6	1101.5	1069.5	953.7

	Oligopolistic competition (OC)					
CO_2 price [€/tCO_2]	0	0	20	20	40	40
Demand elasticity	0.1	0.2	0.1	0.2	0.1	0.2
Scenario acronym	OCe0.1c0	OCe0.2c0	OCe0.1c20	OCe0.2c20	OCe0.1c40	OCe0.2c40
Austria	13.1	14.6	11.7	12.1	10.7	9.8
Belgium	10.3	12.1	9.7	10.3	8.8	8.7
Czech Republic	22.2	23.9	20.7	21.4	19.1	18.5
Denmark	25.4	24.9	22.7	20.1	18.8	15.1
Finland	17.1	17.1	14.2	12.8	11.6	8.7
France	42.9	47.5	36.0	35.4	31.9	30.2
Germany	269.6	284.8	245.8	250.0	218.0	208.3
Hungary	18.5	17.1	17.4	15.5	16.7	13.7
Italy	156.7	157.9	142.5	137.6	129.0	121.6
Netherlands	67.0	64.7	58.6	58.2	56.9	56.0
Norway	0.3	0.2	0.2	0.1	0.1	0.1
Poland	139.3	146.1	133.4	133.7	124.5	118.8
Portugal	18.9	20.0	17.5	18.0	16.7	16.6
Slovakia	5.0	6.0	4.2	3.7	3.0	2.6
Slovenia	6.6	6.6	6.2	6.4	5.2	6.0
Spain	93.6	99.3	88.7	91.6	76.6	74.8
Sweden	5.3	4.4	4.5	3.5	3.7	1.7
Switzerland	3.6	3.2	3.6	3.2	3.6	3.2
UK	188.4	187.5	154.1	141.3	137.7	102.8
EU-20	1103.9	1138.0	991.8	974.9	892.6	817.1

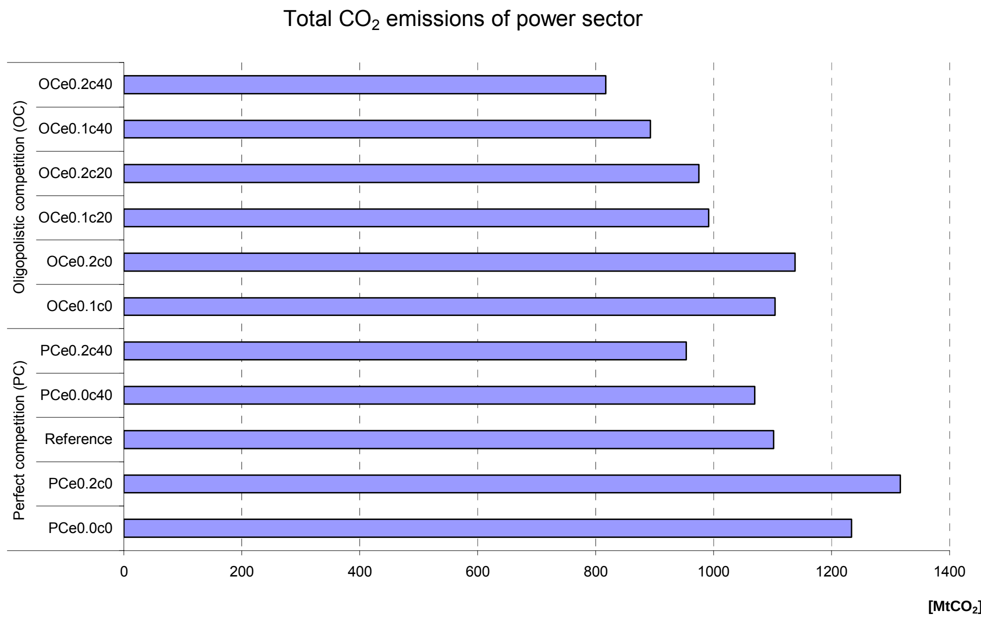


Figure 5.5 *Total CO_2 emissions of the power sector in the EU-20 under various COMPETES model scenarios*

Finally, Table 5.11 also shows that at similar carbon prices and demand elasticities, CO_2 emissions are generally much lower under OC than PC. This is due to the higher electricity prices and, hence, lower power sales under OC, thereby illustrating once again the trade-off between the short-term interest of the consumer (low prices, high sales) and the long-term interests of the environment (high prices, fewer emissions).[98] Note, however, that - in similar cases - the CO_2 emissions in the Netherlands and the UK are considerably higher under OC than PC. The explanation for this result is that coal units in the competitive fringe (exerting no market power under OC) change from being a marginal unit in the PC scenarios (operating at partial or no capacity) to a largely baseload unit in the OC scenarios (operating at full capacity).

Decomposition of emission reductions

A reduction in total CO_2 emissions by the power sector, however, may result not only from a demand response (i.e. fewer total power sales) but also from a change in technology (i.e. a re-dispatch or change in the merit order, notably a shift from coal to gas). In Table 5.12, a decomposition of these two effects is provided for the impact of emissions trading on CO_2 emissions under different scenarios.[99]

Table 5.12 *Decomposition of ETS-induced reductions in total CO_2 emissions of the power sector in the EU-20 countries under various COMPETES model scenarios [Mt CO_2]*

	PCe0Δ20	PCe0.2Δ20	PCe0Δ40	PCe0.2Δ40
Demand response	0	82	0	198
Re-dispatch	133	133	165	165
Total reduction	133	215	165	363
As% of reference emissions	*12%*	*20%*	*15%*	*33%*

[98] For different views on this issue, see Lise (2005) and Lise, et al. (2006).

[99] Note that the CO_2 emission reduction due to changes in the merit order do not only depend on the CO_2 allowance costs of the generation technologies but also on their fuel costs as shifts in the merit order could be different under another set of relative fuel prices, notably of coal versus gas.

The decomposition of Table 5.12 is based on the following approach. Under perfect competition with fixed demand (PCe0), emission reductions due to (ETS-induced) demand response are 0. The total carbon abatement of 133 $MtCO_2$ in PCe0Δ20 is, hence, fully due to re-dispatch. This amount of CO_2 reduction is assumed to be due to re-dispatch in PCe0.2Δ20 as well. Since the total carbon abatement under this scenario is 215 $MtCO_2$, the CO_2 reduction due to demand response amounts to 82 $MtCO_2$. A similar reasoning can be followed in the case of the PC scenario at a carbon price of 40 €/tCO_2 (see right part of Table 5.12).

Table 5.12 illustrates that emissions trading and the resulting pass-through of carbon cost to electricity prices may reduce CO_2 emissions significantly by affecting not only producers decisions - through a re-dispatch or change in the merit order of generation technologies - but also consumer decisions, i.e. through reducing power demand in response to ETS-induced increases in electricity prices. Therefore, if power demand is price responsive (notably in the medium or long run), the pass-through of carbon costs to higher electricity prices for end-users is a major element in a policy regime of reducing CO_2 emissions in the medium or long term.

Changes in the merit order

ETS-induced changes in the merit order at carbon prices of 20 and 40 €/tCO_2 are illustrated in Figure 5.6 and Figure 5.7, respectively. Each of these figures show three curves of the marginal production costs for the mix of power generation technologies at the EU-20 level. These curves include:

- The merit order or ranking of the supply technologies based on their marginal (fuel) production costs before emissions trading at zero carbon costs (blue line).
- A curve showing the marginal (fuel + carbon) costs after emissions trading, i.e. at either 20 or 40 €/tCO_2, based on the merit order or ranking of generation technologies before emissions trading (green line).
- A curve illustrating the marginal (fuel + carbon) costs after emissions trading, i.e. at either 20 or 40 €/tCO_2, based on the resorting or new ranking of generation technologies according to these costs (redline).

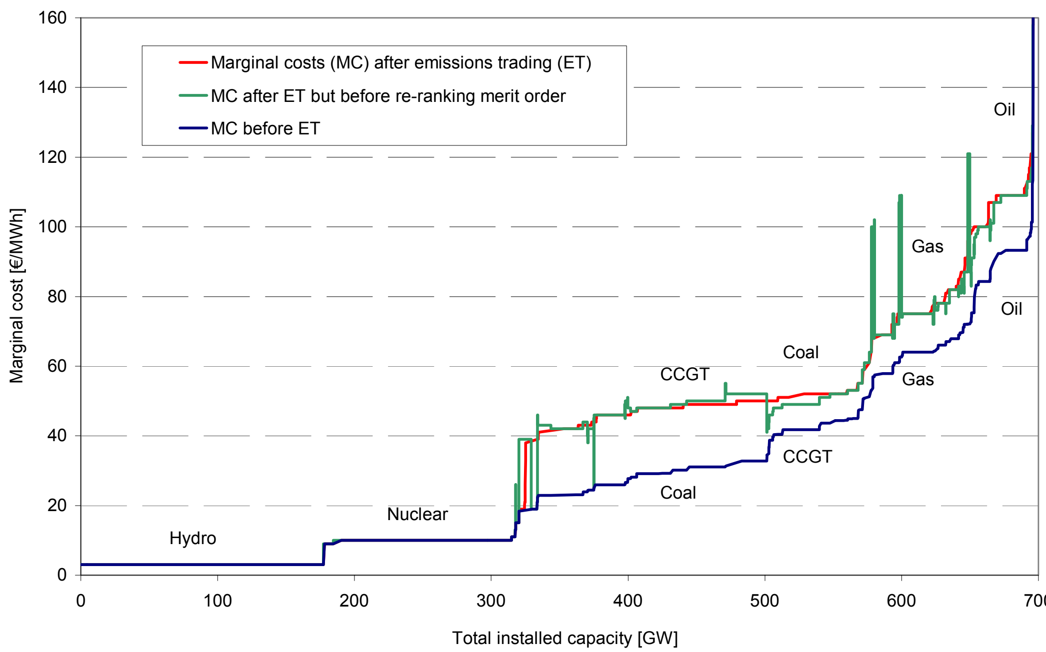


Figure 5.6 *ETS-induced changes in the EU-20 merit order at 20 €/tCO_2 and 2006 fuel prices*

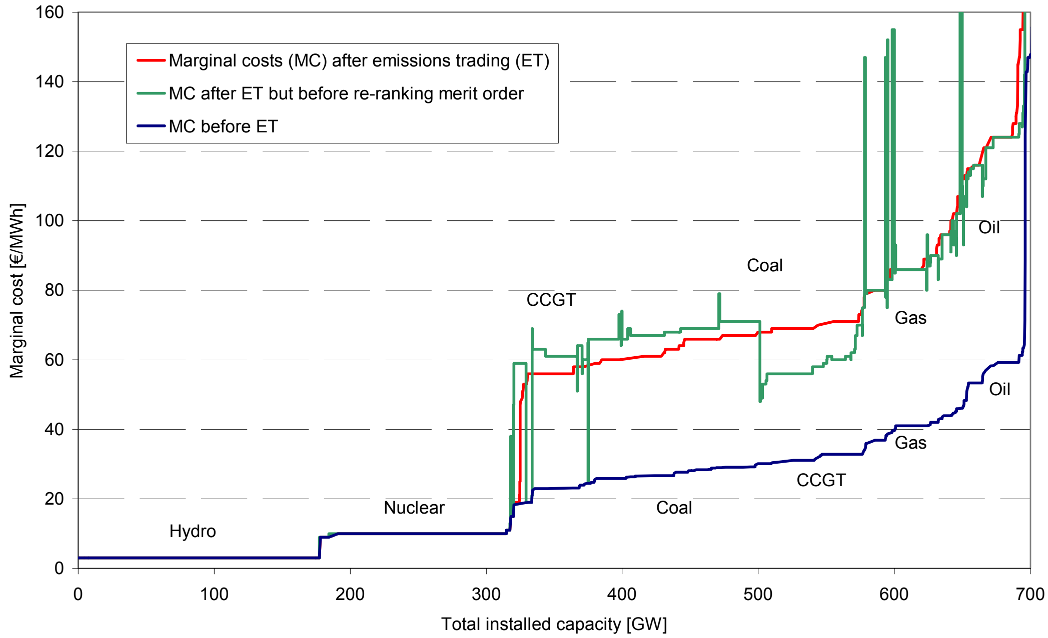


Figure 5.7 *ETS-induced changes in the EU-20 merit order at 40 €/tCO_2 and 2006 fuel prices*

Figure 5.6 and Figure 5.7 show that, due to emissions trading, the marginal production costs of carbon inefficient technologies - notably coal or lignite - increase substantially (green line) and that, subsequently, the merit order may change significantly - especially at higher carbon prices - in the sense that less carbon efficient technologies (coal) shift to the right of the merit order while more carbon efficient units (CCGT) move to the left (red line). Since technologies on the right of the merit order run fewer load hours - or may even close due to a lack of demand/profitability - the carbon emissions of the technologies decline accordingly (i.e. the re-dispatch effect on carbon emissions discussed above). The decline in carbon emissions is further enhanced if power demand is responsive to ETS-induced increases in electricity prices, resulting in even fewer operating hours for (more) carbon emitting technologies (i.e. the demand response effect outlined above).

For illustrative purposes, Figure 5.6 and Figure 5.7 present shifts in the merit order of all generation technologies at the EU-20 level. In practise, but also within the COMPETES model, however, there is a variety of differentiated and (partially) integrated power markets across the EU-20 with different marginal technologies setting different levels of power prices in these markets, depending on the level of power demand, the mix of generation technologies and the transmission capacity of the countries involved. Nevertheless, the principle of a shift in the merit order can be generalised and illustrated at the EU-20 level.

Whether a shift in the merit order occurs in particular markets or countries depends not only on the carbon price - or the relative fuel prices - but also on differences in the mix - and carbon efficiency - of generation technologies in these markets or countries. At a carbon price of 20 or 40 €/tCO_2, the COMPETES model observes hardly any technology switching in Finland, Hungary, Portugal, Slovenia, Sweden and Switzerland while, on the other hand, significant shifts in generation technologies occur in Germany and the UK, i.e. countries with a major share of both coal and CCGT technologies and, where at 2006 fuel prices, CCGT is nearly competitive compared to coal.

Sensitivity analysis with regard to fuel prices
Changes in the merit order, but also other variables such as electricity prices or carbon emissions of the power sector, depend not only on the carbon price but also on the relative fuel prices. The results presented thus far have all been based on the average fuel prices of 2006. However, during the first two years of the EU ETS, i.e. 2005-2006, average gas prices increased substantially in EU countries - by some 60% compared to 2004 - whereas coal prices remained largely the same. Therefore, a sensitivity analysis has been conducted by means of the COMPETES model based on average fuel prices in 2004.

More specifically, as part of the sensitivity analysis, the COMPETES model has been run for three additional perfect competition (PC) scenarios with fixed demand, 2004 fuel prices, and carbon prices of 0, 10 and 20 €/tCO_2. These scenarios are indicated by the acronyms PCe0c0*, PCe0c10* and PCe0c20* (where the * refers to the sensitivity analysis based on 2004 fuel prices). A carbon price of 10 €/tCO_2 has been added, based on the assumption that lower gas prices result in a shift from coal to gas-fuelled power generation and, hence, in fewer carbon emissions and, therefore, in a lower carbon price.

Figure 5.8 presents the ETS-induced changes in the merit order at the EU-20 level, based on 2004 fuel prices and a carbon price of 20 €/tCO_2. Compared to Figure 5.6, it shows that (i)at 2004 fuel prices, the marginal (fuel) costs of gas-fired stations are generally lower and, hence, coal becomes less competitive, and (ii) the incidence of fuel switch - from coal to gas - is larger due to emissions trading at 20 €/tCO_2.

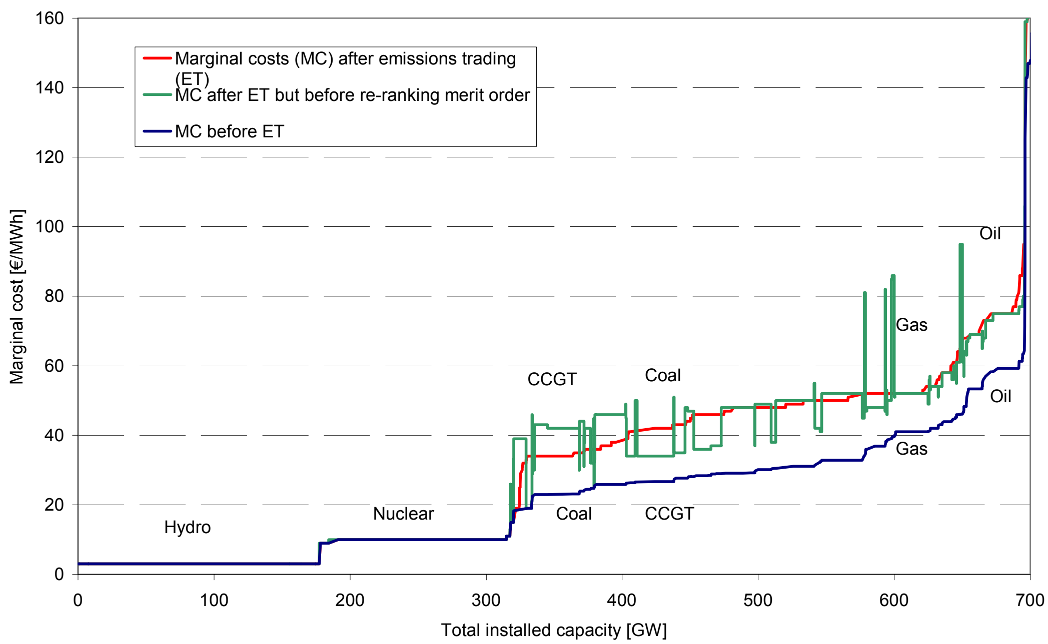


Figure 5.8 *ETS-induced changes in the EU-20 merit order at 20 €/tCO_2 and 2004 fuel prices*

In addition, Table 5.13 presents the sensitivity analysis results for electricity prices and carbon emissions of the power sector. It shows that the average electricity price in the EU-20 is 10.4 €/MWh - or 18% - lower in the PCe0c20* scenario compared to the reference scenario (see Table 5.2). This indicates that gas is often the price-setting technology in the EU-20. Moreover, in the PCe0c10* scenario (based on 2004 fuel prices and the assumption that if the gas price is lower, the carbon price is also lower), the EU-20 power price is even 17.9 €/MWh - or 30% - lower compared to the reference scenario.

Finally, Table 5.13 shows that, under fixed demand and a carbon price of 20 €/tCO_2, carbon emissions of the power sector are lower under 2004 fuel prices, compared to 2006 fuel prices (see Table 5.12). Comparing PCe0c20* to the reference scenario, the decrease in carbon emissions occurs mainly in Germany (-37 MtCO_2) and Spain (-10 MtCO_2), indicating a substantial fuel switch form coal to CCGT in these two countries. However, if lower gas prices result in lower carbon prices (as in PCe0c10*), the decrease in carbon emissions is lower due to less fuel switch. In addition, if power demand is price responsive, the decrease in carbon emissions due to lower gas prices would also have been lower.

Table 5.13 *Sensitivity analysis: electricity prices and CO_2 emissions of the power sector in EU countries under perfect competition with fixed demand and 2004 fuel prices*

	Prices [€/MWh]			CO_2 emissions [Mt]		
	PCe0c0*	PCe0c10*	PCe0c20*	PCe0c0*	PCe0c10*	PCe0c20*
Austria	37.3	45.0	52.0	12.4	12.7	12.8
Belgium	35.6	43.9	51.0	26.0	23.1	23.0
Czech Republic	29.3	38.0	47.0	52.4	52.3	51.1
Denmark	32.6	40.3	49.5	25.1	23.4	21.6
Finland	29.8	36.6	43.9	14.3	12.6	13.8
France	28.6	34.8	41.0	43.7	42.4	41.6
Germany	33.4	41.6	50.0	294.8	291.8	268.5
Hungary	35.7	42.0	49.0	14.7	14.7	14.7
Italy	44.8	54.0	60.8	162.1	147.0	143.8
Netherlands	35.7	44.1	50.9	61.4	55.5	54.4
Norway	24.8	30.2	36.7	0.2	0.2	0.1
Poland	23.1	32.6	42.0	136.5	133.5	133.5
Portugal	39.7	47.5	55.3	21.9	21.9	21.9
Slovakia	29.3	37.9	46.9	8.6	7.8	7.4
Slovenia	34.6	41.7	48.5	6.6	6.5	6.5
Spain	38.0	45.9	53.8	100.3	100.3	99.8
Sweden	28.3	34.5	41.6	2.4	2.4	2.0
Switzerland	36.3	44.6	51.9	3.0	2.3	1.4
UK	30.5	38.8	47.2	120.5	116.6	115.9
EU-20	33.1	40.9	48.4	1106.8	1066.8	1033.8

5.3.6 Power generators' profits

Profits of power producers are affected by emissions trading in general and its allocation method in particular. In the case of emissions trading with free allocations, resulting changes in profits of existing producers ('incumbents') can be distinguished into two categories according to two different causes of these profit changes:

A. *Changes in incumbents' profits due to ET-induced changes in production costs, power prices and sales volumes.* This category of profit changes (denoted as 'windfall profits A') occurs irrespective whether eligible companies receive all their allowances for free or have to purchase them at an auction or market. The impact of changes in generation costs (including the opportunity costs of EUAs), power prices and sales volumes on incumbents' profits can vary significantly among companies (or even countries) and can be positive or negative, depending on the fuel generation mix of these companies (or countries), the price on an emission allowance, and the ETS-induced changes in power prices set by the marginal installation versus the ETS-induced changes in generation costs and sales volumes of both marginal and infra-marginal operators (where these operators can be either a high-, low- or non-CO_2 emitter). For instance, if the power price is set by a coal (high-emitting) installation, an operator of such a plant may either break even - if the change in carbon and other generation costs is passed fully to the power price, while sales volumes do not change - or loose if price changes are lower than cost changes or if sales volumes drop due to (i) lower, price-responsive demand levels or (ii) lower load hours resulting from a loss of competitiveness and an attendant change in the merit order of power supply. However, in such a situation, infra-marginal operators of a low- or non-CO_2 emitting station may benefit from a higher profit margin and higher load hours (i.e. sales volumes) due to gains in competitiveness. On the other hand, if the power price is set by a gas (low-emitting) or nuclear (non-emitting) plant, the operator of such an installation may more or less break even, whereas infra-marginal producers operating a higher-emitting station will make a loss as the increase in their carbon cost is not covered by a similar increase in power revenues.[100] This impact on power generators' profits is called the *'emissions trading' (ET) effect* as this impact occurs regardless of the allocation method.

B. *Changes in incumbents' profits due to the free allocation of emission allowances.* This category of profit changes (denoted as 'windfall B') is an addition or compensation of the first category of windfall profits/losses to the extent in which allowances are obtained for free - rather than purchased - by eligible companies. These changes in incumbents' profits are usually positive, but can vary significantly among companies (or even countries), depending on the fuel generation mix of their installations, the price of an emission allowance, the amount of free allowances received, and the impact of specific free allocation provisions on the power price. For instance, if carbon prices are high and emissions are covered largely by allowances allocated for free in a fuel-specific way (i.e. high polluters such as coal or lignite plants get more free allowances), companies - or countries - with a relative high share of high-emitting installations in their generation mix benefit most, in an absolute sense, while low- or non-CO_2 emitting installations will profit less or not at all from free allocation. This impact on power generators' profits is called the *'free allocation' effect* as this impact is solely due to transferring the value or economic rent of the allowances allocated for free.

The distinction between the two categories of windfall profits is relevant not only to indicate the differences in underlying causes or mechanisms of these profits (or in differences in the incidence of these profits at the installation, sectoral or national level) but also to discuss the differences of these two categories in terms of investment incentives and policy implications. Whereas the first category (windfall A) encourages investments in especially low- or non-CO_2 emitting installations, the second category (windfall B) induces investments in particularly high-emitting technologies (provided that allowances are allocated for free to both incumbents and new entrants, in particular in a fuel- or technology specific way, it implies a capacity subsidy that benefits and, hence, promotes notably more carbon-intensive generation plants). In addition, if for one reason or another one wants to tackle the incidence of generators' windfall profits due to the EU ETS, one has to make a distinction between the two categories of these profits as some policy options affect only the first category but not the second, or vice versa (as discussed in Chapter 6).

Profit changes at the EU-20 level

Table 5.14 presents estimates of ETS-induced changes in power generators' profits under various COMPETES model scenarios for the EU-20 as a whole, including the distinction between the two types - or causes - of profit changes mentioned above (see also Figure 5.9). This table is based on the assumption that 90% of the CO_2 emissions of each power producer - and, hence 90% of its required allowances - are covered by free allocations, while the remaining 10% has to be bought on an auction or market.

Table 5.14 shows, for instance, that total power generators' profits in the EU-20 increase by 75 billion Euro (B€) in the perfect competition scenario with fixed demand and emissions trading at 40 €/tCO_2 (PCe0c40) compared to a similar scenario without emissions trading (PCe0c0).

[100] Note that these changes in profits of (infra-)marginal producers due to changes in relative carbon costs are similar to profit changes resulting from changes in fuel or other generation costs.

Almost half of this increase is due to the introduction of emissions trading, regardless of the allocation method, while the remaining part is due to the free allocation of CO_2 allowances.

More generally, some of the major observations from Table 5:14 include:

Table 5.14 *ETS-induced changes in total generators' profits at the EU-20 level under various COMPETES model scenarios*

	Total Profits[a]	Δ Profits due to:			Δ Profits due to:		
		ET effect	Free allocation[b]	Total effect	ET effect	Free allocation[b]	Total effect
	[B€]	[B€]	[B€]	[B€]	[%]	[%]	[%]
PCe0c0	72						
REF/PCc20	107	16	20	35	21.7	27.6	49.3
PCe0c40	147	37	39	75	50.9	53.7	104.6
PCe0.2c0	79						
REF/PCc20	107	8	20	28	10.4	25.0	35.4
PCe0.2c40	137	24	34	58	30.3	43.0	73.3
OCe0.1c0	163						
OCe0.1c20	188	7	18	25	4.5	11.0	15.5
OCe0.1c40	211	16	32	49	10.1	19.9	30.1
OCe0.2c0	117						
OCe0.2c20	141	7	18	24	5.9	15.0	20.9
OCe0.2c40	163	17	29	47	15.0	25.3	40.3

a) These figures refer to scenario model results, not to facts of life.
b) Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations.

- In all scenarios with emissions trading - either including or excluding (90%) free allocations - operational profits of power generators in the EU-20 as a whole increase significantly compared to similar scenarios without emissions trading (i.e. scenarios with similar market structures and demand elasticities, but no carbon costs). Depending on the specific scenario considered, the increase in these profits due to the emissions trading (ET) effect varies between 5 and 51%, while in addition these profits increase by 11 to 54% owing to the free allocation effect. This implies that even in the case of emissions trading with full auctioning, power operators profits at the EU-20 level improve by 5 to 51%.
- For scenarios with similar carbon prices and demand elasticities, absolute changes in generators' profits are generally higher under perfect competition (PC) than oligopolistic competition (OC). This is due to two reasons. First, the COMPETES model assumes linear responsive demand, implying that the pass-through rate of carbon costs to electricity prices is lower under OC than PC and, hence, the ET effect is smaller under OC (see Chapter 2). Second, since electricity prices are higher under OC (than PC), power demand is lower under OC (in the case of price responsive demand). This implies that power related emissions are also lower and, hence, that the size of the free allocation effect is smaller as well. In relative or proportional terms, the differences in profit changes between comparable PC and OC scenarios are even larger as the profits before emissions trading - i.e. the denominator of the equation - is usually much higher under OC than PC.
- For scenarios with similar carbon prices and market structures, changes in generators' profits are generally higher under scenarios with lower demand elasticities. Once again, this is due to two reasons, similar to those outlined above: if the demand elasticity is lower, (i) the pass-through rate is higher (i.e. a stronger ET effect), and (ii) power demand is higher, resulting in more emissions and, hence, a higher amount of free allocation (i.e. a stronger free allocation effect).

- As expected, for scenarios with similar market structures and demand elasticities, changes in generators' profits are higher under scenarios with higher carbon prices.

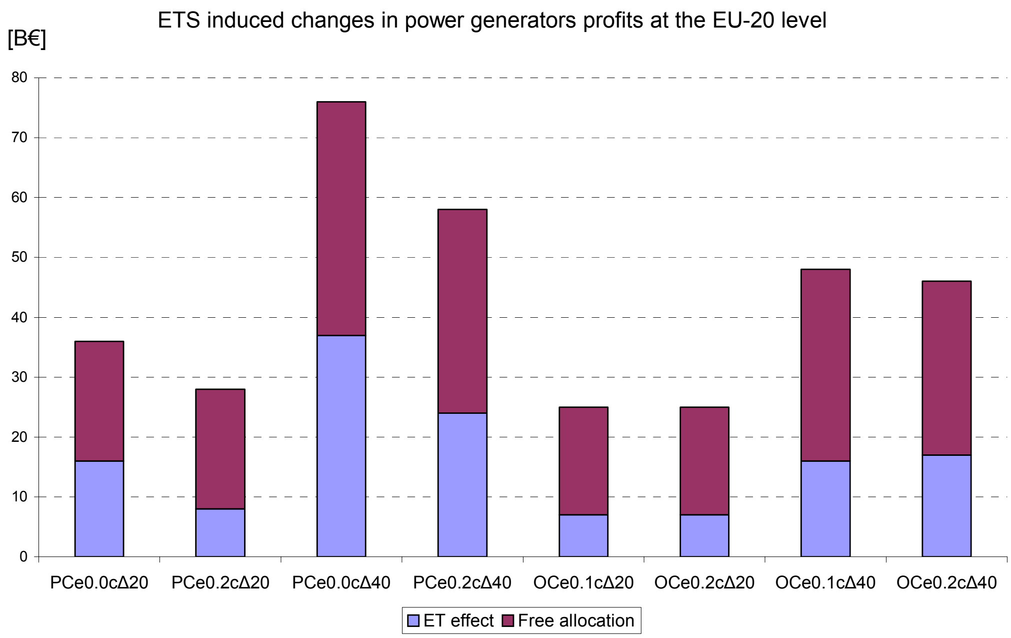


Figure 5.9 *ETS-induced changes in generators' profits at the EU-20 level under various COMPETES model scenarios*

Profit changes at the national level

In addition, Table 5.15 presents estimates of proportional, ETS-induced changes in generators' profits at the *national* level for some selected EU countries under COMPETES model scenarios with a demand elasticity of 0.2 (see also Figure 5.10). The main observations from this table are discussed below.

For individual countries, total generators' profits also increase significantly due to emissions trading with free allocations but the proportional profit changes of individual countries vary not only widely between the scenarios considered but also between these countries within one scenario. For instance, in the OC scenario at 20 €/tCO_2, total profits rise by approximately 17% in the Czech Republic, 24% in France, and 18% in the Netherlands, while in the PC scenario at 40 €/tCO_2 they increase by about 111% (Czech Republic), 16% (France), and 66% (the Netherlands), respectively. These differences between scenarios and countries are due to differences in carbon prices and market structures but also to differences in fuel mix and carbon intensity of price-setting technologies and, hence, to differences in carbon cost passed through, sales volumes, CO_2 emissions and carbon allowances received for free.

In addition to major differences between scenarios and countries with regard to the proportional changes in total generators' profits, there are also major differences between the scenarios and countries concerning the size and mutual importance of the two underlying causes of these profit changes. For instance, in the PC-20 €/tCO_2 scenario, total generators' profits in France increase by 25%, which can be attributed mainly to the so-called ET effect (+16%) and to a lesser extent to the effect of free allocation (+10%). On the other hand, total generators' profits in the Czech Republic rise by 60% in this scenario, which results from the net balance of a positive free allocation effect (+63%) and a negative ET effect (-3%).

Differences in proportional profit changes due to the free allocation effect between countries within a single scenario result mainly from differences in the average carbon intensity of total power output in these countries (as indicated in the second and sixth columns of Table 5.15).[101] Since free allocations are based on (90% of) power-related emissions, countries - or companies - which emit relatively more thus benefit relatively more from free allocations. Between scenarios, however, these differences in proportional profit changes result from differences in carbon prices and/or differences in market structures and related differences in (ETS-induced changes in) electricity prices, merit orders, sales volumes, carbon emissions and, hence, in differences in free allocations.[102]

In addition, although not recorded in Table 5.15, differences between scenarios in proportional profit changes due to free allocation result also from differences in demand elasticities (leading to differences in sales volumes, carbon emissions and, hence, free allocations between scenarios with similar market structures and carbon prices). Finally, it will be clear that the proportional profit changes owing to the free allocation effect will be higher (lower) if the free allocation rate is higher (lower) than the 90% assumed in Table 5.15.

Table 5.15 *ETS-induced changes in power generators' profits at the national level for selected countries under various COMPETES model scenarios [%]*[a]

	Perfect competition (PC)				Oligopolistic competition (OC)			
		Δ Profits due to:				Δ Profits due to:		
	CO_2 rate[b]	ET effect	Free allocation[c]	Total effect	CO_2 rate[b]	ET effect	Free allocation[c]	Total effect
At a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2								
Czech Republic	*836*	-3.0	63.1	60.1	*420*	2.7	14.1	16.8
France	*93*	15.5	9.8	25.3	*74*	19.0	5.4	24.4
Germany	*541*	10.9	41.4	52.4	*478*	5.3	18.5	23.8
Netherlands	*459*	7.5	36.6	44.2	*560*	1.4	16.1	17.5
Spain	*420*	5.0	20.4	25.4	*377*	2.2	10.4	12.5
Sweden	*13*	15.1	17.1	32.2	*25*	7.0	7.8	14.8
At a carbon price of 40 €/tCO_2 and a demand elasticity of 0.2								
Czech Republic	*795*	19.0	111.4	130.4	*378*	4.6	25.1	29.7
France	*70*	48.0	15.7	63.7	*65*	35.7	8.9	44.6
Germany	*483*	41.2	70.8	111.9	*418*	9.9	32.5	42.3
Netherlands	*479*	28.0	66.3	94.4	*560*	3.3	28.9	32.2
Spain	*364*	21.8	34.0	55.8	*318*	5.4	17.6	23.0
Sweden	*11*	44.1	29.5	73.6	*13*	17.5	11.7	29.1

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO_2 emission rate (in g CO_2/MWh).
c) Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations.

Differences in proportional profit changes due to the emissions trading effect between countries within a single scenario result mainly from the fuel generation mix of these countries or, more particularly, from the ETS-induced changes in power prices set by the marginal unit versus the ETS-induced changes in both sales volumes and generation costs - including the opportunity costs of emissions trading - of both marginal and infra-marginal operators (where these operators can be either a high-, low- or non-CO_2 emitter). Between scenarios, however, these differ-

[101] In addition, as Table 5.15 records proportional changes, these differences may also result from differences in absolute profit levels between countries before emissions trading.

[102] Moreover, as Table 5.15 records proportional profit changes, differences in these changes between scenarios with different market structures result also from the fact that absolute profit levels before emissions trading are usually significantly higher under OC than PC and, hence, the proportional profit changes due to the free allocation (and/or ET) effect are substantially lower under OC than PC. Therefore, although these changes are generally lower under OC than PC, the absolute profit levels after emissions trading are usually higher under OC than PC.

ences in proportional profit changes result from differences in carbon prices and/or differences in market structures and related differences in (ETS-induced changes in) electricity prices, merit orders, sales volumes, carbon emissions and, hence, in differences in free allocations.

Moreover, as the ETS-induced changes in both electricity prices and sales volumes are sensitive to the price responsiveness of power demand, differences in ETS-induced changes in generators' profits result also from differences in demand elasticities. More specifically, the proportional profit changes due to emissions trading - as well as to free allocations - are generally higher (lower) if the demand elasticity is lower (higher). As the price responsiveness of power demand is usually higher in the long run (than in the short term), it implies that the profit changes due to emissions trading/free allocations are lower - or, in some cases, even negative - in the long run.[103]

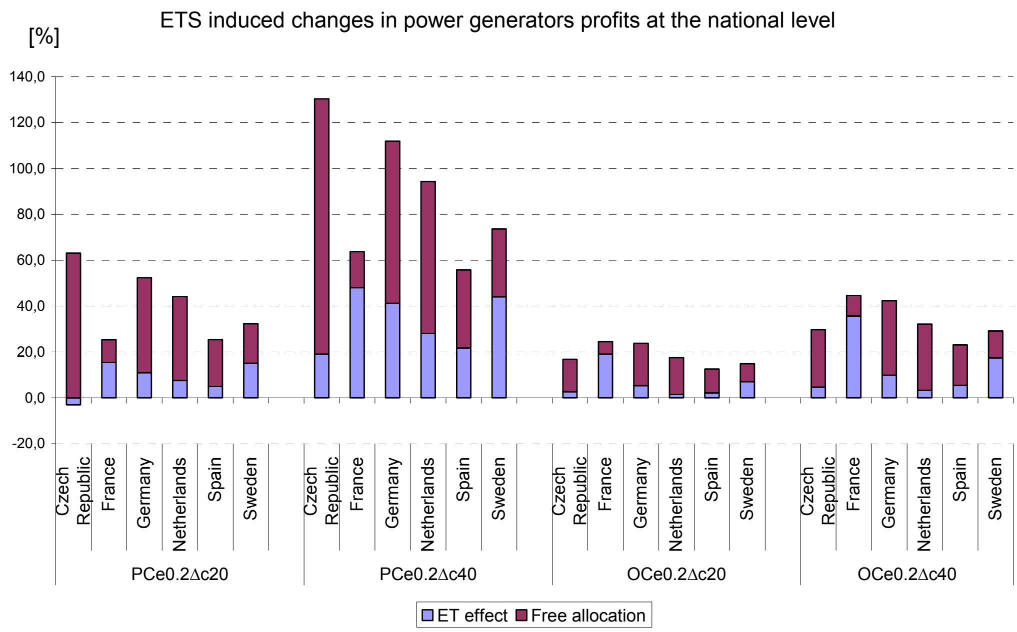


Figure 5.10 *ETS-induced changes in generators' profits at the national level for selected countries under various COMPETES model scenarios*

In Table 5.15 (and Figure 5.10), the profit changes due to emissions trading are based on the assumption that the opportunity costs of emissions trading are actual costs, while the profit changes due to free allocation correct for this assumption if emission allowances are allocated for free (by including the economic rent of the free allowances to power generators' profits). Therefore, the profit changes due to free allocations actually represent the loss in profits if one moves from free allocations to full auctioning, while the profit changes due to the ET effect actually represent the balance of profit changes in the case of full auctioning (compared to the situation before emissions trading).

Table 5.15 shows that the profit changes due to free allocation - and, hence, the losses if one moves to full auctioning - can be very substantial.[104] In addition, however, it shows that the balance of profit changes under full auctioning - compared to the situation before emissions trading - is still significantly positive in most cases, notably in those countries where:

[103] In addition, in the medium to long run, ETS-induced increases in power profits lead to extra investments in new production capacity, which reduces increases in power prices and, hence, reduces increases in generators' profits.

[104] Note that Table 5.15 does not include the impact of the specific free allocation provisions - e.g. to new entrants - on generators' profits. As discussed, these provisions may reduce ETS-induced increases in power prices and, hence, generators' profits in the long run. Shifting towards full auctioning, however, abolishes these provisions and, therefore, their possible impact on generators' profits.

- A major part of power production is generated from non-carbon resources (nuclear, renewables),
- electricity prices are set by carbon intensive technologies while the infra-marginal producers are less carbon intensive,
- the pass-through rate of carbon costs to electricity prices is high, and/or
- the price elasticity of power demand - or the loss in trade competitiveness - and, hence, the reduction in sales volumes is low.

- In a single case, however, a shift towards full auctioning results in an overall reduction of generators' profits (compared to a situation before emissions trading). This applies notably for the Czech Republic under the PC-20 scenario. This reduction in generators' profits in the Czech Republic is mainly due to ETS-induced lower power sales and a pass-through rate smaller than 1.0.

Profit changes at the firm level

Finally, Table 5.16 presents the ETS-induced changes in power generators' profits at the *firm* level for selected EU companies under two COMPETES model scenarios, i.e. a PC versus OC scenario at a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2 (see also Figure 5.11). In addition to some large power companies, the table includes also the so-called 'competitive fringe' in some EU countries, denoted by Comp_Belgium, Comp_France, etc.

Table 5.16 *ETS-induced changes in power generators' profits at the firm level for selected companies under two COMPETES model scenarios [%]*[a]

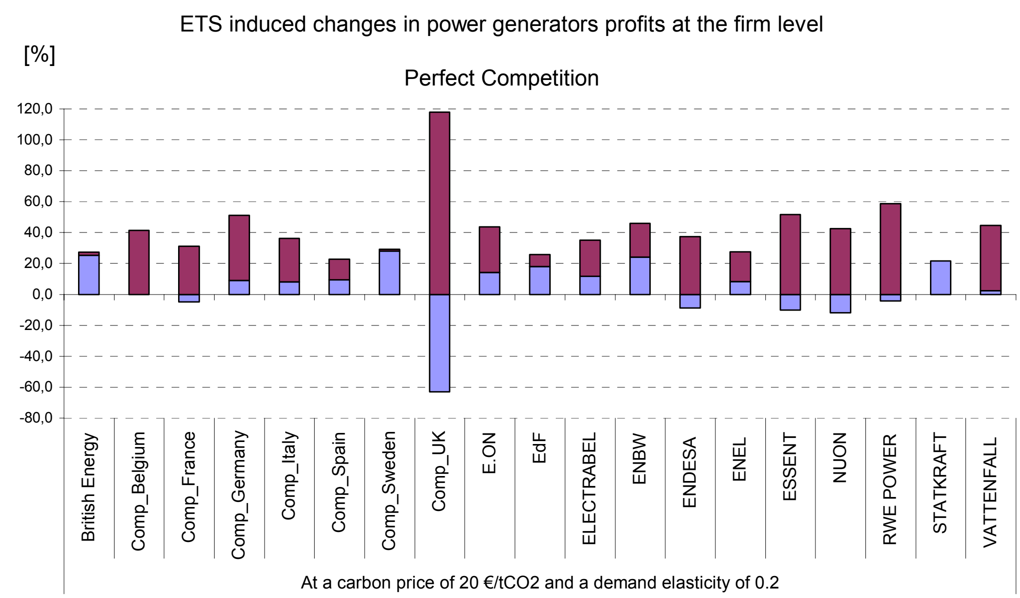
		Perfect competition (PC)			Oligopolistic competition (OC)		
		Δ Profits due to:			Δ Profits due to:		
	CO_2 rate [b]	ET effect	Free allocation[c]	Total effect	ET effect	Free allocation[c]	Total effect
		At a carbon price of 20 €/tCO_2 and a demand elasticity of 0.2					
British Energy	*166*	25.4	1.9	27.3	63.5	0.0	63.5
Comp_Belgium[d]	*530*	0.0	41.4	41.4	-5.6	11.4	5.8
Comp_France	*561*	-4.9	31.3	26.4	2.6	26.8	29.5
Comp_Germany	*651*	9.0	42.2	51.3	0.8	31.7	32.5
Comp_Italy	*569*	8.1	28.1	36.3	2.3	15.0	17.2
Comp_Spain	*337*	9.5	13.4	22.9	5.2	9.6	14.8
Comp_Sweden	*125*	27.9	1.2	29.1	11.9	1.8	13.7
Comp_UK	*581*	-62.9	117.9	55.0	-26.9	159.3	132.3
E.ON	*524*	14.2	29.4	43.6	9.3	4.2	13.5
EdF	*212*	18.0	7.8	25.9	19.4	3.5	22.9
ELECTRABEL	*442*	11.8	23.4	35.2	-0.5	4.7	4.2
ENBW	*403*	24.3	21.6	45.8	8.5	10.5	19.0
ENDESA	*681*	-8.6	37.4	28.8	-8.4	15.4	7.0
ENEL	*592*	8.3	19.2	27.5	5.1	8.6	13.7
ESSENT	*690*	-10.1	51.6	41.4	-8.9	24.1	15.1
NUON	*959*	-11.9	42.5	30.3	-11.2	19.4	8.2
RWE POWER	*692*	-4.2	58.7	54.5	-6.2	16.0	9.8
STATKRAFT	*0*	21.8	0.0	21.8	-0.9	0.0	-0.9
VATTENFALL	*579*	2.4	42.3	44.7	-8.4	23.3	14.9

a) These figures refer to scenario model results, not to facts of life.
b) Average, capacity-weighted CO_2 emission rate of total power sales [kg CO_2/MWh].
c) Assuming that 90% of the emissions and, hence, 90% of the required allowances are covered by free allocations.
d) Comp_Belgium refers to the power producers in Belgium who belong to the so-called competitive fringe.

Table 5.16 shows some major differences between the PC and OC scenario with regard to both the ET effect, the free allocation effect and the total profit effect (which can be similarly explained as discussed above concerning the differences observed in Table 5.15). In addition, the table presents some interesting differences regarding these effects between individual companies within one scenario. For instance, under the PC scenario, the ETS-induced total profit change is significantly positive for all individual firms but ranges from 22% for Statkraft to 55% for RWE. As Statkraft has no emissions, it does not benefit from the free allocation effect. For all other firms included in Table 5.16, however, the free allocation effect is positive in all cases, varying from 8% for EdF to 59% for RWE under the PC scenario.

On the other hand, the so-called 'emissions trading' (ET) effect - excluding free allocations - is positive for some individual firms but negative for others. For instance, due to this effect (at 20 €/tCO_2) generators' profits under the PC scenario increase by 18% for (French-based) EdF and even by 24% for (German-based) ENBW, while they decrease by some 10-12% for (Dutch-based) companies such as ESSENT and NUON.

The differences between the ETS-induced profit effects at the firm level can be explained mainly by the carbon intensity of individual companies - as indicated in the second column of Table 5.16 - compared to the carbon intensity of the marginal unit setting the electricity price during the respective load periods and countries considered. For instance, Dutch-based companies such as ESSENT and NUON are, on average, relatively carbon intensive, while the power price in the Netherlands is set by less carbon intensive, gas-fuelled stations during major (peak) periods of the year, implying that coal-generated power becomes less profitable in the case of emissions trading without grandfathering (i.e. free allocations based on historic, fuel-specific emissions).[105] On the other hand, EdF relies heavily on nuclear, while the power price in France - or in neighbouring, trading countries - is set by fossil-fuelled plants during major periods of the year, implying that nuclear based power becomes more profitable in the case of emissions trading.[106]



[105] This is particularly the case when the pass-through rate of carbon costs to electricity prices is less than 1.0, e.g. when power demand is price responsive or under oligopolistic market structures with linear, downward sloping demand.

[106] Note that both the competitiveness and profitability of nuclear based companies usually benefit from emissions trading regardless of the allocation method, but that in the case of shifting from free allocations to auctioning their profitability improves relatively, i.e. compared to the profitability of fossil-fuel based companies.

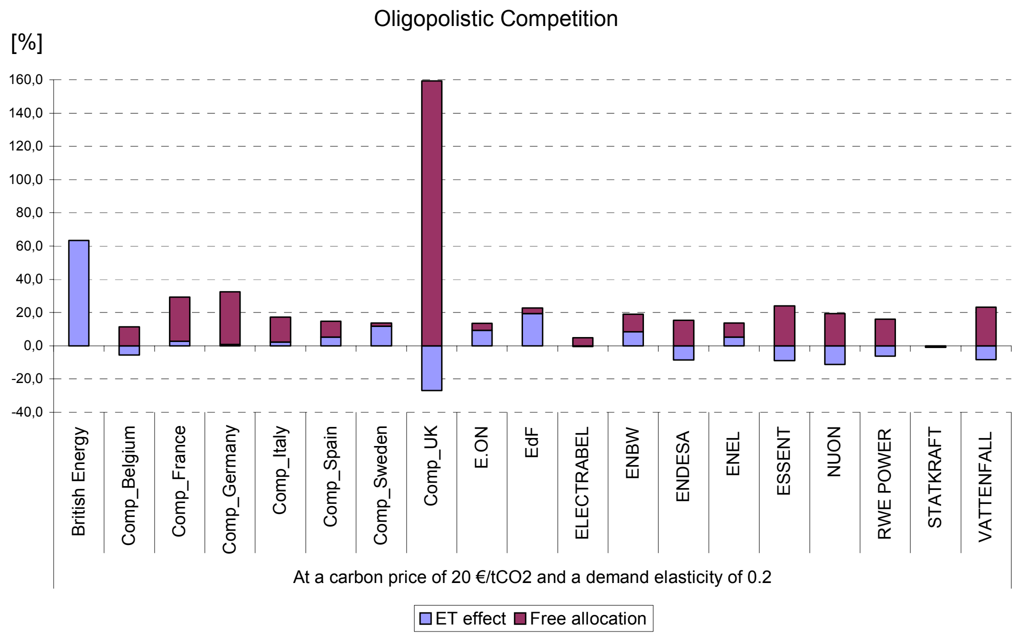


Figure 5.11 *ETS-induced changes in generators' profits at the firm level for selected companies under two COMPETES model scenarios*

Moreover, due to emissions trading total sales volumes may decline (if power demand is responsive), while some carbon intensive firms may loose competitiveness and, hence, their power sales may decrease relatively more, while others may gain competitive strength and, thus, their sales may decrease less (or even increase). Therefore, to conclude, whereas the profits of carbon intensive companies such as ESSENT, NUON or RWE benefit largely from emissions trading based on fuel-specific free allocations - i.e. grandfathering - they suffer from emissions trading based solely on auctioning (depending on the carbon efficiency of the marginal producer and the price responsiveness of power demand). On the other hand, profits of nuclear based companies such as EdF increase absolutely due to emissions trading in general and relatively - i.e. compared to their fossil-fuel based competitors - from auctioning in particular.

Qualifications

It should be emphasised that the figures on power generators' profits discussed above should be treated with due care. These figures are derived from a model that aims to simulate strategic behaviour on the wholesale market. Although the model is quite detailed and based on recently calibrated data, it does not pretend to give a full realistic picture of the power sector. The scenarios of this model are 'extreme' scenarios aimed at analysing the impact of market structure on variables such as power prices, production output and firm profits. Total power sales, including the associated emissions - and, hence, the free allowances and profit changes - vary largely between these scenarios, in particular at the firm level.

Nevertheless, the model offers some useful insights, also with regard to the impact of emissions trading on electricity prices and power generators' profits. For instance, it can estimate the impact of different CO_2 price levels, different market structures and different demand elasticities on the extent to which carbon costs are passed through to power prices. In addition, it can assess the order of magnitude of the impact of emissions trading on operational profits at the firm level. If interpreted prudently, the results can even be helpful in considering the policy implications of emissions trading and allocation methods for the power sector. These implications are further addressed in the next chapter.

6. Policy implications and options to address concerns regarding EU ETS-induced increases in power prices and profits

This chapter discusses some policy implications and options to address social concerns regarding EU ETS-induced increases in electricity prices and generators' profits, i.e. the so-called 'windfall profits'. First, Section 6.1 below discusses the issue of windfall profits. Subsequently, Section 6.2 deals with some policy implications and options to address these profits as well as other concerns regarding the pass-through of carbon costs to electricity prices, in particular the resulting cost increases for power-intensive industries. Finally, Section 6.3 provides a summary and conclusion.

6.1 The issue of windfall profits

The pass-through of the opportunity costs of EU allowances (EUAs) to power prices has raised the issue of the so-called 'windfall profits'. As power companies receive most of the required EUAs for free during the period 2005-2012, the value of these EUAs cannot be considered as actually paid costs but rather as the transfer of a lump-sum subsidy enhancing the profitability of these companies. In addition, even if companies have to pay fully for all allowances needed, some infra-marginal producers may benefit (or lose) from emissions trading, depending on the ETS-induced increase in power prices set by the marginal producer versus the EUA costs of the infra-marginal producer (where both the marginal and the infra-marginal producers can be either a high-, low- or non-CO_2 emitter).

Several qualifications, however, can be added to the issue of EU ETS-induced windfall profits in the power sector. First, the term 'windfall profits' is often poorly defined and understood, notably in the context of emissions trading in the power sector. Literally (or originally), the term seems to refer to the fruit that falls from the tree due to the wind. Hence, it relates to something one gets for free, i.e. an extra bonus without having to make an additional effort and which, usually one did not expect to receive. Therefore, in the context of EU emissions trading in the power sector, the term defined broadly refers to the changes in generators' profits (either positive or negative) due to the implementation of the EU ETS which these generators had not expected once they made their investment decisions. Consequently, windfall profits have a bearing only on existing installations - i.e. 'incumbents' or, more precisely, on investments made before the policy decision to introduce (or change the fundamental conditions) of emissions trading - but not on new investments as the level and kind of these investments (including those in more expensive, but low- or non-CO_2 emitting installations) are based on the new policy conditions and the attendant profit expectations.

Moreover, as outlined in the previous chapter, changes in incumbents' profits due to policy decisions on the fundamentals of emissions trading (i.e. windfall profits, defined broadly) can or should be distinguished into the following two categories:

- *Changes in incumbents' profits due to ET-induced changes in production costs, power prices and sales volumes.* This category of profit changes (denoted as 'windfall A') occurs irrespective of whether eligible companies have to purchase all their allowances at an auction or market or receive them for free.
- *Changes in incumbents' profits due to the free allocation of emission allowances.* This category of profit changes (denoted as 'windfall B') is an addition to or compensation for the first category of windfall profits/losses to the extent to which allowances are obtained for free - rather than purchased - by eligible companies.

In most EU ETS countries, the debate on windfall profits has focussed on category B. Electricity end-users, policy makers and analysts have raised the question why power producers receive EUAs for free while they pass on the 'costs' of these allowances to their output prices anyway, resulting in additional profits that can be questioned from both an efficiency and equity point of view. On the other hand, in some Member States - notably in countries, such as France or Sweden, which rely largely on non-fossil fuels to generate power - the debate has also centred on category A of windfall profits. In particular small end-users and power-intensive industries have raised the question why they should pay more for their electricity consumption, which benefits mainly existing, non-fossil power producers who often made their investments many years ago (amply before the introduction of the EU ETS), while the additional profits to these incumbents do not lead to extra CO_2 mitigation in the nearby future, for instance due to all kinds of constraints limiting the further expansion of nuclear or hydro in these countries.

One may question, however, whether category A should indeed be called 'windfall profits'. They are not necessarily bad or undesirable. On the contrary, they are the intended outcome of a rational climate change policy to internalise the costs of CO_2 emissions in end-user prices and to encourage investments in new, carbon-saving technologies.

Nevertheless, the distinction between the two categories of windfall profits is relevant not only to indicate the differences in the underlying causes or mechanisms of these profits but also to discuss the differences of these two categories in terms of investment incentives and policy implications. Whereas the first category (windfall A) encourages investments in carbon saving technologies, the second category (windfall B) induces investments in particularly high-emitting technologies: provided that allowances are allocated for free to both incumbents and new entrants, in particular in a fuel- or technology specific way, it implies a capacity subsidy that benefits and, hence, promotes more carbon-intensive generation plants. In addition, if for one reason or another one wants to tackle the incidence of generators' windfall profits due to the EU ETS, one has to make a distinction between the two categories of these profits as some policy options affect only the first category but not the second, or vice versa (as discussed below).

Third, the term windfall profits has a negative connotation, mainly because it is associated with either 'unfair' or 'unjustified' practices resulting in higher power prices for small and less-benevolent end-users and, hence, in a transfer of wealth from these end-users (or the public sector) to privileged stakeholders of large, private power companies filling their pockets. As stated, however, the pass-through or internalisation of the opportunity costs of emission allowances into power prices is a rational, intended (and expected) effect from both a business economics and an environmental policy perspective. If someone is to blame for the resulting windfall profits one should primarily look at the policy makers deciding to allocate these allowances for free (rather than at the power producers who act as could be expected from a rational, profit-maximising perspective). Moreover, a major part of the windfall profits in the power sector accrues to public hands, as these profits are subject to public taxation while, in addition, in several EU countries a large number of the power companies are still owned by the public sector (including municipalities, provinces or federal states).

A fourth and last qualification is that estimates of windfall profits have to be treated with due care since it is very hard to estimate these profits empirically in an exact and reliable way, in particular at the company level or in the long run. Most estimates of windfall profits are based on estimates (or sometimes even on assumptions) of the EUA cost pass-through rate (PTR) on a certain market during a certain period (e.g. the wholesale forward market in Germany during the peak or off-peak period in 2006). As discussed in Chapter 4, however, it is very difficult to estimate these PTRs empirically, not only on forward markets but even more on spot markets as power prices on these markets are affected by a large variety of factors besides fuel/carbon costs. Hence, in practice, it is very hard to estimate what the power price would have been without emissions trading. It is even more difficult to estimate changes in generators' profits due to emissions trading as, besides changes in power prices, these profits are affected by changes in carbon or other generation costs and changes in sales volumes (due to lower, price-responsive power demand and carbon price-induced changes in the merit order or other abatement measures). Moreover, ET-induced changes in sales volumes (or other variables affecting profits) may vary significantly at the company level (depending on their fuel generation mix), making it even more complicated to estimate the incidence of windfall profits at the company level (see Chapter 5, notably Section 5.3.6).

In addition, in the long run, the price elasticity or responsiveness of power demand to ET-induced increases in power prices may become more significant (i.e. reducing windfall profits) while ET-induced investments in new capacity will further affect changes in power prices, cost structures, sales volumes and, hence, generators (windfall) profits. Another complicating factor is that estimates of windfall profits are usually based on transactions and pass-through rates on the wholesale power market, while at the retail level transactions, pass-through rates and other factors influencing profits of (integrated) power companies are often affected by the incidence of time lags, long-term contracts or other considerations besides maximising short-term profit such as maintaining or reaching a certain market share. Hence, due to all these factors and changes it is hard to make a reliable, empirical estimate of windfall profits, notably of the first category ('windfall A') at the company level or in the long run.

At first sight, it seems to be easier to estimate the second category of windfall profits (B), since this can be done quite straight forwardly through multiplying the amount of allowances obtained for free by their (average) price, resulting in their market value or 'economic rent'. However, in the case of specific free allocation provisions -such as (i) updating, (ii) closure rules or (iii) free allocation to new entrants - this category is also rather hard to estimate empirically, notably in the long run, as these provisions have contrary, long-term effects on power prices on the one side (i.e. reducing the ET-induced increases in these prices) and carbon prices on the other side (i.e. raising these prices and, hence, the carbon cost passed through to power prices). Therefore, these provisions have contrary, indeterminate effects on changes in generators (windfall) profits, which are, hence, difficult to estimate empirically.

Nevertheless, despite all the qualifications and complications involved, rough/conservative estimates of ETS-induced windfall profits in the power sector can be made in order to get a feeling of the order of magnitude concerned. For instance, at an (average) price of 15 €/tCO_2, the market value or economic rent of the allowances allocated for free during 2005-2006 is equal to approximately € 5 billion in Germany and at least € 15 billion in the EU ETS as a whole. Or, assuming an ET-induced increase in (average) power prices of only 3 €/MWh in 2005-2006 (while average generation costs and sales volumes are supposed to be more or less similar to 2004), windfall profits in the power sector due to the EU ETS amount to almost € 2 billion in Germany and more than € 9 billion in the EU ETS as a whole.[107]

For the short run, these are rough but rather conservative estimates, implying that they may be significantly higher if the (average) carbon price or the (average) pass-through is higher. However, even conservative estimates of windfall profits raise questions on the socio-political acceptability of these profits. The next section addresses options to deal with the incidence of windfall profits and other concerns regarding the pass-through of the opportunity costs of EU emission allowances.

[107] For other estimates of ETS-induced windfall profits in the power sector in countries such as Germany, the Netherlands or the UK see, among others, IPA (2005) VIK (2005), Sijm et al. (2006b), Frontier Economics (2006), Kesisoglou (2007), and Point Carbon (2008). For a further discussion on the issue of windfall profits see recent contributions from Woerdman et al. (2007) and Verbruggen (2008).

6.2 Policy options and implications

As supported by economic theory and empirical evidence, power producers in competitive, unregulated electricity markets pass through (part of) the opportunity cost of CO_2 emissions trading, even if they receive carbon allowances for free. From a climate policy perspective, passing-through the costs of CO_2 emissions is a rational and intended effect, enhancing the efficiency of emissions trading by giving incentives to end-users to reduce their consumption of carbon-intensive goods. For instance, the COMPETES model simulations show that price-induced reductions in power demand can potentially account for a large fraction of emission reductions. Hence, the pass-through of emissions trading costs should be supported and promoted rather than discouraged - even if the allowances are granted for free - by creating conditions for competitive power markets and avoiding measures to regulate price formation or carbon cost pass-through on these markets.

Nevertheless, as indicated above, the pass-through of CO_2 emission costs - notably in the case of free allocations - may raise certain questions or concerns affecting the socio-political acceptability of the EU ETS. In particular, these questions or concerns refer to:

- *Windfall profits - i.e. more surpluses - for power producers.* As noted, the pass-through of carbon costs to electricity prices results in windfall profits for incumbents, which may be quite substantial even in the case where all allowances have to be purchased at an auction or a market (See Section 5.3.6). To some extent, windfall profits for (infra-)marginal producers due to ETS-induced changes in power prices, generation costs and sales volumes ('windfall A') can be accepted as the outcome of normal, every-day changes in policy-economic conditions (which in the case of policy-induced losses can justify some free allocations or other compensation measures). As mentioned, however, in countries with a large share of nuclear/hydro installations as baseload capacity (such as France or Sweden), this category of windfall profits may not only be substantial but also raise questions and concerns about these profits. Similar questions and concerns are raised even more outspokenly in the case of windfall profits due to free allocations ('windfall B'), in particular (i) if these profits - or the EU ETS as a whole - do not lead to significant carbon abatements in the power sector or, through fuel-specific free allocation provisions to new entrants, even encourage investments in CO_2 intensive power plants, and (ii) if these profits actually imply a wealth transfer from less-benevolent electricity consumers to privileged stakeholders of power companies and, hence, raising both efficiency and equity concerns.
- *Higher prices - i.e. lower surpluses - for electricity consumers*. The pass-through of CO_2 emission costs of power generation leads to higher prices for electricity end-users, regardless of whether the carbon allowances are allocated for free or not. As noted, this is a rational, intended/expected effect of emissions trading enhancing the carbon efficiency of the EU ETS and, therefore, it can be regarded as an acceptable, necessary or unavoidable effect. In some particular cases, however, the ETS-induced increases in electricity prices raise concerns from either a competitiveness or carbon leakage point of view. For instance, some industrial end-users face higher power prices but, in turn, are not able to (fully) pass on these higher costs themselves due to outside competition or relatively high price responsiveness of demand for their output products, resulting in a loss of competitiveness, market shares, sales volumes or profits. Although this issue has sometimes been exaggerated, when external competitors do not face comparable carbon costs, there are indeed some power-intensive industries or specific products that are disadvantaged by this effect.

In order to address the (either putative or real) concerns outlined above, policy makers, analysts, industrial stakeholders or other interest groups have suggested a wide variety of options, including options to change the allocation system, both inside and outside the EU ETS. More specifically the suggested options include:

1. Auctioning
2. Allocating free allowances indirectly to power consumers
3. Free allocation based on benchmarking

4. Policies to mitigate carbon prices
5. Regulating power prices
6. Encouraging competitive power markets
7. Taxing windfall profits

These options are evaluated briefly below in terms of (i) their impact on power prices, (ii) their impact on windfall profits in the power sector, distinguished between categories 'windfall A' and 'windfall B', (iii) their impact on the competitiveness of power-intensive industries, (iv) some other major effects (or advantages and disadvantages) of these options, and (v) the overall performance of these options in terms of socio-political acceptability, feasibility and addressing the concerns related to carbon cost pass-through outlined above.

6.2.1 Auctioning

The first and most widely suggested option to address in particular the EU ETS-induced windfall profits is to sell the CO_2 emission allowances at an auction rather than allocating them for free. In the two ideal types of allocation, i.e. auctioning versus perfect free allocation, both types have the same effects in terms of environmental effectiveness, economic efficiency, cost pass-through and output prices. The only difference concerns the distribution of the 'economic rent' of the CO_2 emission allowances in the sense that this value accrues to the public sector in the case of auctioning and that it is transferred as a kind of lump-sum subsidy to eligible companies in the case of free allocations, thereby enhancing the profits of these companies (compared to a situation of emissions trading with auctioning). Therefore, in the ideal situation, auctioning eliminates only the windfall profits due to the free allocations of emission allowances (windfall B) by abolishing the transfer of the market value of these allowances to eligible companies. Auctioning, however, does not reduce the windfall profits due to the ETS-induced changes in power prices, generation costs and sales volumes (windfall A).

In addition, it should be recalled that the present system of free allocations in the EU ETS does not meet the ideal type of perfect grandfathering/benchmarking as it is characterised by some specific free allocation provisions called 'updating' as a result of periodic allocation decisions instead of more permanent provisions, including the loss of free allowances in the case of plant closures and the allocation of free allowances to new entrants. The implication of these provisions is that they may reduce the ETS-induced increases in power prices and generators' profits in the long run, depending on whether the CO_2 budget of the EU ETS - including its cap and the inflow of JI/CDM credits - is fixed in the long run or not (as explained in Section 2.2). If not, a shift towards auctioning implies that these free allocation provisions are nullified and, hence, that their reducing effects on power prices and generators' profits are nullified as well.

Similarly, empirical estimates of carbon cost pass-through rates (PTRs) on power markets are often less than 1.0 in the short run, but little is known about the actual reasons why these rates are less than 100% (let alone the values and determinants of these PTRs in the medium or long term). For instance, is the value of these estimates influenced by the effects of the specific free allocation provisions and, if yes, what is - on balance - the impact of these provisions (or abolishing these provisions by means of auctioning) on the power prices and generators' profits in the long run? Moreover, the pass-through of the opportunity costs of carbon allowances is based on the assumption that power producers try to maximise their profits. However, in the case of free allocation, producers may perhaps sacrifice some of the resulting windfall profits - by reducing the amount of carbon cost pass-through - in order to achieve other short-term objectives such as reaching or maintaining a certain (retail) market share. In the case of auctioning, however, producers lack these windfall resources and, hence, they may increase the amount of carbon cost pass-through. Therefore, in these examples, shifting from free allocation to auctioning not merely abolishes the windfall profits due to the economic rent of allocating allowances, but may also affect (i.e. increase) power prices and, hence, windfall profits due to other factors than transferring economic rents of free allocations.

To conclude, shifting from perfect free allocation to auctioning implies that windfall profits due to the transfer of economic rents will disappear, but it will have no impact on electricity prices or other factors affecting generators' profits, including windfall profits due to ETS-induced changes in these prices and other factors (assuming that power producers try to maximise their profits). However, if emissions trading is characterised by specific free allocation provisions (such as plant closure rules or free allocation to new entrants) a shift towards auctioning may imply that - depending on whether the CO_2 budget of the EU ETS is fixed in the long run or not - the potential reducing effects of these provisions on power prices and generators' (windfall) profits are nullified.[108]

Other effects of auctioning
In addition, auctioning of emission allowances has some other effects.[109] A major advantage of auctioning is that it raises revenues which can be used (i) to finance public expenditures on carbon abatement or other useful, social objectives, (ii) to reduce taxation and related efficiency distortions ('double dividend'), or (iii) to compensate power-intensive industries and other electricity consumers for the ETS-induced increases in power prices. Recycling of auction revenues, however, raises all kinds of new allocation issues (Sijm et al., 2006b).

The main disadvantage of auctioning is that, if external competitors do no face comparable carbon costs, it may entail a risk of carbon leakage and loss of competitiveness, in particular for some highly exposed, energy-intensive industries which are not able to pass on carbon costs to their outlet prices. This, however, does not apply to the EU power sector as it hardly faces any outside competition. Moreover, free allowances to electricity producers would not be of any avail to power-intensive industries as these producers pass through the cost of carbon allowances anyhow.

Overall, to conclude, auctioning of emission allowances seems to be a proper option for the power sector after 2012 in order to address the issue of windfall profits due to free allocations up to 2012 and the efficiency distortions of some specific free allocation provisions. Moreover, auction revenues can be used to finance expenditures for climate change related policies or other useful social objectives such as improving industrial competitiveness or compensating certain consumer groups for ETS-induced increases in power prices.

6.2.2 Allocating free allowances to power consumers

Rather than allocating free allowances directly to power producers, these allowances could be allocated indirectly to power consumers while power producers are still obliged to cover their emissions by submitting allowances to the emission authority. This would imply that these consumers could sell these allowances while the producers have to buy them.

Basically, for power producers, the option has the same effects as auctioning in terms of abolishing the windfall profits due to free allocations and, if present, eliminating the effects of specific free allocation provisions on power prices and related generators surplus. The major difference is that electricity consumers are subsidised directly for the ETS-induced increases in power prices (rather than the auction revenues accruing to the public sector).

For the benefiting sectors, however, such subsidies, even if not dependent on actual production or emission levels, are likely to increase capacity and production and thereby emissions. Moreover, if allocation of allowances to individual power consumers depends on their decisions on

[108] For a further discussion on the implications of free allocation versus auctioning of EUAs on the performance of the power sector in the Netherlands, see Sijm et al. (2008a).
[109] For a broader discussion including design options, advantages and disadvantages of auctioning emission allowances, see Hepburn et al. (2006), Burtraw et al. (2007), Matthes and Neuhoff (2007), and Harrison et al. (2007).

the quantities of electricity purchased, it may have an even stronger perverse, i.e. stimulating effect on power consumption and related CO_2 emissions (similar to the effects of recycling auction revenues in a direct, targeted way as discussed above). In addition, it may easily lead to an overcompensation of at least some of the consumers, in particular those able to pass on higher power costs into higher output prices. Moreover, besides an adjustment of the present EU ETS directive and current practice of allocating allowances directly to power producers, it may imply a significant increase in transaction costs if allowances have to be allocated to hundreds of millions of end-users and, subsequently, sold on the market.

There have been suggestions that, to some extent, the problems or disadvantages outlined above can be relieved by restricting allocations to end-users who cannot pass on the costs of higher electricity prices, or by allocating allowances to local distribution companies or to an independent trustee who could sell the allowances to power producers and use the revenues to rebate consumers on a per capita or household basis independent of the quantities of electricity purchased by each consumer.[110] However, although this option may at first sight seem sympathetic, its overall performance seems to be low compared to the first option of auctioning discussed above and using the auction revenues in more general ways (including appropriate means to compensate end-users who actually need it without having an adverse effect on their power consumption decisions).

6.2.3 Free allocation based on benchmarking

Benchmarking implies allocating emission allowances for free based on a standard emission factor (i.e. the benchmark) multiplied by a certain quantity or activity level (for instance a certain input, output or capacity level). While the benchmark itself is usually fixed ex-ante, the quantity or activity level can be either fixed ex-ante, (i.e. before the start of the trading period, resulting in a fixed cap and trade system) or adjusted ex-post (i.e. after the actual activity level realised, resulting in a relative cap and trade system).

If a similar amount of free allowances is allocated in a benchmarking system with a similar fixed cap as in a grandfathering system, it has the same performance in terms of environmental effectiveness, economic efficiency, carbon prices, cost pass-through, output prices and overall (windfall) profits. However, in terms of distributing the economic rent of the free allocations - and, hence, the related windfall profits - it may result in a different outcome among the sectors or installations involved, depending on the specifics of the benchmarking system. This applies in particular to a 'perfect' benchmarking system (compared to a 'perfect' grandfathering system), i.e. a free allocation system with a fixed cap and no updating - including no specific free allocation provisions for new entrants or plant closures - but also to a benchmarking system with a fixed cap and updating provisions (compared to a similar, less perfect grandfathering system).

An ex-post benchmarking system reduces - or even nullifies - the ETS-induced increases in power prices and generators' (windfall) profits but, on the other hand, it also reduces the carbon efficiency of the trading scheme. In addition it is incompatible with the core architecture of the present EU ETS as it is based on an ex-ante fixed cap. Therefore, this ex-post system is not further analysed here.[111].

6.2.4 Policies to mitigate the price of an emission allowance

In addition to changing the allocation system, there are some other options for addressing concerns related to the ETS-induced increases in power prices, for instance by policies that mitigate

[110] For a further discussion of these approaches, see Burtraw and Palmer (2006).
[111] For a discussion on the pros and cons of ex-post benchmarking see, among other, Schyns (2005 and 2007), Demailly and Quirion (2007), Wesselink et al. (2008), and Sijm et al. (2008b).

the price of an emission allowance and, hence, the pass through of the allowance cost to power prices. In particular, such policies may include (i) increasing the inflow of JI/CDM offset credits, (ii) implementing other policies besides emissions trading that reduce emissions of the ETS sectors, or (iii) encouraging the R&D of carbon-saving technologies.

In the January 2008 proposals by the European Commission, the use of JI/CDM offset credits by ETS installations is limited, but covers nevertheless already about half of the emissions reductions to be achieved by the EU ETS over the period 2008-2020. One of the major arguments for this limit and, hence, against a further increase of the inflow of JI/CDM credits is to ensure a certain EUA price level that encourages domestic carbon-saving innovations and, therefore, dynamic efficiencies in the long run. Another important argument is the need for international credibility which would be undermined if a greater share of the reduction would be achieved in third countries. Moreover, an unconditional increase of the use of JI/CDM credits could undermine the incentive for third countries to join an international agreement and put in place more ambitious climate change policies.

Implementing other climate or energy policies besides emissions trading - for instance policies to promote renewables or energy efficiency - may lead to fewer emissions in the ETS sectors and, hence, to lower EUA prices. Likewise, policies to enhance, for instance, energy security or air quality may also reduce carbon emissions and, hence, mitigate allowance prices. When setting the cap for the EU ETS and the overall reduction target for sectors outside the EU ETS, such policies must be taken into account in order to achieve an efficient climate policy. On the other hand, additional policy measures that are implemented solely to reduce emissions in the ETS sectors may reduce overall efficiency as they may replace cheaper abatement options (induced by emissions trading) by more expensive options (Sorrell and Sijm, 2003).

At the same time, measures to encourage energy saving may well be appropriate in view of the failure of consumers to take the true societal cost of energy into account. Also policies encouraging R&D and innovation in the field of energy saving and emissions reductions may have significant positive spill-over impacts. Market imperfections in the R&D stages of new carbon-saving technologies can be overcome by adequate public support in a socially optimum way. Such policies are, effectively, important to mitigate the carbon cost (and hence the price of a CO_2 allowance) of achieving the much deeper emissions cuts that are needed in the long term.

6.2.5 Regulating power prices

Another option to reduce ETS-induced increases in power prices and generators' profits due to free allocation is to have these prices regulated by an external authority, for instance the national Transmission System Operator (TSO) or the energy market surveillance authority. In practice, this option would imply that power producers are allowed to pass through only the (average) costs of carbon allowances bought on an auction or market (and the abatement costs of reducing power-related CO_2 emissions, or other changes in generation costs due to emissions trading) but not the opportunity costs of the allowances obtained for free. Besides limiting increases in electricity prices in favour of end-users, including small firms and low-income households, a related advantage of this option is that it reduces the deterioration of the international competitiveness of some power-intensive industries.

Regulating power prices, however, has some serious drawbacks. First, this option is nowadays not popular among EU policy makers as it does not fit in the current process of market liberalisation, privatisation and deregulation in order to achieve competitive, efficient power markets. Second, it may be hard and administratively demanding to determine (ex ante) the (average) costs of purchasing the necessary allowances over a certain trading period or the abatement costs (and other changes in generation costs) due to emissions trading, notably in the case of setting wholesale spot or forward prices.

Third, if effective and assuming power demand to be price responsive - notably in the medium and long terms - this option implies higher power production, and, hence, higher sector-related emissions, thereby forfeiting an efficient strategy to meet future mitigation commitments. Moreover, lower power prices imply fewer incentives for investments in more expensive, but carbon-saving technologies such as renewables.

Finally, one may question the effectiveness of this option to reduce power prices. As noted above, if effective, this option would result in more power demand, fewer carbon-saving technologies and, hence, more power production by CO_2 intensive plants. However, as operators of these plants are not allowed to pass through the opportunity costs of allowances obtained for free, they are inclined to reduce their production and sell the allowances on the market, resulting in serious power market scarcities and induced higher (rather than lower) electricity prices. Therefore, for a variety of reasons, regulating power prices does not seem to be a cost-effective or politically attractive option to reduce ETS-induced increases in electricity prices or generators' profits due to free allocations of allowances.

6.2.6 Encouraging competition in the power sector

It is sometimes suggested that the ETS-induced increases in power prices and windfall profits resulting from free allocations are due to a lack of competition in the power sector and, hence, that encouraging this competition would reduce these increases in prices and profits. However, although encouraging power market competition may increase sector efficiency or reduce the incidence of market power - and, hence, reduce power prices - one may question whether this option is effective in reducing ETS-induced increases in power prices and generators' profits due to free allocations.

As supported by economic theory and empirical evidence, in competitive markets power producers also pass through the opportunity costs of carbon allowances into their price bids (even up to 100%), regardless of whether they have purchased these allowances or obtained for free. Moreover, depending on the specific characteristics of non-competitive market structures and power demand (i.e. a constant elasticity or linear demand curve), the carbon cost PTR on a monopolistic or oligopolistic market may be either significantly higher or lower than 100% (Section 2.2). Therefore, encouraging competition in the power sector will not eliminate ETS-induced increases in power prices and windfall profits due to free allocation (on the contrary), but may even result in a higher carbon cost PTR and, hence, to even higher increases in these prices and profits.

In addition, a similar or related suggestion is that free allocations to new entrants lead to earlier investments in additional generation capacity and, perhaps, even in more power producers actively supplying on the market, resulting in less market scarcity, less market power or more competition and, therefore, in reducing or compensating the ETS-induced increases in power prices and windfall profits due to free allocation to existing producers. However, although to some extent these effects may occur, several qualifications can be made to free allocations to new entrants (in addition to the qualifications made above with regard to the impact of market competition on cost pass-through and power prices).

First, this option is only effective if it indeed leads to additional, earlier investments in generation capacity, which in the power sector may take at least several years to implement. Second, due to a variety of technical, economic and other constraints, investments in new generation capacity are usually conducted by existing firms rather than by newcomers. Third, if effective and assuming power demand to be price-responsive, this option implies higher power production and, hence, higher sector-related emissions, thereby giving up an efficient strategy to meet mitigation targets.

Moreover, lower power prices imply less incentive for investments in more expensive, but carbon-saving technologies such as renewables. This applies particularly if free allowances to new entrants are allocated in a fuel-specific or technology-biased way (i.e. high polluters get more, while non-CO_2 emitters receive nothing), thereby undermining the ETS incentive structure towards carbon-saving investments.

Finally, if one is interested in increasing generation capacity or power market competition, there are most likely more socially efficient measures than free allocations to new entrants, such as introducing capacity markets or direct capacity payments to power producers, including by newcomers, or separating power network structures from production and marketing activities.

Therefore, to conclude, although encouraging competition in the power sector would have a beneficial effect on reducing oligopolistic price-setting and resulting generators' profits (and, hence, act as a counter-balancing effect on ETS-induced increases in power prices and profits), it is a questionable option to achieve this objective by means of free allocation to new entrants for a variety of reasons.

6.2.7 Taxing windfall profits

Another major, final option to address the issue of windfall profits due to the EU ETS is skimming these profits through taxation, either fully or partially. Compared to auctioning, a major advantage of taxation is that it can address both categories of windfall profits, i.e. not only category B but also category A. Another advantage of taxing windfall profits is that it raises revenues that can be either recycled or used to finance public expenditures (although recycling tax revenues raises similar problems as recycling auction revenues, discussed above).

The major problem of taxing windfall profits is that, in practice, it is hard to estimate them reliably just as it is rather difficult to estimate empirically exact, reliable PTRs and, hence, to estimate what power prices (or sales volumes, generation costs, etc.) would have been without emissions trading. This applies in particular to estimating windfall profits at the individual company level, or to estimating such profits when free allocation provisions such as updating or free allocations to new entrants reduce ETS-induced increases in power prices and windfall profits in the medium or long run. An additional complicating issue is whether only ETS-induced windfall profits in the power sector should be taxed or also similar profits in other sectors, and how to determine these profits in a fiscal-juridical correct way.

Another problem concerns the definition of windfall profits, notably whether they refer to category A or B, or both categories, and whether they are related only to existing producers or also to new entrants (see Section 6.1 above). While in some EU ETS countries the issue of windfall profits in the power sector refers almost solely to category B (i.e. windfall profits due to free allocations), in other countries it is related primarily to category A (i.e. windfall profits due to ETS-induced changes in power prices, sales volumes and generation costs).

In addition, while some observers refer the issue of windfall profits to both existing and new producers, others relate it solely to incumbents, arguing that new entrants have based their investment decisions on profit expectations *after* the policy decision to introduce emissions trading. Moreover, taxing windfall category A to new entrants would imply that the incentive to invest in carbon-saving technologies would be reduced. On the other hand, however, taxing windfall category B accruing to new entrants would mean that the incentive to invest in CO_2 intensive technologies and the distorting effects on output prices and abatement efficiency would be reduced, notably if the free allocation to new entrants is applied in a fuel-specific or technology-biased way.

To some extent, the dilemmas outlined above could be relieved by restricting taxation to the full or partial (average) market value of the allowances allocated for free to both incumbents and new entrants in the power and other sheltered sectors of the EU ETS. However, a similar and, perhaps, even simpler solution would be to auction the corresponding amount of allowances to these sectors. In addition, a problem of full, i.e. 100%, taxation (or auctioning) is that it may lead to 'overtaxation' of windfall profits due to free allocations - depending on the actual PTR and the ETS-induced changes in sales volumes - while, as noted, it is hard to estimate the right tax rate to break even, notably at the company level or in the long run. Moreover, taxing only windfall category B would not solve the issue of windfall category A, which is not only more important in some EU ETS countries but, in addition, would deny these countries the potential revenues to address some concerns related to the ETS-induced increases in electricity prices such as losses in purchasing power of low-income households or losses in international competitiveness of some exposed, power-intensive industries.

Another option would be no taxation but auctioning of carbon allowances to all power operators (and other sheltered producers) and, as far as category A of windfall profits to existing, private companies is a relevant problem in some countries, these profits can be taxed by these countries - based on a conservative, prudent estimate of the size of windfall A - while the revenues can be used at their own discretion.

Finally, there are easy second-best solutions to tax the production of existing nuclear and hydro power plants in a relatively simple and straightforward way and, hence, to address the windfall profits of category A. For instance, Sweden levies a lump-sum tax on the owner of a hydro dam that is not at all related to annual output and, therefore, is a simple option creating no perverse incentive like cutting output of a low-carbon power source.

6.3 Summary and conclusion

A summary of the performance of the major options discussed above is presented in Table 6.1. The table shows that the effectiveness of options to control or reduce carbon/power prices - either directly or indirectly - is low to medium, partly depending on the means to achieve these objectives, in the first place because they reduce the efficiency to achieve the emission reduction target for which the system has been designed. Moreover, in general they largely fail to address the ETS-related concerns mentioned above or they have certain disadvantages or other side-effects which make these options not attractive or acceptable to policy makers.

On the other hand, the overall performance of auctioning allowances to power producers is considered to be high as it enhances the carbon efficiency of the EU ETS and eliminates the windfall profits due to free allocations. Moreover, it raises revenues that can be used to (i) finance public expenditures on carbon abatement or other useful, social objectives, (ii) invest in improving competitiveness or reduce taxation and related efficiency distortions (the so-called 'double dividend'), or (iii) address potential social concerns of poorer electricity consumers.

However, auctioning does not reduce generators' windfall profits due to ETS-induced increases in power prices - in particular for infra-marginal, less carbon-intensive plant operators - and may even lead to an increase in such profits (notably when it implies the termination of free allocation to new entrants, leading to higher power prices in the medium or long run). As far as such profits are a major point of concern in some EU countries, these profits can be taxed by these countries, while the revenues can be used to their own discretion (similar to recycling auction revenues).

Table 6.1 *Performance of options to address concerns regarding ETS-induced increases in output prices and windfall profits in the power sector*

Option	Impact on power prices	Impact on windfall profits		Other main effects (including major advantages and disadvantages)	Overall performance
		Type A	Type B		
1. Auctioning	0/+?	0/+?	-	- Raising auction revenues - May reduce competitiveness of specific firms	High
2. Allocation to power consumers	0/+?	0/+?	-	- Direct compensation - Perverse consumption effect - Overcompensation of sheltered industries	Medium
3. Benchmarking:					
• *Fixed (ex-ante) cap*	0	0	0	- Effects are similar to grandfathering with fixed cap	Low
• *Variable (ex-post) cap*	-/0?	-/0?	-	- Loss of carbon efficiency - Incompatible with present EU ETS	Low
4. Reducing EUA price by:					
• *Increasing JI/CDM credits*	-	-	-	- Technical, economic and/or other limitations	Medium
• *Other carbon reducing policies*	-	-	-	- Neither abatement effective nor efficient	Low
• *Encouraging carbon saving technologies*	-	-	-	- Mainly effective in the long run	Medium/High
5. Regulating power prices	-	-	-	- Interferes with liberalised, competitive markets - More demand/emissions - Less carbon-saving investments - More market scarcities	Low
6. Encouraging market competition	-/+?	-/+?	-/+?	- Effects depend on PTR of more versus less competition	Medium
• *By free allocation to new entrants*	-/0?	-/0?	-/0?	- Abatement inefficiency - Undermines incentives EU ETS	Low
7. Taxing windfall profits	0	-	-	- Windfall profits are hard to estimate	Medium

Note: '+' indicates that prices or profits increase; '-' indicates that prices or profits decrease due to the policy option, while '?' indicates that the effect is uncertain.

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Appendix A Impact of power market structure on CO_2 cost pass-through to electricity prices: Mathematical proofs

This appendix provides several mathematical derivations of the pass-through rate (PTR) of CO_2 emissions trading costs (*CC*) to the price of electricity under different levels of market concentration – or market competitiveness – as well as under different shapes of the power supply and demand curves.[112] In the cases discussed below, the demand curve is either iso-elastic or linear, while the supply (or marginal cost) curve is either iso-elastic, linear or perfect elastic (i.e., a flat horizontal line of constant marginal costs regardless of the quantity produced). Combining these variations results in the following six cases:

1. Iso-elastic demand and iso-elastic supply.
2. Iso-elastic demand and linear supply.
3. Iso-elastic demand and perfect elastic supply.
4. Linear demand and iso-elastic supply.
5. Linear demand and linear supply.
6. Linear demand and perfect elastic supply.

The derivations of the PTR for each of these six cases are provided in the sections below.

A.1 Iso-elastic demand and iso-elastic supply

The iso-elastic demand curve is assumed to be $Q = Q_o(P/P_o)^{-\varepsilon}$, where Q is quantity, P is price, $-\varepsilon$ is demand elasticity ($\varepsilon > 0$), and Q_o and P_0 are a reference quantity-price pair (where supply and demand are assumed to intersect under perfect competition and no emissions trading). Thus, the inverse demand function can be written as $P = P_0(Q/Q_0)^{-1/\varepsilon}$. The iso-elastic supply function is $MC = P_0(Q/Q_0)^b$, where $1/b > 0$ is the supply elasticity. Then the marginal cost for firm f is $MC_f = P_0(Nq_f/Q_0)^b$, where N is the number of symmetric firms in the market and q_f is output from firm f.

Assume that *CC* expresses the carbon cost (in € per megawatt-hour, €/MWh) due to emissions trading, then the marginal cost for firm f is as follows:

$$MC_f = P_0(\frac{Nq_f}{Q_0})^b + CC \qquad \text{(A.1)}$$

Thus, assuming Cournot competition, the first-order profit maximization condition $MR = MC$ and symmetry among firms yields the following equilibrium condition for firm f:

$$P(1-\frac{1}{N\varepsilon}) - P_0(\frac{Q}{Q_0})^b - CC = 0 \qquad \text{(A.2)}$$

To investigate cost pass-through (the change in the price P related to the change in the carbon costs *CC*), we take the total derivative dP/dCC of (A.2), defined as F for convenience:

[112] This appendix is a revised and extended version of the appendix published in Chen et al. (2008). The authors would like to thank Yihsu Chen (University of California, Merced, USA) and Prof. Ben Hobbs (The Johns Hopkins University, Baltimore, USA) for their contributions to this appendix.

$$F = \frac{dP}{dCC} = \frac{1}{1 - \frac{1}{N\varepsilon} + b\varepsilon P_0^{\varepsilon b+1} P^{-\varepsilon b-1}} \quad \text{(A.3)}$$

We then evaluate dP/dCC at $CC = 0$ by substituting P in terms of N, ε and b into (A.3) using (A.2):

$$F = \frac{dP}{dCC} = \frac{1}{(1 - \frac{1}{N\varepsilon})(1 + b\varepsilon)} \quad \text{(A.4)}$$

Note that if the price elasticity of supply is much higher than the demand elasticity (so that $1 + b\varepsilon$ is close to 1), then the PTR can exceed 1. To examine the effect of demand elasticity ε, supply elasticity $1/b$, and number of firms N on F, we need the sign of the partial derivative with respective to ε, b and N (i.e., $\partial F/\partial\varepsilon$, $\partial F/\partial b$, and $\partial F/\partial N$, respectively). We discuss each in turn.

Demand elasticity ε

When $N\varepsilon > 1$, then dP/d$CC = F > 0$. The term $1/(1 + b\varepsilon)$ in (A.4) is unaffected by ε if $b = 0$, and is decreasing in ε if $b > 0$. The term $1/(1 - 1/(N\varepsilon))$ is unaffected by ε if N is infinite and is otherwise decreasing in ε. Thus, if $b > 0$ and N is finite, then F is positive and decreasing in demand elasticity ε (i.e., $\partial F/\partial\varepsilon = -((1 - 1/(N\varepsilon)(1 + b\varepsilon))^{-2}((N\varepsilon)^{-2}N(1 + b\varepsilon)+(1 - 1/(N\varepsilon)b) < 0$. That is, more elastic demand means less pass-through.

Supply elasticity b

When $N\varepsilon > 1$, both terms $1/(1 + b\varepsilon)$ and $1/(1 - 1/(N\varepsilon))$ in (A.4) are positive, and $1/(1 + b\varepsilon)$ is decreasing in b given that supply elasticity $\varepsilon > 0$. Thus, $F =$ dP/dCC >0 and is decreasing in b (i.e., $\partial F/\partial b = -((1 - 1/(N\varepsilon)(1 + b\varepsilon))^{-2}(1 - 1/(N\varepsilon)\varepsilon < 0))$. In the limiting cases of perfectly inelastic and elastic supply ($b = \infty$, 0, respectively), there is no pass-through and pass-through of $1/(1 - 1/(N\varepsilon))$, respectively. Less elastic supply (i.e., higher b) means less pass-through.

Number of firms N

As noted, both terms $1/(1 + b\varepsilon)$ and $1/(1 - 1/(N\varepsilon))$ in (A.4) are positive; further, $1/(1 + b\varepsilon)$ is not affected by N and $1/(1 - 1/(N\varepsilon))$ is decreasing in N, given that demand elasticity $\varepsilon > 0$ and $N\varepsilon > 1$ (i.e., $\partial F/\partial N = -((1 - 1/(N\varepsilon)(1 + b\varepsilon))^{-2}(1 + b\varepsilon)\varepsilon\, (N\varepsilon)^{-2} < 0$.) As an extreme case, if $1 + b\varepsilon$ is close to 1, then the PTR approaches 1 from above as N increases. Thus, more competitive markets mean less pass-through.

A.2 Iso-elastic demand and linear supply

For simplicity, we assume that the iso-elastic demand curve and the linear supply curve take the following forms:

$$P = Q^{-\frac{1}{\varepsilon}} \text{ (or } Q = P^{-\varepsilon}\text{)} \quad \text{(A.5)}$$

$$MC = A + uQ \quad \text{(A.6)}$$

Where u is the coefficient of the linearly upward sloping supply curve. Assuming that firms compete in the Cournot fashion (i.e., quantity as variable), the first-order condition is defined by:

$$MR = MC = P + \frac{\partial P}{\partial q_f} q_f = A + uNq_f \tag{A.7}$$

If we further assume that firms are symmetric, we can substitute $\frac{\partial P}{\partial q} = -\frac{1}{\varepsilon} Q^{-\frac{1}{\varepsilon}-1}$ into the first-order condition mentioned above:

$$MR = MC = P + \left(-\frac{1}{\varepsilon} Q^{-\frac{1}{\varepsilon}-1} \right) \frac{1}{N} Q = A + uQ \tag{A.8}$$

and then derive the equilibrium condition equal to:

$$P - \frac{1}{N\varepsilon} Q^{-\frac{1}{\varepsilon}} - A - uQ = 0 \tag{A.9}$$

With emissions trading, marginal cost increases by *CC*. The equilibrium condition becomes:

$$P - \frac{1}{N\varepsilon} Q^{-\frac{1}{\varepsilon}} - A - uQ - CC = 0 \tag{A.10}$$

Again, perturb around $CC = 0$ and find $\frac{dP}{dCC}$ by taking the total partial on both sides. This results into:

$$\frac{dP}{dCC} - (-\frac{1}{\varepsilon}) \frac{1}{N\varepsilon} Q^{(-\frac{1}{\varepsilon}-1)} \frac{dQ}{dP} \frac{dP}{dCC} - u \frac{dQ}{dP} \frac{dP}{dCC} - 1 = 0 \tag{A.11}$$

From (A.5), we can derive that

$$\frac{dQ}{dP} = -\varepsilon P^{-\varepsilon-1} \tag{A.12}$$

Substitute (A.12) into (A.11), the PTR can be expressed as follows:

$$\frac{dP}{dCC} = \frac{1}{1 - \frac{1}{N\varepsilon} Q^{(-\frac{1}{\varepsilon}-1)} (P^{-\varepsilon-1}) + uP^{-\varepsilon-1}} \tag{A.13}$$

Substituting $P = Q^{-\frac{1}{\varepsilon}}$ in (A.13) results in:

$$\frac{dP}{dCC} = \frac{1}{1 - \frac{1}{N\varepsilon} + uP^{-\varepsilon-1}} \tag{A.14}$$

Given that $\frac{1}{N\varepsilon} < 1$, (A.14) will be positive. Thus, the PTR under iso-elastic demand and linear supply is always positive.

A.3 Iso-elastic demand and perfect elastic supply

Compared to the case of Section A.1, this is a special case where $b = 0$, which reduces Equation A.4 to the following:

$$F = \frac{dP}{dCC} = \frac{1}{1 - 1/(N\varepsilon)} \tag{A.15}$$

Thus, when carbon cost increases by CC due to emissions trading, the equilibrium price increases by $CC \cdot N\varepsilon/(N\varepsilon - 1)$.[113]

A.4 Linear demand and iso-elastic supply

Under linear demand, the inverse demand curve is parameterized as Equation A.16 so that the competitive equilibrium with no carbon trading passes through (Q_0, P_0) and has elasticity ε at that point:

$$P = P_0(1 + \frac{1}{\varepsilon}) - (\frac{P_0}{Q_0\varepsilon})Q \tag{A.16}$$

For N symmetric firms, the individual firm's marginal cost is $P_0(Nq_f/Q_0)^b$, as in Section A.1. For an individual Cournot firm, the first-order condition $MR = MC$ under emission cost equal to CC is:

$$P - \left(\frac{1}{\varepsilon N}\right)\left(\frac{P_0}{Q_0}\right)Q - P_0\left(\frac{Q}{Q_0}\right)^b - CC = 0\,. \tag{A.17}$$

We evaluate the total derivative $\frac{dP}{dCC}$ at $CC = 0$ using $\frac{dQ}{dP} = -\varepsilon\left(\frac{Q_0}{P_0}\right)$ derived from equation (A.16):

$$F = \frac{dP}{dCC} = \frac{1}{1 + \frac{1}{N} + \varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}}\,. \tag{A.18}$$

We then substitute P from (A.16) into (A.17) and derive $\frac{\partial Q}{\partial N}$, $\frac{\partial Q}{\partial \varepsilon}$ and $\frac{\partial Q}{\partial b}$ as a function of N, b, ε and Q:

$$\frac{\partial F}{\partial N} = \frac{-\left(\frac{-1}{N^2} + \frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial N}\right)}{\left(1 + \frac{1}{N} + \varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2} \tag{A.19}$$

113 A similar result is obtained by substituting $u = 0$ into Equations A.6 up to A.14.

$$\frac{\partial F}{\partial \varepsilon} = \frac{-\left(b\left(\frac{Q}{Q_0}\right)^{b-1} + \frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial \varepsilon}\right)}{\left(1+\frac{1}{N}+\varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2} \tag{A.20}$$

$$\frac{\partial F}{\partial b} = \frac{-\left(\varepsilon\left(\frac{Q}{Q_0}\right)^{b-1}\left(1+b\left(\ln\frac{Q}{Q_0}\right)\right) + \frac{\varepsilon b(b-1)}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2}\frac{\partial Q}{\partial b}\right)}{\left(1+\frac{1}{N}+\varepsilon b\left(\frac{Q}{Q_0}\right)^{b-1}\right)^2}. \tag{A.21}$$

Substitute $\frac{\partial Q}{\partial N} = \frac{1}{\varepsilon N^2\left(\frac{b-1}{Q_0}\left(\frac{Q}{Q_0}\right)^{b-2} + \frac{Q_0}{(1+\varepsilon)Q^2}\right)}$ into equation (A.19) and rearrange the terms.

If $b > 1$, it implies that $\frac{\partial F}{\partial N} > 0$. Thus, the cost pass-through is positively associated with the number of firms N in the market.

Equation (A.20) is < 0 given $b > 1$ and $\frac{\partial Q}{\partial \varepsilon} > 0$ (because decrease in elasticity ε would lead to higher price with smaller equilibrium quantity Q). Thus, the cost pass-through is negatively associated with demand elasticity.

Finally, the cost pass-through is expected to be positively associated with supply elasticity $1/b$, if $b > 1$ and $\ln\frac{Q}{Q_0} > -\frac{1}{b}$ (Equation (A.21)). That is, the equilibrium quantity relative to the reference Q_0 is bounded by exponential of negative supply elasticity.

A.5 Linear demand and linear supply

Again, assuming there are N firms in the market. Then, the marginal cost curve of firm f is equal to $MC_f = A + uNq_f$ and demand is $P = B - vQ$, where $Q = q_1 + q_2 + q_3 + q_4 + q_5 + \ldots q_N$

Prior to emissions trading, the optimal condition MC = MR is expressed:

$$A + u(Nq) = B - v(Nq) - vq \tag{A.22}$$

Thus, $A + u(Q) = B - v(Q) - v(Q/N)$ and solve for equilibrium $Q_0 = \frac{B-A}{u+v+v/N}$

Then, substitute Q_0 into demand function for price: $P_0 = B - v(\frac{B-A}{u+v+v/N})$

Similarly, if we assume that emissions trading raises marginal cost by *CC*, the equilibrium conditions are then derived as follows:

$$A + u(Nq) + CC = B - v(Nq) - vq = A + u(Q) + CC = B - v(Q) - v(Q/N) \quad \text{(A.23)}$$

The equilibrium price and quantity under emissions trading become:

$$Q_1 = \frac{B - A - CC}{u + v + v/N}, \text{ and } P_0 = B - v\left(\frac{B - A - \Delta C}{u + v + v/N}\right) \quad \text{(A.24)}$$

Hence, in case of linear demand and linear supply, the equation for the PTR becomes:

$$\text{F} = \frac{v}{u + v + v/N} \quad \text{(A.25)}$$

A.6 Linear demand and perfect elastic supply

For simplicity, we assume linear demand curve is $P = 1 - Q$, where P is price and Q ($\sum_{f=1,..,F} q_f$) is total quantity consumed. Without loss of generality, the marginal cost for firm f is assumed to be zero before emissions trading, while emissions trading increases marginal cost by *CC*. Given that MC is zero, q_f will always be positive. Then this yields the first-order profit maximization condition $MR = MC$ as follows:

$$(1 - Q) - q_f - CC = 0 \quad \text{(A.26)}$$

Next, we impose the symmetry assumption (i.e., $Q = Nq_f$) into (A.26) and solve for q_f and price:

$$q_f = \frac{1 - CC}{N + 1}, \text{ and} \quad \text{(A.27)}$$

$$p = \frac{1 + N \cdot CC}{N + 1} \quad \text{(A.28)}$$

Comparing Equations (A.27) and (A.28), power price increases by $(N \cdot CC)/(1 + N)$ and market output decreases by $CC/(N + 1)$ when marginal cost increase by *CC*. Hence, the PTR = $N/(N + 1)$.[114] Thus, as N becomes large, the pass-through of *CC* approaches 1. Thus, the CO_2 costs will be fully passed on to power prices in the limiting case of perfect competition.

The calculation of equilibrium prices, pass-through and output under perfect, monopoly, duopoly, and oligopoly competition are summarized in Table A.1.

Table A.1 *Effects of imposing CO_2 trading as a function of number of firms in the market*

Case	N	Price increase [€/MWh]	PTR [%]	Individual firm's output [MWh]	Total output [MWh]
Perfect	∞	CC	100	n.a.	$-CC$
Monopoly	1	$CC/2$	50	$-CC/2$	$-CC/2$
Duopoly	2	$2CC/3$	67	$-CC/3$	$-2CC/3$
Oligopoly	$2 \le N < \infty$	$N \cdot CC/(N+1)$	$100N/(N+1)$	$-CC/(N+1)$	$-N \cdot CC/(N+1)$

Note: n.a. Not Applicable.

[114] This result can also be obtained by substituting either $b = 0$ into Equation A.18 or $u = 0$ into Equation A.25.

Appendix B Empirical and statistical analyses - country studies

B.1 Methodology

The objective of this Appendix is to present some results of the statistical analyses of the impact of the EU ETS on electricity prices in nine Member States, including estimates of the pass-through rates of the CO_2 emission allowance costs on these prices in 2005 and 2006. The general approach to the empirical estimation of these rates is based on the assumption that power prices tend to reflect the underlying costs of generation. In the merit order model of the power market, the power production system spans a set of generation technologies that will be committed in order of increasing short-term marginal costs, i.e. the short-term costs of production mainly comprising of fuel costs and - in the case of carbon policies setting a CO_2 price - the costs associated with carbon emissions. In the case of the EU ETS, these CO_2 emission costs refer to the (opportunity) costs of an EU allowance (EUA).

According to the merit order model, the most expensive production facility to be run in order to meet a specified level of demand is called the marginal technology and sets the minimum price of power for the demand level considered. Generally, power prices are higher than this marginal cost level, as capital cost, operation and maintenance costs and the like are to be covered as well. The sum of the short-term marginal costs and these latter cost components is referred to as the long-term marginal cost of production. In addition less quantifiable inflatory pressures may be present, such as market power, risk premiums and speculative tendencies.

In the context of the merit order model, the difference between the power price and the fuel costs is often called '*spark* spread' if the marginal technology is *gas*-fired, and '*dark* spread' if the marginal plant is *coal*-fired. In order to identify the pass-through rate of EUA costs, the present study examines whether - and to what extent - changes in the EUA costs of power production are reflected in either the electricity prices or the related power spreads. This examination covers both spot and forward markets, while distinguishing between peak and off-peak hours in order to account for different levels of power demand during a day (and, hence, different price-setting technologies during these periods).

However, several implicit assumptions underlie this approach. First, it assumes that the fixed cost components and the other, less quantifiable components are relatively stable. The first part of this assumption is generally correct, as it requires significant changes in the power generation system for the fixed cost components to change. The second part of the assumption, however, may be seriously questioned as significant changes in these other price-setting components may arise over relatively short periods of time.

Second, the approach assumes that demand levels for peak and off-peak hours are fairly stable in the short and medium term. However, the stability of demand may be seriously compromised by extreme weather events in the short run, seasonal variations or mid- to long term trends in power demand. Generally, seasonal differentiation cannot straightforwardly be applied in forward markets as the most liquid forward products often involve year ahead products. Of course event driven deviations occurring unexpectedly, like extreme weather events, cannot be accounted for beforehand as no product markets addressing such events exist. One should therefore seek to identify and validate the impact of such extreme events a posteriori in order to explain unexpected behaviour of the power markets.

Finally, the approach assumes stability of the availability of power production capacity. In general, however, it should be recognized that maintenance scheduling can lead to significant changes in the availability of power production capacity, as can unscheduled outages.

As noted, on the basis of the methodology and assumptions outlined above, the chapters below present some preliminary analyses of the impact of the EU ETS on electricity prices in nine Member States. These analyses include both spot and forward markets, while distinguishing between peak and off-peak hours.

Spot markets in the power sector generally involve a day ahead market where one can trade hourly products, each of which shows a power price for the average demand level over the hour of delivery. As demand levels during peak and off-peak hours are assumed to be fairly stable, so that in general a single marginal technology applies to each of these periods, the prices of the hourly products traded on the spot markets of the countries analysed have been averaged by day corresponding to the specification of the peak and off-peak hours in the relevant forward market of each country.

In addition, spot markets show a relatively high degree of volatility corresponding to the increasing risks of defaulting due to the short period between trade and delivery. In other words, less and less opportunities are available to the trader to balance the portfolio of power demand and supply in the short run. The market is therefore strongly event driven. Unexpected outages or demand hikes are strongly reflected in the prices of day ahead markets. Hence, for the purpose of analysing longer-term trends in the spot markets, a smoothing procedure was applied to the peak and off-peak spot products, by calculating the 14 days-moving average price of these products.

Regarding the forward markets, a range of base and peak load products is usually traded in the countries analysed. Typically, the year ahead product markets are relatively liquid, so that these products represent a substantial proportion of the power traded in most markets. Further, the process of price formation is presumed to be more robust in these liquid markets so that the year ahead products are presumed to represent forward cost of the various commodities relatively well. As only base and peak load products are traded in the forward markets, an off-peak product price has been calculated by means of the following formula:

$$P_{off\text{-}peak} = ((N * P_{baseload}) - (M * P_{peak})) / (N - M) \qquad (B.1)$$

where $P_{baseload}$, P_{peak} and $P_{off\text{-}peak}$ stand for the power prices of baseload, peak and off-peak products, respectively, and where N is the total baseload hours, M the total peak hours, and N - M the total off-peak hours.[115]

B.2 General notes on data used

For each country analysed, specific data on power prices have been gathered on an hourly or daily basis for both spot (i.e. day ahead) markets and, if present, forward (i.e. year ahead) markets (for details, see the country-specific notes on data used in the last section of each country in the chapters below). As said, these data been transformed to daily prices for peak and off-peak products, based on the country-specific definition of peak versus off-peak hours. Major exceptions include (i) Italy, Poland, Spain, and the Czech Republic (which do not have a forward market), (ii) Sweden (which trades only baseload products on the forward market, but no separate peak or off-peak products), and (iii) the United Kingdom (where the seasonal ahead markets have been used as they are more liquid that the year-ahead markets).

In addition, for each country - depending on the price-setting technology to generate peak and off-peak power - fuel prices have been gathered for coal, oil and gas on various markets, and

[115] Depending on the period analysed, the total number of baseload, peak and off-peak hours can be expressed by day, week, month, year, etc. In addition, the definition of peak versus off-peak hours may vary by country and, hence, the numbers of hours included in the formula may also vary, depending on the period and country considered.

transformed to fuel costs per MWh. Unless specified otherwise, international quotations of prices for coal (i.e. ARA CIF API#2)[116] and oil (Brent) have been used, while gas prices have been obtained from (inter)national hubs such as Zeebrugge, Bunde, Title Transfer Facility (TTF) or the UK National Balancing Point (NBP).[117] These fuel prices have been used as a first approach, assuming that they provide a good indicator and reflection of the changes of the market opportunity costs of the fuels used in the countries analysed.

Carbon prices for EU allowances (EUAs) have been obtained from Nord Pool and Point Carbon. Year ahead prices (Cal05, Cal06, and Cal07) have been used for analysing trends in EUA costs relative to power prices and spreads on both spot and forward markets, firstly because spot prices for EUAs are lacking for the first part of 2005 and, secondly, because price differences on the EUA spot and forward markets have almost been absent for deliveries during the first phase of the EU ETS.

B.3 Key figures of power sector

Table B.1 presents data on power production, imports, exports and generation capacity in the nine EU ETS countries for 2005 and 2006. Comparison between these countries shows that the fuel mix in generation capacity varies widely. In Poland, for instance, the share of combustible fuels in the total fuel mix amounted to 92%, while Sweden relied only for 19% on combustible fuels.

In addition, the trade pattern varies between the nine EU ETS countries. For instance, Italy's dependence on power imports is the highest among all presented countries. Five countries - France, Poland, the Czech Republic, Spain and Germany - are net exporters of electricity. France is the largest net exporter of electricity. In terms of volumes, France exported almost 72 TWh in 2006. Finally, it may be noticed that the Netherlands and the United Kingdom are a net importer of electricity.

[116] Day ahead coal costs have been derived from the average of the daily bid and offer prices for monthly contracts (e.g. product 'Jan 06, traded on January 05, 2006), while year ahead coal cost have been derived from the average of the daily bid and offer prices for yearly contracts.

[117] These fuel prices have been used as a first approach, assuming that they provide a good indicator and reflection of the changes of the market opportunity costs of the fuels used in the countries analysed. If deemed necessary, however, more country-specific fuel data may be used during the next phase of the project.

Table B.1 *Key figures of power sector in nine EU ETS countries*

	Unit	France	Germany	Italy	Poland	Spain	Sweden	Czech Republic	The Netherlands	United Kingdom
2005										
Total gross Production	[TWh]	580	620	300	160	290	160	80	100	400
Imports	[TWh]	8	60	50	5.0	10	10	10	20	10
Exports	[TWh]	70	60	1.1	20	10	20	20	5.4	2.8
2006										
Total gross Production	[TWh]	570	630	320	160	300	140	80	100	400
Imports	[TWh]	9	50	46	4.8	4.5	20	10	30	10
Exports	[TWh]	70	70	1.6	20	7.8	10	20	5.9	2.2
2005/2006										
Capacity	[GW_e]	110	110	80	30	70	30	15	20	74
Combustible fuels	[%]	20	58	71	92	54	19	62	92	78
Nuclear	[%]	57	18			10	29	25	2	16
Hydro	[%]	22	7	26	8	24	50	13	0.2	6
Renewables	[%]	1	17	3	0.1	11	2	0.2	6	
Other	[%]			0.1						

Source: IEA statistics database (Electricity information 2007).

B.4 France

B.4.1 Power market structure, price formation and regulation

Power market structure

The French power market is strongly connected with the German and British power markets, and less so with Spain and Italy, although market interaction has increased with all neighbouring countries in recent years. Power exchanges with the German market represent the bulk of electricity exports and imports. The incumbent, EdF, dominates the generation sector, covering almost 90% of installed production capacity (DG TREN, 2007). So, EdF has a *de facto* monopoly on the French electricity market (Scheepers et al., 2003). The other two main producers of electricity are Electrabel-Suez with 4% of installed capacity and SNET (a subsidiary company of the Endesa group), which holds 2%. In addition to being involved in generation, EDF owns the TSO and is also a DSO supplying 95% of customer sites. Around 160 local distribution companies supply most of the remaining 5% of the market (EC, 2007a). There are also around 80 alternative suppliers, five of which have some production capacity in France. The market share of these suppliers still remains negligible.

Regulation

Regulated tariffs are in place for most electricity consumers and must cover all EDF's or local suppliers' costs (ERGEG, 2007). However, in practice, over the past few years, end-user prices have not always been updated according to these economic principles. Wholesale market prices plus network tariffs have become significantly higher than end-user regulated prices. Nuclear generation costs are significantly below wholesale prices. As the majority of EDF's production capacity consists of nuclear generation, regulated prices are considerably below the EU averages in the retail market. Since January 2007, all customers who have chosen a market offer can have an end-user regulated price for a maximum of two years (ERGEG, 2007).

B.4.2 Trends in power prices, drivers and spreads

Figure B.1 shows trends in power prices, cost drivers and spreads on spot and forward markets in France, 2004-2006. According to the upper left panel of this figure, peak prices on the French spot market show a period of relative stability during 2004 and the first half of 2005. During the second half of 2005 the peak price levels and volatility show increases that correspond to the increasing price levels and volatility on the Zeebrugge day ahead market for natural gas. In the second half of 2006 a strong price rise occurs for the peak products on the spot market, corresponding to a heat wave in July 2006.

The off-peak prices show a stronger correspondence to the underlying EUA cost as may be expected on the basis that EUA costs form a relatively high cost component of coal-fired power. The upward trend in the EUA prices starting in early 2005 is fairly well reflected in the off-peak prices on the French spot market, as is the collapse of the EUA prices in May 2006. In addition the off-peak prices show a period of significant price rises during the summer of 2006, corresponding the higher prices on the Zeebrugge day ahead market for natural gas. Accordingly, the dark spreads show an increase over this period as well.

The lower two panels of Figure B.1 show the forward power products and their respective underlying costs. The development of the year ahead forward prices of peak products in the French market shows a relatively stable development over 2004. After January 2005, the year ahead prices of both the peak products show an upward trend corresponding to the increasing underlying cost of both the year ahead cost of gas and the year ahead cost of EUAs in the case of the peak product and the increase in the year ahead cost of EUAs in the case of the off-peak product. However, the pass-through of the natural gas costs seems to occur slightly delayed, so that the spark spread declines accordingly. By mid 2006, the upward trend of the year ahead power prices came to a halt, in accordance with the stabilization of the underlying cost of natural gas. Also the collapse of the EUA prices in May 2006 is well reflected in the year ahead peak power prices. After mid 2006, the year ahead cost of natural gas gradually decreases over the remaining period, the second half of 2006, while the year ahead costs of EUAs decline to levels below 10 €/MWh for gas-fired facilities. Again power prices seem to reflect the changes in the underlying natural gas cost slightly delayed, so that the spark spread gradually increases over the second half of 2006.

In contrast, the forward off-peak prices reflect the EUA costs development over the full period of evaluation fairly well. The off-peak prices increase steadily with the underlying cost of EUAs, up to the collapse of the EUA market in May 2006. Also in the second half of 2006, off-peak prices follow the EUA price profile.

B.4.3 Estimates of CO_2 costs pass-through rates

Table B.2 *Estimates of PTRs on power markets in France, 2005-2006*

		Regression of power spreads versus carbon costs			
		Spot		Forward	
		Peak	Off-peak	Peak	Off-peak
2005	PTR	1.96*	0.98*	0.66**	0.40**
	Δ	(±0.97)	(±0.33)	±0.08	±0.05
	R^2	0.75	0.72	0.23	0.22
2006	PTR	1.18	0.76*	0.58**	0.59**
	Δ	(±0.96)	(±0.17)	±0.07	±0.04
	R^2	0.64	0.80	0.26	0.47

* Statistically significant at 10% level.
** Statistically significant at 1% level.

B.4.4 Data used

French power prices for baseload and peak load refer to the day-ahead contracts and (calendar) year contracts traded on Powernext. The overall dominant production technology involves nuclear facilities. However the price of electricity in France bears close resemblance with the German power prices, particularly regarding the forward markets. As peak and off-peak prices for the German market are assumed to be driven by natural gas and coal prices respectively, the same assumption has been applied to France.

Coal in the French case refers to the internationally traded commodity classified as coal ARA CIF API#2. In the French case, gas contracts traded on the spot market and forward market refer to the Zeebrugge Hub.

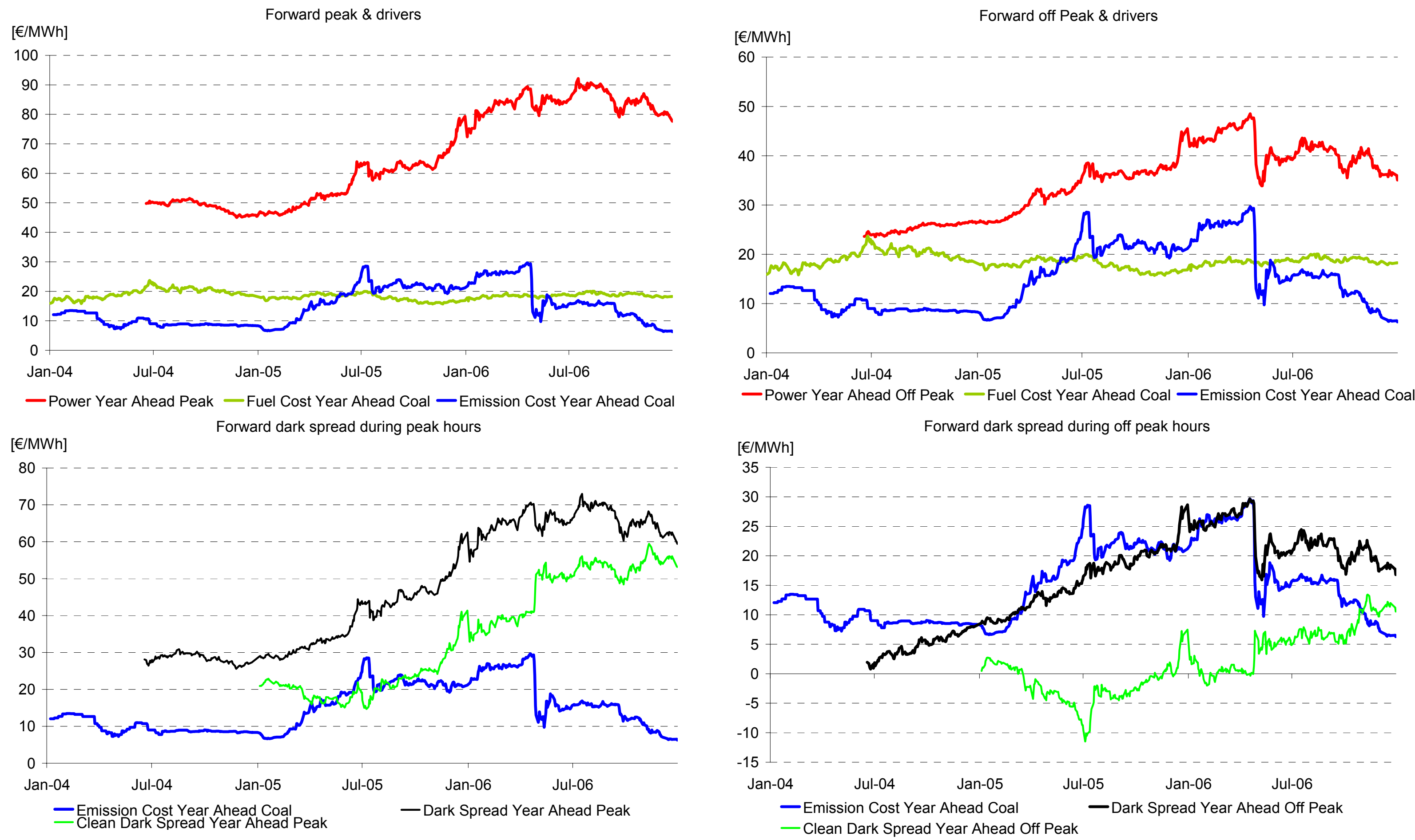
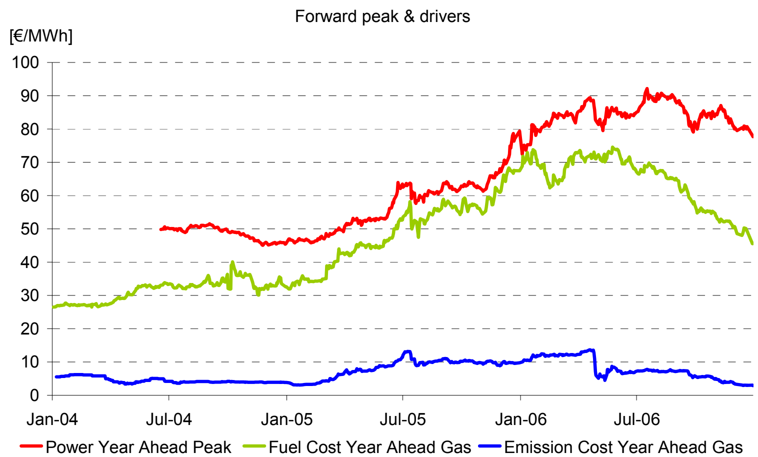


Figure B.1 *Trends in power prices, cost drivers and spreads on forward markets in France, 2004-2006 (first choice marginal technology)*



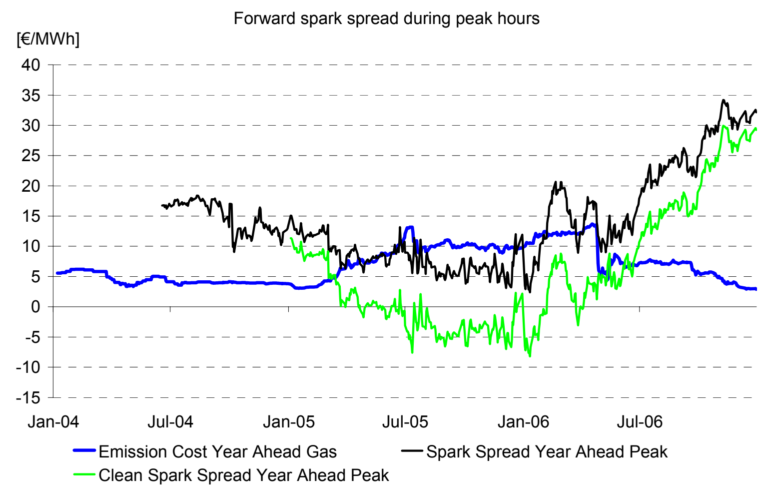


Figure B.2 *Trends in power prices, cost drivers and spreads on forward markets in France, 2004-2006 (alternative marginal technology)*

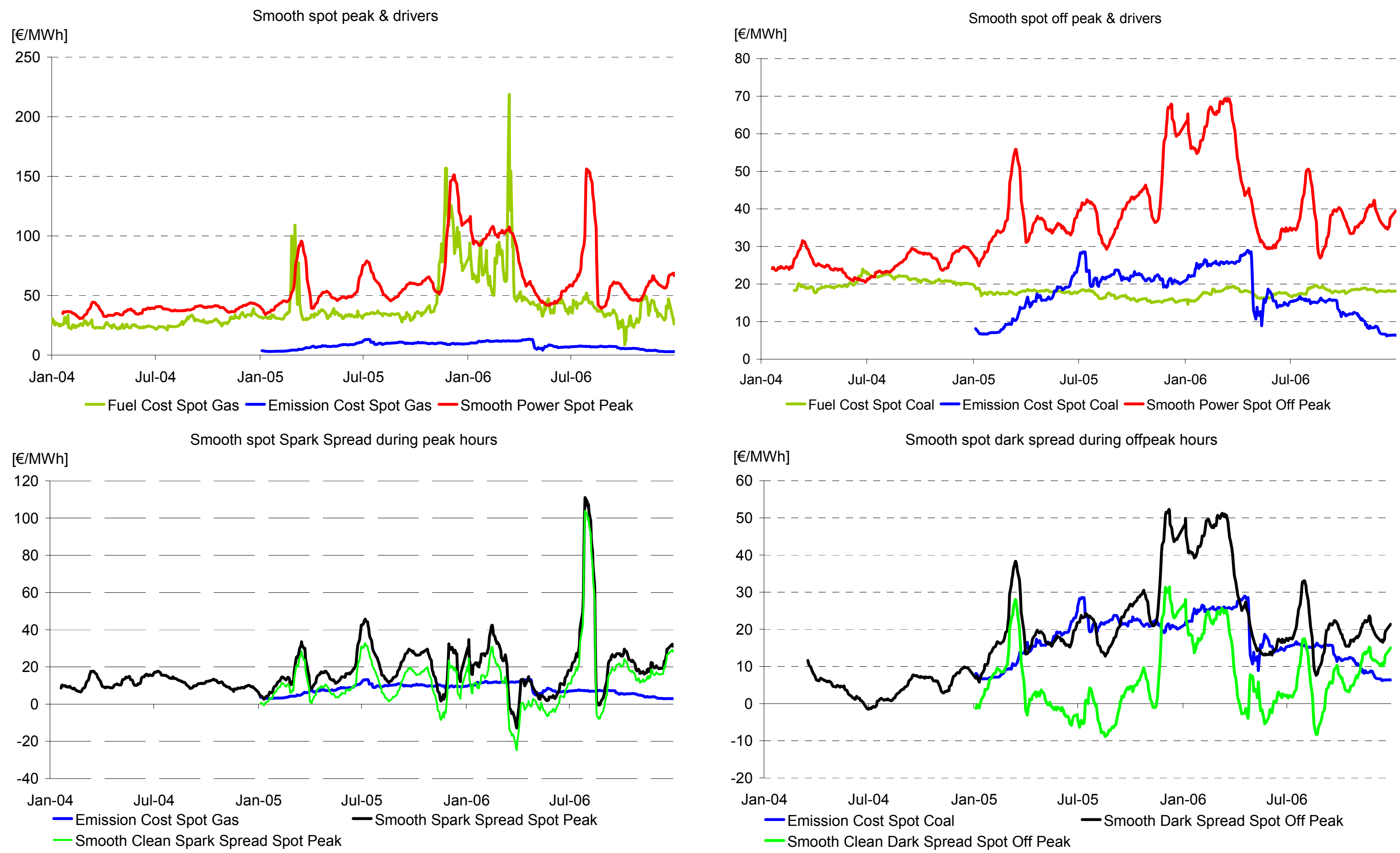


Figure B.3 *Trends in power prices, cost drivers and spreads on spot markets in France, 2004-2006 (first choice marginal technology)*

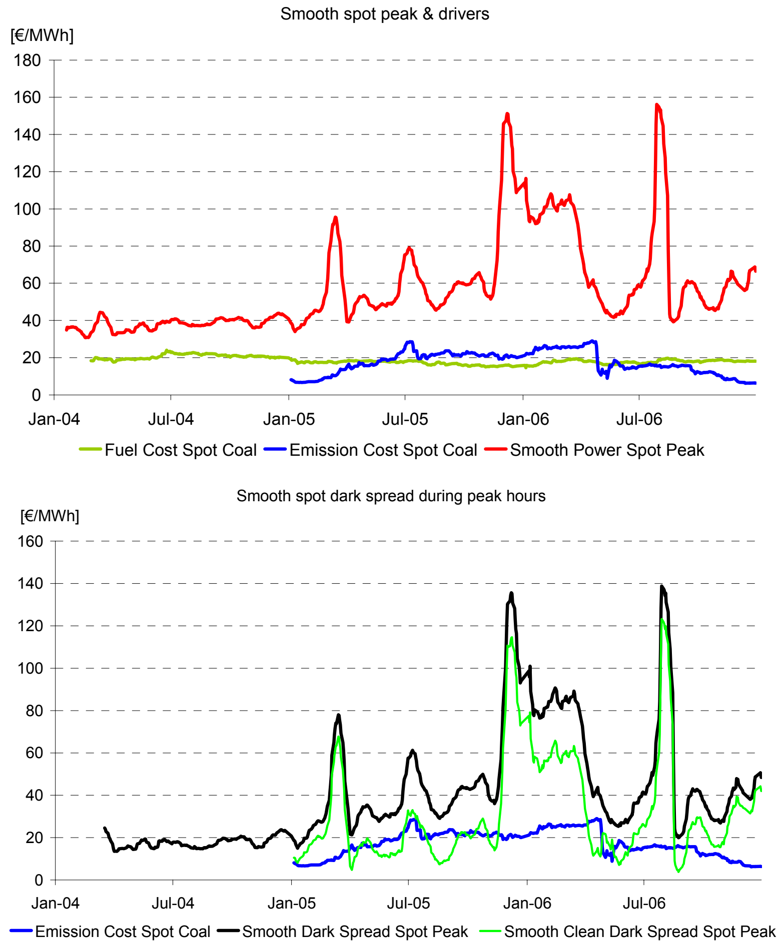


Figure B.4 *Trends in power prices, cost drivers and spreads on spot markets in France, 2004-2006 (alternative marginal technology)*

B.5 Germany

B.5.1 Power market structure, price formation and regulation

Power market structure

Four large private-sector companies dominate the German electricity market. RWE, E.ON, Vattenfall and EnBW control respectively 28%, 21%, 14% and 11% of the country's generating capacity in 2005. Combined, this quatropoly control almost the entire high voltage transmission network and about half the retail network. The remaining capacity comes from independent suppliers, industry self-generators selling back to the grid and industry producing for its own use (IEA, 2007). According to Eurelectric (2005), more than 520 independent energy suppliers were active in the German wholesale power market in 2002. Although in recent years this number has fallen sharply with many suppliers choosing to exit this market due to poor business prospects (EC, 2007a).

Price formation

Both supply and demand factors play a role in the electricity price formation of the wholesale market. However, factors influencing prices in the spot market can be rather different from those in the forward market (EC, 2007b). Spot power prices are determined by plant availability, fuel prices, precipitation, wind speed, interconnector availability temperature and, since 2005, EUA prices. Forward prices are influenced by supply-demand fundamentals expected to prevail in the long term such as forward fuel prices, (new) cost of generation capacity (or closures of power plants), water reservoir levels, weather trends, interconnector capacities, EUA prices and economic growth. In addition, sellers and buyers participate in forward contracts because they prefer price certainty to unknown spot prices in the long term. For that reason, forward prices will also include a risk element.

Assuming that the price of electricity is primarily determined by the fuel costs of the marginal generation technology, it is important to identify this technology for Germany. Based on the COMPETES model, coal-fired steam turbines in the off peak and natural gas-based plants in the peak are derived as the marginal units in Germany

Regulation

In Germany, wholesale electricity trading takes place both on the bilateral/OTC market and the European Energy Exchange (EEX) in Leipzig. The EEX operates spot and forward markets for energy products. Especially the forward market experienced a rather severe increase in wholesale prices in recent years (see Figure B.5). It should be mentioned, however, that only a small part of electricity is actually traded in organized wholesale markets. In the case of the EEX spot market, traded volumes amount to only 13% of national electricity consumption. In the case of the EEX forward market, traded volumes amount to 74% of national electricity consumption (EC, 2007b).

The above described market structure in Germany, in combination with the congestion prevailing at all German borders (with the exception of Austria), is thought to withhold effective competitive price formation (DG TREN, 2007). Adjustments in energy industry legislation in 2005 were made to improve conditions for competition in Germany's energy markets. Gas and electricity grid operators are now subject to regulation by the newly established Bundesnetzagentur and by regulatory authorities in the individual German states.

B.5.2 Trends in power prices, drivers and spreads

The upper panels of Figure B.7 show trends in power prices, cost drivers and spreads on the spot market in Germany, 2004-2006. Even though the volatility of the spot market is relatively high, some general trends may be identified. In the case of the peak prices, the spot market shows a period of relative stability during 2004. Both the volatility and the trend of the peak prices were on the rise during 2005, partially reflecting the increasing cost of natural gas and EUAs in this period. The increasing costs of natural gas do not fully justify the observed increase in the peak prices for spot power as can be derived from the increasing spark spread in the same period. In December 2005, wind should have caused significantly lower peak prices as wind generation capacity increased with almost 45% compared to November (EGL, January 13 2006, vol. 60). Besides, relatively warm temperatures lowered demand. However, peak prices on the spot market were on a rise during this period. As a consequence, it was the availability of fossil fuelled power stations that influenced the power prices. According to (EGL, January 13 2006, vol. 60), it is very likely that coal-fired power generation was below the level of the previous years, as low water levels led to supply shortages on important transport routes. In 2006 cost of natural gas on the German spot market started to decline, partially followed by the peak prices on the spot market for power. By July 2006 a strong increase occurs in the peak price, corresponding to a heat wave in early July 2006.

The off-peak prices show a stronger correspondence to the underlying EUA cost as may be expected on the basis that EUA costs form a relatively high cost component of coal-fired power. The upward trend in the EUA prices starting in early 2005 is fairly well reflected in the off-peak prices on the German spot market, as is the collapse of the EUA prices in May 2006. The lasting lower nuclear plant availability in France resulted in increasing exports from Germany. As a likely result the German spot off-peak market experienced a peak in December 2005 and March 2006.

Another mild peak can be observed in July 2006 during the incidence of a heat wave in North-Western Europe.

The lower two panels of Figure B.7 show the forward power products and their respective underlying costs. The development of the year ahead forward prices of peak and off-peak in the German market shows a relatively stable profile in 2004, up to early 2005. After January 2005, the year ahead prices of both the peak and off-peak products show an upward trend corresponding to the increasing underlying cost of both the year ahead cost of natural gas and the year ahead cost of EUAs in the case of the peak product and the increase in the year ahead cost of EUAs in the case of the off-peak product. As power prices responded slightly delayed to the development of the natural gas prices, a declining trend may be observed in the spark spread over the same period. By late July 2006 the upward trend of the year ahead power prices came to a halt. In this period the cost of natural gas stabilized while the cost of EUAs for the first commitment period collapses two months earlier, upon the evaluation of the national emissions over 2005. The year ahead cost of natural gas gradually decreases during the second half of 2006, while the year ahead cost of EUAs declines to below 10 €/MWh for both gas- and coal-fired facilities. However, forward power prices on average seem to stabilize in the second part of 2006

The spark spread for the year ahead peak products shows a steadily declining trend up to autumn 2005, in contrast to the increasing cost of EUAs. In January 2006 the spark spread starts to increase due to declining natural gas prices in conjunction with stabilizing forward peak prices. The steady increase in the spark spread that can be observed up until the end of 2006 is difficult to explain. The dark spread associated with the year ahead off-peak products, roughly reflects the development of the EUA prices and suggesting a fair correlation between the two time series.

B.5.3 Estimates of CO_2 costs pass-through rates

Table B.3 *Estimates of PTRs on power markets in Germany, 2005-2006*

		Regression of power spreads versus carbon costs			
		Spot		Forward	
		Peak	Off-peak	Peak	Off-peak
2005	PTR	1.76*	0.82*	0.60**	0.41**
	Δ	±0.88	±0.23	±0.06	±0.04
	R^2	0.69	0.75	0.32	0.35
2006	PTR	0.92	0.68*	0.57**	0.64**
	Δ	±0.72	±0.17	±0.05	±0.04
	R^2	0.22	0.76	0.38	0.58

* Statistically significant at 10% level.
** Statistically significant at 1% level.

B.5.4 Data used

German power prices for baseload, peak load and off peak periods refer to the European Energy Exchange (EEX) Phelix traded hour contracts and year contracts for respectively the spot market and forward market.

In general the marginal production technology in Germany is coal-fired during both off-peak and peak periods. However, gas-fired generation facilities can be identified to be marginal during (super) peak periods as well. In this first approach it has been assumed that the marginal technology in the peak is gas-fired.

Coal in the German case refers to the internationally traded commodity classified as coal ARA CIF API#2. Quotes on the German natural gas markets were derived from the Bunde trading hub as reported by Platts, both regarding day-ahead and year ahead trading.

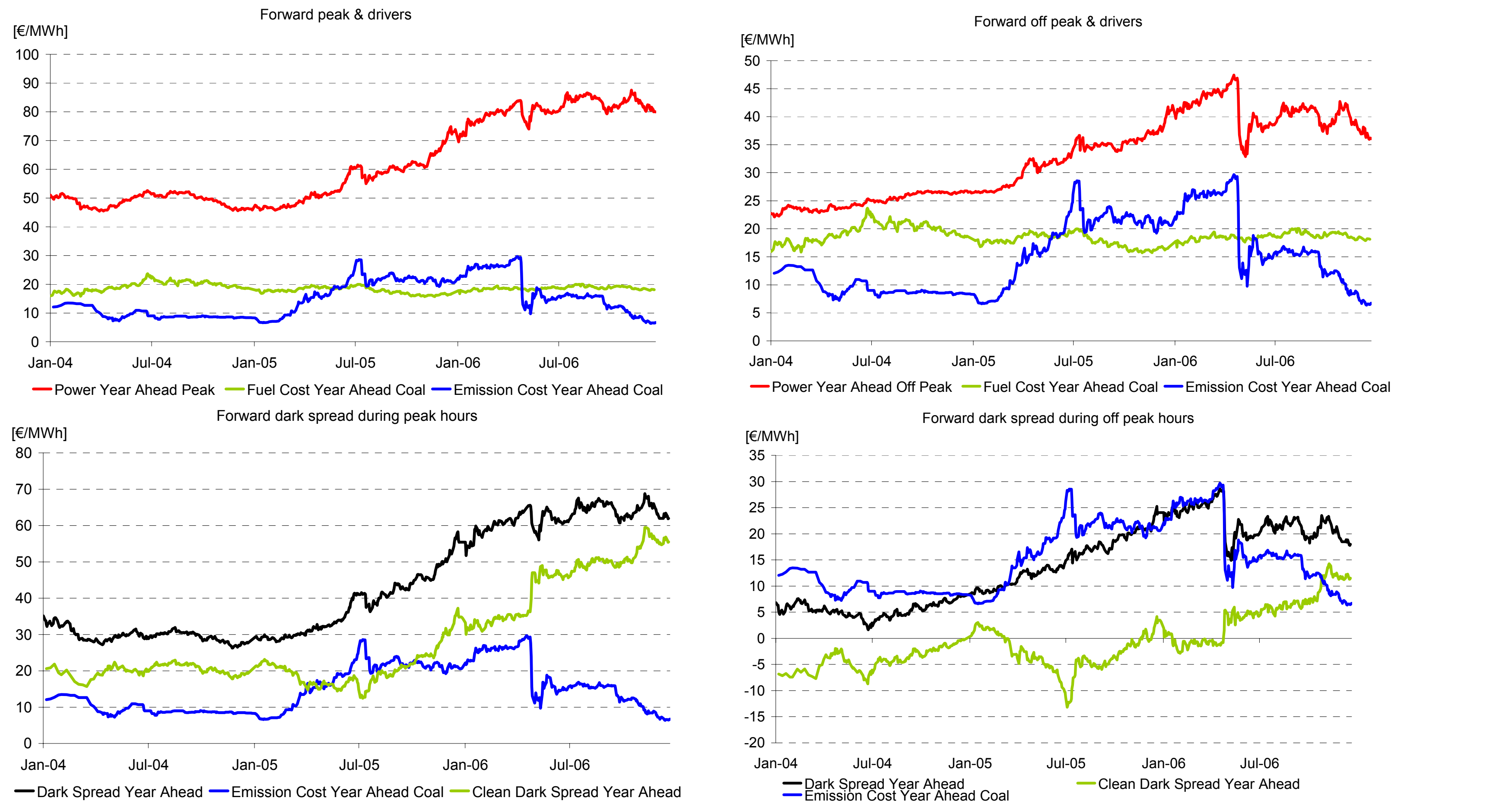


Figure B.5 *Trends in power prices, cost drivers and spreads on forward markets in Germany, 2004-2006 (first choice marginal technology)*

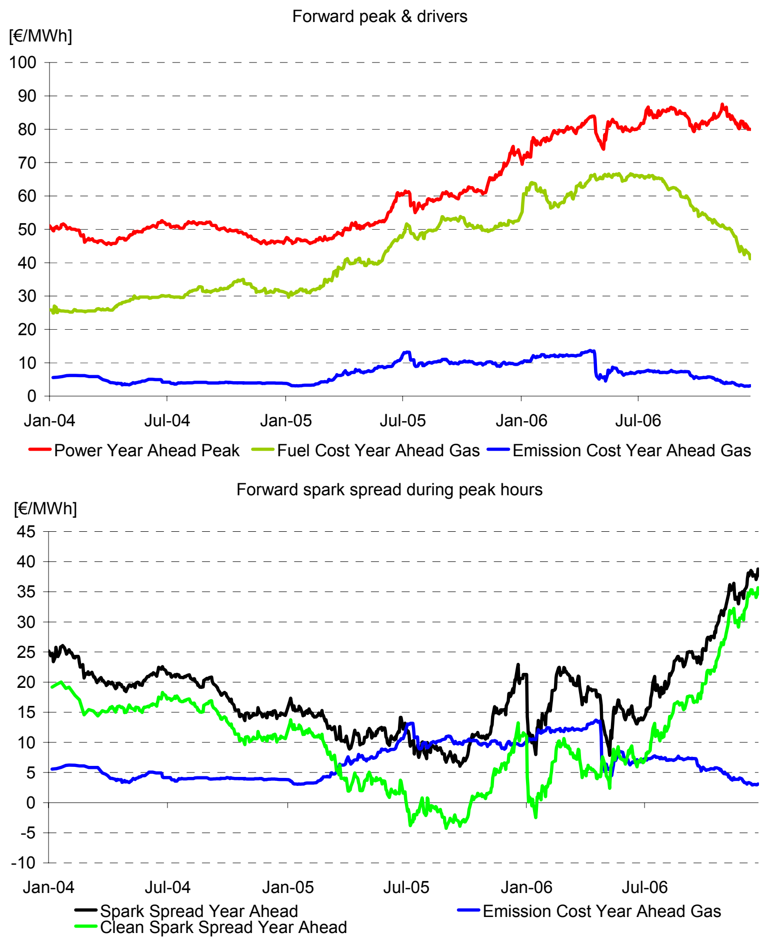


Figure B.6 *Trends in power prices, cost drivers and spreads on forward markets in Germany, 2004-2006 (alternative marginal technology)*

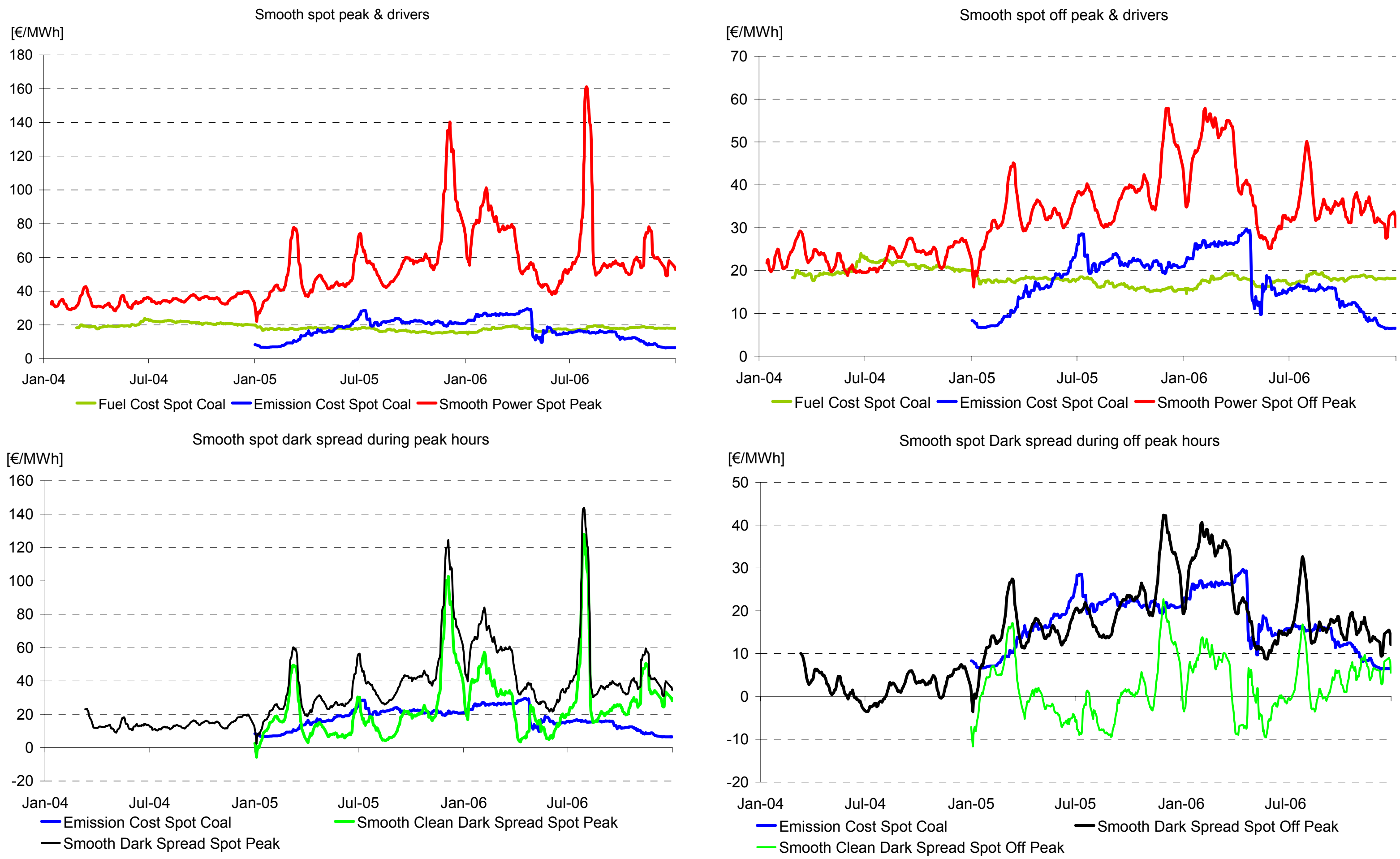


Figure B.7 *Trends in power prices, cost drivers and spreads on spot markets in Germany, 2004-2006 (first choice marginal technology)*

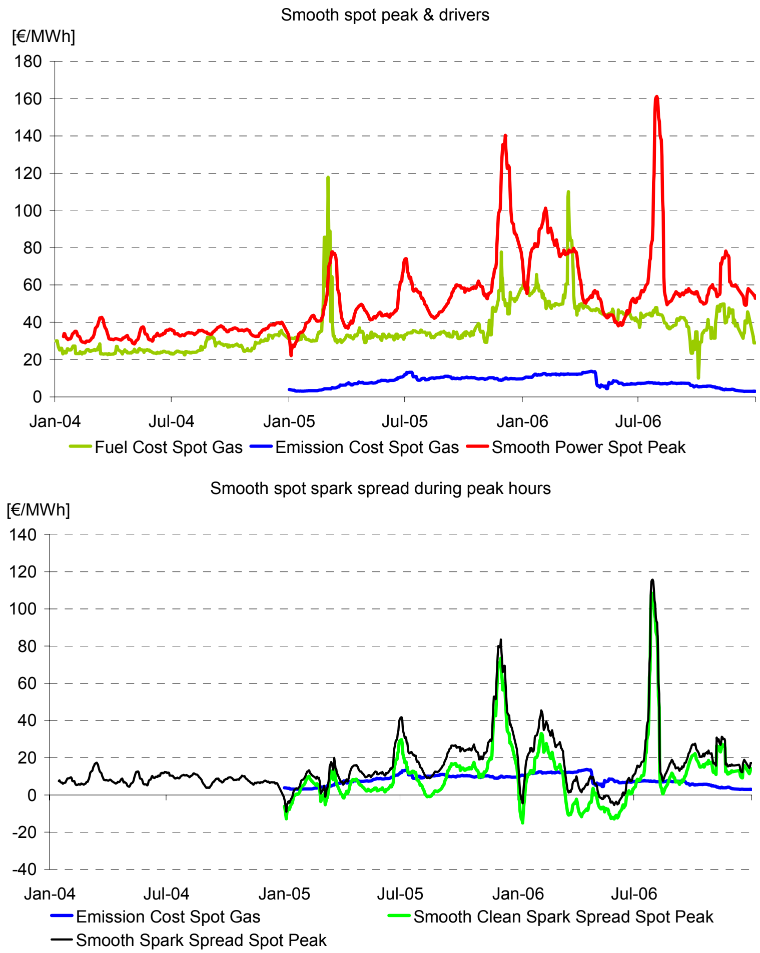


Figure B.8 *Trends in power prices, cost drivers and spreads on spot markets in Germany, 2004-2006 (alternative marginal technology)*

B.6 Italy

B.6.1 Power market structure, price formation and regulation

Power market structure

The Italian electricity generation market consists of one dominant operator, former state-owned ENEL (39%), one main competitor, Edison (12%), which also has a 40% stake in Edi power that has 9% of the market, two smaller competitors, Endesa Italia (7.4%) and ENI (6%), plus other minor players, none of which has more than a 2.5% share (DG TREN, 2007). The country has large interconnection capacities (it is connected with France, Switzerland, Austria, Slovenia and Greece).

Price formation

A significant price differential is present between the electricity exchange of Italy (IPEX) and other EU exchanges. In both peak and off-peak periods the Italian electricity price was one of the highest over 2005-2006. An important reason for this fact is the enjoyed market power of ENEL in four relevant regional markets (North, South, Sardinia and Sicily). Another reason is the persisting congestion and transmission constraints with neighbouring countries (EC, 2007a).

The Italian power exchange has some kind of obligation to trade via the exchange (EC, 2007b). As a consequence of such an incentive OTC brokered volumes are negligible compared to spot volumes traded on IPEX.

Regulation

In Italy*,* the retail market is split in two sectors, more or less of the same size: the free market and the regulated market consisting of non-eligible customers (i.e. households) and eligible customers who never left the sector and still buy electricity at regulated tariffs. On the wholesale market, there is one single buyer for the electricity supplied to the regulated market (DG TREN, 2007).

B.6.2 Trends in power prices, drivers and spreads

Figure B.9 show trends in power prices, cost drivers and spreads on the spot market in Italy, 2004-2006 (no forward market exists in Italy). The Italian power prices show strong volatility over the period January 2004-December 2006. Concentrating on 2006, the first major price hike can be related to the continuing cold spell in the beginning of 2006. The second major price hike in spot prices in July can be related to a heat wave. The increased demand on the Italian power spot market was met with extra imports from France and Switzerland (EGL, 2006a). At the same time wind generation dropped significantly compared to the previous months. Furthermore, the increase in spot prices might have been caused by rising oil prices. Assuming that the price of electricity during the peak hours is primarily determined by oil-fired production, one could argue that the trend in the fuel (i.e. oil) costs to produce electricity is reflected in the Italian power prices over the period January 2004-December 2006 (see left panel of Figure B.9).

In addition, EUA costs for oil-fired power production facilities have been rather stable over the full evaluation period in comparison to the fluctuation of the power prices. Consequently the impact of changes in the EUA costs is likely to be obscured by the impact of other power price drivers, such as the noted extreme weather events. In general, the Italian peak prices on the spot market seem to be heavily driven by power prices in neighbouring countries, temperature and precipitation levels.

The right panel in Figure B.9 shows that the volatility in the prices for off-peak products are not driven by the fuel costs, as the fuel costs curve is relatively stable. In contrast to the peak period, EUA costs of the assumed underlying fuel driver show a closer correspondence with the power prices. Off-peak prices in Italy were relatively stable during 2004, increased gradually to about 65 €/MWh in the first quarter of 2006 and, subsequently, declined to a level of approximately 55 €/MWh at the end of 2006. These developments correspond to the trends observed in the EUA costs for coal-fired generation including the pronounced reflection of the EUA market collapse by the end of April 2006.

B.6.3 Estimates of CO_2 costs pass-through rates

Table B.4 *Estimates of PTRs on spot power markets in Italy, 2005-2006*

		Regression of power spreads versus carbon costs	
		Peak	Off-peak
2005	PTR	-0.97	0.39
	Δ	±0.62	±0.70
	R^2	0.69	0.58
2006	PTR	-0.67*	-2.98*
	Δ	±0.23	±0.68
	R^2	0.79	0.84

* Statistically significant at 10% level.

B.6.4 Data used

Power prices in the Italian case refer to the daily market prices settled in the spot market of the Gestore Mercato Electtrico (GME) for both peak load and off peak hours. A forward market in Italy is not in existence.

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During peak hours, the marginal production technology involves oil-fired production facilities in Italy, while off-peak demand is mainly served by coal-fired facilities.

The daily Brent Oil spot prices from the International Petroleum (IPE) where used as a reference for the 'Fuel cost spot oil' as presented in Figure B.9. This price index is assumed to reflect oil price movements most effectively while it as acknowledged that oil-fired facilities generally consume fuel oil, an oil product that comes at a discount. The discount has been accounted for by assuming a relatively high efficiency. Coal in the Italian off-peak period refers to the internationally traded commodity classified as coal ARA CIF API#2.

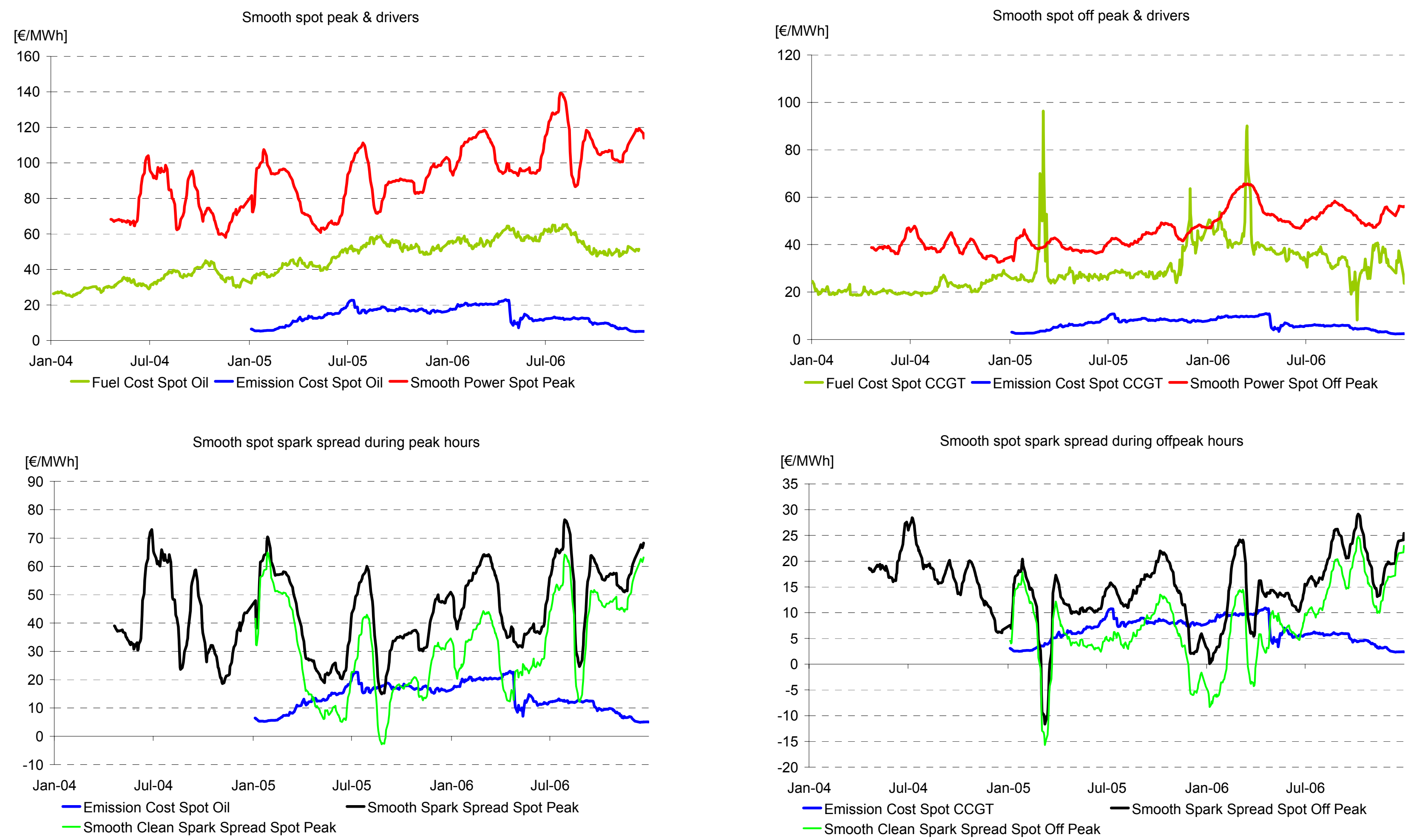

Figure B.9 *Trends in power prices, cost drivers and spreads on spot markets in Italy, 2004-2006*

B.7 Poland

B.7.1 Power market structure, price formation and regulation

Power market structure

The major generators on the electricity market in Poland are BOT and PKE, who together own around 45% of capacity (EC, 2007a). There are a large number of small electricity producers. Some foreign companies have entered the Polish market but they have little or no generation capacity.

The electricity wholesale market in Poland is a bilateral trading market, with brokered deals. The Polish power exchange, PolPx experiences low liquidity; less than 2% of the total Polish electricity supply is traded over the PolPx (EFET, 2006).The liquidity on the exchange is low due to the high fixed and variable costs set by the Warsaw Stock Exchange (Gielda) and high operational risk. In the supply market, the distribution companies are still dominant in their particular region although new traders are entering the market, often linked to one of the main generators.

Price formation

Around 35% of the Polish power plants are tied to the so-called Long-term Power Purchase Agreements (LT PPAs). In the past, the PSE operator acted rather like a single buyer. The PSE operator can be identified as the electricity TSO, but is owned by an incumbent. The LT PPAs introduce price distortions and are perceived by the EC as prohibited state aid (EC, 2007a). However, contracts are being restructured at present, which should increase liquidity.

Regulation

The Polish regulator seems not effective enough to impose a proper functioning of the power market (EC, 2007a). The regulator's control on power transportation tariffs is insufficient and it lacks competence for cross-border issues. As from 1st July 2007, regulated prices have been abandoned with a changed supplier of last resort arrangement. Whether this new regulation solves the problem of distorted wholesale market functioning remains unclear. In the recent past, electricity was priced too low and operating margins in the supply business were extremely low, which pushes the wholesale market prices down as well (EC, 2007a).

B.7.2 Trends in power prices, drivers and spreads

Figure B.10 shows the trends in spot power prices, cost drivers, and spreads on the spot market in Poland over the period January 2004-December 2006 (there is no forward power market in Poland). The spot market shows strong stability compared to the other European markets considered. Effectively, the Polish spot prices for peak and off-peak products have been steadily rising over the full evaluation period, as have the associated dark spreads. For 2005, this rise in power prices and spreads corresponds to the rising EUA costs. The collapse of the EUA market price in April-May 2006, however, is hardly reflected in the power prices, thereby questioning the relationship between power and carbon prices on the spot market in Poland.

B.7.3 Estimates of CO_2 costs pass-through rates

Table B.5 *Estimates of PTRs on spot power markets in Poland, 2005-2006*

		Regression of power spreads versus carbon costs	
		Peak	Off-peak
2005	PTR	0.09	0.09
	Δ	±0.07	±0.06
	R^2	0.58	0.82
2006	PTR	-0.04	0.00
	Δ	±0.03	±0.06
	R^2	0.72	0.61

* Statistically significant at 10% level.

B.7.4 Data used

Power prices in the Polish case only refer to the daily market prices settled in the spot market of the Polish Power Exchange (PolPX) for both peak load and off peak hours.

The dominant production technology in Poland during baseload and peak periods is lignite and coal-fired generation. Lignite is not an internationally traded commodity and no indicators for daily changes in price are available. Regarding coal prices, Poland Baltic coal price information is available on a monthly basis. The Poland Baltic coal price curve shows strong correlation with ARA CIF API#2, be it at a discounted level (Poland Baltic is on average some 10% lower than the ARA CIF API#2 price index). As the sequence of relative prices, i.e. reflecting the dynamics are more important than the absolute values for correlation analysis, the ARA CIF API#2 price index offers a better indicator as it is quoted on a daily basis.

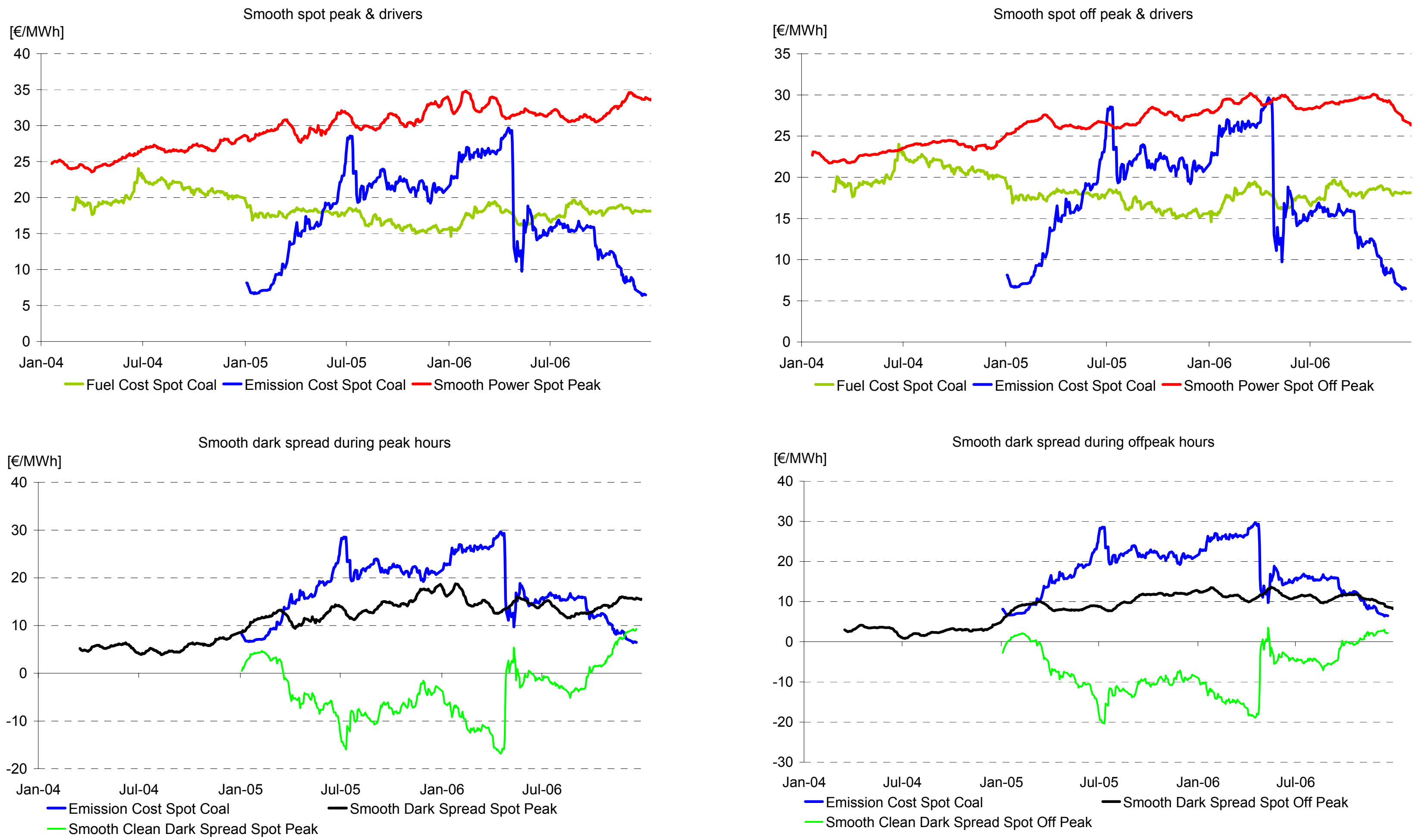

Figure B.10 *Trends in power prices, cost drivers and spreads on spot markets in Poland, 2004-2006*

B.8 Spain

B.8.1 Power market structure, price formation and regulation

Power market structure

Spain can be considered as a market on its own, because of the limited interconnection capacities with France and Portugal (EC, 2007a). This prevents market integration and competitive pressures from lower prices from France. The Spanish generation and supply markets are dominated by the four incumbent generators and distributors, Endesa, Iberdrola, Hidrocantabrico and Union Fenosa, controlling 90% of retail supply (the two largest alone, Endesa and Iberdrola, control 70%). The TSO is independent from the electricity generators. Nevertheless, it is not considered fully unbundled as it also undertakes trading activities. 325 distribution companies are registered, the main ones being the four incumbent suppliers.

Price formation

The Spanish power exchange (OMEL) has some kind of obligation to trade via the exchange (EC, 2007b). As a consequence, OTC brokered volumes are negligible compared to spot volumes traded on OMEL.

Regulation

The Spanish electricity regulatory framework combined with strong market concentration of the four incumbents is widely seen as a major constraint for a correct functioning of a competitive market (EC, 2007a). All market players criticize the wholesale market for being heavily unstable and unpredictable. Incumbent generators supply their customers with electricity under a regulated tariff, which is below liberalised market prices. These generators are financially compensated for the deficit caused by the low level of tariffs. Another consequence of the fact that the regulated tariff is below the power price on the liberalised market is that customers remain within the regulated market. In 2005 and 2006, the price difference between the liberalised and regulated market increased considerably due to the increase in the liberalised market prices. As a consequence, customers actually returned to the regulated market.

B.8.2 Trends in power prices, drivers and spreads

Figure B.11 shows power prices, cost drivers and spreads on the spot market in Spain over the period January 2004-December 2006 for peak load and off-peak hours (a forward market is lacking).

The Spanish power prices show significant volatility over the period January 2004-December 2006, particularly between the first quarter of 2005 and the second quarter of 2006. This period can be characterized by an exceptional draughts and hot periods. The major price hikes in July 2005 and June 2006 can be directly related to these weather events. The outage of nuclear plant Almaraz I has been one of the major factors explaining the major price hike in February 2006 (EGL, 2006b).

Assuming that the price of electricity during the peak hours is primarily determined by gas-fired production, the Spanish case illustrates that the trend in the fuel costs to produce electricity is not reflected in the Spanish power prices over the period January 2004-December 2006 (see left panel of Figure B.11). Effectively, the above-mentioned power price hikes have been major drivers for the peak prices on the Spanish spot market and the role of the underlying fuel costs as a driver has been obscured by the resulting volatility, let alone the much lower associated EUA costs. Though the upward trend in fuel cost over 2004 and 2005 seems to be reflected in the power prices, the relative stability of the fuel cost in 2006 is not. Other price-setting factors such as power plant outages, heat waves, precipitation and associated Spanish water reserves play a more important role.

According to the right panel in Figure B.11, the off-peak products also show more volatility than justified by the underlying fuel costs. In contrast to the peak period, however, EUA costs associated with the underlying fuel driver show some resemblance with the off-peak power prices. Intriguingly, however, the collapse of the EUA market by the end of April 2006 seems to be preceded by a strong decrease of the off-peak power prices, which is inconsistent with the assumed causality relation.

B.8.3 Estimates of CO_2 costs pass-through rates

Table B.6 *Estimates of PTRs on spot power markets in Spain, 2005-2006*

		Regression of power spreads versus carbon costs	
		Peak	Off-peak
2005	PTR	0.50	0.64*
	Δ	±0.67	±0.23
	R^2	0.65	0.74
2006	PTR	1.11*	0.52*
	Δ	±0.49	±0.28
	R^2	0.76	0.90

* Statistically significant at 10% level.

B.8.4 Data used

Power prices in the Spanish case only refer to the daily market prices settled in the spot market of the Operador del Mercado Ibérico de Energía - Polo Español, S.A (OMEL) for both peak load and off-peak hours. A forward market in Spain is not in existence.

The marginal production technology in Spain during the peak periods mainly involves gas-fired generation, while coal-fired facilities dominate the off-peak periods. No transparent and liquid natural gas market exists in Spain, so that pricing information on this commodity is not straightforwardly acquired. In a first approach, it has been assumed that natural gas prices should reflect the dynamics of the international oil markets. The daily Brent Oil prices were used for the calculation of the 'Fuel cost spot oil' in the spot peak market as can be seen in Figure B.11. The efficiency assumed reflects the relatively high efficiency of the Spanish gas-fired facilities that in most cases have been installed in the past decade. Coal in the Spanish off peak periods case refers to the internationally traded commodity classified as coal ARA CIF API#2.

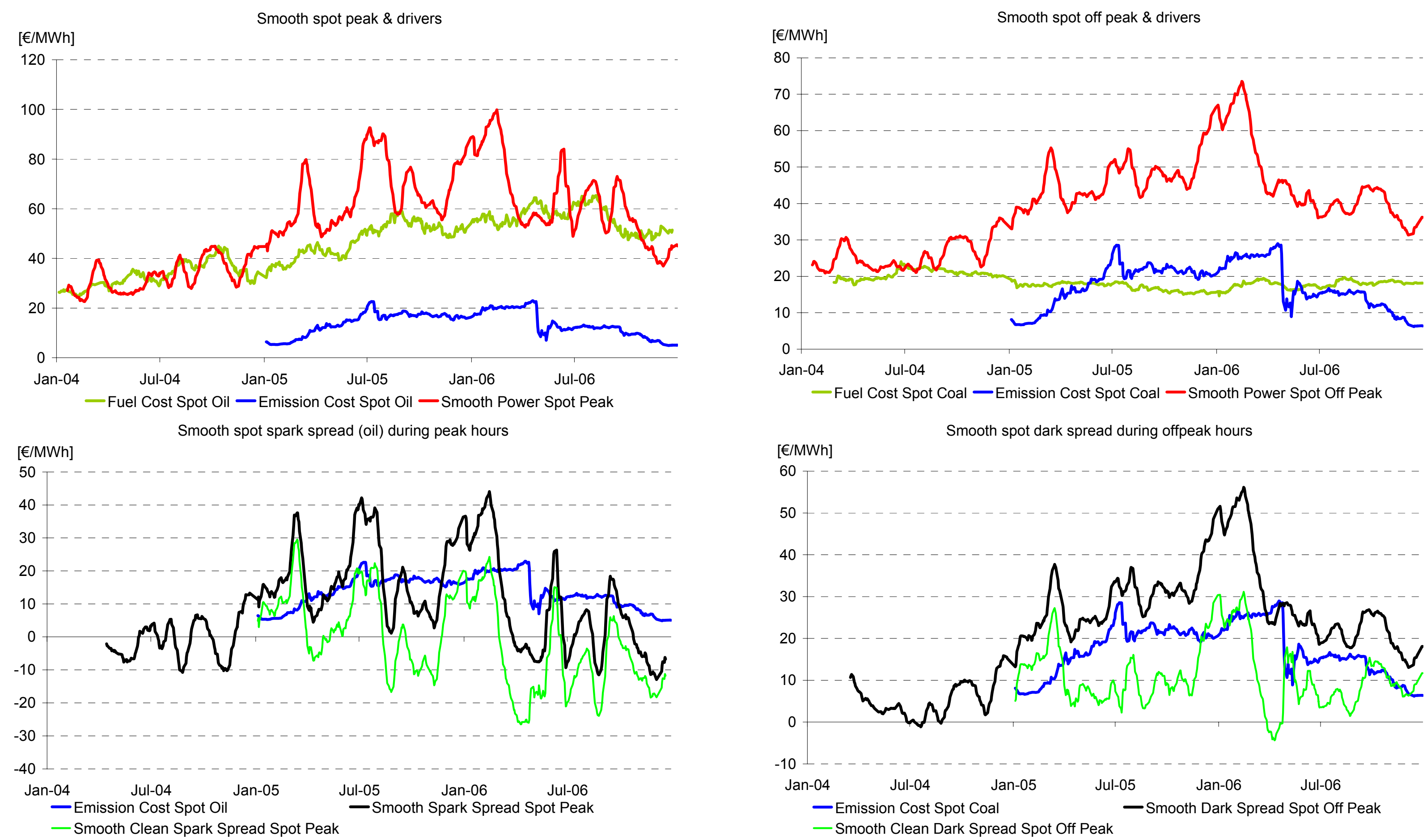

Figure B.11 *Trends in power prices, cost drivers and spreads on spot markets in Spain, 2004-2006 (first choice marginal technology)*

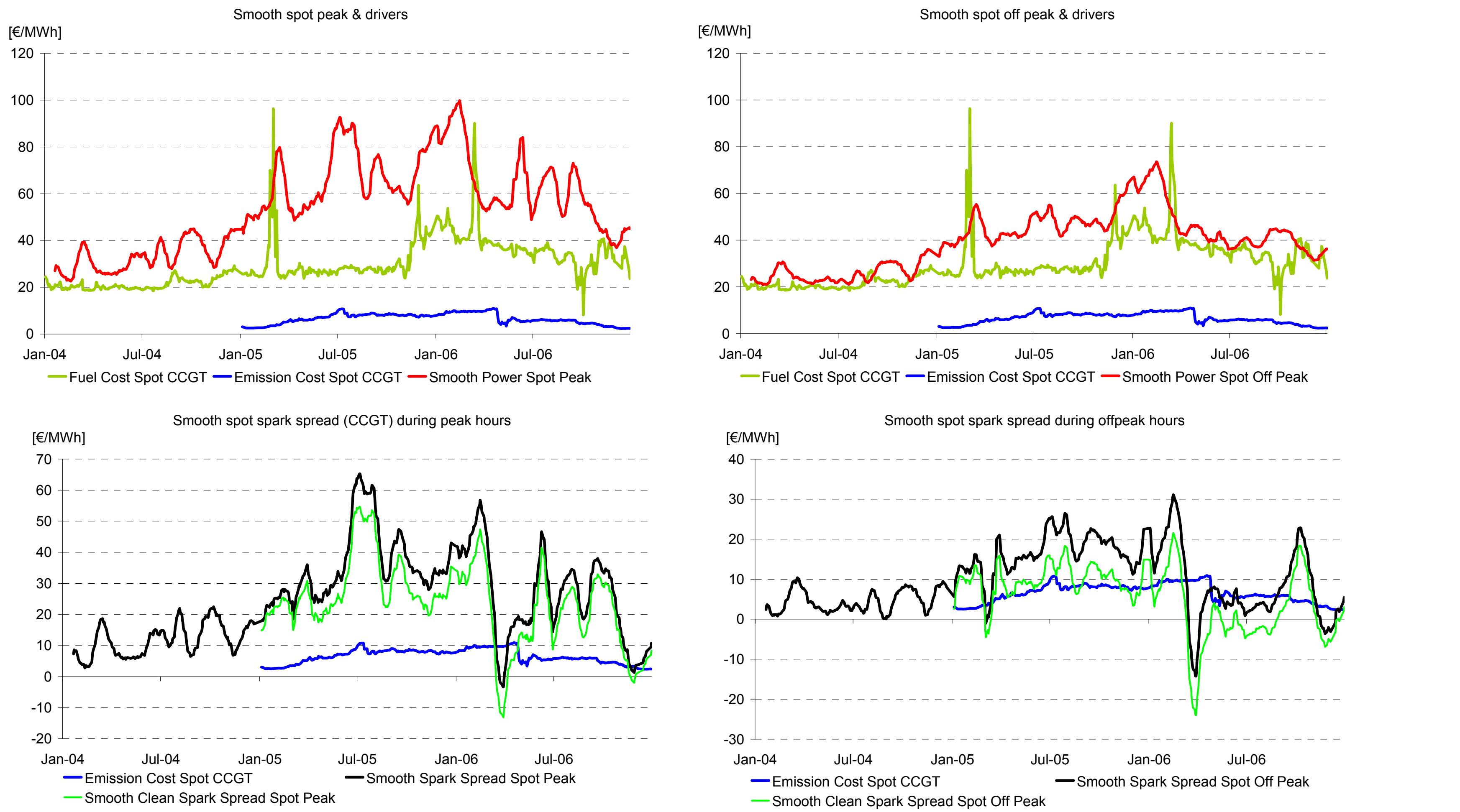

Figure B.12 *Trends in power prices, cost drivers and spreads on spot markets in Spain, 2004-2006 (alternative marginal technology)*

B.9 Sweden

B.9.1 Power market structure, price formation and regulation

Power market structure

Electricity generation in Sweden is dominated by a small number of generators. In 2005, three companies (Vattenfall, Fortum and E.ON Sweden) accounted for almost 90% of generated electricity. However, due to the presence of the Nordic regional market in which Sweden takes part, the wholesale power market is more competitive. The three largest Swedish generators only held an aggregate 41% of the Nordic market (DG TREN, 2007). The TSO is unbundled in terms of ownership, whereas the distribution companies are required to unbundle in legal and functional terms. In 2005, there were 175 distribution companies and 130 supply companies. The largest electricity suppliers, Vattenfall, E.ON and Fortum, had a market share of about 50%, which is the equivalent of about 2.5 million customers.

A serious issue on the Swedish wholesale market is the handling of transmission constraint. The current discussion is largely focused on whether Sweden should have more than one price area.As opposite to the wholesale market, the retail market is considered to be largely national.

Price formation

As is stated in EC (2007b), the Swedish power exchange (Nord Pool) has some kind of obligation to trade spot contracts via the exchange. As a consequence of such an incentive OTC spot brokered volumes are negligible compared to spot volumes traded on Nord Pool. In contrast, OTC forward markets traded higher volumes than transactions on Nord Pool.

Regulation

The Swedish state retains no control on the electricity prices charged to end-users.

B.9.2 Trends in power prices, drivers and spreads

Figure B.13 shows power prices, cost drivers and spreads in Sweden over the period January 2004-December 2006 for peak load and off-peak hours on the spot market, and for baseload products on the forward market. The spot market in Sweden shows a low volatility in comparison to most spot markets for power due to the relatively large hydro-capacity in the fuel mix, both in Sweden and neighbouring Norway, offering large amounts of flexible capacity that can easily smoothen the impact of unexpected events destabilizing the supply and demand balance. In addition most thermal capacity is coal-fired so that this is the marginal technology for both peak and off-peak. Also, pump storage technology offers the opportunity to arbitrate between day and night. Consequently the spread between peak and off-peak is relatively small.

The upper two panels of Figure B.13 show the smoothed spot prices during the period 2004-2006. In the case of the peak prices, the spot market shows a period of relative stability during 2004 and the first half of 2005. The peak prices were on the rise during the second half of 2005, partially reflecting the increasing cost of EUAs in this period. In May 2006 the collapse of the EUA prices occurred, which is well reflected by the spot prices. In the second half of 2006 a strong hike of both the peak and off-peak prices occurs as a consequence of low reservoir levels. The reservoir levels started to deviate significantly from the median levels shortly after the collapse of EUA prices and the prices of power on the Swedish spot markets started to rise accordingly starting in July 2006. By September 2006 reservoir levels started to approach median levels again and the power prices on the Swedish spot markets declined accordingly.

The lower panel of Figure B.13 shows the forward prices for baseload power and their respective underlying costs. The development of the year ahead baseload prices in the Swedish market shows a relatively stable profile, roughly following the same path as the spot products. This notion is somewhat counterintuitive as the incidence of low reservoir levels only impacts the short-term delivery of power, whereas the forward product under study involves year ahead delivery.

B.9.3 Estimates of CO_2 costs pass-through rates

Table B.7 *Estimates of PTRs on power markets in Sweden, 2005-2006*

		Regression of power spreads versus carbon costs		
		Spot		Forward
		Peak	Off-peak	Base
2005	PTR	0.48*	0.35*	0.53**
	Δ	±0.12	±0.12	±0.04
	R^2	0.60	0.85	0.42
2006	PTR	0.44	0.82*	0.62**
	Δ	±0.31	±0.21	±0.05
	R^2	0.75	0.92	0.38

* Statistically significant at 10% level.
** Statistically significant at 1% level.

B.9.4 Data used

Power prices in the Swedish case refer to the Elspot prices (Stockholm price area) and (calendar) year contracts (classified as FWYR-05, ENOYR-06, ENOYR-07) both traded at NordPool representing the spot and forward market respectively. It should be noted that the contracts in the forward market are only traded for the baseload period.

Although in Sweden the generation mix is largely characterised by hydro and nuclear plants, power prices in the Swedish market - which is highly integrated with the Nord Pool power market - is largely set by a coal-fired plant. The Swedish coal costs are based on the internationally traded commodity classified as coal ARA CIF API#2.

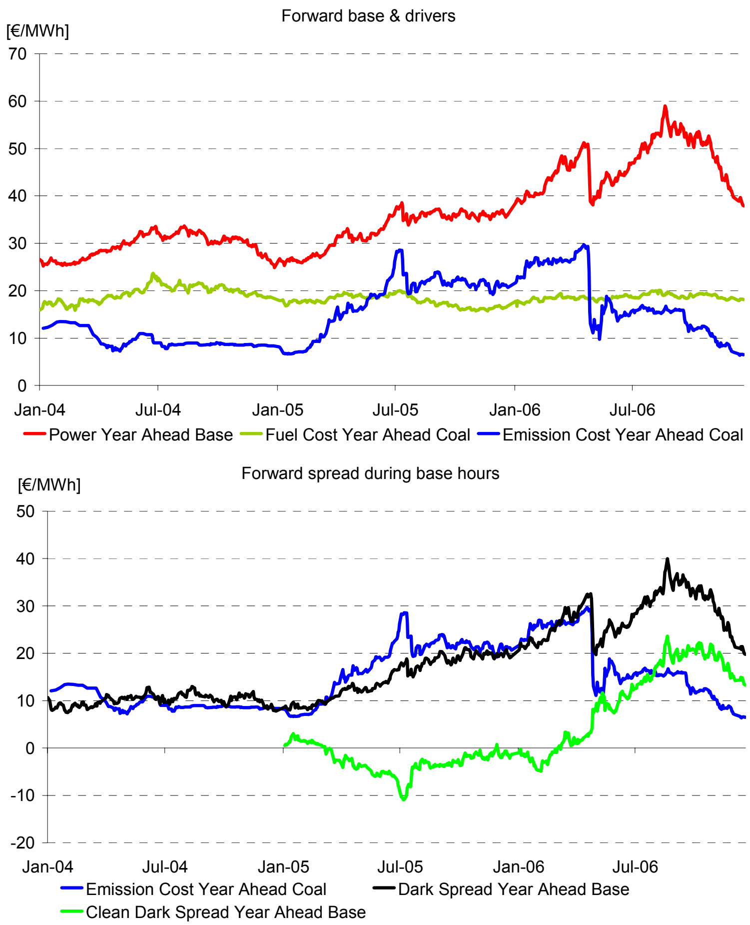

Figure B.13 *Trends in power prices, cost drivers and spreads on forward markets in Sweden, 2004-2006*

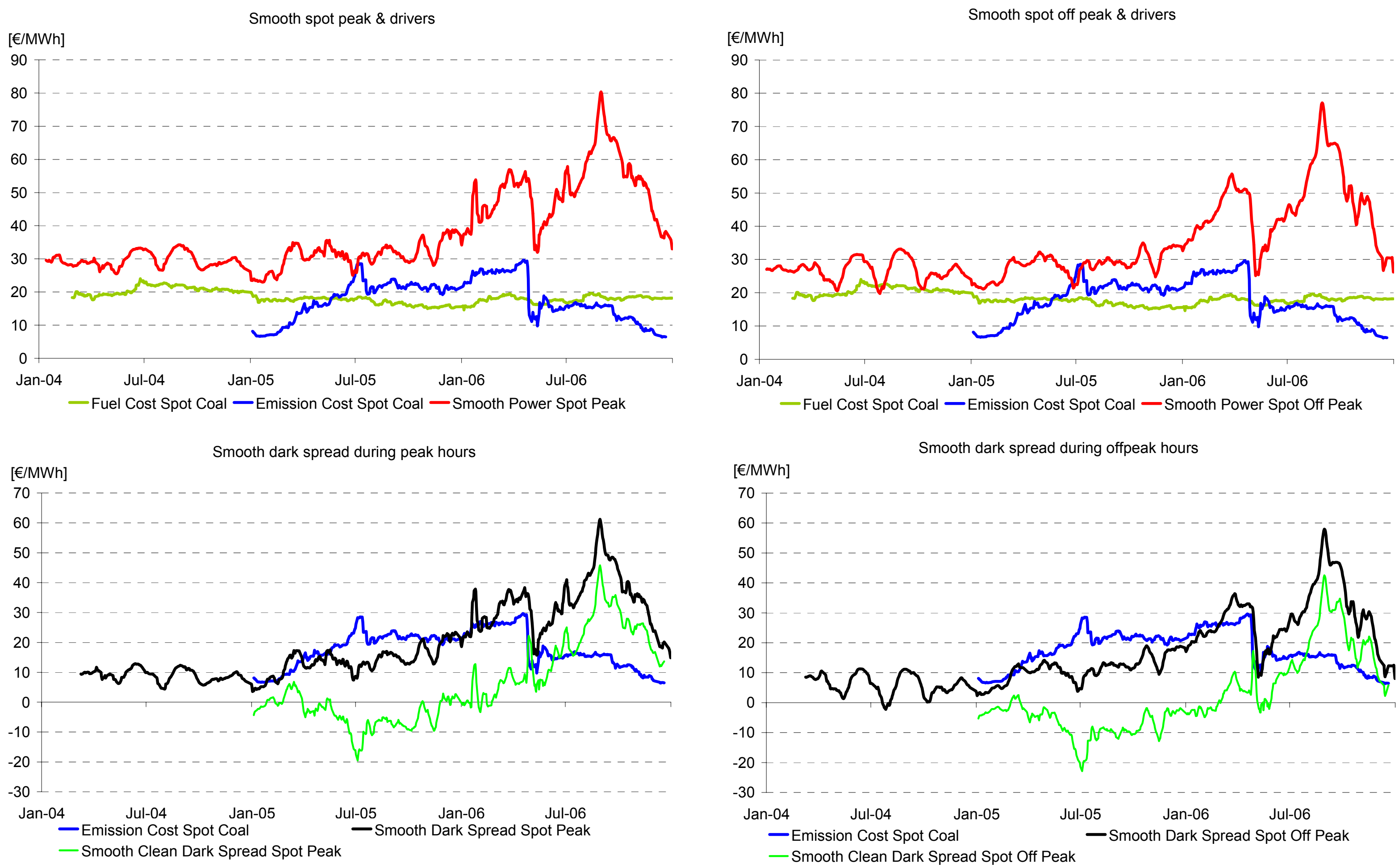

Figure B.14 *Trends in power prices, cost drivers and spreads on spot markets in Sweden, 2004-2006*

B.10 The Czech Republic

B.10.1 Power market structure, price formation and regulation

Power market structure

The power market is dominated by three vertically integrated companies (CEZ, E.ON and PRE) that all act as both generators and distributors. The combined share is more than 95% of final customers' total consumption; in the case of small customers, the combined share is more than 99% (DG TREN, 2007). There are also about 10 independent suppliers actively operating in the retail market. They offer electricity bought from smaller generators or imported from other countries mainly to large industrial customers. The generation sector is similarly concentrated, consisting of a single generator (CEZ) that accounts for 73% of national production capacity, and a number of much smaller generators none of which have a share more than 3% of the total.

Regulation

The Czech Republic state retains no control on the electricity prices charged to end-users

B.10.2 Trends in power prices, drivers and spreads

Figure B.15 shows the trends in power prices, cost drivers and dark spreads on the spot market of the Czech Republic over the period January 2004-December 2006 for peak and off-peak hours (a forward power market is not present in the Czech Republic). The spot market shows a period of relative stability in 2004, while prices are on the rise during 2005 and, subsequently, volatile prices in 2006. Especially the two major price hikes in the first quarter and the summer of 2006 are worth mentioning. The first major price hike was a result of temporarily growing demand and lack of capacity. The ill-organized virtual power auction of 500 megawatts in the summer of 2006 lead to a second major price hike in the Czech Republic spot market (both peak load and off-peak).

In contrast, fuel costs based on coal prices have been more or less stable at a level of about 20 €/MWh during the period January 2004-December 2006. This might suggest that increasing Czech Republic power prices during this period have no close relation with the underlying fuel driver (i.e. coal). Instead, the power price trend presented in Figure B.15 is the partial reflection of the trend in emission costs of coal-generated power. The upward trend in the EUA prices starting in early 2005 is fairly well reflected in both the peak and off-peak process on the Czech Republic spot market, as is the collapse of the EUA prices in May 2006.

B.10.3 Estimates of CO_2 costs pass-through rates

Table B.8 *Estimates of PTRs on spot power markets in the Czech Republic, 2005-2006*

		Regression of power spreads versus carbon costs	
		Peak	Off-peak
2005	PTR	1.50*	0.44*
	Δ	±0.39	±0.22
	R^2	0.49	0.28
2006	PTR	-0.71	-0.27
	Δ	±0.84	±0.26
	R^2	0.65	0.46

* Statistically significant at 10% level.

B.10.4 Data used

Power prices in the Czech Republic case refer to the daily market prices settled in the spot market for both peak load and off peak hours. A forward power market is not yet available. The objective of the Czech Republic Electricity Market Operator (OTE), is to introduce forward contracts on a new commodity exchange starting in June 2007 (Prague Stock Exchange, 2006).

The marginal production capacity in the Czech Republic during both base and peak periods are coal-fired and lignite-fired generation capacity. Assuming that the price of electricity is primarily determined by coal, the average between the daily bid price and offer price for the monthly ARA CIF API#2 is used to determine the coal costs for generating spot power in the Czech Republic.

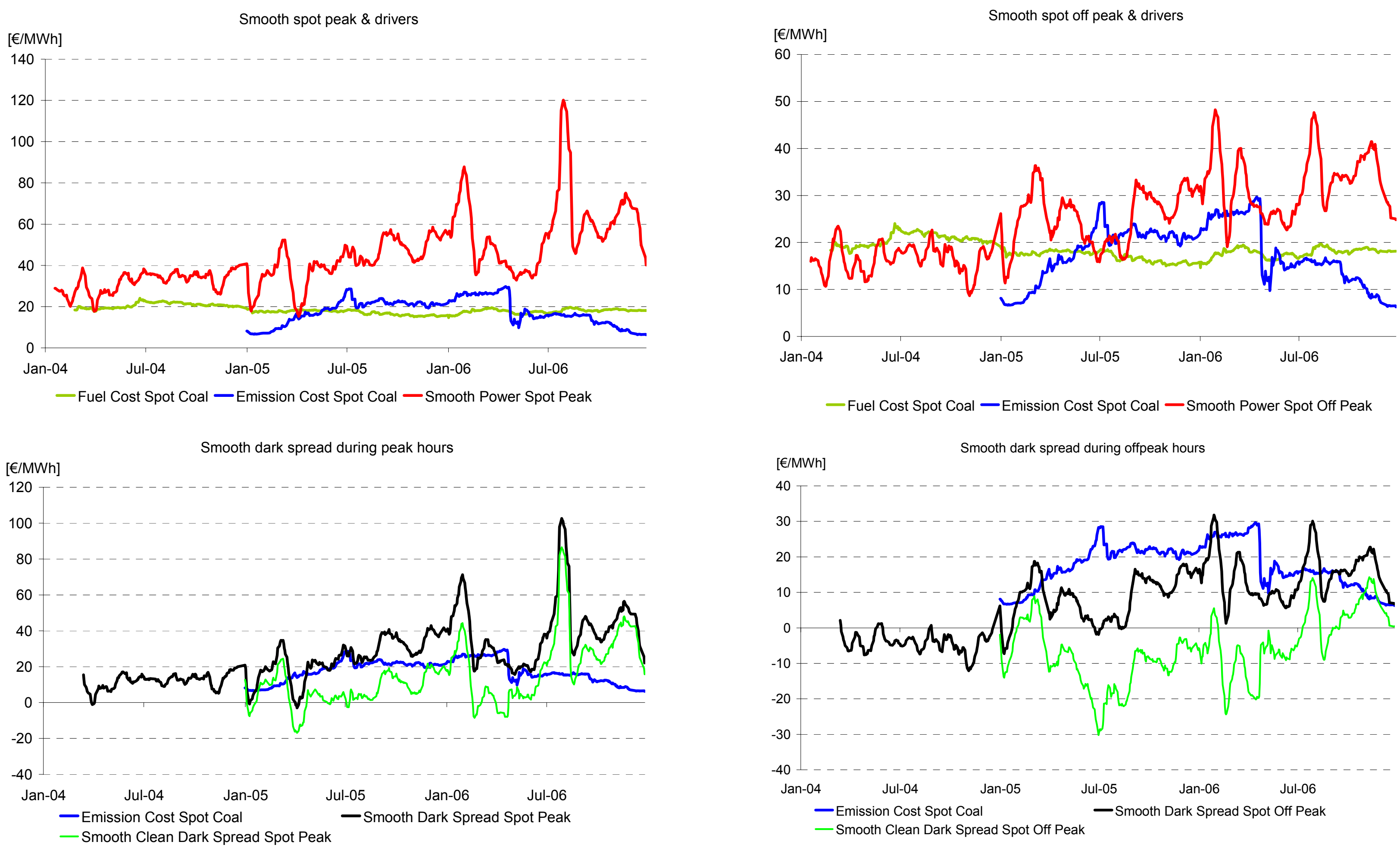

Figure B.15 *Trends in power prices, cost drivers and spreads on spot markets in the Czech Republic, 2004-2006*

B.11 The Netherlands

B.11.1 Power market structure, price formation and regulation

Power market structure

The Netherlands are very well connected with neighbouring Member States for electricity and act as a net importer. The generation segment is dominated by four producers of electricity (Electrabel, E.ON Benelux, Essent and Nuon). Prices are higher than the neighbouring countries, mainly due to the fact that the Dutch generation capacity is largely gas-fuelled, while Germany chiefly has coal and France nuclear power. Besides the four large suppliers, there are many smaller companies active in the market. Some of them are resellers with network activities, and some of them are new entrants who operate without a network or generation capacity. Switching rates are considered satisfactory and it is believed that there is active competition for end-users, including households, in the Netherlands. The relatively low difference between wholesale and end-user prices in the Netherlands is pointed to as an indicator that the market is functioning well (DG TREN).

Price formation

In the Netherlands, electricity is mainly traded via OTC contracts. In fact, between 2001 and 2005 the OTC forward market experienced an increasing trend of traded volumes. Next to it, electricity is traded via the power exchanges (APX for spot market and ENDEX for forward market).

Regulation

The Dutch regulator has the possibility to take measures against unreasonable tariffs of incumbents by defining maximum reasonable regulated prices per product for households and small business.

B.11.2 Trends in power prices, drivers and spreads

The upper two panels of Figure B.16 show the smoothed spot prices in the Netherlands. Even though the volatility of the spot market is relatively high, some general trends may be identified. In the case of the peak prices, the spot market shows a period of relative stability during 2004 and the first half of 2005. The peak prices were on the rise during the second half of 2005, partially reflecting the increasing cost of natural gas in this period. However the increasing costs of natural gas does not fully justify the observed increase in the peak prices for spot power as can be derived from the increasing spark spread in the same period. By mid 2006 the cost of natural gas on the Dutch spot market has declined to lower levels, around 40 €/MWh, a trend that is followed partially by the peak prices on the power spot market. In the second half of 2006, two strong hikes can be observed in the peak prices on the spot market. By July 2006 a strong increase occurs in the peak price, corresponding to a heat wave in early July 2006 and, on average, the warmest July month in three centuries. A second hike can be observed in late 2006 which is less straightforwardly explained.

The off-peak prices show a stronger correspondence to the EUA cost as may be expected on the basis that EUA costs form a relatively high cost component of coal-fired power. The upward trend in the EUA prices starting in early 2005 is fairly well reflected in the off-peak prices on the Dutch spot market, as is the collapse of the EUA prices in May 2006. The pronounced peaks in July 2006 and late 2006 observed in the peak prices on the spot markets are also present in the off-peak price series, be it in a somewhat milder form.

The lower two panels of Figure B.16 show the forward power products and their respective underlying costs. The development of the year ahead forward prices of peak and off-peak in the

Dutch market shows a relatively stable profile over the first year of evaluation, up to early 2005. After January 2005, the year ahead prices of both the peak and off-peak products show an upward trend corresponding to the increasing cost of both the year ahead cost of gas and the year ahead cost of EUAs in the case of the peak product, and the increase in the year ahead cost of EUAs only in the case of the off-peak product.

By late spring 2006 the upward trend of the year ahead power prices came to a halt. In this period the cost of natural gas stabilized while the cost of EUAs for the first commitment period collapsed in April-May 2006 after the publication of the verified 2005 emissions data of the installations covered by the EU ETS. The year ahead cost of natural gas gradually decreases over the remaining period, the second half of 2006, while the year ahead cost of EUA prices levels off to less than 10 €/MWh for both gas and coal-fired facilities. Though the trend in the forward power prices on average seems to stabilize over this period, two strong hikes of peak prices may be observed by mid and late 2006. Neither of the two hikes can be explained by either the underlying fuel cost or the EUA costs and, hence, the change in peak prices should be attributed to other factors. The hikes do correspond to the hikes observed over the same period in the spot markets. However as delivery of the forward products is due in the next year, the relationship with extreme weather events during the trading period does not seem very convincing.

The spark spread for the year ahead peak products shows a stable development up to spring 2006, reflecting the increasing cost of EUAs. A strong and volatile increase in the spark spread for the year ahead peak products can be observed after the EUA price crash, as a result of the price hikes in the forward power market. The dark spread associated with the year ahead off-peak products roughly reflects the development of the EUA prices and suggesting a fair correlation between the two time series.

B.11.3 Estimates of CO_2 costs pass-through rates

Table B.9 *Estimates of PTRs on power markets in the Netherlands, 2005-2006*

		Regression of power spreads versus carbon costs			
		Spot		Forward	
		Peak	Off-peak	Peak	Off-peak
2005	PTR	4.17*	0.19	1.34**	0.40**
	Δ	±0.84	±0.17	±0.14	±0.04
	R^2	0.37	0.72	0.28	0.34
2006	PTR	0.69*	1.21	1.10**	0.38**
	Δ	±1.16	±0.16	±0.14	±0.03
	R^2	0.45	0.68	0.20	0.38

* Statistically significant at 10% level.
** Statistically significant at 1% level.

B.11.4 Data used

Power prices in the Dutch case refer to the APX traded spot contracts and ENDEX traded year ahead forward contracts. In both markets data are available for base and peak load.

In the Netherlands coal-fired facilities span the dominant thermal technology regarding the off-peak hours while peak hours are mainly served by gas-fired power facilities.

The Dutch coal costs are based on to the internationally traded commodity classified as coal ARA CIF API#2. Fuel cost for natural gas, as another marginal technology of power production in the Dutch case, refers to high caloric gas from the Title Transfer Facility (TTF) hub. Both spot and forward products are traded on the TTF hub.

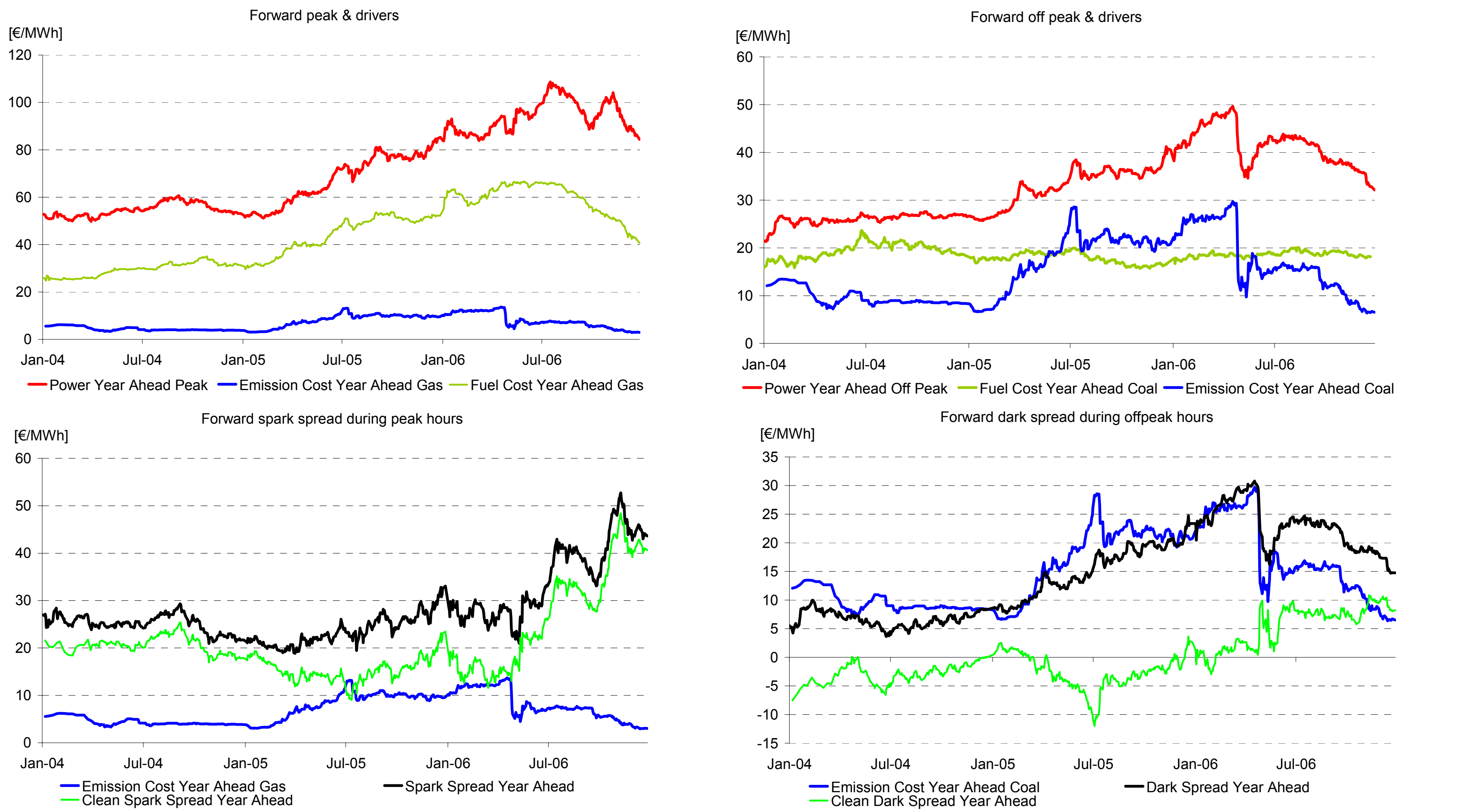

Figure B.16 *Trends in power prices, cost drivers and spreads on forward markets in the Netherlands, 2004-2006 (first choice marginal technology)*

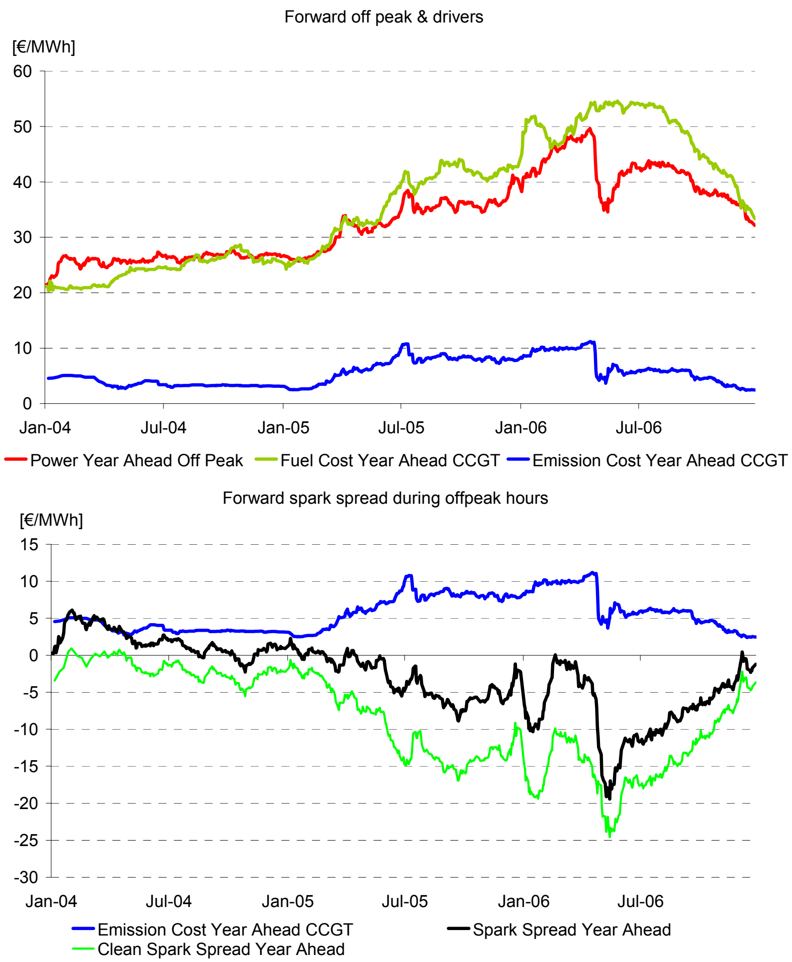

Figure B.17 *Trends in power prices, cost drivers and spreads on forward markets in the Netherlands, 2004-2006 (alternative marginal technology)*

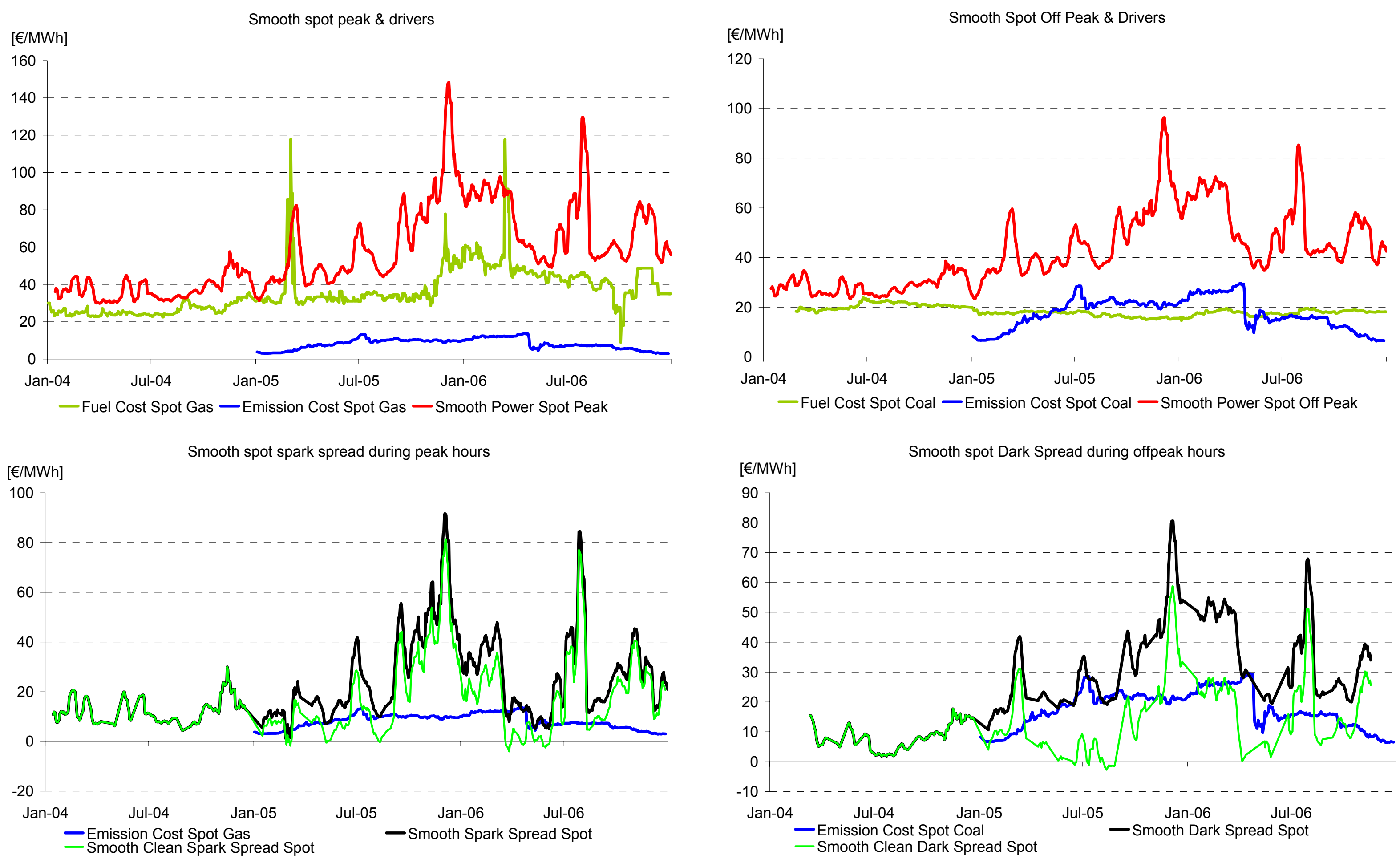

Figure B.18 *Trends in power prices, cost drivers and spreads on spot markets in the Netherlands, 2004-2006 (first choice marginal technology)*

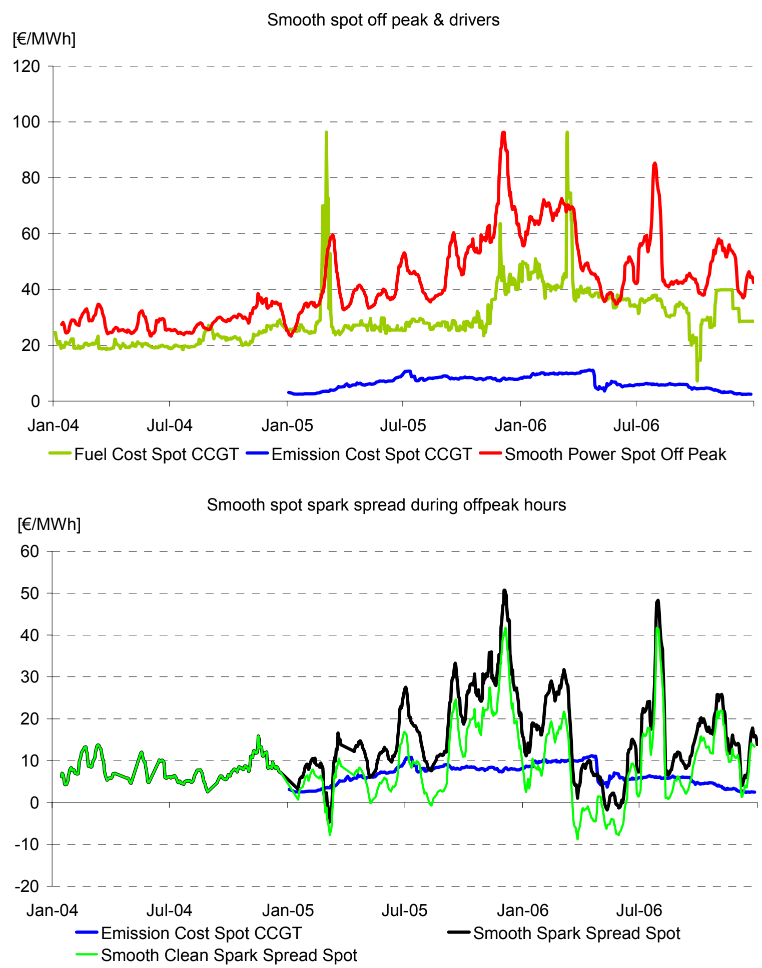

Figure B.19 *Trends in power prices, cost drivers and spreads on spot markets in the Netherlands, 2004-2006 (alternative marginal technology)*

B.12 The United Kingdom

B.12.1 Power market structure, price formation and regulation

Power market structure

Ownership in the UK power generation market is rather diverse, with the UK having the lowest generation sector concentration in the EU. On the retail side, there are six main suppliers (Centrica, NPower(RWE), Powergen (E.ON), EdF Energy, Scottish Power, Scottish and Southern Electricity) active in the household market with additional companies active in the large user sector. The UK electricity supply market is moderately concentrated and has consolidated to closely match the structure of the generation market. However, the degree of competition is considered acceptable even though the number of fully independent suppliers is limited to three incumbents. The changing nature of the energy business towards providing more integrated energy services has reduced liquidity in the wholesale market, which may have exacerbated market volatility (EC, 2007a).

Price formation

Electricity in the UK occurs OTC and on the exchange UKPX. The OTC market experienced decreasing volumes during 2004 and 2005. A reason for this trend is the ongoing vertical reintegration of the industry.

Regulation

The electricity market is free from price controls. This is one of the reasons why in recent years the sharp rise of the wholesale prices in the UK has fed through in varying degrees into retail market price levels. This recent increase in power prices however, should not distract from the fact that customers have, over the years, derived a very high level of benefits from the introduction of power market competition and the surveillance of the market by a strong independent regulator.

B.12.2 Trends in power prices, drivers and spreads

The upper two panels of Figure B.20 show the trends in smoothed spot prices, cost drivers and spreads in the UK. In the case of the peak prices, the spot market shows a period of relative stability during 2004. The peak prices show strong volatility during 2005 and 2006, affectively reflecting volatility in the spot prices for natural gas. Though the spark spread for the peak prices shows significant volatility, the spark spread for this power product seems fairly stable on average.

The off-peak prices show a stronger correspondence to the underlying EUA cost as may be expected on the basis that EUA costs form a relatively high cost component of coal-fired power. The upward trend in the EUA prices starting in early 2005 is fairly well reflected in the off-peak prices on the UK spot market, as is the collapse of the EUA prices in May 2006.

The lower two panels of Figure B.20 show the forward power products for the *summer* seasons and their respective underlying costs. The development of the year ahead forward prices of summer peak and off-peak in the UK market shows a relatively stable profile over the first year of evaluation, up to early 2005. After January 2005, the year ahead prices of both the summer peak and off-peak products show an upward trend corresponding to the increasing underlying cost of both the year ahead cost of natural gas and the year ahead cost of EUAs in the case of the peak products and the increase in the year ahead cost of EUAs only in the case of the off-peak products.

By mid 2006 the upward trend of the year ahead power prices came to a halt. In this period the cost of natural gas stabilized. The cost of EUAs for the first commitment period dropped substantially in April-May 2006. The year ahead cost of natural gas gradually decreased over the remaining period, the second half of 2006, while the year ahead cost of EUA prices declined to about 10 €/MWh and less for both gas- and coal-fired facilities. Though the trend in the forward power prices on average seems to follow the decline of the underlying natural gas cost, the power prices reflect the decline of this cost component slightly delayed, so that the spark spread increases steadily up to the end of 2006. The summer off-peak products roughly reflect the underlying cost of EUAs.

The two panels of Figure B.21 show the forward power products for the *winter* seasons and their respective underlying costs. The development of the year ahead forward prices of winter peak and off-peak in the UK market shows a relatively stable profile over the first year of evaluation, up to early 2005. After January 2005, the year ahead prices of the winter peak roughly follow the development of the underlying cost of both natural gas and EUAs. In the case of the winter off-peak, power prices also follow the development of the underlying cost up to the collapse of the EUA prices in May 2006. However the increase in the winter off-peak products cannot be justified by the underlying costs only as the dark spread steadily increases up to July 2005. The dark spread stabilizes in the period afterwards, up to May 2006, when the EUA market collapses. From thereon the dark spread steadily declines, while the actual collapse of the EUA price is neither reflected in the winter off-peak forward prices, nor in the associated dark spread.

B.12.3 Estimates of CO_2 costs pass-through rates

Table B.10 *Estimates of PTRs on power markets in the United Kingdom, 2005-2006*

		Regression of power spreads versus carbon costs					
		Spot		Forward (Winter)		Forward (Summer)	
		Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
2005	PTR	3.70*	0.70*	1.18**	1.82**	0.83**	1.03**
	Δ	±0.75	±0.40	±0.17	±0.19	±0.17	±0.18
	R^2	0.28	0.84	0.15	0.29	0.09	0.12
2006	PTR	0.89	1.53*	0.59**	0.66**	0.58**	0.60**
	Δ	±1.31	±0.25	±0.11	±0.11	±0.06	±0.06
	R^2	0.14	0.66	0.10	0.12	0.31	0.29

* Statistically significant at 10% level.
** Statistically significant at 1% level.

B.12.4 Data used

Power prices for the UK market refer to the UKPX traded spot contracts and LCI traded GMTA season or multiple seasons ahead forward contracts. In both markets data are available for base and peak load.

In the UK coal-fired facilities span the dominant thermal technology regarding the off-peak hours while peak hours are mainly serves by gas-fired power facilities. The UK coal costs are based on to the internationally traded commodity classified as coal ARA CIF API#2. Fuel cost for natural gas, as another marginal technology of power production in the UK case, refers to natural gas prices for products traded on the NBP hub. Both spot and forward products are traded on NPB.

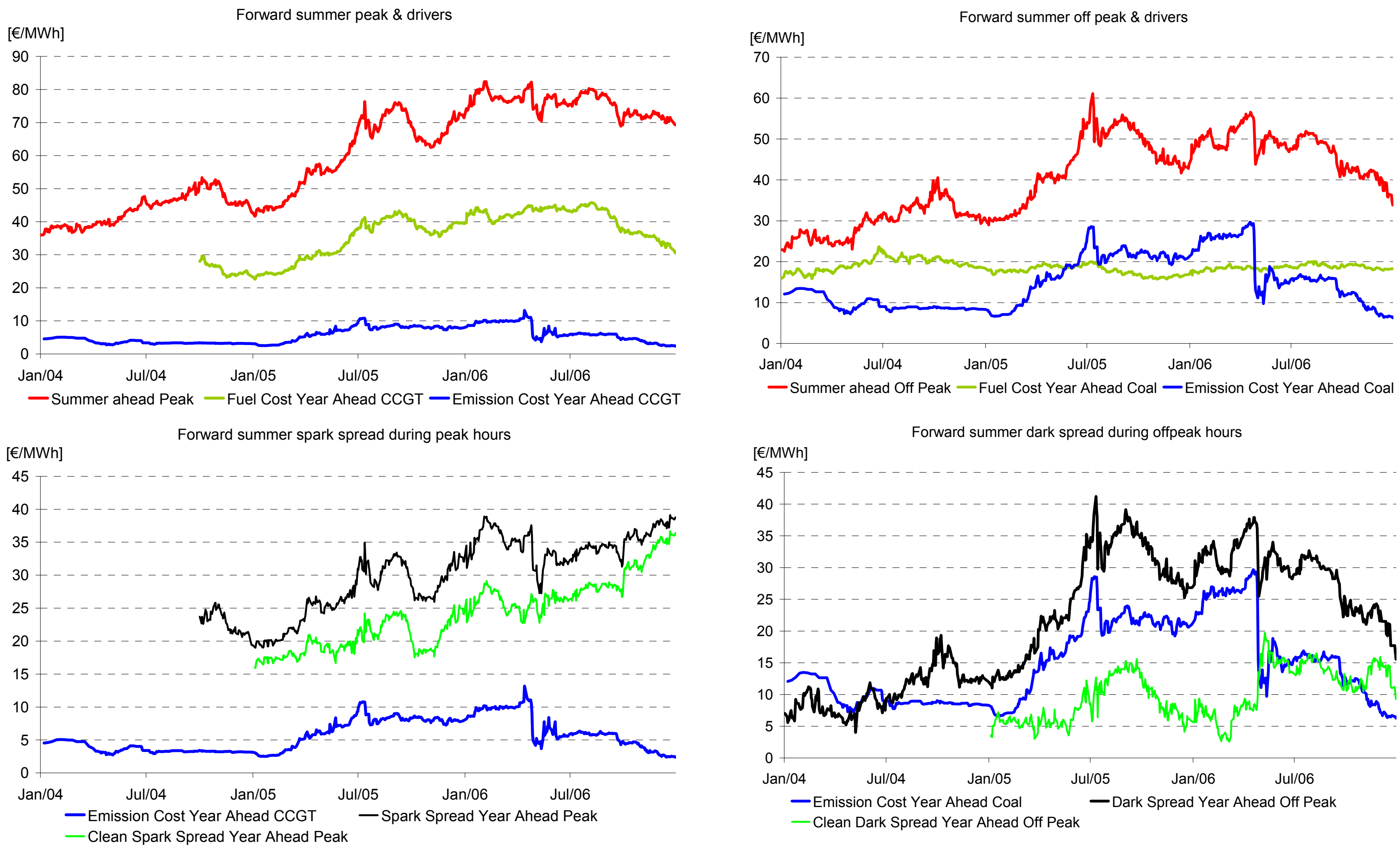

Figure B.20 *Trends in power prices, cost drivers and spreads on forward (summer) markets in the United Kingdom, 2004-2006*

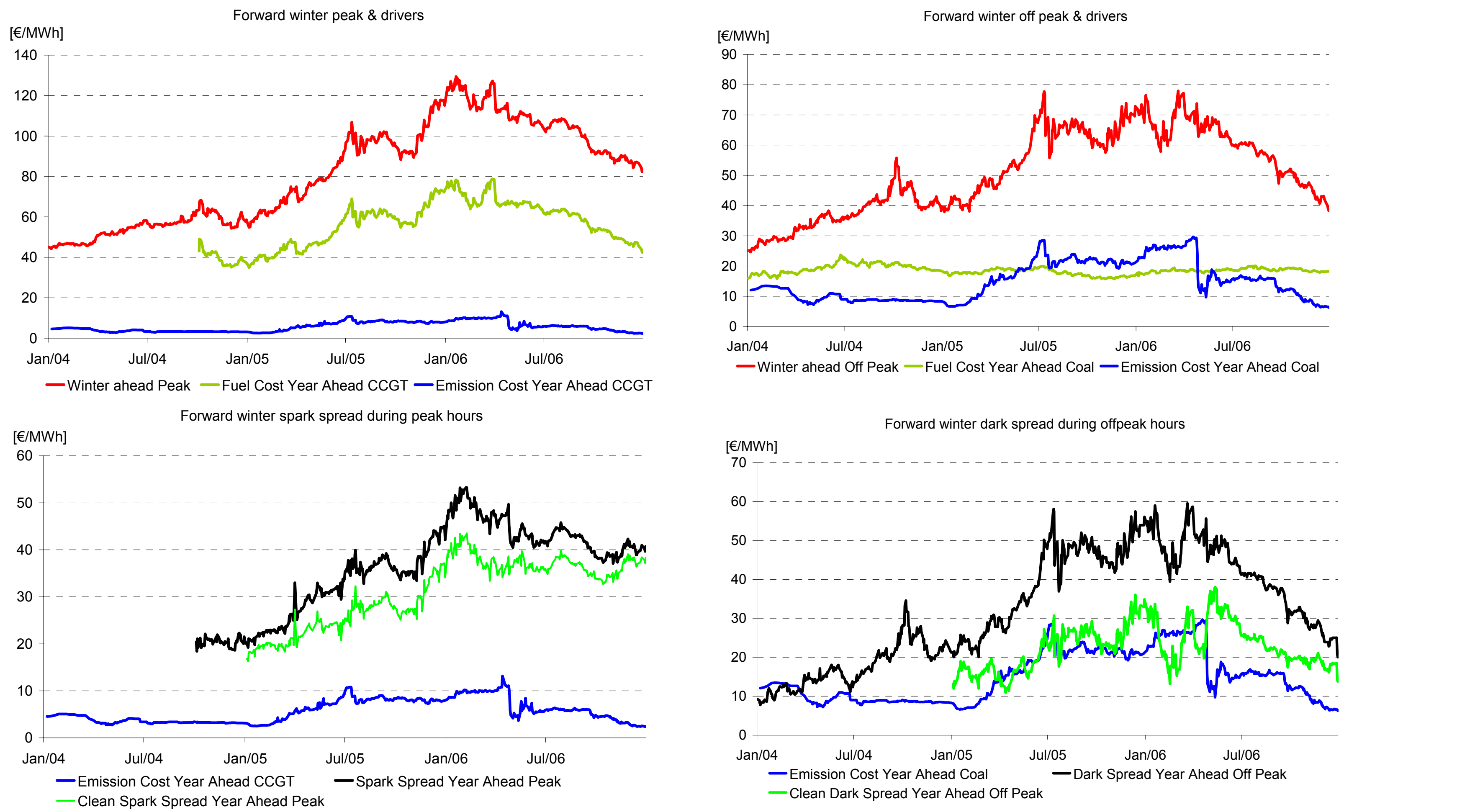

Figure B.21 *Trends in power prices, cost drivers and spreads on forward (winter) markets in the United Kingdom, 2004-2006*

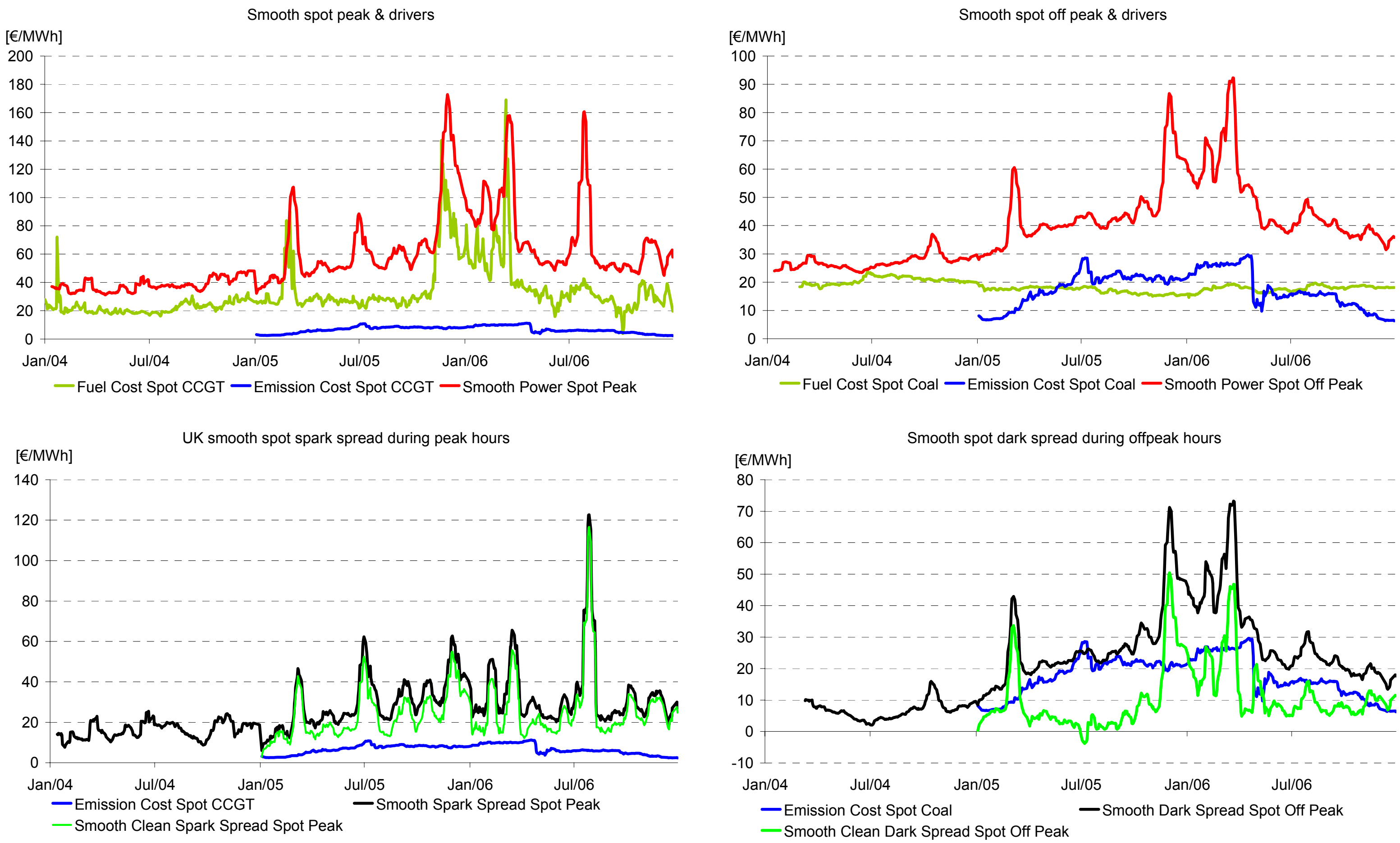

Figure B.22 *Trends in power prices, cost drivers and spreads on spot markets in the United Kingdom, 2004-2006*

Appendix C Regression analyses on the pass-through of carbon costs to power prices - Methodology and detailed results

C.1 Methodology

C.1.1 Price data, load periods and fuel drivers

Regression analyses on the pass-through of carbon costs to power prices have been conducted for nine countries of the EU ETS, including France (FR), Germany (DE), Italy (IT), Poland (PL) Spain (ES), Sweden (SE), the Czech Republic (CZ), the Netherlands (NL) and the United Kingdom (UK). These analyses are based on daily prices for power, fuel and EU carbon emission allowances (EUAs). The extent to which the (opportunity) costs of these allowances are passed through to spot power prices have been estimated for two years, 2005-2006, and two load periods, i.e. the peak (daytime) versus the off-peak (night) in order to account for major differences in power demand during these periods and in marginal, price-setting technologies to meet this demand.

For two countries, i.e. the Netherlands and the UK, daily peak and off-peak spot power prices are readily available (or could be easily derived from peak and baseload data). For the other 7 countries, however, peak and off-peak spot prices are less readily available and have been derived by taking the daily averages of hourly prices during the peak and off-peak periods. Definitions of peak and off-peak periods vary, however, among the countries analysed. More specifically, these definitions include:

- Peak (7:00 - 23:00) and off-peak (23:00 - 7:00): the Netherlands,
- Peak (7:00 - 19:00) and off-peak (19:00 - 7:00): the UK,
- Peak (8:00 - 20:00) and off-peak (20:00 - 8:00): Czech Republic, France, Germany, Italy, Poland, Spain and Sweden.

The daily electricity prices per load period have to be matched to daily fuel and CO_2 prices. To make this match, it is necessary to make assumptions for each country on the marginal price-setting unit during the peak or off-peak period. This is, however, not an easy task, because the price-setting technology is not known a priori. In reality, the marginal unit could vary from hour to hour depending upon various factors, among which fuel cost and - in the case of emissions trading - carbon costs are probably the most important factors. In the analyses, it was assumed that in each country there is one technology that sets the price during either the peak or off-peak hours following the analyses done in the past (Sijm et al., 2005, 2006a and 2006b).

To obtain an indication of the marginal unit in each country during peak and off-peak hours, the COMPETES model can be used (see Chapter 5 and Appendix D and E of the present report). Table C.1 shows the resulting price-setting marginal technologies in COMPETES in the reference case during 12 load periods, varying over season (winter, summer and spring/autumn) and load (super peak, peak, shoulder and off-peak).

Table C.1 shows that, in general, the price-setting technology is either coal, gas, oil or CCGT (i.e. a combined cycle gas turbine), except for a few - mainly off-peak - cases in France and Sweden in which nuclear is the marginal unit, and one case in Sweden (summer, super peak) where generation by waste sets the price.

Table C.1 *Marginal unit during 12 load periods in COMPETES in the reference case (perfect competition and an EUA price of 20 €/tCO$_2$, with 2006 fuel prices)*

	CZ	DE	ES	FR	IT	NL	PL	SE	UK
(w, super peak)[a]	Gas	Gas	Oil	Oil	Oil	Gas	Coal	Gas	Coal
(w, peak)	Gas	Gas	Oil	Oil	Oil	Gas	Coal	Gas	Coal
(w, shoulder)	CCGT	Coal	Oil	Oil	Gas	Oil	Coal	Coal	Coal
(w, off peak)	Coal	Coal	CCGT	Coal	Gas	CCGT	Coal	Coal	Coal
(m, super peak)	CCGT	Gas	Gas	Gas	Gas	Gas	Coal	Gas	Coal
(m, peak)	CCGT	Gas	Gas	Gas	Oil	Gas	Coal	Gas	Coal
(m, shoulder)	Coal	Coal	CCGT	Coal	Gas	CCGT	Coal	Coal	Coal
(m, off peak)	Coal	Coal	CCGT	Nuclear	Gas	CCGT	Coal	Nuclear	CCGT
(s, super peak)	Coal	Coal	Oil	Coal	Oil	Gas	Coal	Waste	Coal
(s, peak)	Coal	Coal	Oil	Coal	Oil	Gas	Coal	Coal	Coal
(s, shoulder)	Coal	Coal	CCGT	Nuclear	Gas	CCGT	Coal	CCGT	Coal
(s, off peak)	Coal	Coal	CCGT	Nuclear	Gas	CCGT	Coal	Nuclear	CCGT

a) w = winter; s = summer, m = spring/autumn.

In addition, Table C.2 presents the shares of the four main fossil-fuel technologies in total power generation in 2005-2006, based on empirical production data of Eurostat. The table shows that these shares vary widely, ranging from 1% in Sweden to 97% in Poland. Even in countries, however, with a small share of fossil-fuel technologies in total electricity output - such as France or Sweden - these technologies still set the power price during major parts of the year.

Table C.2 *Shares of fossil fuel technologies in total generation output*

[%]	CZ	DE	ES	FR	IT	NL	PL	SE	UK
2005									
Coal	61.4	49.1	30.9	5.4	16.3	24.5	93.0	0.8	33.4
CCGT	1.1	3.3	15.6	0.3	16.7	34.0	1.6	0.0	35.6
Gas	1.7	7.3	6.0	3.6	29.6	29.6	0.4	0.5	4.7
Oil	0.4	1.6	8.5	1.0	15.8	1.0	1.6	0.0	0.6
Total	64.6	61.4	61.0	10.3	78.4	89.0	96.7	1.3	74.4
2006									
Coal	60.4	48.7	31.9	4.7	17.4	24.4	93.5	0.8	34.3
CCGT	1.0	3.2	16.1	0.2	17.9	33.8	1.6	0.0	36.6
Gas	1.6	7.3	6.2	3.1	31.8	29.5	0.4	0.5	4.9
Oil	0.3	1.6	2.4	1.4	11.1	1.1	1.6	0.0	0.7
Total	63.3	60.9	56.6	9.5	78.3	88.8	97.2	1.4	76.5

Source: Eurostat.

Based on Tables C.1 and C.2, the most likely or dominant, price-setting unit has been selected for each country during either the peak or off-peak period (see Table C.3). For these cases where it is hard to define a single, dominant marginal technology, an alternative price-setting technology is indicated between brackets.

Table C.3 *Marginal unit during peak and off-peak periods in EU ETS countries*

	CZ	DE	ES	FR	IT	NL	PL	SE	UK
Peak	Coal	Coal (Gas)[a]	Oil (Gas)	Coal (Gas)	Oil	Gas	Coal	Coal	CCGT
Off-peak	Coal	Coal	Coal (CCGT)	Coal	CCGT (Gas)	Coal (CCGT)	Coal	Coal	Coal

Note: Technologies between brackets indicate alternative marginal (i.e. price-setting) unit. Gas refers to an open cycle gas turbine (OCGT) while a combined cycle gas turbine is indicated by its acronym CCGT.

C.1.2 Estimation periods

Pass-through rates (PTRs) have been estimated for both peak and off-peak hours during the annual periods 2005 and 2006 separately. However, as the trend in the carbon price of an EU allowance (EUA) has shown some major changes over these two years, PTRs have been estimated for certain sub-periods of these two years as well. These sub-periods, characterised by the behaviour of the EUA price, include:

I. The EUA price shows a rapidly rising trend: 14/2/2005 - 7/7/2005
II. The EUA price has a stable trend: 15/7/2005 - 16/1/2006
III. The EUA price, after a short period in which it increased rapidly, shows again a stable trend: 24/1/2006 - 31/3/2006
IV. The EUA price collapses: 1/4/2006 - 31/5/2006
V. The EUA price has a stable trend: 1/6/2006 - 15/9/2006
VI. The EUA price shows a decreasing trend: 16/9/2006 - 31/12/2006

The following graph illustrates the delineation of these six sub-periods in the time series of the EUA price.

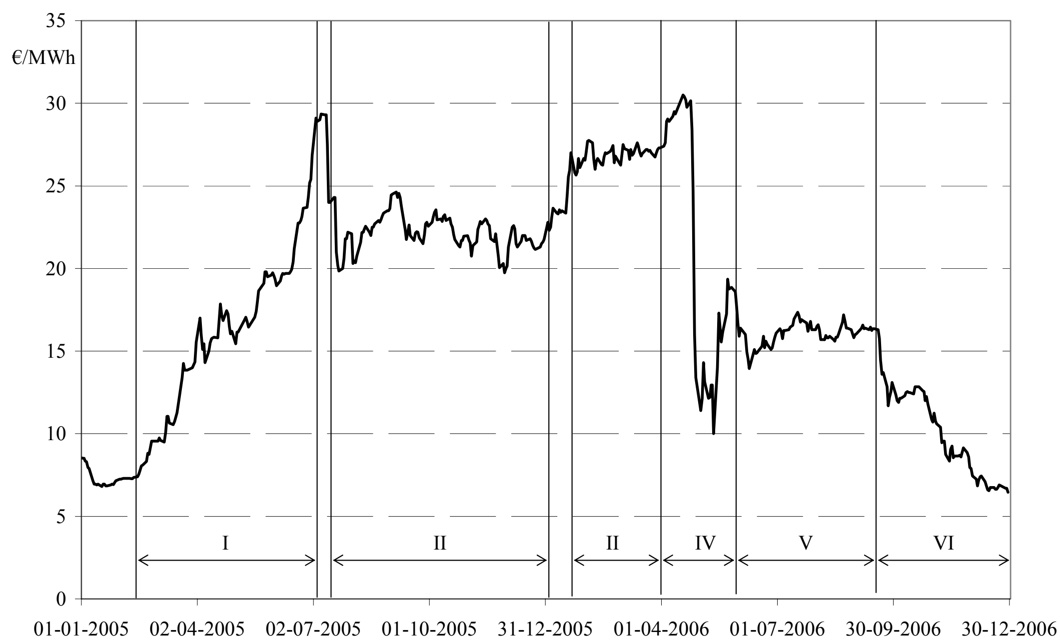

Figure C.1 *Distinction of EUA price into six sub-periods*

C.1.3 Data tests

A stationarity test has been conducted on the time-series regression data, including the fuel and carbon prices, the spark/dark spreads, and the power demand data during the peak and off-peak hours. The results are reported in Table C.4 for the forward market data and Table C.5 for the sport market data. A value larger than 3.1 in absolute terms of the Adjusted Dickey-Fuller (ADF) test statistic indicates stationarity with at least 90% confidence. For each time series the unit root test has been performed, including trend and intercept and no lag terms. All results are reported for 2005, 2006 and the six sub-periods, starting with the EUA and fuel prices, followed by spark/dark spreads for peak/off-peak hours, where for instance CZ_OFFPEAK_CCGT stands for the combined cycle gas spark spread in the Czech Republic during off-peak hours.

In addition, in the case of the spreads based on the forward data, unit root tests have been performed both in levels and in first differences. In these instances the relevant time series is preceded by the symbol 'Δ', and the former example would become ΔCZ_OFFPEAK_CCGT. In addition, the unit root test has been applied to several residual series, resulting from the Ordinary Least Squares (OLS) estimation of the PTR for the forward markets. In these instances, the series at hand are indicated as 'R(CZ_OFFPEAK_CCGT)'. Finally, stationarity test results are provided for power demand data as well, where for instance CZ_OFFPEAK_DEM stands for power demand during off-peak hours in the Czech Republic.

Forward market data

Table C.4 presents the test results for the forward market data. A yellow cell indicates stationarity. The following observations can be made:

- CO_2 costs are stationary in 2006 and in the stable period III of 2006.
- Spark/dark spreads are generally non-stationary in absolute levels.
- Spark/dark spreads are generally stationary in first differences.
- The residuals resulting from the PTR estimates are generally stationary.

The notion that spark/dark spreads are generally not stationary in absolute levels implies that differencing should be used before the OLS estimation procedure can be applied. As the first differences are all stationary, a first differencing procedure suffices in this respect. However, cointegration may arise under these circumstances. The incidence of cointegration can be detected by testing the residuals resulting from the OLS regression in absolute levels for unit roots. The unit root test was applied to all residuals series for the forward market estimations and no cointegration was found. Therefore, the application of the OLS regression method in first differences for the estimation of the PTRs in the forward markets is confirmed and the estimation procedure was carried out accordingly.

Spot market data

Table C.5 provides the test results for the spot market data. As in the case of the forward market data, a yellow cell indicates stationarity. The following observations can be made:

- CO_2 costs are stationary in 2006 and in the stable period III of 2006.
- All gas costs are stationary in 2006 and in period I of 2005, whereas gas_Bunde is also stationary in 2005. Furthermore, gas_TTF is stationary in collapse period IV and gas_Zeebrugge in period VI.
- Coal cost is never stationary.
- Oil cost is stationary in the last quarter of 2006.
- Spark/dark spreads are quite often stationary.
- Power demand is quite often stationary.

Contrary to expectation, the outcome of the stationarity test is quite encouraging as most of the series behave reasonably well, and could be used in a simple Ordinary Least Squares (OLS) regression analysis.[118]

[118] Note that Section C.1.4 below also includes an AR(1) (autoregressive term with one lag), which provides another indicator for stationarity.

In addition, tests have been conducted with regard to the incidence of correlation among the spot market data. The results of these tests are presented in Tables C.6 and C.7. The correlation can range from -1 (perfect negative correlation) through 0 (no correlation) to +1 (perfect positive correlation).

The main observation from Table C.6 is that the different price indicators for gas are often strongly correlated (values larger than 0.8) and that, surprisingly the correlation between the EUA price and various gas price indicators was rather weak in 2005 but significantly positive in 2006. Moreover, whereas the correlation between EUA and coal prices was weakly negative in both 2005 and 2006, it was strongly positive between EUA and oil prices in 2005 but far less positive in 2006.

Table C.7 shows the correlation between fuel, carbon and electricity spot prices. The correlations often show a high positive correlation between gas and power prices, but a mixed result between oil and power prices as well as between EUA and power prices. Correlations between electricity and coal prices are often negative. Over the period 2005-2006, coal prices decreased somewhat, whereas electricity prices tended to rise. In 2006, this trend in power prices reverses in some cases and, therefore, a number of correlations between coal and spot prices become positive for this year.

C.1.4 OLS regression analysis

The basic assumption of the statistical analyses is that during the observation period (say 'peak 2005' or 'off-peak 2006') changes in power prices can be explained by variations in the fuel and carbon costs of the price-setting technology over this period. Hence, it is assumed that during this period other costs - for instance, capital, 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, generation capacity, risks or other factors). In addition, it is assumed that fuel costs are fully and directly passed on to power prices.

Based on these assumptions, the pass-through rate of carbon costs to power prices has been estimated by means of the following basic equation:

$$p^{power} - p^{fuel} = a + b_1 p^{EUA} + e \qquad \text{(C.1)}$$

The left hand side of the equation involves the spark spread in the case of gas-fired generators and the dark spread in the case of coal-fired generators. The first constant on the right hand side of the equation represents some fixed components of the fuel spread, including for example the fixed cost elements and the other, less quantifiable but stable, components. The second term on the right hand side represents the costs of the CO_2 emission allowances needed for the generation of a MWh multiplied by the pass-through rate (b_1). The last term, i.e. the error term (e), represents all other non-stable components in the fuel spread.

Forward market analyses
As outlined in Section C.1.3 above, in the case of the forward markets stationarity of the data was established after first differencing of these data. Therefore, in order to estimate the carbon cost pass-through rate on forward markets by means of an OLS regression analysis, equation C.1 has been transformed into;

$$\Delta\left(p^{power} - p^{fuel}\right) = b_1 \Delta p^{EUA} + e \qquad \text{(C.2)}$$

where Δ refers to the difference between sequential data, and all other variables are as in the original approach.

Spot Market Analysis

The analysis of the spot market data is more complex than the analysis of the year-ahead products on forward markets as spot markets tend to be severely event-driven and may show extreme levels of volatility.[119] In other words, besides fuel costs, CO_2 emission allowance costs, and fixed cost components, there may be a significant number of events, such as weather-related or equipment failure-related events that drive the price on the spot markets for power. If one seeks to quantify the pass trough rate, one should not only filter out the impact of fuel prices, but also these events. In order to estimate reliable, unbiased values of the PTR for carbon costs to power prices, one should ideally account for the impact of these events on these prices. Hence, a demand parameter (d) was included in the regression equation for the spot market analyses in order to account for some demand-related events on the power price.[120] Due to a lack of data, however, it was not possible to quantify and account for other events driving spot power prices. Therefore, the estimated PTRs on the spot market may be biases (i.e. over- or underestimated) due to the impact of these other events on the spot power prices.

Moreover, contrary to the case of forward markets, spot markets for power often close at some particular hour the day before delivery, an hour at which knowledge of the next days fuel price may not be available yet. A trader may therefore turn to the fuel prices at the day of trade instead of the fuel price at the day of (power) delivery, in order to find a proxy for the relevant fuel prices. In that case spot prices of power would be lagging one day. In order to establish this effect, spot prices for fuel and power were correlated with spot prices for power lagging zero up to several days. It was indeed found that correlations where highest in case spot prices for power were lagging the fuel prices by one day, particularly for oil and gas. Therefore the fuel price of the day preceding power delivery, i.e. the day of power trade, was used for the calculations of the fuel spreads in the case of oil and gas (but not for coal).

As discussed in Section C.1.3 above, tests of the spot market data show that most time series for power prices are stationary, while some of the fuel drivers show some level of non-stationarity. In this case, the time series on EUA costs may be regressed on the fuels spreads in absolute levels. In addition most regressions showed significant levels of serial correlation, which has been accommodated for by implementing an additional first-order autoregressive term in the OLS regression equation.

The resulting regression equation is given by:

$$p^{power} - Lp^{fuel} = a + b_1 p^{EUA} + b_2 d + b_3 AR(1) + e \tag{C.3}$$

The left hand side of the equation refers again to the fuel spread, where L is the lag operator in the case of the oil and gas prices. On the right hand side, the first term *a* refers to the stable component of the fuel spread. The second term, p^{EUA}, represents the costs of the EU allowances needed to cover the emissions of generating a MWh of power. The third term (d) refers to power demand, the AR(1) term is the first order auto-regressive term eliminating serial correlation and the last term is the error term. All the cost variables are converted into the same unit (€/MWh). Demand (*d*) for example is converted into '€/MWh' by multiplying demand with the average of the dependent variable $<p^{power} - Lp^{fuel}>$ and dividing it by the average demand.

[119] Markets or control areas with substantial levels of flexible, low-cost, production capacity, like hydropower, may not be so prone to such volatility behaviour as sudden shifts in the supply and demand balance may be easily absorbed.

[120] Only hourly demand data for 2006 were available for all market considered.

C.2 Detailed estimation results

Detailed results of the estimated pass-through rates (PTRs), as well as their standard error (SE), their statistical significance and their goodness of fit (R^2) for both the annual periods and the six sub-periods of 2005 and 2006 are recorded in Table C.8 up to C.12. Whereas Table C.8 provides estimates of the PTRs on forward power markets using the reference values of the assumed fuel efficiencies, Table C.9 presents the results of a sensitivity analysis by assuming a different set of values for these efficiencies. Estimates of PTRs on spot markets in selected EU ETS countries are presented in Tables C.10, C11 and C.12 using different samples (i.e. 100, 90 and 80%, respectively) of the data base in order to account for the impact of very high/low values ('outliers') on the estimated PTRs. The major results of these tables are summarized and discussed in the main text of the present report (in particular Section 4.2).

Table C.4 *Stationarity test results on forward data series of the regression analyses*

	2005	2006	I	II	III	IV	V	VI
EUA	-1.0	-3.5	-0.7	-2.9	-3.8	-1.5	-3.0	-2.6
DE_OFFPEAK_COAL	-2.7	-3.2	-1.4	-1.8	-3.4	-1.5	-2.2	-1.5
DE_PEAK_COAL	-2.0	-3.0	-1.4	-1.8	-3.4	-1.5	-2.2	-1.5
FR_OFFPEAK_COAL	-1.9	-3.1	-1.4	-0.9	-2.4	-1.3	-1.5	-1.6
FR_PEAK_COAL	-1.8	-2.8	-1.4	-0.9	-2.4	-1.3	-1.5	-1.6
NL_OFFPEAK_COAL	-2.0	-2.7	-0.8	-1.6	-1.8	-1.4	-4.1	-1.9
NL_PEAK_GAS	-2.4	-1.0	-1.4	-1.5	-2.1	-1.6	-0.3	-0.7
SE_BASE_COAL	-1.9	-0.2	-1.7	-3.1	-2.0	-1.5	-1.9	-1.9
UKS_OFFPEAK_COAL	-1.0	-1.7	-2.6	-1.6	-1.3	-4.9	-2.6	-2.5
UKS_PEAK_CCGT	-1.5	-1.5	-2.6	-1.6	-1.5	-4.9	-1.0	-2.4
UKW_OFFPEAK_COAL	-2.5	-2.2	-0.7	-3.5	-2.2	-4.4	-1.2	-1.6
UKW_PEAK_CCGT	-2.3	-1.8	-2.0	-3.6	-1.6	-4.7	-1.8	-2.0
ΔEUA	-11.4	-9.5	-7.4	-10.8	-7.8	-2.8	-8.4	-7.3
ΔDE_OFFPEAK_COAL	-15.6	-12.6	-8.6	-13.7	-7.3	-4.0	-8.5	-7.6
ΔDE_PEAK_COAL	-13.5	-13.5	-8.6	-13.7	-7.3	-4.0	-8.5	-7.6
ΔFR_OFFPEAK_COAL	-13.2	-13.0	-10.0	-10.1	-7.8	-3.8	-9.1	-8.0
ΔFR_PEAK_COAL	-15.7	-15.4	-10.0	-10.1	-7.8	-3.8	-9.1	-8.0
ΔNL_OFFPEAK_COAL	-13.1	-11.5	-8.6	-9.6	-5.7	-3.6	-7.7	-8.7
ΔNL_PEAK_GAS	-13.1	-14.1	-9.8	-10.3	-6.6	-5.5	-7.9	-7.4
ΔSE_BASE_COAL	-14.8	-11.0	-8.6	-14.2	-5.6	-1.9	-8.0	-8.0
ΔUKS_OFFPEAK_COAL	-16.6	-15.3	-16.1	-12.3	-7.2	-6.3	-6.3	-7.4
ΔUKS_PEAK_CCGT	-17.5	-15.7	-13.0	-10.3	-5.3	-6.4	-6.6	-8.7
ΔUKW_OFFPEAK_COAL	-15.5	-14.5	-14.6	-10.6	-6.7	-6.2	-8.4	-8.0
ΔUKW_PEAK_CCGT	-16.9	-15.7	-12.6	-11.0	-8.0	-6.2	-9.1	-8.7
R(DE_OFFPEAK_COAL)	-15.7	-16.6	-7.0	-11.9	-6.6	-7.3	-8.0	-7.5
R(DE_PEAK_COAL)	-13.8	-13.8	-7.0	-11.9	-6.6	-7.3	-8.0	-7.5
R(FR_OFFPEAK_COAL)	-13.2	-16.3	-8.9	-9.1	-6.3	-6.5	-7.9	-7.5
R(FR_PEAK_COAL)	-15.7	-13.4	-8.9	-9.1	-6.3	-6.5	-7.9	-7.5
R(NL_OFFPEAK_COAL)	-13.5	-14.6	-6.9	-10.9	-6.0	-6.0	-8.0	-9.0
R(NL_PEAK_GAS)	-14.6	-14.0	-8.2	-12.3	-6.7	-5.5	-8.5	-7.8
R(SE_BASE_COAL)	-15.3	-14.2	-7.0	-9.0	-5.7	-5.3	-8.3	-7.4
R(UKS_OFFPEAK_COAL)	-16.6	-15.2	-13.1	-10.8	-6.9	-5.8	-7.5	-7.4
R(UKS_PEAK_CCGT)	-17.2	-15.6	-12.1	-10.3	-5.6	-6.0	-8.0	-8.3
R(UKW_OFFPEAK_COAL)	-16.7	-14.6	-14.5	-10.1	-6.9	-5.9	-9.5	-8.3
R(UKW_PEAK_CCGT)	-16.8	-15.5	-11.6	-11.0	-6.8	-5.9	-10.9	-8.6

Note: Yellow coloured cells indicate the absence of a unit root (ADF value larger than 3.1 in absolute terms, constant and intercept included and no lags), indicating that the time series are stationary with at least 90% confidence.

Table C.5 *Stationarity test results on spot data series of the regression analyses*

	2005	2006	I	II	III	IV	V	VI
EUA	-1.0	-3.5	-0.7	-2.9	-3.8	-1.5	-3.0	-2.9
GAS_BUNDE	-4.8	-4.0	-4.1	-2.9	-2.0	-3.0	-2.3	-2.3
GAS_TTF	-2.9	-4.6	-5.2	-3.1	-2.3	-3.6	-2.4	-2.2
GAS_UK	-3.0	-5.0	-3.9	-1.9	-2.8	-3.1	-2.2	-2.2
GAS_ZEEBRUGGE	-2.7	-5.1	-4.1	-2.4	-3.1	-2.4	-2.4	-4.6
COAL	-2.6	-2.0	-2.5	-3.1	-2.7	-1.3	-1.2	-1.5
OIL_BRENT	-2.0	-1.9	-0.8	-2.4	-1.5	-2.3	-0.6	-3.7
CZ_OFFPEAK_CCGT	-9.6	-6.9	-7.2	-5.8	-3.0	-5.0	-3.8	-7.3
CZ_OFFPEAK_COAL	-9.0	-6.7	-7.6	-7.4	-2.5	-5.0	-3.2	-4.9
CZ_OFFPEAK_GAS	-8.4	-6.5	-6.3	-5.1	-2.8	-5.0	-3.9	-6.7
CZ_OFFPEAK_OIL	-6.3	-5.6	-5.5	-6.5	-2.6	-4.1	-3.3	-4.4
CZ_PEAK_CCGT	-7.9	-5.1	-6.0	-5.6	-3.3	-4.9	-2.6	-4.8
CZ_PEAK_COAL	-7.7	-4.9	-4.7	-5.8	-3.0	-4.8	-2.5	-4.2
CZ_PEAK_GAS	-7.5	-5.1	-6.2	-5.3	-3.2	-4.8	-2.6	-5.2
CZ_PEAK_OIL	-6.7	-4.8	-3.8	-5.9	-3.1	-4.0	-2.5	-3.9
DE_OFFPEAK_CCGT	-7.9	-5.9	-6.7	-5.0	-2.9	-4.7	-3.7	-5.9
DE_OFFPEAK_COAL	-5.7	-5.3	-3.8	-5.6	-3.0	-4.7	-3.3	-4.9
DE_OFFPEAK_GAS	-7.2	-5.6	-5.9	-4.7	-2.5	-4.6	-3.8	-5.4
DE_OFFPEAK_OIL	-3.5	-3.4	-3.5	-3.8	-2.5	-3.3	-3.2	-5.0
DE_PEAK_CCGT	-6.6	-9.9	-5.6	-4.9	-4.8	-3.9	-5.5	-8.1
DE_PEAK_GAS	-7.2	-9.9	-6.5	-5.1	-4.4	-3.8	-5.5	-8.3
DE_PEAK_OIL	-5.2	-9.2	-3.9	-4.6	-4.1	-3.9	-5.3	-6.8
ES_OFFPEAK_CCGT	-3.3	-5.2	-3.0	-2.6	-2.9	-4.5	-2.6	-4.0
ES_OFFPEAK_COAL	-5.2	-3.8	-3.5	-3.6	-3.1	-4.6	-2.9	-3.7
ES_OFFPEAK_GAS	-3.0	-5.3	-3.1	-2.5	-2.9	-4.2	-2.5	-3.9
ES_OFFPEAK_OIL	-3.8	-2.7	-4.0	-3.2	-3.1	-4.6	-1.7	-2.6
ES_PEAK_CCGT	-3.8	-5.7	-3.8	-3.7	-2.7	-4.1	-2.9	-5.8
ES_PEAK_COAL	-5.3	-4.8	-3.5	-4.0	-3.5	-3.1	-2.7	-5.5
ES_PEAK_GAS	-3.5	-5.7	-3.8	-3.3	-2.7	-4.3	-2.8	-5.6
ES_PEAK_OIL	-4.8	-4.8	-3.3	-4.0	-3.8	-2.8	-2.8	-6.3
FR_OFFPEAK_CCGT	-4.4	-7.3	-5.8	-4.3	-4.0	-3.1	-3.7	-4.3
FR_OFFPEAK_COAL	-5.2	-4.1	-3.5	-5.2	-3.1	-3.3	-3.2	-4.0
FR_OFFPEAK_GAS	-3.7	-7.7	-6.0	-3.6	-3.9	-3.1	-3.6	-4.2
FR_OFFPEAK_OIL	-3.7	-3.3	-3.7	-4.1	-2.7	-2.3	-2.9	-3.5
FR_PEAK_CCGT	-7.6	-6.0	-3.4	-7.5	-4.1	-3.9	-3.2	-4.6
FR_PEAK_COAL	-4.9	-5.2	-3.1	-4.3	-3.3	-4.1	-3.0	-4.6
FR_PEAK_GAS	-8.0	-6.2	-3.5	-8.0	-4.2	-3.9	-3.2	-4.6
FR_PEAK_OIL	-6.0	-5.2	-3.5	-5.4	-3.0	-3.2	-3.0	-4.4
IT_OFFPEAK_CCGT	-2.9	-7.2	-5.6	-2.7	-3.5	-3.4	-4.6	-4.0
IT_OFFPEAK_COAL	-7.2	-5.1	-4.3	-6.4	-2.4	-4.4	-6.1	-3.4
IT_OFFPEAK_GAS	-2.8	-6.9	-5.6	-2.6	-3.4	-3.1	-3.9	-3.9
IT_OFFPEAK_OIL	-5.0	-3.0	-3.9	-5.6	-1.6	-2.7	-3.7	-3.7
IT_PEAK_CCGT	-3.3	-6.5	-4.0	-3.7	-3.1	-3.7	-3.4	-4.7
IT_PEAK_COAL	-4.8	-5.7	-1.9	-4.9	-1.4	-3.5	-3.2	-5.7
IT_PEAK_GAS	-3.1	-6.6	-4.1	-3.3	-3.2	-3.6	-3.4	-4.6
IT_PEAK_OIL	-5.0	-5.3	-2.6	-4.8	-0.8	-3.0	-3.3	-5.1
NL_OFFPEAK_CCGT	-6.2	-7.6	-5.5	-4.9	-3.5	-3.9	-5.7	-5.0
NL_OFFPEAK_COAL	-5.9	-6.8	-4.6	-4.7	-2.7	-4.2	-5.0	-6.1
NL_OFFPEAK_GAS	-5.4	-7.0	-5.6	-4.4	-3.1	-3.9	-5.7	-4.2

	2005	2006	I	II	III	IV	V	VI
NL_OFFPEAK_OIL	-3.2	-4.0	-3.7	-2.9	-2.2	-3.5	-4.1	-5.2
NL_PEAK_CCGT	-9.3	-7.4	-2.7	-8.1	-5.5	-5.8	-3.9	-4.8
NL_PEAK_COAL	-8.9	-7.1	-2.9	-7.9	-5.0	-4.9	-3.9	-4.2
NL_PEAK_GAS	-9.4	-7.4	-2.7	-8.1	-4.8	-5.7	-3.9	-4.9
NL_PEAK_OIL	-10.3	-5.4	-3.6	-9.9	-4.4	-4.6	-2.7	-3.8
PL_OFFPEAK_CCGT	-5.0	-4.3	-4.2	-2.6	-1.9	-3.7	-4.2	-3.3
PL_OFFPEAK_COAL	-5.3	-8.4	-5.1	-5.6	-4.0	-3.0	-4.7	-7.2
PL_OFFPEAK_GAS	-4.9	-4.2	-4.2	-2.7	-1.9	-3.5	-3.7	-3.1
PL_OFFPEAK_OIL	-2.2	-2.3	-1.0	-2.4	-2.4	-2.5	-1.3	-4.0
PL_PEAK_CCGT	-5.4	-4.6	-4.5	-3.1	-2.1	-3.4	-3.1	-3.3
PL_PEAK_COAL	-8.4	-5.5	-6.5	-6.6	-2.5	-3.5	-4.3	-5.6
PL_PEAK_GAS	-5.2	-4.4	-4.3	-3.0	-2.0	-3.1	-2.9	-3.1
PL_PEAK_OIL	-3.1	-2.3	-2.7	-2.8	-2.5	-2.1	-1.0	-3.7
SE_OFFPEAK_CCGT	-5.2	-2.3	-4.1	-3.1	-2.1	-1.5	-0.9	-3.9
SE_OFFPEAK_COAL	-5.1	-1.9	-4.5	-3.8	-3.4	-1.8	-1.1	-3.2
SE_OFFPEAK_GAS	-5.1	-2.7	-4.1	-3.0	-2.0	-1.5	-1.0	-3.7
SE_OFFPEAK_OIL	-3.0	-2.0	-2.0	-3.2	-1.7	-1.4	-1.7	-3.0
SE_PEAK_CCGT	-6.3	-3.5	-4.7	-4.6	-2.8	-0.8	-2.9	-4.4
SE_PEAK_COAL	-7.0	-3.8	-5.6	-5.2	-6.3	-1.1	-3.3	-4.3
SE_PEAK_GAS	-5.8	-3.5	-4.5	-3.8	-2.4	-0.7	-2.7	-3.9
SE_PEAK_OIL	-4.8	-3.9	-3.4	-4.3	-5.5	-0.9	-2.9	-3.7
UK_OFFPEAK_CCGT	-5.9	-12.0	-8.1	-5.0	-6.3	-3.0	-4.8	-4.2
UK_OFFPEAK_COAL	-4.3	-7.1	-3.5	-3.2	-3.9	-2.2	-4.2	-5.3
UK_OFFPEAK_GAS	-4.6	-9.9	-6.6	-3.8	-5.4	-3.3	-4.0	-3.5
UK_OFFPEAK_OIL	-2.8	-5.8	-3.3	-2.0	-3.7	-2.3	-3.6	-4.0
UK_PEAK_CCGT	-12.0	-10.9	-5.5	-9.8	-6.8	-5.5	-4.4	-6.5
UK_PEAK_COAL	-4.8	-7.9	-3.4	-3.7	-4.2	-4.8	-4.1	-5.2
UK_PEAK_GAS	-12.7	-11.3	-6.6	-10.8	-7.4	-5.6	-4.5	-6.6
UK_PEAK_OIL	-5.0	-8.2	-3.8	-3.6	-4.1	-4.3	-4.2	-5.0
CZ_OFFPEAK_DEM	-2.4	-2.5	-3.7	-3.6	-1.9	-4.1	-2.6	-2.5
CZ_PEAK_DEM	-3.0	-3.1	-4.6	-4.1	-2.8	-4.7	-2.9	-2.7
DE_OFFPEAK_DEM	-4.2	-4.2	-5.5	-3.9	-5.0	-4.3	-5.3	-2.4
DE_PEAK_DEM	-6.8	-6.9	-7.2	-4.6	-4.7	-4.9	-7.0	-3.1
ES_OFFPEAK_DEM	-4.6	-4.6	-3.3	-4.0	-4.0	-4.2	-2.9	-3.8
ES_PEAK_DEM	-6.3	-6.3	-3.3	-5.4	-3.2	-3.9	-2.2	-5.7
FR_OFFPEAK_DEM	-2.5	-2.6	-3.9	-4.2	-2.7	-3.6	-4.5	-4.5
FR_PEAK_DEM	-4.7	-4.8	-6.0	-6.8	-4.8	-5.5	-6.0	-7.3
IT_OFFPEAK_DEM	-6.1	-6.0	-4.9	-3.7	-7.3	-4.7	-2.0	-4.2
IT_PEAK_DEM	-6.4	-6.4	-5.2	-4.1	-3.2	-5.4	-1.9	-4.7
NL_OFFPEAK_DEM	-4.6	-4.6	-3.4	-2.8	-3.2	-3.3	-2.4	-2.8
NL_PEAK_DEM	-5.3	-5.4	-5.1	-3.5	-2.8	-4.4	-3.3	-2.7
PL_OFFPEAK_DEM	-4.2	-4.2	-5.1	-6.6	-4.0	-4.1	-5.6	-4.8
PL_PEAK_DEM	-4.6	-4.6	-5.4	-6.7	-2.4	-4.6	-5.6	-5.1
SE_OFFPEAK_DEM	-2.4	-2.5	-4.8	-3.9	-4.7	-2.4	-2.9	-3.2
SE_PEAK_DEM	-3.1	-3.3	-5.9	-5.1	-6.0	-2.9	-3.9	-4.6
UK_OFFPEAK_DEM	-4.3	-4.4	-4.3	-5.5	-5.6	-5.7	-11.6	-4.5
UK_PEAK_DEM	-7.9	-8.1	-8.9	-7.8	-7.6	-5.6	-9.2	-5.6

Note: Yellow coloured cells indicate the absence of a unit root (ADF value larger than 3.1 in absolute terms, constant and intercept included and no lags), indicating that the time series are stationary with at least 90% confidence.

Table C.6 *Correlation test results between fuel and EUA prices, 2005-2006*

	EUA	Coal	Oil_Brent	Gas_Bunde	Gas_TTF	Gas_UK	Gas_Zeebrugge
2005							
EUA	1.000	-0.158	0.667	-0.010	-0.030	-0.044	-0.039
Coal	-0.158	1.000	-0.475	-0.504	-0.477	-0.561	-0.494
Oil_Brent	0.667	-0.475	1.000	0.023	0.021	-0.024	0.000
Gas_Bunde	-0.010	-0.504	0.023	1.000	0.936	0.877	0.887
Gas_TTF	-0.030	-0.477	0.021	0.936	1.000	0.836	0.876
Gas_UK	-0.044	-0.561	-0.024	0.877	0.836	1.000	0.894
Gas_Zeebrugge	-0.039	-0.494	0.000	0.887	0.876	0.894	1.000
2006							
EUA	1.000	-0.096	0.323	0.576	0.548	0.596	0.805
Coal	-0.096	1.000	-0.162	-0.086	-0.058	-0.024	-0.269
Oil_Brent	0.323	-0.162	1.000	0.165	0.159	0.064	0.269
Gas_Bunde	0.576	-0.086	0.165	1.000	0.884	0.905	0.629
Gas_TTF	0.548	-0.058	0.159	0.884	1.000	0.790	0.624
Gas_UK	0.596	-0.024	0.064	0.905	0.790	1.000	0.684
Gas_Zeebrugge	0.805	-0.269	0.269	0.629	0.624	0.684	1.000

Note: Light yellow coloured cells have a light positive correlation between 0 and 0.5, dark yellow coloured cells have a positive correlation between 0.5 and 1, and orange coloured cells have a light negative correlation between -0.5 and 0.

Table C.7 *Correlation test results between carbon, fuel and electricity spot prices, 2005-2006*

		2005				2006			
		EUA	COAL	GAS	OIL	EUA	COAL	GAS	OIL
CZ	Peak	0.184	-0.252	0.255	0.249	-0.105	-0.114	0.068	0.070
	Off-peak	-0.078	-0.243	0.337	0.015	-0.002	-0.063	0.170	-0.022
DE	Peak	0.130	-0.462	0.751	0.053	0.119	-0.076	0.202	0.098
	Off-peak	0.183	-0.502	0.746	0.073	0.603	-0.024	0.574	0.019
ES	Peak	0.386	0.101	0.275	0.139	0.515	-0.502	0.546	0.238
	Off-peak	0.205	-0.282	0.625	0.144	0.658	-0.426	0.670	0.014
FR	Peak	0.128	-0.420	0.821	0.038	0.264	-0.169	0.406	0.130
	Off-peak	0.161	-0.450	0.780	0.014	0.636	-0.115	0.747	-0.100
IT	Peak	0.608	-0.217	0.323	0.437	-0.074	-0.088	0.027	0.017
	Off-peak	0.437	-0.641	0.357	0.593	0.452	0.375	0.493	0.059
NL	Peak	0.212	-0.605	0.656	0.172	0.153	-0.113	0.271	0.065
	Off-peak	0.180	-0.388	0.699	0.022	0.640	0.020	0.574	0.046
PL	Peak	-0.006	-0.320	0.404	0.054	-0.008	-0.064	0.365	-0.333
	Off-peak	0.101	-0.538	0.370	0.347	0.213	0.063	0.121	-0.069
SE	Peak	-0.183	-0.233	0.632	-0.099	-0.055	0.517	-0.248	0.076
	Off-peak	-0.184	-0.278	0.527	-0.071	0.055	0.606	-0.177	0.062
UK	Peak	0.118	-0.483	0.877	0.032	0.329	-0.023	0.589	0.171
	Off-peak	0.089	-0.534	0.915	0.043	0.734	0.038	0.871	0.130

Note: Light yellow coloured cells have a light positive correlation between 0 and 0.5, dark yellow coloured cells have a positive correlation between 0.5 and 1, and orange coloured cells have a light negative correlation between -0.5 and 0.

Table C.8 *Estimates of carbon costs pass-through rates on forward markets in EU ETS countries during the peak and off-peak period in 2005-2006*

		2005			2006			I			II			III			IV			V			VI		
		PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2
DE	Peak_coal	0.60	0.06	0.32	0.57	0.05	0.38	0.41	0.08	0.16	0.68	0.10	0.27	0.78	0.17	0.30	0.47	0.07	0.61	1.05	0.19	0.30	0.94	0.20	0.26
	Peak_gas	1.07	0.11	0.29	1.07	0.09	0.36	0.71	0.15	0.15	1.23	0.18	0.25	1.48	0.33	0.28	0.87	0.13	0.58	1.85	0.35	0.27	1.69	0.36	0.25
	Off-peak_coal	0.41	0.04	0.35	0.64	0.04	0.58	0.33	0.05	0.28	0.41	0.06	0.25	0.71	0.12	0.40	0.63	0.06	0.77	0.71	0.14	0.26	0.73	0.16	0.26
FR	Peak_coal	0.66	0.08	0.23	0.58	0.07	0.26	0.38	0.11	0.07	0.74	0.14	0.17	0.90	0.25	0.21	0.45	0.09	0.47	0.91	0.26	0.15	1.17	0.23	0.28
	Peak_gas	1.04	0.15	0.17	1.02	0.12	0.24	0.61	0.22	0.05	1.23	0.27	0.13	1.45	0.49	0.15	0.80	0.17	0.42	1.69	0.51	0.14	2.09	0.43	0.27
	Off-peak_coal	0.40	0.05	0.22	0.59	0.04	0.47	0.35	0.06	0.22	0.39	0.09	0.12	0.64	0.12	0.37	0.56	0.06	0.71	0.92	0.18	0.28	0.86	0.18	0.26
NL	Peak_gas	1.34	0.14	0.28	1.10	0.14	0.20	0.95	0.17	0.15	1.93	0.25	0.30	1.67	0.51	0.18	0.93	0.19	0.41	1.71	0.53	0.12	2.20	0.58	0.16
	Off-peak_coal	0.40	0.04	0.34	0.38	0.03	0.38	0.39	0.05	0.35	0.50	0.07	0.32	0.48	0.14	0.15	0.37	0.06	0.58	0.29	0.14	0.05	0.47	0.10	0.19
	Off-peak_ccgt	0.90	0.10	0.27	0.93	0.08	0.35	0.91	0.13	0.33	1.19	0.16	0.29	1.23	0.38	0.13	0.92	0.15	0.52	0.62	0.35	0.03	0.92	0.24	0.15
SE	Base_coal	0.53	0.04	0.42	0.62	0.05	0.38	0.47	0.06	0.42	0.47	0.07	0.29	0.50	0.21	0.08	0.57	0.06	0.76	1.05	0.27	0.14	1.13	0.22	0.23
UK-S[a]	Peak_ccgt	0.83	0.17	0.09	0.58	0.06	0.31	0.77	0.13	0.20	0.66	0.13	0.16	0.52	0.18	0.14	0.59	0.08	0.63	0.76	0.20	0.17	0.31	0.24	0.02
	Peak_coal	1.87	0.44	0.07	1.38	0.14	0.29	1.77	0.32	0.18	1.45	0.33	0.14	1.15	0.42	0.13	1.47	0.20	0.63	1.49	0.49	0.12	0.57	0.56	0.01
	Off-peak_coal	1.03	0.18	0.12	0.60	0.06	0.29	0.76	0.18	0.11	0.71	0.18	0.12	0.74	0.26	0.14	0.58	0.08	0.63	0.52	0.22	0.07	0.98	0.26	0.16
	Off-peak_ccgt	2.42	0.47	0.10	1.48	0.16	0.27	1.79	0.44	0.11	1.62	0.44	0.10	1.73	0.64	0.13	1.44	0.21	0.61	1.23	0.50	0.08	2.40	0.66	0.13
UK-W	Peak_ccgt	1.18	0.17	0.15	0.59	0.11	0.10	0.48	0.26	0.04	1.52	0.28	0.20	2.05	0.67	0.16	0.43	0.22	0.08	0.62	0.27	0.05	1.03	0.22	0.23
	Peak_coal	2.28	0.40	0.11	1.36	0.25	0.11	1.06	0.65	0.04	3.01	0.63	0.15	4.43	1.50	0.15	1.05	0.45	0.12	1.32	0.57	0.05	2.27	0.54	0.17
	Off-peak_coal	1.82	0.19	0.29	0.66	0.11	0.12	0.98	0.22	0.15	1.92	0.31	0.24	1.70	0.78	0.09	0.51	0.19	0.16	0.74	0.22	0.11	1.25	0.24	0.28
	Off-peak_ccgt	3.97	0.44	0.25	1.52	0.26	0.12	2.27	0.53	0.14	4.13	0.73	0.20	3.50	1.83	0.07	1.26	0.42	0.21	0.99	0.52	0.02	2.74	0.53	0.24

Note: These estimates are based on the following (standard) fuel efficiency assumptions: coal: 0.35; gas: 0.40, and CCGT: 0.55. In addition to the assumed dominant price-setting technology for each country and load period, an alternative marginal technology has been indicated in blue for those cases where this technology presumably sets the price during a major part of the load period as well. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate. A light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75.

a) UK-S refers to the summer-ahead power market, and UK-W to the winter-ahead power market.

Table C.9 *Estimates of carbon costs pass-through rates on forward markets in EU ETS countries during the peak and off-peak period in 2005-2006, sensitivity analyses*

		2005			2006			I			II			III			IV			V			VI		
		PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2
DE	Peak_coal	0.69	0.06	0.32	0.65	0.06	0.38	0.47	0.09	0.16	0.77	0.11	0.27	0.88	0.19	0.29	0.53	0.08	0.61	1.19	0.22	0.29	1.07	0.23	0.26
	Peak_gas	1.12	0.11	0.29	1.12	0.10	0.36	0.74	0.16	0.15	1.29	0.19	0.25	1.55	0.34	0.28	0.91	0.14	0.58	1.94	0.37	0.26	1.77	0.38	0.24
	Off-peak_coal	0.46	0.04	0.34	0.73	0.04	0.58	0.37	0.06	0.28	0.47	0.07	0.25	0.80	0.14	0.39	0.72	0.07	0.77	0.81	0.16	0.26	0.84	0.18	0.26
FR	Peak_coal	0.75	0.09	0.23	0.66	0.07	0.26	0.44	0.12	0.07	0.84	0.16	0.16	1.02	0.29	0.21	0.51	0.10	0.47	1.04	0.30	0.15	1.34	0.27	0.28
	Peak_gas	1.08	0.16	0.16	1.07	0.13	0.24	0.63	0.23	0.05	1.28	0.29	0.13	1.51	0.52	0.14	0.84	0.18	0.41	1.77	0.54	0.14	2.19	0.45	0.27
	Off-peak_coal	0.46	0.06	0.22	0.68	0.05	0.47	0.40	0.07	0.22	0.45	0.11	0.12	0.73	0.14	0.37	0.64	0.07	0.71	1.05	0.21	0.28	0.98	0.21	0.25
NL	Peak_gas	1.40	0.15	0.28	1.15	0.15	0.20	0.99	0.18	0.15	2.02	0.26	0.30	1.75	0.53	0.18	0.97	0.20	0.41	1.79	0.56	0.12	2.30	0.61	0.16
	Off-peak_coal	0.45	0.04	0.34	0.44	0.04	0.38	0.44	0.06	0.35	0.57	0.08	0.32	0.55	0.16	0.14	0.43	0.06	0.58	0.33	0.16	0.05	0.54	0.11	0.19
	Off-peak_ccgt	0.83	0.09	0.28	0.85	0.07	0.35	0.85	0.12	0.34	1.09	0.15	0.30	1.12	0.34	0.13	0.84	0.14	0.52	0.58	0.32	0.03	0.87	0.21	0.16
SE	Base_coal	0.60	0.05	0.42	0.71	0.06	0.38	0.53	0.06	0.42	0.53	0.08	0.29	0.57	0.24	0.07	0.65	0.07	0.76	1.20	0.31	0.14	1.29	0.26	0.22
UK-S[a]	Peak_ccgt	1.73	0.40	0.07	1.27	0.13	0.29	1.63	0.29	0.18	1.34	0.30	0.14	1.07	0.39	0.13	1.35	0.19	0.63	1.36	0.44	0.12	0.55	0.51	0.01
	Peak_coal	0.95	0.20	0.09	0.66	0.06	0.31	0.88	0.15	0.20	0.75	0.15	0.16	0.59	0.21	0.14	0.68	0.09	0.63	0.87	0.23	0.17	0.35	0.28	0.02
	Off-peak_coal	1.18	0.21	0.12	0.69	0.07	0.29	0.86	0.20	0.11	0.81	0.20	0.12	0.84	0.30	0.14	0.67	0.09	0.63	0.59	0.25	0.07	1.12	0.30	0.15
	Off-peak_ccgt	2.23	0.43	0.10	1.36	0.14	0.27	1.65	0.40	0.11	1.49	0.40	0.10	1.59	0.58	0.13	1.32	0.19	0.61	1.13	0.46	0.08	2.22	0.60	0.13
UK-W	Peak_ccgt	2.14	0.37	0.11	1.25	0.23	0.10	0.99	0.59	-0.04	2.81	0.58	0.16	4.11	1.38	0.15	0.97	0.42	0.11	1.21	0.52	0.05	2.11	0.49	0.17
	Peak_coal	1.34	0.20	0.15	0.67	0.13	0.10	0.55	0.30	-0.04	1.73	0.32	0.19	2.34	0.76	0.16	0.50	0.25	0.08	0.71	0.30	0.04	1.17	0.25	0.23
	Off-peak_coal	2.08	0.21	0.29	0.75	0.13	0.12	1.12	0.25	0.15	2.19	0.36	0.24	1.94	0.89	0.09	0.59	0.22	0.16	0.85	0.25	0.11	1.43	0.27	0.28
	Off-peak_ccgt	3.67	0.40	0.26	1.39	0.24	0.12	2.09	0.48	0.14	3.83	0.67	0.21	3.27	1.68	0.07	1.16	0.39	0.21	0.91	0.48	0.02	2.54	0.49	0.24

Note: These estimates are based on the following (alternative) fuel efficiency assumptions: coal: 0.40; gas: 0.42, and CCGT: 0.50. In addition to the assumed dominant price-setting technology for each country and load period, an alternative marginal technology has been indicated in blue for those cases where this technology presumably sets the price during a major part of the load period as well. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate. A light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75.

a) UK-S refers to the summer-ahead power market, and UK-W to the winter-ahead power market.

Table C.10 *Estimates of carbon costs pass-through rates on spot markets in EU ETS countries, 2005-2006, full data set*

		2005			2006			I			II			III			IV			V			VI				
		PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	T-stat
CZ	Peak_coal	1.50	0.39	0.49	-0.71	0.84	0.65	0.66	0.80	0.42	0.58	1.64	0.35	-	5.66	0.62	-0.47	0.26	0.18	2.09	8.64	0.69	5.02	1.74	0.40	3	4
	Off-peak_coal	0.44	0.22	0.28	-0.27	0.26	0.46	-0.90	0.44	0.22	1.03	0.86	0.35	-8.15	3.30	0.68	-0.45	0.25	0.13	3.87	2.69	0.60	2.86	0.71	0.36	2	5
DE	Peak_coal	1.76	0.88	0.69	0.92	0.72	0.22	1.05	0.80	0.56	-3.33	3.62	0.65	16.38	5.99	0.54	0.38	0.25	0.50	36.49	18.66	0.23	0.78	1.98	0.05	5	3
	Peak_gas	3.24	1.02	0.51	-0.16	1.27	0.18	3.21	0.89	0.33	-7.22	5.85	0.53	23.31	11.97	0.58	0.52	0.52	0.45	63.37	31.65	0.21	3.87	2.47	0.05	1	4
	Off-peak_coal	0.82	0.23	0.75	0.68	0.17	0.76	0.27	0.21	0.65	-0.83	0.86	0.71	5.07	2.03	0.67	0.38	0.16	0.72	2.14	1.66	0.72	1.46	0.67	0.24	5	5
ES	Peak_oil	0.50	0.67	0.65	1.11	0.49	0.76	1.03	1.13	0.62	-0.60	1.96	0.67	3.37	3.09	0.89	0.00	0.73	0.25	5.45	4.23	0.60	3.58	0.65	0.54	4	2
	Peak_gas	2.34	0.59	0.54	-1.70	0.73	0.63	4.32	1.01	0.54	-0.36	2.99	0.62	0.75	9.39	0.68	-0.78	0.67	0.14	11.82	6.45	0.63	3.30	1.11	0.42	1	5
	Off-peak_coal	0.64	0.23	0.74	0.52	0.28	0.90	0.25	0.33	0.60	0.07	0.66	0.78	-0.22	1.60	0.89	0.27	0.12	0.17	3.06	0.99	0.59	1.35	0.55	0.72	6	5
	Off-peak_CCGT	1.56	0.46	0.46	-1.31	0.67	0.69	2.36	1.06	0.41	-0.06	2.04	0.70	-5.35	9.96	0.61	0.00	0.46	0.09	8.54	3.14	0.73	3.64	1.50	0.64	1	5
FR	Peak_coal	1.96	0.97	0.75	1.18	0.96	0.64	0.56	1.21	0.64	-3.16	3.21	0.76	-3.17	5.99	0.52	0.48	0.19	0.51	0.64	15.07	0.60	0.27	0.93	0.54	6	2
	Peak_gas	4.27	1.15	0.61	-1.37	1.57	0.54	2.94	1.28	0.47	-6.22	6.60	0.55	-8.47	12.62	0.30	0.09	0.36	0.35	5.79	26.41	0.57	0.15	1.93	0.46	2	2
	Off-peak_coal	0.98	0.33	0.72	0.76	0.17	0.80	0.01	0.51	0.59	-0.38	1.14	0.73	-0.49	2.78	0.59	0.22	0.16	0.64	1.10	2.20	0.61	1.17	0.53	0.44	6	3
IT	Peak_oil	-0.97	0.62	0.69	-0.67	0.23	0.79	0.40	1.30	0.76	-1.88	1.08	0.69	-2.57	2.31	0.78	-0.18	0.30	0.95	5.77	3.98	0.72	0.07	0.72	0.86	2	2
	Off-peak_CCGT	0.39	0.70	0.58	-2.98	0.68	0.84	1.49	1.19	0.51	2.28	1.82	0.82	-0.22	8.40	0.41	-0.88	0.52	0.48	5.30	3.58	0.63	-3.74	0.83	0.68	2	2
	Off-peak_gas	0.19	0.70	0.61	-2.94	0.69	0.87	1.43	1.20	0.51	1.67	1.56	0.86	-1.03	8.27	0.42	-0.90	0.46	0.57	4.13	2.86	0.68	-2.97	0.67	0.71	3	3
NL	Peak_gas	4.17	0.84	0.37	0.69	1.16	0.45	2.14	1.08	0.49	-1.29	6.38	0.29	13.31	13.15	0.32	0.10	0.55	0.51	40.43	21.57	0.52	5.39	2.62	0.35	2	4
	Off-peak_coal	0.19	0.17	0.72	1.21	0.16	0.68	-0.03	0.18	0.35	-0.40	0.54	0.74	1.05	1.69	0.69	0.58	0.18	0.64	1.78	1.87	0.39	0.28	0.38	0.26	6	2
	Off-peak_CCGT	0.45	0.45	0.41	0.95	0.53	0.46	1.65	0.83	0.37	0.66	1.60	0.63	5.90	9.48	0.51	1.44	0.54	0.57	7.41	3.97	0.33	2.02	2.45	0.42	5	4
PL	Peak_coal	0.09	0.07	0.58	-0.04	0.03	0.72	0.02	0.08	0.20	-0.28	0.26	0.61	-0.89	0.40	0.81	-0.11	0.04	0.61	-0.59	0.42	0.57	-0.01	0.10	0.70	2	2
	Off-peak_coal	0.09	0.06	0.82	0.00	0.06	0.61	-0.02	0.04	0.59	0.07	0.14	0.74	-0.53	0.32	0.63	0.04	0.08	0.74	-0.15	0.30	0.53	-0.43	0.24	0.77	3	1
SE	Peak_coal	0.48	0.12	0.60	0.44	0.31	0.75	0.05	0.20	0.27	-0.30	0.47	0.61	3.22	1.63	0.54	0.94	0.09	0.87	0.91	1.64	0.81	3.05	0.48	0.92	5	4
	Off-peak_coal	0.35	0.12	0.85	0.82	0.21	0.92	0.00	0.15	0.63	0.03	0.26	0.79	0.78	0.46	0.93	1.15	0.14	0.87	0.45	0.68	0.97	0.48	1.04	0.89	8	3
UK	Peak_CCGT	3.70	0.75	0.28	0.89	1.31	0.14	4.06	1.47	0.31	-5.76	5.27	0.10	23.72	38.93	0.01	1.13	0.53	0.25	8.56	33.73	0.35	-2.15	2.15	0.10	2	3
	Off-peak_coal	0.70	0.40	0.84	1.53	0.25	0.66	0.34	0.26	0.68	-0.89	1.03	0.81	2.26	7.80	0.26	0.78	0.09	0.86	3.62	1.03	0.43	-0.01	0.32	0.16	4	4
		18	16		13	13		15	8		7	1		3	7		16	13		5	8		9	13			

Note: In addition to the assumed dominant price-setting technology for each country and load period, an alternative marginal technology has been indicated in blue for those cases where this technology presumably sets the price during a major part of the load period as well. PTR stands for the pass-through rate of carbon costs to power prices and StE for the standard error of the estimated value of the PTR. Dark green PTR values indicate a value between 0.5 and 1.5; light green PTR values indicate a value between 0 and 0.5 or 1.5 and 1, while the other PTR values are coloured orange. A yellow StE value indicates a statistically significant estimate. A light yellow R^2 indicates a value between 0.5 and 0.75, while a dark yellow R^2 value indicates a R^2 larger than 0.75. The last row indicates the number of PTR values between 0 and 2 (column PTR) and the number of statistically significant estimates (column SE). The last two columns have a different interpretation: Column 'PTR' shows the number of estimates of the CO_2 cost pass-through rate with a value between 0 and 2. Column 'T-stat' shows the number of statistical significant estimates of the PTR.

Table C.11 *Estimates of carbon costs pass-through rates on spot markets in EU ETS countries, 2005-2006, middle 90% data set*

		2005			2006			I			II			III			IV			V			VI				
		PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	T-stat
CZ	Peak_coal	1.54	0.26	0.47	-0.62	0.31	0.49	0.70	0.56	0.26	1.96	1.44	0.35	-9.95	5.87	0.52	0.00	0.29	0.10	6.38	3.81	0.50	4.78	1.64	0.40	3	3
	Off-peak_coal	0.77	0.18	0.30	0.21	0.13	0.43	-0.40	0.41	0.09	1.48	0.75	0.40	-5.96	2.88	0.63	-0.29	0.17	0.39	6.07	1.74	0.51	2.03	0.65	0.40	3	6
DE	Peak_coal	1.11	0.24	0.69	1.20	0.15	0.56	0.04	0.41	0.59	0.83	1.33	0.66	7.13	5.07	0.32	0.71	0.24	0.31	7.50	2.59	0.47	-0.01	0.81	0.07	5	4
	Peak_gas	2.11	0.29	0.49	0.50	0.28	0.33	1.14	0.58	0.34	2.69	1.69	0.48	22.24	8.93	0.49	0.91	0.44	0.18	14.92	4.30	0.46	2.69	0.94	0.15	3	7
	Off-peak_coal	0.83	0.12	0.77	0.70	0.11	0.76	0.36	0.18	0.61	0.66	0.57	0.72	3.79	1.92	0.65	0.49	0.17	0.69	3.10	1.60	0.55	1.23	0.53	0.28	6	7
ES	Peak_oil	0.79	0.41	0.58	1.05	0.37	0.78	1.58	0.48	0.50	-1.74	1.69	0.69	2.19	2.98	0.89	0.48	0.85	0.27	1.52	2.90	0.78	3.49	0.62	0.55	5	4
	Peak_gas	1.54	0.36	0.47	-0.81	0.38	0.53	2.66	0.59	0.48	5.41	2.88	0.60	-5.15	7.21	0.71	-0.65	0.30	0.18	16.69	4.02	0.66	2.93	1.09	0.41	1	7
	Off-peak_coal	0.79	0.14	0.69	0.91	0.19	0.88	0.64	0.19	0.58	0.24	0.65	0.70	-2.32	1.69	0.81	0.37	0.13	0.34	3.06	0.99	0.59	1.32	0.53	0.72	6	6
	Off-peak_CCGT	1.21	0.21	0.45	-0.45	0.44	0.65	1.49	0.31	0.42	0.78	2.08	0.70	-13.50	6.79	0.68	0.00	0.46	0.09	8.54	3.14	0.73	1.94	1.28	0.55	4	4
FR	Peak_coal	2.10	0.32	0.72	0.99	0.18	0.73	1.41	0.77	0.61	1.69	1.49	0.76	0.26	4.54	0.64	0.47	0.18	0.62	8.74	3.06	0.38	0.33	0.92	0.54	6	5
	Peak_gas	3.56	0.40	0.57	-1.52	0.34	0.40	3.24	0.96	0.57	3.35	2.61	0.40	-14.67	10.72	0.28	-0.06	0.30	0.45	15.55	5.00	0.42	0.15	1.62	0.40	1	4
	Off-peak_coal	0.94	0.15	0.75	0.72	0.14	0.81	0.38	0.28	0.55	0.75	0.70	0.76	-3.52	2.58	0.67	0.39	0.19	0.70	1.33	2.05	0.59	1.13	0.52	0.40	7	4
IT	Peak_oil	-0.37	0.44	0.72	-0.38	0.24	0.88	0.17	0.73	0.86	-1.76	1.21	0.62	-2.42	2.37	0.73	0.05	0.16	0.66	4.90	1.77	0.93	0.83	0.58	0.69	3	1
	Off-peak_CCGT	0.30	0.27	0.44	-2.43	0.45	0.82	0.55	0.21	0.34	2.69	1.58	0.73	-8.60	6.88	0.46	-0.88	0.52	0.48	5.30	3.58	0.63	-2.78	0.82	0.61	2	3
	Off-peak_gas	0.05	0.29	0.50	-2.32	0.46	0.89	0.58	0.18	0.32	1.76	1.26	0.84	-7.85	5.92	0.57	-0.90	0.46	0.57	4.13	2.86	0.68	-2.35	0.73	0.66	3	4
NL	Peak_gas	2.85	0.47	0.47	1.34	0.30	0.35	1.44	1.07	0.48	3.50	3.55	0.39	7.94	7.85	0.33	0.59	0.32	0.38	12.01	3.90	0.47	3.75	1.63	0.21	3	5
	Off-peak_coal	0.40	0.11	0.68	1.24	0.11	0.72	0.22	0.12	0.33	-0.98	0.63	0.62	0.70	1.28	0.53	0.61	0.14	0.63	2.79	1.34	0.32	0.53	0.32	0.23	6	5
	Off-peak_CCGT	0.55	0.19	0.37	1.66	0.33	0.50	0.91	0.24	0.37	-0.33	1.41	0.58	2.02	4.19	0.69	0.50	0.60	0.58	9.24	3.02	0.34	2.25	1.32	0.36	4	5
PL	Peak_coal	0.25	0.06	0.60	-0.02	0.04	0.72	0.10	0.09	0.23	-0.25	0.28	0.60	-0.91	0.40	0.80	-0.05	0.07	0.59	-0.59	0.42	0.57	0.02	0.09	0.66	3	2
	Off-peak_coal	0.21	0.05	0.81	0.01	0.06	0.59	-0.01	0.05	0.61	0.05	0.14	0.73	-0.58	0.27	0.67	0.05	0.07	0.71	-0.15	0.30	0.53	-0.46	0.26	0.76	4	3
SE	Peak_coal	0.69	0.07	0.76	0.30	0.23	0.76	0.32	0.14	0.35	0.08	0.36	0.68	2.93	1.98	0.61	0.94	0.09	0.87	1.20	1.63	0.73	2.91	0.49	0.92	6	4
	Off-peak_coal	0.59	0.09	0.89	0.65	0.18	0.92	0.31	0.18	0.72	0.15	0.24	0.82	0.16	0.53	0.94	1.04	0.07	0.97	0.00	0.66	0.96	0.77	1.01	0.88	8	3
UK	Peak_CCGT	3.27	0.45	0.38	0.41	0.36	0.06	2.02	0.94	0.30	4.80	2.92	0.20	22.97	13.27	0.19	1.13	0.53	0.25	-7.97	8.10	0.10	-2.75	2.03	0.10	2	4
	Off-peak_coal	1.06	0.19	0.84	0.99	0.09	0.84	0.54	0.22	0.51	-0.28	0.80	0.79	-0.77	2.78	0.34	0.79	0.09	0.86	3.75	1.00	0.43	0.26	0.30	0.22	5	5
		18	21		16	17		19	15		12	2		3	7		16	15		4	14		11	14			

Note: See Table C.10.

Table C.12 *Estimates of carbon costs pass-through rates on spot markets in EU ETS countries, 2005-2006, middle 80% data set*

		2005			2006			I			II			III			IV			V			VI				
		PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	StE	R2	PTR	T-stat
CZ	Peak_coal	1.28	0.22	0.38	-0.16	0.28	0.38	0.59	0.56	0.19	2.60	1.25	0.30	-9.97	3.95	0.36	0.19	0.29	0.19	6.51	3.57	0.51	4.51	1.52	0.32	3	5
	Off-peak_coal	0.71	0.16	0.32	0.44	0.12	0.44	-0.12	0.30	0.06	1.59	0.72	0.36	-5.95	2.56	0.56	-0.05	0.16	0.51	4.49	1.80	0.52	1.94	0.52	0.38	4	6
DE	Peak_coal	1.06	0.19	0.63	1.23	0.13	0.60	0.17	0.36	0.50	1.74	1.20	0.61	9.01	4.85	0.26	0.78	0.24	0.42	4.41	2.28	0.53	-0.42	0.74	0.02	5	5
	Peak_gas	1.73	0.23	0.50	0.52	0.23	0.30	0.75	0.44	0.51	2.67	1.45	0.35	8.88	7.53	0.44	0.66	0.28	0.29	10.56	4.02	0.48	2.50	0.78	0.18	4	7
	Off-peak_coal	0.88	0.11	0.75	0.90	0.09	0.78	0.46	0.16	0.57	1.29	0.60	0.63	2.61	1.88	0.52	0.72	0.21	0.84	3.65	1.30	0.48	1.11	0.51	0.26	6	7
ES	Peak_oil	0.85	0.28	0.55	1.24	0.29	0.72	1.22	0.39	0.49	0.38	1.85	0.62	-0.21	3.37	0.84	0.46	0.25	0.25	3.78	3.23	0.73	3.49	0.62	0.55	5	5
	Peak_gas	1.23	0.29	0.45	-0.31	0.27	0.51	1.99	0.56	0.50	2.77	2.72	0.54	-8.25	6.12	0.70	-0.46	0.23	0.22	10.34	3.88	0.76	1.91	0.80	0.41	3	5
	Off-peak_coal	0.93	0.10	0.70	0.98	0.14	0.84	0.71	0.16	0.57	-0.25	0.60	0.55	-1.98	1.80	0.77	0.46	0.12	0.54	3.07	0.99	0.57	0.86	0.59	0.73	5	5
	Off-peak_CCGT	1.28	0.17	0.43	0.31	0.36	0.58	1.40	0.27	0.40	2.35	1.49	0.46	-9.15	6.73	0.64	0.29	0.49	0.20	8.54	3.14	0.73	1.15	1.09	0.44	5	3
FR	Peak_coal	2.05	0.20	0.75	1.18	0.15	0.77	1.70	0.42	0.68	1.48	1.13	0.75	-6.01	3.67	0.62	1.00	0.17	0.83	4.81	2.46	0.28	0.61	0.85	0.60	5	5
	Peak_gas	3.10	0.27	0.56	-1.04	0.28	0.32	2.58	0.57	0.41	2.76	2.04	0.33	-1.70	8.82	0.06	0.14	0.29	0.49	10.41	3.88	0.36	-0.70	1.20	0.36	1	4
	Off-peak_coal	0.84	0.15	0.71	0.79	0.12	0.81	0.40	0.24	0.41	0.60	0.70	0.70	-2.97	2.62	0.71	0.38	0.17	0.76	3.25	1.79	0.56	0.81	0.47	0.27	6	5
IT	Peak_oil	0.31	0.43	0.71	-0.24	0.23	0.84	0.53	0.58	0.86	-1.66	1.31	0.58	-2.99	2.21	0.56	0.31	0.09	0.79	5.46	1.90	0.89	0.96	0.66	0.65	4	2
	Off-peak_CCGT	0.47	0.19	0.32	-1.74	0.40	0.77	0.67	0.19	0.34	2.03	1.55	0.49	-0.95	6.04	0.39	-0.88	0.52	0.48	5.30	3.58	0.63	-2.59	0.83	0.53	2	4
	Off-peak_gas	0.35	0.18	0.35	-2.03	0.39	0.83	0.62	0.18	0.33	1.38	1.29	0.73	-3.98	6.37	0.35	-0.90	0.46	0.57	4.13	2.86	0.68	-1.75	1.05	0.53	3	4
NL	Peak_gas	2.12	0.39	0.47	1.61	0.25	0.41	1.12	0.90	0.40	4.66	3.22	0.39	4.96	6.44	0.42	0.68	0.17	0.46	6.66	3.01	0.38	4.36	1.19	0.44	3	5
	Off-peak_coal	0.53	0.08	0.70	1.17	0.08	0.78	0.40	0.11	0.38	-0.61	0.60	0.58	0.18	1.38	0.30	0.66	0.12	0.75	1.29	1.20	0.20	0.76	0.29	0.37	7	5
	Off-peak_CCGT	0.61	0.14	0.36	1.47	0.26	0.45	0.67	0.22	0.36	-0.32	1.19	0.54	1.86	3.66	0.59	0.91	0.33	0.60	8.87	2.64	0.34	2.02	1.32	0.32	5	5
PL	Peak_coal	0.32	0.06	0.61	0.00	0.05	0.72	0.13	0.10	0.25	-0.15	0.31	0.58	-0.84	0.40	0.78	-0.16	0.06	0.24	-0.59	0.42	0.57	0.20	0.11	0.54	3	4
	Off-peak_coal	0.30	0.04	0.83	0.02	0.07	0.61	0.01	0.06	0.60	0.27	0.13	0.69	-0.40	0.27	0.64	0.06	0.03	0.94	-0.15	0.30	0.53	-0.49	0.28	0.79	5	4
SE	Peak_coal	0.75	0.07	0.79	0.42	0.20	0.75	0.52	0.13	0.49	0.26	0.42	0.64	3.77	2.29	0.53	0.94	0.09	0.87	1.02	1.39	0.77	2.85	0.55	0.91	6	5
	Off-peak_coal	0.67	0.09	0.90	0.72	0.18	0.90	0.29	0.21	0.73	0.10	0.29	0.80	0.33	0.62	0.94	1.01	0.07	0.97	-0.15	0.56	0.96	1.18	0.95	0.83	7	3
UK	Peak_CCGT	2.58	0.36	0.40	0.78	0.29	0.09	1.84	0.65	0.29	4.83	2.30	0.23	28.79	10.18	0.28	1.31	0.43	0.30	2.50	6.78	0.12	-1.07	1.57	0.11	3	6
	Off-peak_coal	1.08	0.13	0.83	0.90	0.06	0.87	0.45	0.15	0.44	0.85	0.97	0.73	-2.78	1.48	0.58	0.83	0.08	0.87	1.14	0.87	0.54	0.39	0.29	0.26	7	5
		20	23		17	18		22	15		11	6		3	6		19	19		3	14		12	13			

Note: See Table C.10.

Appendix D The COMPETES model

In order to analyse the performance of wholesale electricity markets in European countries, ECN has developed the so-called COMPETES model.[121] The present version of the model covers twenty European countries, i.e. Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom.

In the COMPETES model, the representation of the electricity network is aggregated into one node per country, except for Germany and Luxembourg, which are joined into one nod, while Denmark is divided into two nods belonging to two different, non-synchronised networks (i.e. Eastern versus Western Denmark, see Figure D.1). Virtually all individual power companies and generation units in the 20 countries - including CHP plants owned by industries or energy suppliers - are covered by the input data of the model and assigned to one of these nodes. The user can specify which generation companies are assumed to behave strategically and which companies are assumed to behave competitively (i.e. the price takers). The latter subset of companies is assigned to a single entity per node indicated as the 'competitive fringe'.

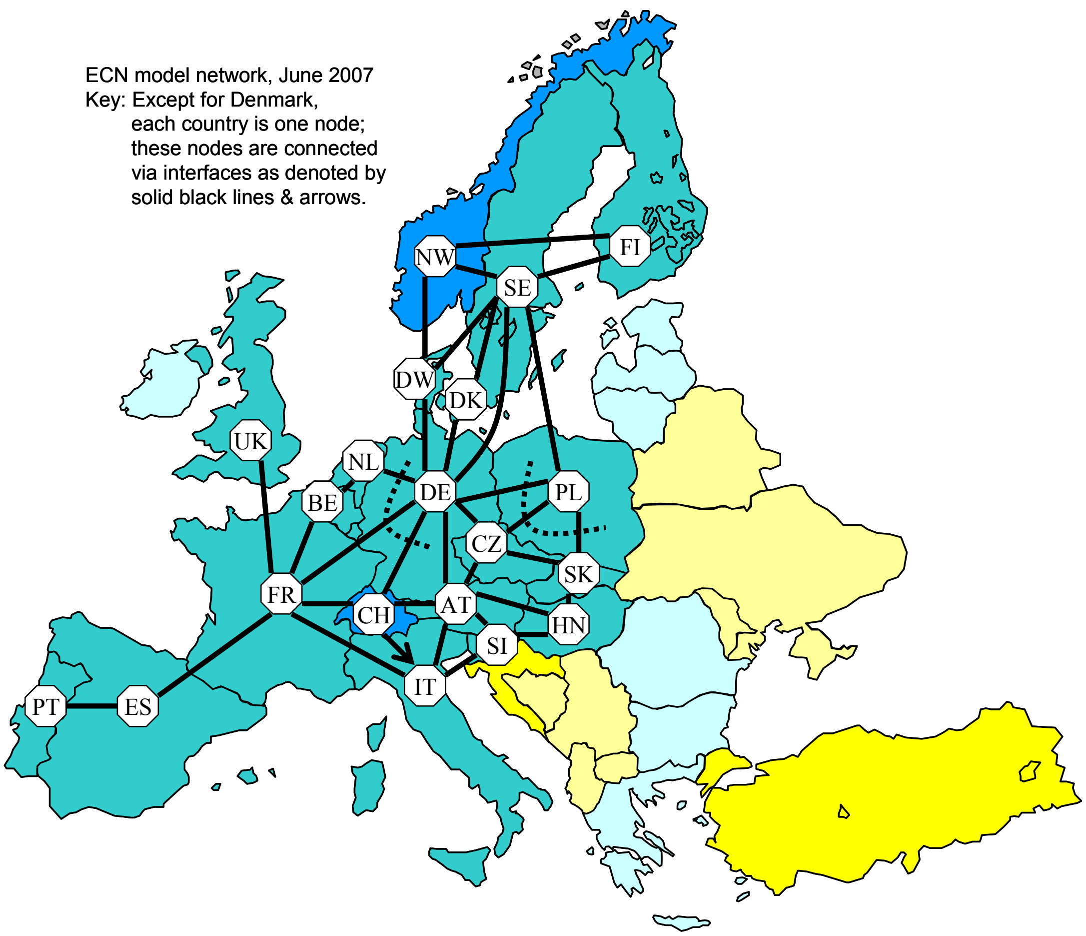

Figure D.1 *Physical and path-based representation of the electricity network in COMPETES*

[121] 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.

Producer behaviour

The COMPETES model is able to simulate the effects of differences in producer behaviour and wholesale market structures, including perfect versus oligopolistic competition. In addition, it is able to simulate the effects of electricity trade and transmission constraints between countries. Simulating oligopolistic (or strategic) behaviour of power producers is based on the theory of Cournot competition and so-called ‘Conjectured Supply Functions’ (CSF) on electric power networks.[122]

Strategic behaviour of generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate each company’s expectations concerning how rivals will change their electricity sales when power prices change in response to the company’s actions. These expectations determine the perceived profitability of capacity withholding and other strategies.

Cournot’s theory of oligopolistic competition represents one possible conjecture, i.e. rivals will not change their outputs. COMPETES can also simulate the other extreme: company’s actions will not change the power price (i.e. price taking behaviour or perfect competition). CSFs can be used to represent conjectures between these two extremes. COMPETES can also represent different systems of transmission pricing, among them fixed transmission tariffs, congestion-based pricing of physical transmission, netting restrictions, and auction pricing of interface capacity between countries.

The model calculates the optimal behaviour of the generators by assuming that they simultaneously try to maximise their profits. Profits are determined as the income of power sales (market prices multiplied by total sales) minus the costs of generation and - if sale is not at the node of generation - transmission. Costs of generation are calculated by using the short-run marginal costs (i.e. fuel and other variable costs). Start-up costs and fixed operating costs are not taken into account since these costs have less effect on the bidding behaviour of suppliers on the wholesale market in the time horizon considered by the COMPETES model.

Power demand and consumer behaviour

The model considers 12 different periods or levels of power demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The ‘super peak’ period covers 240 hours per annum, consisting of the 120 hours with the highest sum of power loads for the 20 countries considered during spring/fall and 60 hours each in winter and summer. The other three periods represent the rest of the seasonal load duration curve covering equal numbers of hours during each period and season. Altogether, the 12 periods include all 8760 hours of a year. Power consumers are assumed to be price sensitive by using decreasing linear demand curves depending on the electricity price. The number and duration of periods and the price elasticity of power demand in different periods are user-specified parameters.

Transmission system operator

The electricity network covering the 20 countries is represented by a direct current (DC) load flow approximation. This approximation is a linear system that accounts only for real power flows and is a simplification of the alternating current (AC) power flow model. However, the approximation ensures that both the current law and the voltage law of Kirchhoff are respected. Using these two laws, the flows within the electricity network can be uniquely identified using

[122] The basic transmission-constrained Cournot formulation underlying COMPETES was first presented in Hobbs (2001), while the conjectured supply function generalization appeared first in Day et al. (2002). COMPETES itself, including alternative transmission pricing formulations, is presented and applied in Hobbs et al. (2004a and 2004b). COMPETES has been used to analyse issues such as effects of proposed mergers among power companies (Scheepers et al., 2003), market coupling (Hobbs et al., 2005), market power (Lise et al., 2008), electricity prices and power trade (Özdemir et al., 2008), and the EU Emissions Trading System (Chen et al., 2008; and Sijm et al. 2005 and 2008a).

the net input of power at each node, i.e., where supply is subtracted from demand.[123] Besides the physical network, path-based constraints are defined using the net transmission capacities (NTC) between the 20 countries. In the current application, these NTCs are set equal to the capacities that are available for the trade on the interconnections between the countries.

In the model, generators or traders will buy network capacity when they want to transport power from one region to another. The total amount of transportation between two nodes can be limited due to physical transmission constraints (such as thermal or security limits) or due to the limited availability of interconnection capacity between countries due to regulation (see Figure D.1). It is assumed that there is no netting for any of the interconnections. In other words, a power flow from, for example, Belgium to the Netherlands will not increase the available interconnection capacity from the Netherlands to Belgium.

In addition to the bilateral interconnection capacities between two countries in the path-based representation of COMPETES, there are also two multilateral interconnection capacities, namely Germany versus France, the Netherlands and Switzerland; and Poland versus the Czech Republic, Germany and Slovakia. Hence, the total flow between Germany (Poland) and the three indicated countries is also restricted contractually. This is indicated in Figure D.1 with two dotted curvy lines. There is also an arrow running from Switzerland to Italy indicating that power is only possible in one direction.

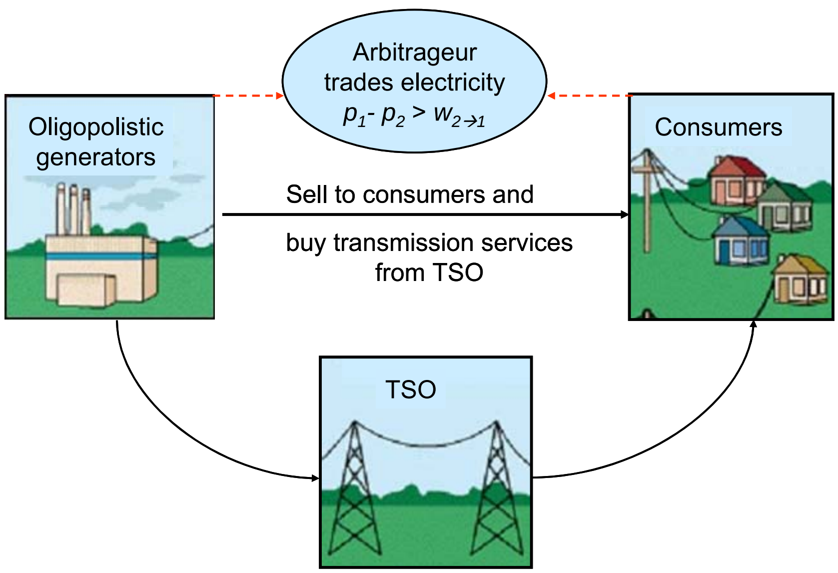

Figure D.2 *Model structure of COMPETES showing the relevant actors*

Traders' behaviour

Between countries and nodes it can be assumed that arbitrageurs are active (see Figure D.2). An arbitrageur (or trader) is assumed to maximise its profits by buying electricity at a low price node and selling it to a high price node as long as the price differences between these nodes is higher than the cost for transporting the power between these nodes. This is equivalent to a TSO running a 'market splitting' type of auction in which the TSO automatically moves power from low-price locations to high-price locations. The model scenarios do not allow for arbitrage that has not yet been realised, and full arbitrage indeed may not be realised because of many institutional barriers.

Limitations and legitimacy of the model

[123] The DC load flow representation is done through power transmission distribution factors (PTDFs), which are based on a detailed study of the UCTE region by Zhou and Bialek (2005).

- Power consumers are modelled as being price sensitive. In reality, in the short-term demand response is probably small. On longer time scales, however, elasticity will be substantially higher. The output of the model is a static equilibrium situation in which the optimal price, profit and production is calculated. This can be seen as a medium-term situation, which justifies a small price elasticity.
- COMPETES is a static model. This implies that it does not integrate new investments endogenously. Currently, the situation in 2006 is represented. The inputs are based on the situation in 2006, taking into account new power plants that will be taken into operation until 2006, the demand situation that prevails in 2006 and the available transmission capacity in 2006.
- In their bidding strategy, generators do not take into account the start-up costs of their power plants. Integrating start-up costs in the bidding curves would not have a large impact on the fuel mix (i.e. the choice between gas-fired versus coal-fired plants) because coal-fired plants are generally already more profitable to run during the baseload hours as they have lower marginal costs. Some switching to gas-fired power plants may be possible after adding a substantial CO_2 tax to the marginal costs.
- Strategic behaviour of generators is modelled by using the Cournot assumption: All generators maximise their profits by choosing a certain level of production under the somewhat naive assumption that their competitors will not change the level of output. 'Naive' because when a generator changes its output and the market price increases as a result, competitors would have an incentive to anticipate and increase their outputs. The CSF theory is actually developed in order to reckon with this effect, so it is possible to model this in COMPETES.
- In reality the electricity wholesale market consists of a number of markets (day-ahead market, OTC market, balance market). The COMPETES model assumes an efficient arbitrage between these markets. A real market is characterised by several inefficiencies and irrational behaviour of participants, which is not covered by this model, based on efficient and rational behaviour. An important example of inefficiency in the real market is the time lag between the market clearing of the spot market and the daily auction of the interconnection capacity on the Dutch borders. The existing inefficiencies are, however, assumed to have a similar effect on the different scenarios that will be calculated. Therefore, it does not harm the comparisons of scenarios and variants.

Input data
The most relevant input data used for the model that influence the output data are:
- The fuel prices assumed for each country.
- The availability and efficiency per generation technology. Availability during peak seasons is limited by forced outage rates, while availability during off-peak seasons also accounts for maintenance outages.
- The demand load per season and period within each country.

The fuel prices and the generating unit characteristics are based upon a comparison among various data sources, namely IEA, Eurostat, etc. The generating units are taken from the WEPP database (UDI, 2004) and ownership relations are retrieved from the annual reports of the energy companies. The remaining capacities are assigned to price taking competitive fringes.

Technology mix of power generation
Figure D.3 presents the technology mix of power generation in 20 European countries under the COMPETES model reference scenario. It shows that there is a large variety in generation technologies. For instance, Norway is highly specialised in hydro, Poland in coal, France in nuclear and the Netherlands in gas.

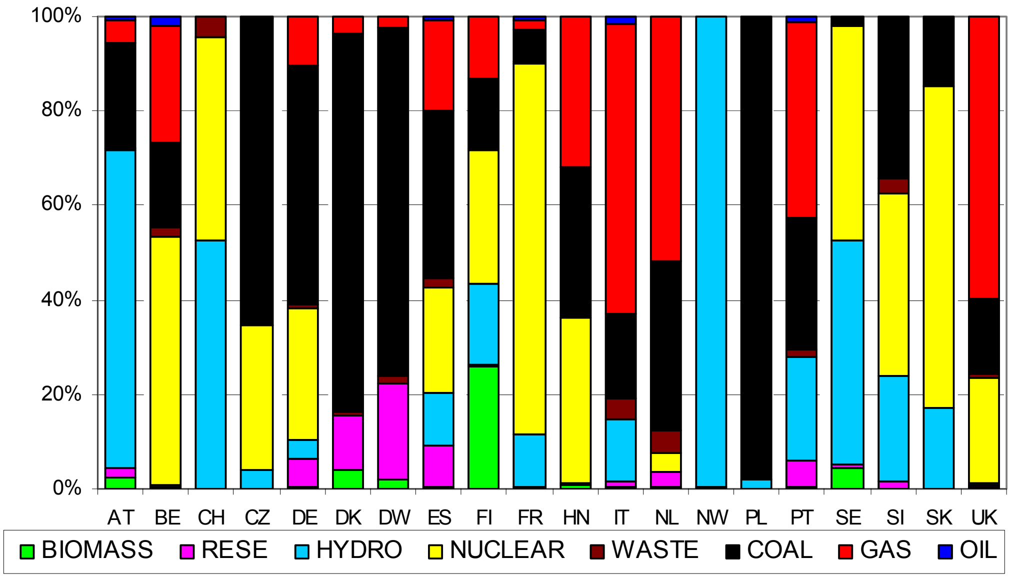

Figure D.3 *Technology mix of power generation in 20 European countries under the COMPETES model reference scenario*

In addition to the technology mix, it is also important to consider the level of market concentration, because this is an important determining factor in market power. Table D.1 shows the market shares of the firms that can exercise market power. In each market, the competitive fringe is represented by a single entity, aggregating the price-taking companies, and indicated with the prefix 'Comp'. Note that power markets in Poland, Slovenia and Switzerland are relatively competitive, as a result of the presence of large competitive fringes in those countries, representing 86% of generation capacity in Poland and 100% of generation capacity in Slovenia and Switzerland (see Table D.1).

To solve the model, it is assumed that the competitive fringes can only sell in the market where they are located. Large firms can sell in the market where they are located and all countries to which they are directly connected. For instance, EdF can sell in almost all countries, except Norway, Finland and Portugal. Table D.2 shows the assumptions concerning market access. Alternative assumptions could be made, such as all firms having access to all countries. In theory, the EU Directive allows for such freedom of trade, but due to not yet fully liberalised markets and regulatory rules, access may be limited.

Finally, active cross-border ownership is assumed so that a single firm owning generation plants in various countries optimises over its full portfolio. This assumption may somewhat overestimate the ability of firms to use market power, because due to a number of organisational and technical reasons, firms may, in practice, optimise their behaviour only within single markets.

Table D.1 *Generation capacity and market shares of power companies in EU countries*

		Total [MW]	Share [%]
Austria			
Comp_AT	AT	9844	57%
VERBUND-AUSTRIAN HYDRO POWER	AT	7418	43%
ESSENT ENERGIE PRODUCTIE BV	AT	28	0%
Belgium			
ELECTRABEL SA	BE	13083	85%
Comp_BE	BE	2215	14%
UNION ELECTRICA FENOSA SA	BE	51	0%
ESSENT ENERGIE PRODUCTIE BV	BE	19	0%
Switzerland			
Comp_CH	CH	8417	49%
GRANDE DIXENCE SA	CH	1998	12%
KERNKRAFTWERK LEIBSTADT AG	CH	1220	7%
AXPO HOLDING AG	CH	1025	6%
KKW GOESGEN DAENIKEN	CH	1020	6%
MAGGIA UND BLENIO KRAFTWERKE	CH	1004	6%
KRAFTWERKE OBERHASLI AG (KWO)	CH	976	6%
ENERGIE OUEST SUISSE (EOS)	CH	750	4%
KRAFTWERKE HINTERRHEIN AG	CH	640	4%
E.ON ENERGIE AG	CH	103	1%
ELECTRICITE DE FRANCE	CH	25	0%
ENBW	CH	21	0%
Czech Republic			
CEZ AS	CZ	12735	84%
Comp_CZ	CZ	2407	16%
ELECTRICITE DE FRANCE	CZ	48	0%
RWE POWER	CZ	17	0%
Germany			
Comp_DE	DE	36279	30%
E.ON ENERGIE AG	DE	28030	23%
RWE POWER	DE	27384	23%
VATTENFALL AB	DE	17034	14%
ENBW	DE	10192	8%
ELECTRICITE DE FRANCE	DE	1035	1%
ESSENT ENERGIE PRODUCTIE BV	DE	695	1%
ELECTRABEL SA	DE	422	0%
NUON NV	DE	57	0%
Denmark East			
ENERGI E2 A/S	DK	3905	91%
Comp_DK	DK	398	9%
Denmark West			
ELSAM A/S	DW	4266	75%
Comp_DW	DW	1439	25%
Spain			
Comp_ES	ES	24984	38%
ENDESA GENERACION	ES	17967	27%
IBERDROLA SA	ES	16268	25%
UNION ELECTRICA FENOSA SA	ES	4865	7%
ENBW	ES	847	1%
RWE POWER	ES	423	1%
ENEL SPA	ES	129	0%
CIA PORTUGESA PRODUCAO ELEC	ES	124	0%
Finland			
Comp_FI	FI	10706	72%
FORTUM POWER & HEAT	FI	4069	27%
E.ON ENERGIE AG	FI	165	1%
France			
ELECTRICITE DE FRANCE	FR	92628	83%
Comp_FR	FR	13820	12%
ELECTRABEL SA	FR	4828	4%
ENBW	FR	49	0%
RWE POWER	FR	26	0%
Hungary			
Comp_HN	HN	3383	38%
ELECTRABEL SA	HN	2154	24%
PAKSI ATOMEROMU RT	HN	1866	21%
RWE POWER	HN	655	7%
ELECTRICITE DE FRANCE	HN	428	5%
ENBW	HN	240	3%
E.ON ENERGIE AG	HN	95	1%
Italy			
ENEL SPA	IT	43577	50%
Comp_IT	IT	25686	30%
EDISON SPA	IT	8871	10%
ENDESA GENERACION	IT	6907	8%
ELECTRABEL SA	IT	1615	2%
RWE POWER	IT	15	0%
Netherlands			
ELECTRABEL SA	NL	4917	24%
Comp_NL	NL	4893	24%
ESSENT ENERGIE PRODUCTIE BV	NL	4696	23%
NUON NV	NL	4110	20%
E.ON ENERGIE AG	NL	1889	9%
Norway			
Comp_NW	NW	19028	67%
STATKRAFT SF	NW	9403	33%
ELSAM A/S	NW	124	0%
Poland			
Comp_PL	PL	30937	86%
ELECTRICITE DE FRANCE	PL	2557	7%
ELECTRABEL SA	PL	1800	5%
VATTENFALL AB	PL	615	2%
Portugal			
CIA PORTUGESA PRODUCAO ELEC	PT	7794	60%
Comp_PT (Portugal)	PT	4250	33%
RWE POWER	PT	1017	8%
Sweden			
Comp_SE	SE	12959	42%
VATTENFALL AB	SE	12906	42%
FORTUM POWER & HEAT	SE	2556	8%
E.ON ENERGIE AG	SE	2224	7%
Slovania			
Comp_SI	SI	1576	52%
TERMOELEKTRARNA SOSTANJ PO	SI	745	25%
NUKLEARNA ELEKTRARNA KRSKO	SI	707	23%
Slovakia			
SLOVENSKE ELEKTRARNE AS (SE)	SK	3531	47%
ELECTRICITE DE FRANCE	SK	3422	46%
Comp_SK	SK	481	6%
E.ON ENERGIE AG	SK	76	1%
United Kingdom			
Comp_UK	UK	44539	54%
BRITISH ENERGY PLC	UK	15804	19%
E.ON ENERGIE AG	UK	8462	10%
RWE POWER	UK	8163	10%
ELECTRICITE DE FRANCE	UK	4764	6%
ELECTRABEL SA	UK	248	0%

Table D.2 *Large firms included in the COMPETES model and countries where they can sell electricity*

	AT	BE	CH	CZ	DE	DK	DW	ES	FI	FR	HN	IT	NL	NW	PL	PT	SE	SI	SK	UK
AXPO HOLDING AG	√		√		√					√		√								
BRITISH ENERGY PLC										√										√
CEZ AS	√			√	√										√				√	
CIA PORTUGESA PRODUCAO ELEC								√		√						√				
E.ON ENERGIE AG	√	√	√	√	√	√	√		√	√	√	√	√	√	√		√	√	√	√
EDISON SPA	√									√		√						√		
ELECTRABEL SA	√	√	√	√	√	√	√	√		√	√	√	√		√		√	√	√	√
ELECTRICITE DE FRANCE	√	√	√	√	√	√	√	√		√	√	√	√		√		√	√	√	√
ELSAM A/S					√		√		√					√			√			
ENDESA GENERACION	√							√		√		√				√		√		
ENEL SPA	√							√		√		√				√		√		
ENERGI E2 A/S					√	√											√			
ENERGIE BADEN-WURTTEMBERG ENBW	√	√	√	√	√	√	√	√		√	√	√	√		√	√	√	√	√	√
ENERGIE OUEST SUISSE (EOS)	√		√		√					√		√								
ESSENT ENERGIE PRODUCTIE BV	√	√	√	√	√	√	√			√	√	√	√		√		√	√		
FORTUM POWER & HEAT					√	√	√		√					√	√		√			
GRANDE DIXENCE SA	√		√		√					√		√								
IBERDROLA SA								√		√						√				
KERNKRAFTWERK LEIBSTADT AG	√		√		√					√		√								
KKW GOESGEN DAENIKEN	√		√		√					√		√								
KRAFTWERKE HINTERRHEIN AG	√		√		√					√		√								
KRAFTWERKE OBERHASLI AG (KWO)	√		√		√					√		√								
MAGGIA UND BLENIO KRAFTWERKE	√		√		√					√		√								
NUKLEARNA ELEKTRARNA KRSKO	√										√	√						√		
NUON NV	√	√	√	√	√	√	√			√			√		√		√			
PAKSI ATOMEROMU RT	√										√							√	√	
RWE POWER	√	√	√	√	√	√	√	√		√	√	√	√		√	√	√	√	√	√
SLOVENSKE ELEKTRARNE AS (SE)				√							√				√				√	
STATKRAFT SF							√		√					√			√			
TERMOELEKTRARNA SOSTANJ PO	√										√	√						√		
UNION ELECTRICA FENOSA SA		√						√		√			√			√				
VATTENFALL AB	√		√	√	√	√	√		√	√			√	√	√		√		√	
VERBUND-AUSTRIAN HYDRO POWER	√		√	√	√						√	√						√		

Appendix E Estimates of ETS induced changes in generators' profits under various COMPETES model scenarios

Table E.1 *COMPETES estimates of ETS-induced changes in generators' profits at the national level under perfect competition at 20 €/tCO_2 and a price elasticity of power demand of 0.2*

[mln €]	Profits under different scenarios:[a]				Δ Profits due to:		
	CO_2 rate [b]	PCe0.2c0	Reference	Reference + free allocation	Price effect	Free allocation	Total effect
Austria	*191*	2610	2952	3270	342	318	659
Belgium	*251*	2332	2593	3177	261	584	845
Czech Republic	*836*	1213	1176	1941	-37	765	728
Denmark	*736*	789	827	1192	39	365	404
Finland	*185*	1950	2506	2761	556	255	811
France	*93*	13348	15412	16725	2063	1313	3377
Germany	*541*	12136	13460	18490	1325	5029	6354
Hungary	*351*	1204	1356	1605	152	249	401
Italy	*429*	11819	12817	15489	998	2672	3670
Netherlands	*459*	2618	2815	3774	197	959	1156
Norway	*1*	4132	4893	4919	761	25	787
Poland	*1013*	875	1054	3021	179	1967	2146
Portugal	*429*	1892	1835	2263	-57	429	372
Slovakia	*303*	718	855	1015	137	161	298
Slovenia	*943*	269	295	335	26	40	66
Spain	*420*	9452	9923	11850	472	1927	2398
Sweden	*13*	3957	4553	5231	597	677	1274
Switzerland	*48*	2308	2707	2917	399	209	608
UK	*372*	5496	5280	7162	-215	1882	1667
EU-20	*365*	79116	87310	107136	8194	19826	28021

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO_2 emission rate in ETS scenario [kg CO_2/MWh].

Table E.2 *COMPETES estimates of ETS-induced changes in generators' profits at the national level under oligopolistic competition at 20 €/tCO$_2$ and a price elasticity of power demand of 0.2*

[mln €]		Profits under different scenarios:[a]				Δ Profits due to:	
	CO_2 rate[b]	OCe0.2c0	OCe0.2c20	OCe0.2c20 + free allocation	Price effect	Free allocation	Total effect
Austria	*195*	2994	3329	3617	335	288	623
Belgium	*147*	4137	4172	4564	35	391	427
Czech Republic	*420*	2741	2814	3201	74	387	461
Denmark	*609*	1268	1354	1579	87	225	311
Finland	*160*	2424	2693	3029	269	337	606
France	*74*	15195	18083	18908	2888	825	3713
Germany	*478*	21905	23067	27113	1162	4046	5208
Hungary	*388*	1399	1614	1853	215	239	454
Italy	*451*	21138	21971	24435	834	2463	3297
Netherlands	*560*	5006	5077	5883	72	806	877
Norway	*1*	4389	4565	4682	176	118	294
Poland	*990*	421	446	2725	25	2279	2304
Portugal	*400*	2841	2915	3260	73	345	419
Slovakia	*161*	1108	1254	1338	146	83	229
Slovenia	*800*	307	336	365	29	30	58
Spain	*377*	15144	15470	17040	326	1570	1896
Sweden	*25*	5615	6009	6448	395	439	833
Switzerland	*54*	3522	3838	4004	316	166	482
UK	*443*	5006	4415	6927	-591	2511	1920
EU-20	*343*	116558	123422	140970	6865	17548	24412

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO_2 emission rate in ETS scenario [kg CO_2/MWh].

Table E.3 *COMPETES estimates of ETS-induced changes in generators' profits at the national level under perfect competition at 40 €/tCO$_2$ and a price elasticity of power demand of 0.2*

[mln €]		Profits under different scenarios:[a]				Δ Profits due to:	
	CO_2 rate[b]	PCe0.2c0	PCe0.2c40	PCe0.2c40 + free allocation	Price effect	Free allocation	Total effect
Austria	*156*	2610	3578	4198	967	620	1587
Belgium	*245*	2332	3027	4048	695	1021	1716
Czech Republic	*795*	1213	1443	2794	231	1350	1581
Denmark	*571*	789	1024	1619	235	595	830
Finland	*126*	1950	3366	3726	1416	360	1776
France	*70*	13348	19759	21849	6411	2089	8500
Germany	*483*	12136	17130	25717	4994	8588	13582
Hungary	*358*	1204	1547	1987	343	440	783
Italy	*425*	11819	14159	19331	2340	5172	7512
Netherlands	*479*	2618	3352	5089	734	1737	2471
Norway	*1*	4132	6267	6297	2135	30	2165
Poland	*994*	875	1309	4799	433	3491	3924
Portugal	*408*	1892	2078	2858	186	780	967
Slovakia	*256*	718	1134	1369	416	235	651
Slovenia	*914*	269	370	433	101	63	164
Spain	*364*	9452	11509	14722	2058	3213	5271
Sweden	*11*	3957	5701	6869	1744	1168	2912
Switzerland	*18*	2308	3532	3808	1224	276	1500
UK	*329*	5496	8092	11197	2597	3105	5701
EU-20	*331*	79116	108378	142710	29262	34332	63594

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO_2 emission rate in ETS scenario (in kg CO_2/MWh).

Table E.4 *COMPETES estimates of ETS-induced changes in generators' profits at the national level under oligopolistic competition at 40 €/tCO_2 and a price elasticity of power demand of 0.2*

[mln €]		Profits under different scenarios:[a]				Δ Profits due to:	
	CO_2 rate [b]	OCe0.2c0	OCe0.2c40	OCe0.2c40 + free allocation	Price effect	Free allocation	Total effect
Austria	*163*	4674	5620	2063	946	3009	4674
Belgium	*126*	4651	6179	2319	1528	3847	4651
Czech Republic	*378*	2253	3791	1040	1538	2579	2253
Denmark	*472*	1379	2072	590	692	1283	1379
Finland	*114*	5052	5419	3102	367	3469	5052
France	*65*	29524	31927	16176	2403	18579	29524
Germany	*418*	26133	36028	13997	9895	23892	26133
Hungary	*351*	2224	2756	1020	532	1552	2224
Italy	*409*	16656	26071	4838	9414	14252	16656
Netherlands	*560*	5184	8103	2565	2919	5485	5184
Norway	*1*	9156	9158	5024	2	5026	9156
Poland	*974*	1936	7220	1061	5284	6345	1936
Portugal	*386*	2822	3934	930	1112	2042	2822
Slovakia	*118*	1813	2052	1096	239	1334	1813
Slovenia	*857*	502	589	233	88	320	502
Spain	*318*	15760	20592	6309	4832	11141	15760
Sweden	*13*	8515	9551	4558	1037	5595	8515
Switzerland	*57*	5128	5488	2819	361	3180	5128
UK	*344*	14516	19229	9021	4713	13733	14516
EU-20	*299*	157878	205779	78762	47901	126663	157878

a) These figures refer to scenario model results, not to facts of life.
b) Average, sales-weighted CO_2 emission rate in ETS scenario [kg CO_2/MWh].