Energy research Centre of the Netherlands

CO_2 Price Dynamics

A follow-up analysis of the implications of EU emissions trading for the price of electricity

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Acknowledgement/Preface

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This project is registered at ECN under number 7.7759. For information on the ECN contribution to the project you can contact Jos Sijm by email (sijm@ecn.nl) or by telephone (+31.22456.8255).

Abstract

The present study discusses the results of some follow-up analyses on the relationship between EU emissions trading and power prices, notably the implications of free allocations of CO_2 emissions allowances for the price of electricity in Germany and the Netherlands. These analyses include:

- An update of the empirical and statistical analyses of the price trends and pass through rates of CO_2 costs in the power sector of Germany and the Netherlands.
- An analysis by means of the model COMPETES of the potential effects of CO_2 emissions trading on the wholesale market shares of the major power producers in the Netherlands.
- An analysis of two policy options to cope with certain adverse effects of passing through the opportunity costs of freely allocated CO_2 emission allowances, i.e. less grandfathering to the major power producers - in favour of major electricity users - by either a more stringent allocation to the power generators or auctioning part of the allowances to these generators.

A major finding of the present study is that dark/spark spreads of power production in Germany and the Netherlands have improved substantially in 2005, especially during the period August-December. Whereas valid CO_2 pass through rates of 40 to 70 percent have been estimated for the first period of 2005 (January- July), estimates for the year 2005 as a whole - and particularly for the latter period August-December - seem to be less or not valid since other factors, such as market power or scarcity, seem also (or even more) responsible for the improvement of dark/spark spreads in the latter period of 2005 (while data are lacking to abstract for these other factors).

Regarding the policy options to address adverse effects of CO_2 cost pass through, the report concludes that a small degree of less grandfathering to the power producers (i.e. 10-20 percent of the allowances needed) will reduce their windfall profits accordingly, without a major, decisive impact on the operational and investment decisions of these producers. Finally, the report discusses policy options to compensate major power users for ETS-induced increases in electricity prices, notably by means of a lenient allocation of CO_2 emission allowances to these users or by recycling revenues of CO_2 emission allowances auctioned to power producers towards consumers of electricity. Both options, however, may be questioned as each of them has certain shortcomings and drawbacks. In practice, a mix of options may be chosen in order to compensate different groups of power users and, hence, to mitigate some shortcomings and drawbacks of these options.

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Summary

Last year, the Energy research Centre of the Netherlands (ECN) published a report on the implications of EU emissions trading for the price of electricity (Sijm et al., 2005). The present report provides some follow-up analyses of these implications, including:

- An update of the empirical and statistical analyses of the price trends and pass through rates of CO_2 costs in the power sector of Germany and the Netherlands.
- An analysis by means of the model COMPETES of the potential effects of CO_2 emissions trading on the wholesale market shares of the major power producers in the Netherlands.
- An analysis of two policy options to cope with certain adverse effects of passing through the opportunity costs of freely allocated CO_2 emission allowances, notably less grandfathering to the major power producers - in favour of major electricity users - by either a more stringent allocation to the power generators or auctioning part of the allowances needed by these generators.

The major results of these follow-up analyses are discussed briefly below.

Update of empirical and statistical analyses

The major findings of the empirical and statistical analyses of the price trends and pass through rates of CO_2 costs in the power sector of Germany and the Netherlands for the year 2005 include:

- Power prices in Germany and the Netherlands have increased considerably in 2005 (+ 50-60 percent).
- While fuel prices in 2005 were more or less stable for coal, they increased by some 60 percent for gas.
- CO_2 prices increased rapidly from 7 €/tCO_2 in early February 2005 to almost 30 €/tCO_2 in early July 2005. Subsequently, they fell to about 20 €/tCO_2 in late July and remained more or less stable at a level of 21-23 €/tCO_2 during the remaining part of 2005.
- CO_2 pass through rates in Germany and the Netherlands for the period January-July 2005 have been estimated to vary roughly between 40 and 70 percent. During the period August-December 2005, dark/spark spreads in these countries have increased substantially, which may to some extent be attributed to a catching up of the CO_2 pass through rates up to 100 percent. However, estimates of CO_2 pass through rates for this latter period of 2005 seem to be not or less valid due to the incidence of other factors affecting changes in power prices - such as market power or scarcity - especially during the peak hours. Therefore, estimates of CO_2 pass through rates for 2005 as a whole seem to be less valid than those for the first part of 2005 (January-July).

Changes in wholesale market shares

The impact of CO_2 emissions trading on wholesale market shares in the Netherlands has been analysed for six scenarios based on the COMPETES model, covering four countries in Northwestern Europe (Belgium, France, Germany and the Netherlands). According to these model scenarios, the major winners - in terms of higher market shares when CO_2 costs increase - are companies with a significant amount of nuclear power production facilities, such as E.ON, Electrabel, EdF and ENBW. On the other hand the companies that lose market share are either Dutch-based and relying on gas-fired generation capacity even in off peak hours - for instance, NUON - or it involves foreign parties offering coal-based capacity, e.g. RWE.

More detailed analyses, however, show that changes in wholesale market share vary per scenario, depending on factors such as generation capacity limits, fuel mix of companies, power exchanges between national markets, total power demand, load periods, demand elasticities, and market structure (i.e. competitive versus strategic/oligopolistic price bidding).

Policy options to address adverse effects of CO_2 cost pass through
In order to reduce the adverse effects of passing through the opportunity costs of grandfathered CO_2 emission allowances, notably the incidence of windfall profits to power producers and higher electricity prices to power consumers, two related options can be considered, i.e. less grandfathering to the power producers by either a more stringent allocation of CO_2 emission allowances to these producers - resulting in more purchases of allowances on the market - or auctioning a part of their allowances needed, and compensating power users for ETS-induced increases in power prices by either a more lenient allocation of CO_2 emission allowances to these users - resulting in less purchases or more sales of allowances on the market - or recycling to these users the revenues of allowances auctioned to the power producers. The major considerations and implications of these options for the major stakeholders involved can be summarized as follows:

Major power producers
Less grandfathering to power generators implies less windfall profits to these generators. However, assuming that less grandfathering to power producers does not affect CO_2 and/or power prices, it does not affect their (short-run) operational decisions, as their operational profits do not change. On the other hand, if it is assumed that less grandfathering leads to higher power prices, the impact on operational/windfall profits and, hence, operational decisions is affected accordingly (i.e. profits and production will be higher). Moreover, less grandfathering to power producers may affect their investment decisions - through its impact on power prices and/or (windfall) profits - but its impact is likely (negligibly) small and temporary, notably if CO_2 prices are low or the reduction in grandfathering is relatively small, since:

- Investment decisions are primarily based on other, more important factors such as long-term power prices and fuel costs.
- Issues such as CO_2 prices, pass-through rates to power prices, allocation of CO_2 emission allowances, etc., are probably abstracted from or highly discounted for future years given the long-term character of investments in new generation capacity and the present high uncertainties regarding future climate policies in general and emissions trading in particular.
- Even if less grandfathering leads to fewer investments in generation capacity, this impact will probably be temporary since less investments now will lead to more scarcity and higher prices on the power market, inducing more investments in the future.

Therefore, less grandfathering will at the most lead to some delay of new investments in generation capacity but most likely not to a cancellation of these investments.

Finally, if less grandfathering to the power sector is only implemented in the Netherlands - and not in neighbouring, competing countries - the impact on relocating investments from the Netherlands to these countries (and exporting power from these countries to the Netherlands) is most likely very small or even absent. Besides the reasons mentioned above, this can be attributed to the consideration that potential differences in windfall profits due to differences in grandfathering among countries are nullified by transmission costs, other (physical or institutional) constraints and uncertainties whether these differences in grandfathering - or other policy induced CO_2 issues - will last in the future. This applies particularly when the difference in rate of grandfathering between the Netherlands and competing countries is small (say 10-20 percent of total allowances needed). The potential impact on relocating investments may be more significant, however, if the difference in grandfathering between the countries concerned becomes more substantial (say, 50 percent or more), and the transmission constraints and costs of exporting power are reduced significantly.

CHP operators
In first instance, the impact of less grandfathering on CHP operators in the Netherlands is similar to its general impact on major power producers outlined above. In second instance, however, its impact depends particularly on the specifics of the (new) CHP subsidy scheme as the impact of less grandfathering on overall (windfall) profits and power prices may be accounted for when determining CHP subsidies to incumbent and/or new operators. Moreover, policy makers can decide to exempt CHP operators from measures to reduce grandfathering to the power sector in general and continue a policy of lenient allocation of CO_2 emission allowances to CHP operators. This option may be questioned, however, since (i) CHP operators - just like the major power producers - also benefit from ETS-induced increases in power prices, grandfathering and resulting windfall profits, (ii) the primary aim of allocating CO_2 emission allowances is to enhance the social benefits and credibility of the ETS and not to favour the financial interests of specific groups, and (iii) if policy makers choose to support CHP, it is generally better to use a specific, well-defined and targeted subsidy scheme than to rely on a general, lenient allocation of CO_2 emission allowances to (incumbent and new) CHP operators.

Major power users
As said, major power users may be compensated for ETS-induced increases in power prices by either a lenient allocation of CO_2 emission allowances to these users or by recycling to them the revenues of allowances auctioned to power producers. In general, both compensation options can be questioned since;

- Higher power prices are an intended, rational effect of emissions trading to reduce CO_2 emissions in an optimal way - regardless the allocation method used - and, hence, there is no general need to compensate these higher power prices.
- Some major power users may be able to pass on higher power prices - and CO_2 costs of their grandfathered allowances - and, hence, there is no need to compensate these users.

More specifically, compensation through a lenient allocation to power users may be further questioned because of some additional, specific considerations, including:

- High emitters, but low power users, may be overcompensated while low emitters, but high power users, may be undercompensated.
- Allocating allowances in proportion to power consumption may provide a perverse incentive to higher electricity use.
- Major power users *not* participating in the EU ETS - notably the aluminium producers - do not get any compensation for higher power prices since they do not receive any allowances at all.
- Allocation is not meant as an instrument to compensate industries for higher power prices.

On the other hand, the major advantage of compensating through recycling auction revenues is that, in principle, all (major) power consumers can be compensated - including those outside the EU ETS - and that the mechanism to compensate these consumers can be rather general and simple, without perverse incentives on energy use or CO_2 emissions, for instance by using the auction revenues to lower general income and business tax rates. However, if only a small amount of emission allowances is auctioned, the revenues will most likely not be sufficient to fully compensate all (major) electricity consumers, while the energy/power-intensive industries will probably be undercompensated and benefit more from another, more targeted approach.

In addition, recycling auction revenues by lowering general income and business tax rates would also - or even mainly - benefit high income groups and relatively profitable firms which hardly suffer from higher electricity prices, such as banks or insurance companies. An alternative would be to recycle auction revenues by lowering the energy tax (called 'EB'). This option, however, would mainly favour small power consumers, notably low-income households, but not offer a solution to major industrial users since they are exempted from paying the EB.

Therefore, to conclude, options to compensate major power users for ETS-induced increases in electricity prices may be questioned as each option has certain shortcomings and drawbacks. In practice, a mix of different options may be preferable to compensate different target groups of electricity consumers, thereby partly mitigating the shortcomings and drawbacks of each option separately, for instance by a lenient allocation of CO_2 emission allowances to industrial power users and a lowering of energy taxes for households and other small consumers of electricity.

1. Introduction

Last year, the Energy research Centre of the Netherlands (ECN) published a report on the implications of EU emissions trading for the price of electricity (Sijm et al., 2005). This report has aroused a lot of attention and discussion, both among stakeholders and policy makers. In response, the Ministry of Economic Affairs in the Netherlands has invited ECN to conduct some follow-up analyses, notably with regard to the following aspects:

1. An update of the empirical analysis of the pass through rates of CO_2 emissions trading costs into the price of electricity. While the analysis in Sijm et al. (2005) covered the period January-July 2005, the update of the present report concerns the full twelve-month period of 2005, a comparison of the trends in power prices, fuel costs and resulting dark/spark spreads in 2005 to previous years (2003 and 2004), and some tests of the robustness of the estimated pass through rates.

2. An analysis by means of the model COMPETES of the potential effects of CO_2 emissions trading on the competitiveness of the power sector, notably on the wholesale market shares of the major power producers in the Netherlands.

3. An analysis of two policy options to cope with certain adverse effects of passing through the opportunity costs of freely allocated CO_2 emission allowances, such as the incidence of windfall profits among power producers or higher electricity prices for major industrial consumers. This analysis includes the impact of these policy options on the competitiveness of major power consumers and producers, with special attention to the position of the Combined Heat and Power (CHP) sub-sector in the Netherlands. These policy options - which fit into the present framework of the EU ETS directive and a liberalised power market - concern particularly:
   a. A more stringent allocation of CO_2 emission allowances to the power sector together with a more lenient allocation to other industries participating in the EU ETS.
   b. A (partial) auctioning of the CO_2 emission allowances, especially to the power sector, and recycling the auction revenues to those industries most affected by EU ETS induced increases in power prices.

   Both options will be considered from two perspectives, namely:
   - The policy options will be implemented in both the Netherlands and neighbouring countries affecting the competitiveness of the Dutch power producers.
   - The policy options will be implemented in the Netherlands only.

These three issues will be outlined in the following three chapters, respectively.

2. Update empirical analyses of price trends and pass through rates

This chapter discusses the major results of the updated empirical and statistical analyses of price trends and pass-through rates in the electricity sector of Germany (DE) and the Netherlands (NL), notably for the year 2005 compared to two previous years (2003-2004). Firstly, Section 2.1 shows some trends in prices of electricity, fuels and CO_2 allowances, and discusses whether there is any relationship between these trends. Subsequently, Section 2.2 presents trends in so-called dark and spark spreads of power production in Germany and the Netherlands over the period 2003-2005. Finally, Section 2.3 discusses the results of the updated statistical regression analyses to estimate rates of passing through CO_2 opportunity costs of EU emissions trading to power prices in Germany and the Netherlands.

2.1 Trends in prices of electricity, fuels and CO_2 allowances

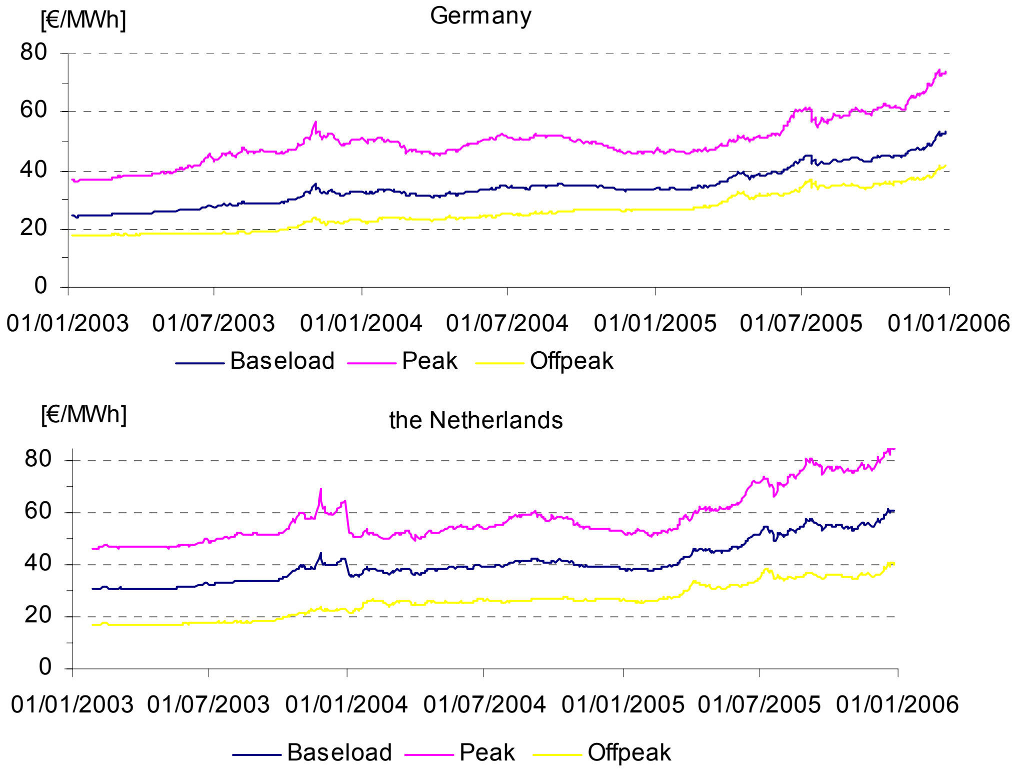

Figure 2.1 *Power prices in Germany and the Netherlands (year ahead, 2003-2005)*

Figure 2.1 shows the trends in forward power prices (year ahead) in Germany and the Netherlands over the years 2003-2005 for base load, peak load and off-peak hours.[1] In general, these prices have approximately doubled in absolute terms over this period. While power prices were

[1] In the Netherlands, peak hours run from 7:00 up to 23:00h each working day, i.e. excluding weekends and public holidays. Assuming 255 working days per year, this implies a total number of 255 × 16 = 4080 peak hours per year. All other hours in the year are considered as off-peak hours, i.e. 8760 - 4080 = 4680 hours per year. The power price for off-peak hours ($O_{ff\text{-}peak}$) has been calculated as follows: $O_{ff\text{-}peak} = ((8760 \times P_{baseload}) - (4080 * P_{peak}))/4680$ (DTe, 2005). For Germany, peak load hours are defined from 8:00 to 20:00h for each working day, regardless whether it is a holiday or not. Assuming 260 working days per year, this implies a total number of 260 × 12 = 3120 peak hours per year. Hence, for Germany, the off-peak power price has been calculated as follows: $O_{ff\text{-}peak} = ((8760 \times P_{baseload}) - (3120 \times P_{peak}))/5640$ (RWE, personal communication).

more or less stable in 2004 (-10 to +20 percent), they have increased substantially in 2003 (+30-40 percent) and, notably, in 2005 (+50-60 percent). Over the years 2003-2005, power prices in Germany and the Netherlands have generally increased faster during the off-peak than peak hours. For instance, peak power prices in the Netherlands rose from 47 €/MWh in early January 2003 to 84 €/MWh in late December 2005 (+80 percent), while the off-peak prices increased from 17 to 40 €/MWh over this period (+133 percent).[2]

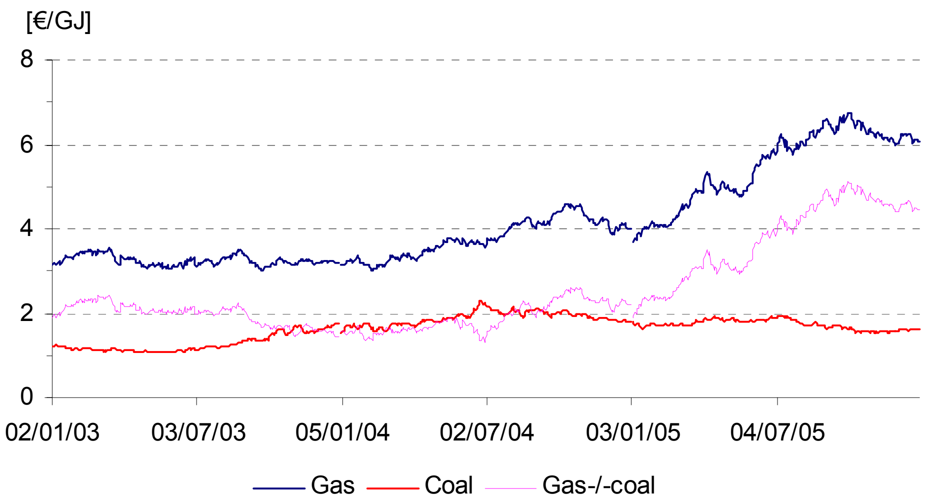

Figure 2.2 *Fuel prices (year ahead, 2003-2005)*

Figure 2.2 presents trends of forward prices (year ahead) of internationally traded fuels such as coal and gas.[3] It can be observed that whereas coal prices increased in 2003 from 1.2 to 1.7 €/GJ (+50 percent), they more or less stabilised in the years 2004-2005 at a level of 1.6-1.8 €/GJ. Gas prices, on the contrary, declined in 2003 from 3.4 €/GJ in early January to 3.2 €/GJ in late December (-5 percent), whereas they increased rapidly in 2004 (+27 percent) and, particularly, in 2005 (+60 percent) up to a level of 6.1 €/GJ in late December 2005. This difference in price trends between coal and gas is caused largely by the fact that wholesale gas prices are linked to the international oil prices - which have increased significantly since 2004 - while coal prices are not. As a result, the price differential between gas and coal declined significantly from 2.2 €/GJ in early January 2003 to 1.5 €/GJ in late December 2003 (-33 percent), but has increased substantially in 2004 and 2005 (i.e. +45 and 115 percent, respectively) up to a gas-coal price difference of 4.5 €/GJ in late December 2005.

The rising price differential between gas and coal has been one of the major factors determining the increase in CO_2 prices on the EUA market, notably during the first half of 2005. Figure 2.3 shows that whereas CO_2 prices were rather stable between April 2004 and January 2005 (at a level of about 7-9 €/tCO_2), they increased rapidly from 7 €/tCO_2 in early February 2005 to almost 30 €/tCO_2 in early July 2005. Subsequently, CO_2 prices fell to about 20 €/tCO_2 in late July and remained more or less stable at a level of 21-23 €/tCO_2 during the remaining part of 2005.

For the year 2004-2005, Figure 2.4 presents power prices versus fuel/CO_2 costs to generate a MWh of power (assuming a fuel efficiency of 40 percent for coal and 42 percent for gas, a related emission factor of 0.85 and 0.48 tCO_2/MWh for coal and gas, respectively, and full 'opportunity' costs for generating electricity by either coal or gas). The upper part of the figure covers the case of coal-generated off peak power in Germany, while the lower part presents the case of gas-generated peak power in the Netherlands.

[2] Note, however, that in the year 2005 only, peak power prices in the Netherlands rose faster than off-peak prices, i.e. about 60 and 50 percent, respectively.

[3] Throughout this chapter, coal refers to the internationally traded commodity classified as coal ARA CIF API#2, while gas refers to the high caloric gas (35.17) from the Dutch Gas Union Trade & Supply (GUTS).

Figure 2.3 *CO_2 prices on EUA market (year ahead, 2004-2005)*

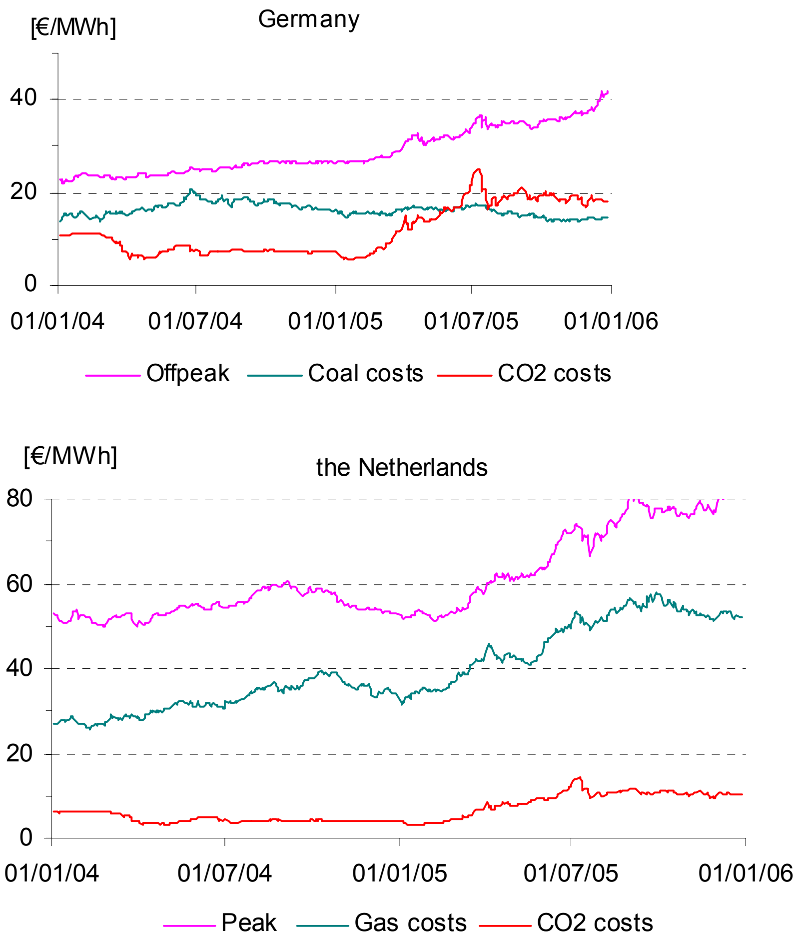

Figure 2.4 *Power prices versus fuel/CO_2 costs in Germany and the Netherlands (year ahead, 2003-2005)*

The German case shows that the fuel (i.e. coal) costs to generate power have been more or less stable at a level of about 16 €/MWh during the years 2004-2005(which comes at no surprise because - as noted above - coal prices have been rather stable over this period). On the other hand,

CO_2 costs of coal-generated power have been stable during the second part of 2004 but have approximately trebled during the first part of 2005 - from about 6 €/MWh in January to some 18 €/MWh in July - which is due to the rising CO_2 prices (and the high - but constant - emission factor of coal-generated power). This suggest that the increasing off-peak prices in Germany over this period - from 27 to 34 €/MWh - have been caused primarily by the rising CO_2 prices (and not by higher fuel prices). However, during the second part of 2005 (August-December 2005) CO_2 costs per coal-generated MWh have been rather stable while off-peak prices have continued to rise (from about 34 €/MWh in mid 2005 to 41 €/MWh in late December 2005).

The Dutch case illustrates that the fuel (i.e. gas) costs to produce electricity has risen substantially from some 33 €/MWh in early January 2005 to about 56 €/MWh in early September 2005. CO_2 costs of gas-generated power have also increased over this period, but less dramatically, i.e. from 4 to 11 €/MWh (partly due to the relatively low - but constant - emission factor of gas-generated electricity). This suggests, hence, that the rising peak load prices in the Netherlands over this period - from about 52 to 80 €/MWh - have been predominantly caused by the rising gas prices. However, comparable to the German case, whereas both gas and CO_2 costs have been more or less stable during the last quarter of 2005 (or even declined a bit as far as gas costs are concerned), peak power prices continued to increase to 84 €/MWh in late December 2005.

2.2 Trends in dark/spark spreads

Figures 2.5 and 2.6 present trends in dark/spark spreads over the years 2003-2005 in Germany and the Netherlands. For the present analysis, a *dark* spread is simply defined as the difference between the power price and the cost of *coal* to generate a MWh of electricity, while a *spark* spread refers to the difference between the power price and the costs of *gas* to produce a MWh of electricity. If the costs of CO_2 are included, these indicators are called '*clean dark/spark spreads'* or '*carbon compensated dark/spark spreads*'[4].

For Germany, Figure 2.5 refers to trends in dark spreads in both peak and off-peak hours (based on the assumption that a coal generator is the price-setting unit during these periods).[5] For the Netherlands, the upper part of Figure 2.6 refers to the trend in the spark spread during the peak hours, while the lower part illustrates trends in the dark spread during the off-peak hours (based on the assumption that a gas- versus coal-fired installation is the price-setting unit during these periods, respectively).

Figures 2.5 and 2.6 show that for all three coal-based cases the dark spreads have improved steadily over the years 2003-2005, notably during the year 2005. For instance, the dark spread during the off-peak hours improved slightly from 7 €/MWh in early 2003 to 11 €/MWh in early 2005 while, subsequently, it jumped to 26 €/MWh in late 2005 (in both Germany and the Netherlands), whereas the dark spread during the peak hours increased from 26 €/MWh in early 2003 to 31 €/MWh in early 2005 and even to 59 €/MWh in late 2005 (Germany only).[6]

In addition, it can be observed from the upper part of Figure 2.6 that the spark spread in the Netherlands shows a slightly declining trend over the years 2003-2005. However, the declining

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

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

[6] It should be noted that the higher German peak dark spread in 2005 partly results from higher peak power prices induced by high gas costs as during certain intervals of the peak period in Germany power prices are set by a gas-fired rather than a coal-fired generator.

trend is not only rather feeble, but also the regression coefficient of the trend line is very low (R^2=0.01), implying that the statistical fit of the regression line is rather poor. Moreover, when considering the year 2005 separately (see Figure 2.7), the trend of the spark spread during peak hours in the Netherlands is significantly moving upwards (with a regression coefficient of the trend line equal to 0.66). More specifically, over the year 2005, the spark spread has increased from about 19 €/MWh in early 2005 to approximately 32 €/MWh in late 2005.

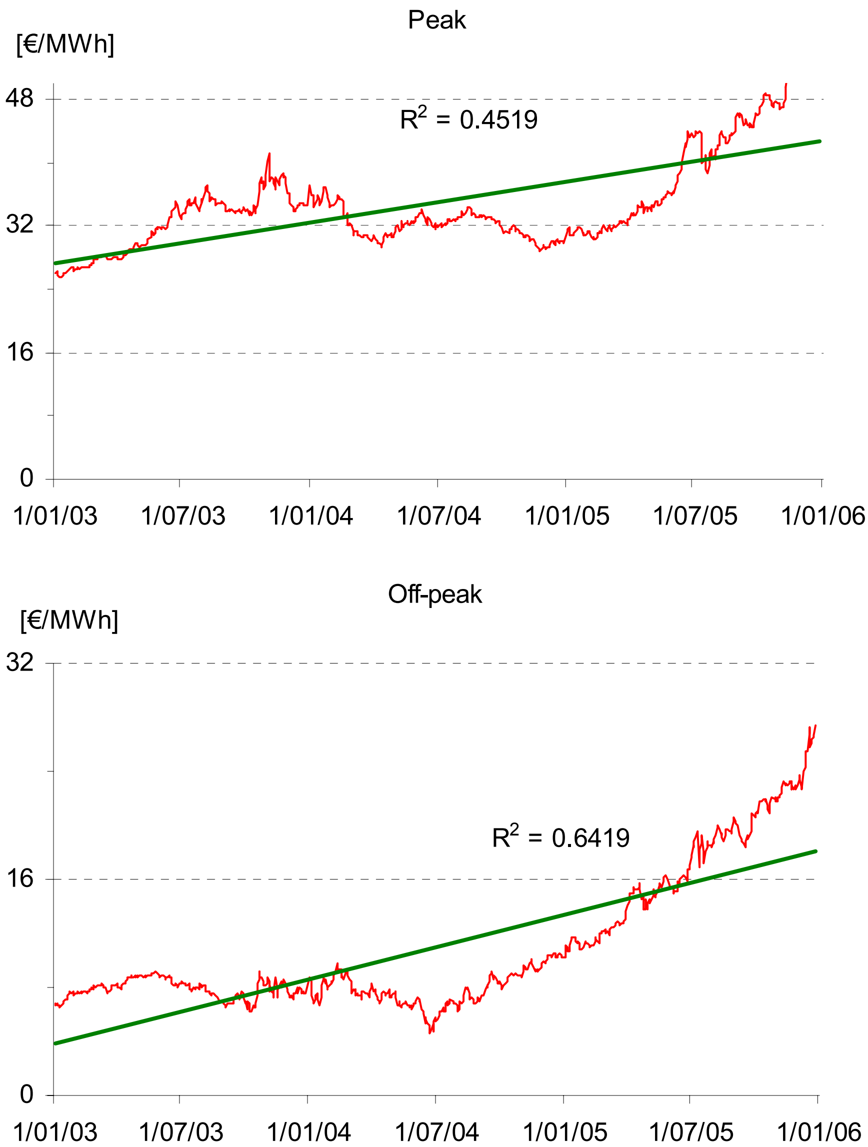

Figure 2.5 *Trends in dark spreads in Germany (year ahead, 2003-2005)*

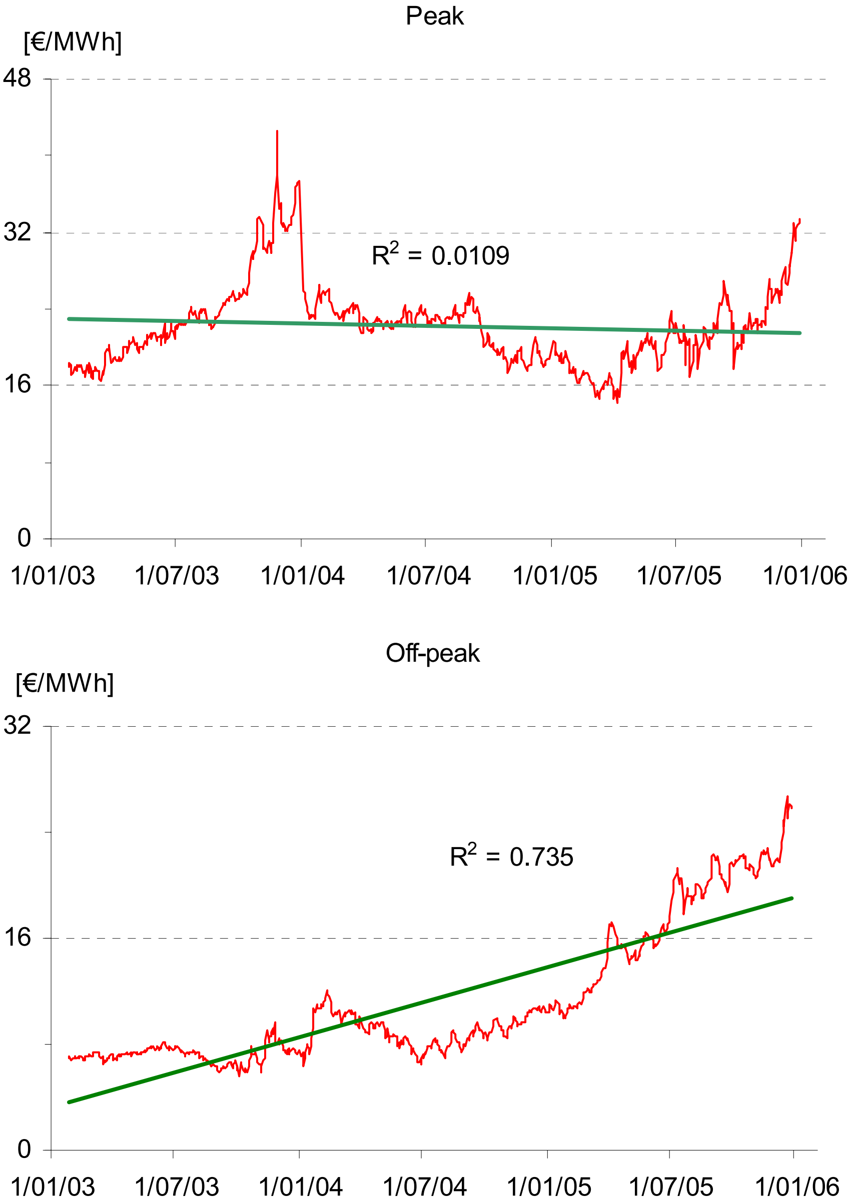

Figure 2.6 *Trends in dark/spark spreads in the Netherlands (year ahead, 2003-2005)*

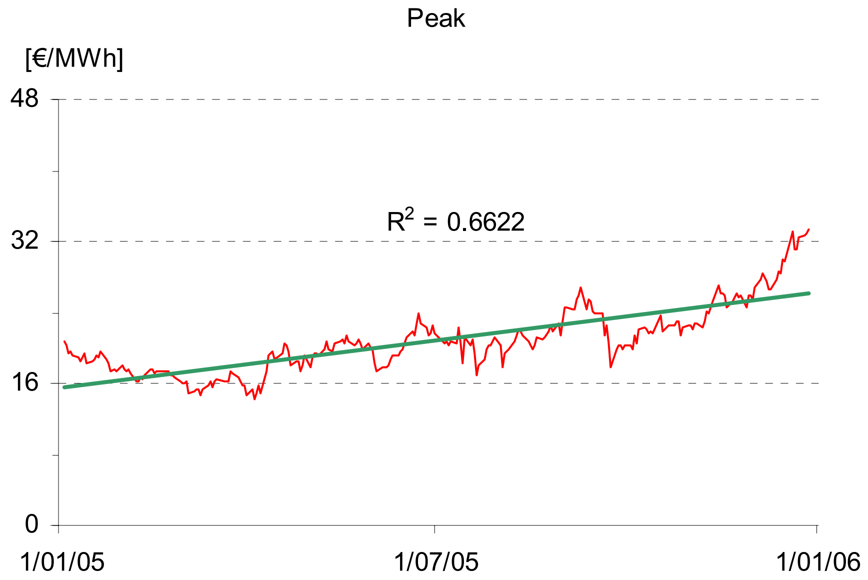

Figure 2.7 *Trends in spark spreads in the Netherlands (year ahead, 2005)*

2.3 Statistical estimates of CO_2 pass through rates

Empirical estimates of pass through rates of CO_2 emission trading costs to power prices in Germany and the Netherlands over the period January-July 2005 have been recorded in Sijm, et al. (2005), using two statistical regression approaches called the Ordinary Least Squares (OLS) method and the Prais-Winston (PW) method. The results are reproduced in the first two rows of Table 2.1, showing that the estimated pass through rates vary roughly between 40 and 70 percent.[7] These estimates are all statistically significant at the 1% level, while the confidence interval of these estimates is generally within reasonable bounds.

As part of the present follow-up analyses, the estimated pass through rates have been updated for the year 2005 as a whole. In addition, besides comparative estimates for the year 2004, some alternative regression approaches have been tested as part of the follow-up activities, including:

- Estimating pass through rates by regressing CO_2 and fuel costs to power prices, compared to the original approach in Sijm, et al. (2005) in which CO_2 costs were directly regressed to dark/spark spreads, assuming that fuel costs are always fully passed on to power prices (i.e. the pass through rate of fuel costs is assumed to be 1).
- Estimating pass through rates by means of the first differences of the variables regressed, compared to the absolute values of the variables regressed as applied in Sijm, et al. (2005).
- Estimating pass through rates by means of a regression equation including a trend variable and generating estimates for two years together (2004 and 2005), versus the equation applied in Sijm, et al. (2005), excluding a trend variable and generating estimates for each year separately.

The performance of these alternative regression approaches is outlined in Appendix A of the present report. Below the most important or interesting results are discussed briefly.

[7] There are a few minor differences between the rates reported in Sijm, et al. (2005) and the corresponding rates in Table 2.1 due to minor adjustments in the data and period considered.

Firstly, rows 3 and 4 of Table 2.1 present alternative estimates of CO_2 pass through rates for the period January-July 2005 by regressing both CO_2 and fuel costs to power prices (i.e. by dropping the assumption that the pass through rate of fuel cost is equal to 1). This approach results in higher estimates of CO_2 pass through rates, particularly during the peak period in the Netherlands. However, whereas all estimates are statistically significant at the 1% level and the confidence interval of the estimated pass through rates look generally reasonable for the coal-based cases (i.e. Germany: peak and off-peak; the Netherlands: peak), they seem rather dubious for the gas-based (peak) case in the Netherlands as the corresponding CO_2 pass through rates are significantly higher than 100 percent. Moreover, the estimated pass through rates for fuel costs are also dubious, notably for the PW estimates in the NL peak case (rather low) and the OLS estimate for the DE peak case (even negative; see rows 5 and 6 of Table 2.1). The reason for these dubious results is most likely that CO_2 and fuel costs - particularly in the case of gas - are highly correlated, leading to spurious results when estimating the pass through rate of these two related variables together within one equation.[8] Therefore, it may be concluded that estimates of CO_2 pass through rates seem more valid when the CO_2 costs are directly regressed to dark/spark spreads (i.e. assuming that fuel costs are always fully passed on to power prices) rather than regressing CO_2 (and fuel) costs to power prices.[9]

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8 Another reason might be that fuel costs used in the current analysis do not represent the actually contracted fuel costs of generating electricity in forward markets. To hedge the risks associated with fuel price volatility, generators always engage in various forms of risk-hedging practices, for instance by signing long-term contracts. The information about these contracts (i.e. settlement prices, quantity, delivery date) is generally confidential and not disclosed to the public. Suing data on market power prices is simply an approximation of this proprietary information and may, hence, lead to less reliable results.

9 This conclusion is supported by similar findings and comparisons of these two regression approaches as discussed in the main text below and Appendix A of the present report.

Table 2.1 *Estimated pass through rates in Germany and the Netherlands for the period January-July 2005*

Line no.	Variables regressed	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	The Netherlands Off-peak [%]	Germany Peak [%]	Germany Off-peak [%]
1	Absolute values	OLS	√	40** (32÷49)	52** (49÷55)	72** (68÷76)	42** (40÷45)
2		PW	√	42** (31÷49)	46** (40÷51)	68** (60÷75)	43** (39÷46)
3		OLS		139** (116÷161)	51** (46÷57)	86** (78÷95)	46** (42÷50)
4		PW		151** (128÷175)	49** (43÷55)	69** (60÷78)	48** (43÷52)
5[d]		*OLS*	*(fuel)*	*46 (34÷60)*	*108 (61÷155)*	*-41 (-107÷27)*	*65 (30÷101)*
6[d]		*PW*	*(fuel)*	*27 (15÷39)*	*49 (24÷75)*	*85 (48÷122)*	*50 (22÷78)*
7	First differences	OLS	√	100** (61÷147)	34** (25÷43)	60** (48÷74)	45** (34÷55)
8		PW	√	100** (63÷141)	34** (25÷43)	61** (48÷74)	42** (33÷52)
9		OLS		126** (96÷156)	38** (29÷47)	61** (48÷75)	49** (39÷59)
10		PW		126** (95÷156)	38** (29÷47)	61** (48÷75)	46** (37÷55)
11[d]		*OLS*	*(fuel)*	*14 (-1÷29)*	*44 (18÷69)*	*91 (53÷130)*	*46 (17÷75)*
12[d]		*PW*	*(fuel)*	*14 (-1÷29)*	*44 (18÷69)*	*91 (53÷130)*	*48 (20÷75)*

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.
d) Estimates in italics refer to pass through rates for fuel costs.

Secondly, rows 7-12 of Table 2.1 provide similar estimates of CO_2 (and fuel) cost pass through rates based on first differences of the variables regressed (compared to absolute values of the variables regressed as applied to the estimates of rows 1-6). In general, the estimates of the univariate analysis (i.e. only CO_2 cost pass through is estimated, while the fuel cost pass through is set at 1), are statistically significant at the 1% level while the confidence interval looks reasonable. The most striking result is that the estimated CO_2 pass through rate in the NL peak case is 100 percent in case of the first difference approach (compared to about 40 percent when absolute values are used. Estimates of pass through rates based on a multi-variate analysis (i.e. pass through rates are estimated for both fuel and CO_2 costs), seem less valid due to the reasons expressed above.

Table 2.2 *Estimated pass through rates in Germany and the Netherlands for the period August-December 2005*

Line no.	Variables regressed	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak [%][c]	The Netherlands Off-peak [%]	Germany Peak [%]	Germany Off-peak [%]
1	Absolute values	OLS	√	-130	-8	-150**	-65**
				(-270÷10)	(-46÷30)	(-253÷48)	(-111÷-19
2		PW	√	109	42	52*	28
				(24÷195)	(23÷62)	(17÷88)	(9÷47)
3		OLS		150	10	-100**	-39**
				(-110÷310)	(-24÷43)	(-187÷-13)	(-74÷-4)
4		PW		200**	47**	62**	34**
				(134÷267)	(29÷66)	(32÷91)	(20÷50)
5[d]		*OLS*	*(fuel)*	*-25*	*-52*	*-338*	*-128*
				(-70÷21)	*(-102÷-3)*	*(-464÷-212)*	*(-180÷-77)*
6[d]		*PW*	*(fuel)*	*0*	*0*	*-25*	*104*
				(-20÷20)	*(-48÷48)*	*(-98÷49)*	*(-28÷49)*
7	First differences	OLS	√	111*	44**	62**	33**
				(16÷205)	(24÷65)	(30÷93)	(16÷51)
8		PW	√	115*	46**	61**	33**
				(24÷207)	(26÷67)	(30÷92)	(15÷51)
9		OLS		203**	46**	64**	35**
				(132÷274)	(28÷66)	(34÷94)	(19÷52)
10		PW		205**	48**	64**	36**
				(134÷276)	(30÷66)	(34÷95)	(20÷52)
11[d]		*OLS*	*(fuel)*	*0.5*	*-3*	*-12*	*13*
				(-2÷2)	*(-51÷44)*	*(-89÷65)*	*(-29÷54)*
12[d]		*PW*	*(fuel)*	*-2*	*-200.7*	*-9*	*11*
				(-23÷19)	*(-46÷45)*	*(-88÷67)*	*(-30÷51)*

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.
d) Estimates in italics refer to pass through rates for fuel costs.

Thirdly, Table 2.2 presents similar estimates of CO_2 (and fuel) cost pass through rates for the period August-December 2005 (compared to the results recorded in Table 2.1 for the period January-July 2005). In general, these estimates seem rather dubious as (i) several of the estimated rates are not statistically significant at either the 1% or 5% level (and, hence, the confidence interval of these rates is rather broad), and (ii) most of the estimated rates are either very low (even negative) or very high (i.e. more than 100 percent).

The most important reason for the dubious results for the period August-December 2005 seems to be that changes in dark/spark spreads (power prices) are affected by other variables than CO_2 (and fuel) costs. As outlined in Sijm, et al. (2005), the estimates for the period January-July 2005 are based on the assumption that the dynamics of the power prices in Germany and the Netherlands over the period January-July 2005 (see Figure 2.1) can be fully explained by the variations in the fuel and CO_2 costs over this period (see Figure 2.4). Hence, it is assumed that during this period other costs, for instance operational or maintenance costs, are constant - i.e. do not change - and that the market structure did not alter over this period (i.e. changes in power prices can not be attributed to changes in technology, market power or other supply-demand relationships). Although questionable, this assumption seems to be rather valid for the period

January-July 2005, but it is certainly not valid for the period August-December 2005. For instance, whereas the CO_2 price on the EUA market is more or less stable at a level of 22 €/tCO_2 during this period, the peak spark spread in the Netherlands increased from about 20 to 32 €/MWh, the off-peak dark spread from approximately 19 to 25 €/MWh (in both Germany and the Netherlands) and the peak dark spread in Germany even from 42 to 58 €/MWh (see Figures 2.5 and 2.6). Even if one allows for the fact that during the period January-July 2005 the estimated CO_2 pass through rates are significantly less than 100 percent (i.e. 40-70 percent) and that during the period August-December these rates may have gradually cached up to 100 percent, this factor may explain the changes in the off-peak dark spreads in Germany and the Netherlands during this period to a large extent, but can not adequately explain the large changes in the peak dark/spark spreads in these countries.[10]

A major part of the changes in power prices (dark/spark spreads) in the period August-December 2005 - particularly during peak hours - seems to be due to other costs - besides fuel and CO_2 costs - for instance, operational or maintenance costs - or, more likely, to changes in other factors, such as changes in market power or scarcity. Due to a lack of data or other information on these potential explanatory factors, it is not possible to abstract the influence of these factors from the impact of CO_2 cost pass through on power prices. Therefore, it may be concluded that the estimated CO_2 pass through rates for the period August-December are generally not valid.

Finally, Table 2.3 provides similar estimates of CO_2 (and fuel) cost pass through rate for the year 2005 as a whole. It shows that the CO_2 pass through rates over the year 2005 as a whole vary roughly between 40 and 70 percent for the coal-based cases (thereby confirming the estimates for the period January-July 2005), while they are significantly higher for the gas-based, peak load case in the Netherlands (>80 percent). At first sight, most of these estimates seem reasonable as they are all statistically significant at the 1% level, while most of them fall within reasonable confidence intervals (the major exception concerns the estimates for peak load hours in the Netherlands, notably when the assumption is dropped that fuel costs are always fully passed on to power prices). As outlined above, however, estimates of CO_2 (and fuel) cost pass through rates for the second part of 2005 seem to be not valid due to the incidence of other factors affecting changes in power prices. As a result, the reliability of the estimated CO_2 pass through rates for 2005 as a whole may be questioned.

To conclude, CO_2 pass through rates in Germany and the Netherlands for the period January-July 2005 have been estimated to vary roughly between 40 and 70 percent. During the period August-December 2005, dark/spark spreads in these countries have increased substantially, which may to some extent be attributed to a catching up of the CO_2 pass through rates up to 100 percent. However, estimates of CO_2 pass through rates for this latter period of 2005 seem to be not or less valid due to other factors affecting power prices, especially during the peak hours. Therefore, estimates of CO_2 pass through rates for 2005 as a whole seem to be less valid than those for the first part of 2005 (January-July).

[10] For instance, based on an average CO_2 price on the EUA market over the period August-December 2005 of about 22 €/tCO_2, and emission factors of 0.85 and 0.48 tCO_2/MWh for coal- and gas-generated power, respectively, the average full CO_2 costs of coal- and gas-generated power is 18.7 and 10.6 €/MWh, respectively. On the other hand, based on an average CO_2 price on the EUA market of about 15 €/tCO_2 over the period January-July 2005 and a CO_2 pass through rate for off-peak (coal) and peak-load (gas) power in the Netherlands, the average CO_2 costs passed through is estimated at 7.2 and 2.8 €/MWh, respectively (Sijm et al., 2005). Assuming a (full) catch up of the CO_2 pass through rate up to 100 percent in the period August-December 2005, this factor may explain the increase in the NL off-peak dark spread (+6 €/MWh) but can not (fully) explain the increase in the NL peak spark spread (+11 €/MWh) as a significant part of this increase (11 - (10.6 - 2.8)) is unaccounted for.

Table 2.3 *Estimated pass through rates in Germany and the Netherlands for the year 2005 as a whole*

Line no.	Variables regressed	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	The Netherlands Off-peak [%]	Germany Peak [%]	Germany Off-peak [%]
1	Absolute values	OLS	√	78** (65÷91)	74** (68÷79)	117** (105÷129)	67** (61÷73)
2		PW	√	80** (65÷96)	72** (67÷78)	60** (48÷74)	46** (38÷54)
3		OLS		19 (-14÷54)	71** (68÷75)	113** (105÷120)	64** (61÷68)
4		PW		144** (114÷173)	43** (36÷50)	63** (50÷76)	50** (44÷58)
5[d]		*OLS*	*(fuel)*	*124 (111÷138)*	*-74 (-91÷-51)*	*-311 (-348÷-273)*	*-117 (-13÷-99)*
6[d]		*PW*	*(fuel)*	*8 (-4÷20)*	*26 (5÷47)*	*63 (27÷99)*	*25 (4÷47)*
7	First differences	OLS	√	106** (64÷147)	36** (27÷45)	61** (47÷73)	42** (33÷51)
8		PW	√	106** (67÷144)	36** (27÷45)	61** (47÷74)	42** (33÷50)
9		OLS		143** (114÷173)	41** (32÷49)	63** (50÷77)	46** (38÷54)
10		PW		143** (113÷174)	40** (32÷49)	63** (50÷77)	45** (37÷53)
11[d]		*OLS*	*(fuel)*	*9 (-3÷22)*	*29 (6÷52)*	*61 (2÷-98)*	*38 (14÷61)*
12[d]		*PW*	*(fuel)*	*8 (-4÷21)*	*29 (5÷53)*	*62 (25÷99)*	*37 (14÷60)*

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.
d) Estimates in italics refer to pass through rates for fuel costs.

3. Impact of CO_2 emissions trading on wholesale power market shares in the Netherlands

This chapter analyses the potential effects of CO_2 emissions trading on the competitiveness of the Dutch power sector, particularly on changes in the wholesale market shares of the major power producers in the Netherlands. This analysis is based on scenario runs by means of the model COMPETES as outlined in Sijm, et al. (2005). In this chapter, the analysis is focussed on a discussion and comparison of total production market shares in six scenarios, while Appendix B analyses changes in market shares during different load periods - such as peak or off peak hours - in each of these scenarios. These six scenarios refer to two basic or 'extreme' market structures, i.e. perfect competition (PC) and oligopolistic competition (ST), each distinguished by three scenarios, including:

- A scenario without emissions trading, i.e. the price of CO_2 is zero (PC0 and ST0).
- A scenario with emissions trading at a price of 20 €/tCO_2 and a price elasticity of demand of 0.2 (PC20 and ST20).
- A scenario with emissions trading at a price of 20 €/tCO_2 and a zero elasticity of demand in the PC scenario (PC20-ze) and a low elasticity of 0.1 in the ST scenario (ST20-le).

In the COMPETES model, opportunity costs of CO_2 are treated as 'real' costs - even if allowances are allocated for free - and, hence, affect the operational production decisions of power generators, depending on a set of drivers and constraints. As far as the overall cap - and, therefore, the price of a CO_2 emission allowance - is not changed, these decisions are, in first instance, not affected by any change in the allocation of CO_2 emission allowances to the power sector, such as a more stringent allocation of free allowances or auctioning a part of total available allowances to the power sector. Such changes in the allocation of CO_2 emission allowances, however, may affect investment decisions and, hence, changes in market shares in the long run. These dynamic aspects, however, are not part of the static model COMPETES and, hence, will not be treated in the present chapter but further addressed in the next chapter dealing with certain policy options to change the allocation of emission allowances to the power sector.

Below, in Section 3.1, first of all the drivers and constraints of changes in market shares due to CO_2 emissions trading are discussed briefly. Subsequently, such potential changes in the Dutch wholesale market are analysed in Section 3.2 by means of the six scenarios mentioned above.

3.1 Drivers and constraints of market shares in the power sector

Below, a number of drivers, constraints and other factors relevant to the dynamics of market shares in the power sector are identified. These factors include:

- *Capacity limits.* Upper capacity limits form an absolute limit to the market share.
- *Fuel mix.* The exploitation of carbon intensive technologies, like coal-based generation, will suffer strong cost-increases due to CO_2 emissions trading, thereby affecting the associated production and sales of power. As indicated by Figure 3.1, there are major differences in fuel or technology mix among the major power producers in the countries covered by the COMPETES model (Belgium, France, Germany and the Netherlands).[11] Hence, a change in CO_2 costs due to emissions trading may have a significant effect on Dutch market shares of these producers, including exporters of power to the Netherlands.

[11] In addition the major power companies, Figure 3.1 also includes the so-called 'competitive fringe' of the countries involved (denoted as Comp_Belgium, Comp_France, etc.). The competitive fringe refers to the group of (smaller) producers in a country that behave competitively (i.e. as price takers) even if the major power companies behave strategically (i.e. as oligopolistic price setters).

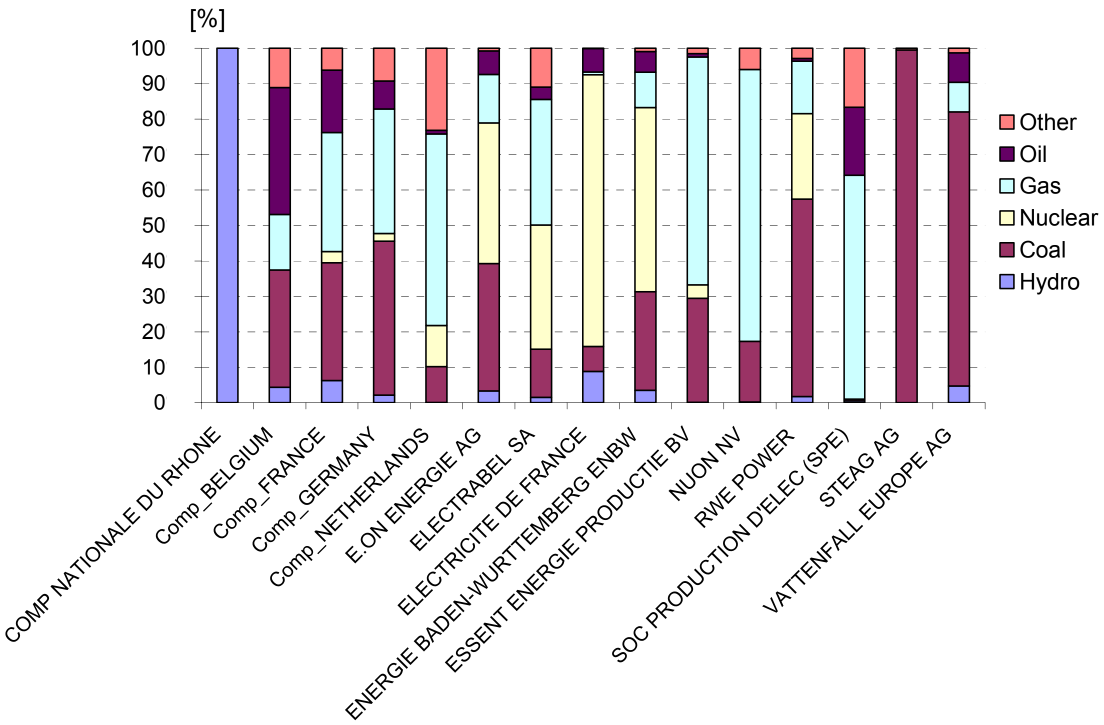

Figure 3.1 *Fuel mix power producers in countries covered by the COMPETES model (Belgium, France, Germany, and the Netherlands*

- *Exchanges between national markets.* Markets served by a carbon-intensive fuel mix will face stronger increases in power price than those served by a carbon-efficient market portfolio. These shifts in price relations between markets will alter import and export patterns and thus relative market shares within the market of interest.
- *Demand elasticity.* Demand is modelled to be price sensitive, so that demand will slightly diminish under (CO_2-induced) price increases at the expense of the relative market share of the marginal or strategic producers.
- *Strategic bidding.* Contrary to competitive bidding, where producers aim to maximise market share by minimizing production costs for any output level, strategic bidding involves maximisation of profits by a trade-off between two profit drivers. Profits can be increased by lowering output levels and increasing price, or by increasing output while maintaining price levels or decreasing them only marginally.

3.2 Scenario analysis

In this section, the development of Dutch wholesale market shares of all power companies operating in the region covered by COMPETES is evaluated. Relative market shares are evaluated so that one should realise that in case of changing total demand, absolute market shares may be retained while relative market shares change (see Figure 3.2 for an overview of the total demand - or market sales - for the six scenarios analysed in the present chapter).

3.2.1 Perfect competition

As noted, three scenarios are presented within the PC-framework (PC0, PC20, and PC20-ze). Under the assumption of perfect competition, several companies such as E.ON, Electrabel and ENBW, turn out to be able to displace a significant share of the supply offered by NUON and the competitive fringes in France, Germany and the Netherlands due to the introduction of CO_2 pricing (see Figure 3.3). The winners in this case are all parties with a significant amount of nuclear power production facilities. On the other hand the companies that lose market share are either Dutch-based and relying on gas-fired generation capacity even in off peak hours or it involves foreign parties offering coal-based capacity. Before emissions trading, the national gas-fired plants were able to compete with foreign nuclear power due to the import costs of electricity (which are significant). After the introduction of emissions trading, an increase of costs for CO_2 allowances associated with gas-fired power production turns the technology less competitive (particularly for NUON and the Dutch competitive fringe).

Figure 3.2 *Total power sales in the Netherlands*

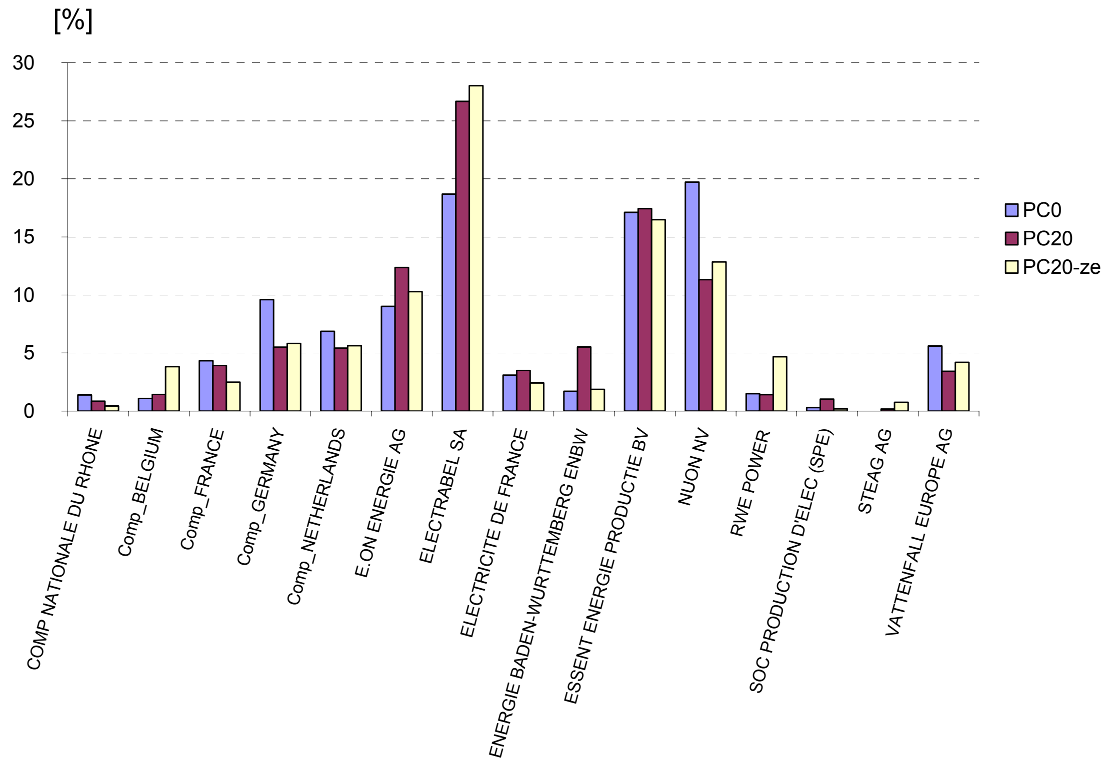

Figure 3.3 *Changes in wholesale power market shares in the Netherlands under different perfect competition scenarios*

Coal-based power generation becomes significantly more costly due to CO_2 pricing. Even though Dutch based coal-fired capacity remains a lower cost technology than gas-fired capacity, the imports of coal-fired capacity may become less attractive as import costs have to be paid as well (this applies particularly to the French and German competitive fringe).

Finally, in case of a zero demand elasticity in the PC-scenarios, the marginal producers gain market shares at the expense of the intra-marginal producers. Since all producers that lose relative market share upon introduction of CO_2 pricing produce at the highest cost, these parties gain some market share if demand is inelastic. The exception is Electrabel that apparently is positioned as a marginal producer for a substantial part of the time as well.

3.2.2 Oligopolistic competition

As noted, the cases for oligopolistic competition have been analysed on the basis of three scenarios: two scenarios with a price elasticity of 0.2 (ST0 and ST20) and one scenario with a low price elasticity of 0.1 (ST20-le).

The 0.2 elasticity scenarios show a striking difference in sensitivity to the cost of CO_2 emissions trading with the former perfect competitive scenarios. This is a direct consequence of the difference in producer behaviour between the CP and ST scenarios. In the CP-scenarios, producer bids in marginal cost, which is directly affected by the introduction of CO_2 pricing. In the ST-scenarios, on the contrary, many producers bid in strategically. This implies that a supply bid is offered that maximises profits, i.e. the difference between the market price and the bidders´ cost curve. In other words the bidding behaviour is only partially dependent on the cost curve and changes thereof through CO_2 pricing.

Further, under the ST scenarios, Belgium shows the highest power prices of the markets covered due to the high degree of market concentration in this country. This implies that Dutch producers export power to Belgium, rather than vice versa.

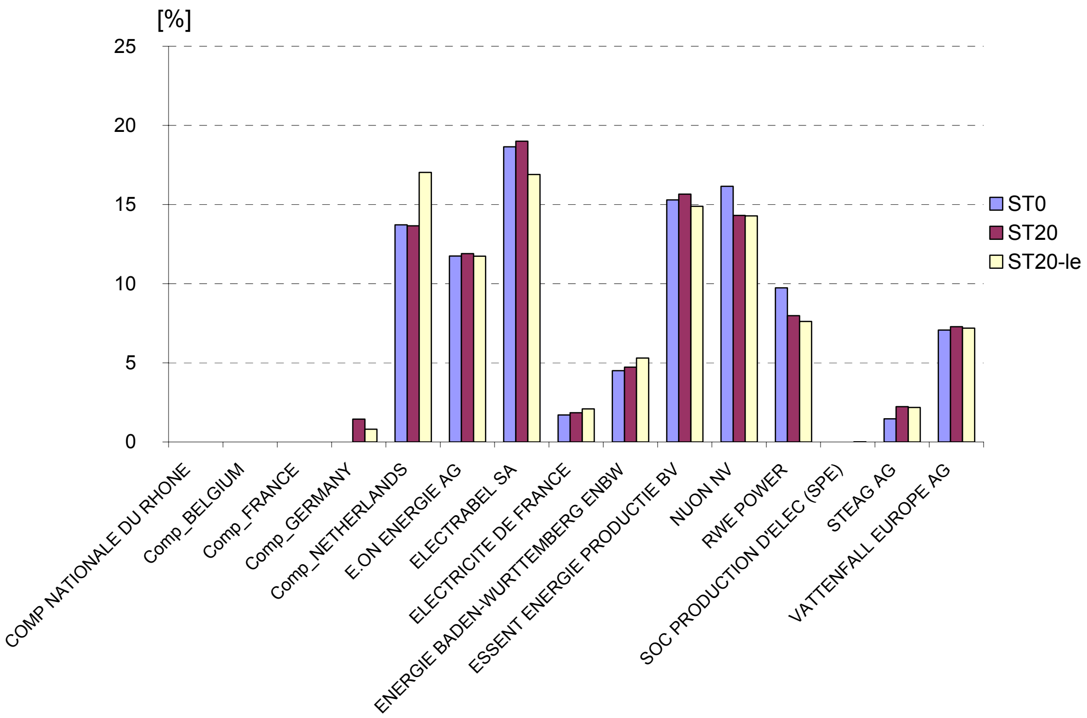

Figure 3.4 *Changes in wholesale power market shares in the Netherlands under different oligopolistic competition scenarios*

The most significant loss of market shares due to the CO_2 emissions trading scheme is faced by NUON and RWE and to a lesser extent by the competitive fringe in the Dutch market (see Figure 3.4). Both NUON and the Dutch competitive fringe are Dutch producers that are forced to rely on gas-fired plants at times even in the off peak hours. The increase of costs due to CO_2 pricing leads to a decreasing competitiveness of these units. Since the Dutch competitive fringe bids marginal cost to maximise market share it is slightly less sensitive to the CO_2 emission allowance scheme than NUON that bids strategically.

The German company RWE relies on coal-fired plants for marginal production during off-peak, whereas it relies on gas-fired plants for peak production. As the marginal costs of these units increase with the cost of CO_2 and the transmission costs associated with supply of the Dutch market increase as well due to increasing price differences between the Dutch and German markets, the production of this company is no longer as competitive and, hence, loss of market share is due.

Winners under the ST-scenarios are again the companies with substantial nuclear power supply in their respective portfolios.

Finally, in case of a lower demand elasticity of 0.1 only the Dutch competitive fringe increases its market share. In short the other relevant producers bid in to increase profits often at the expense of market share, while the marginal cost bidders maximise their respective output volumes.

4. Policy options to address adverse effects of CO_2 pass through

This chapter provides a qualitative analysis of two policy options to cope with certain adverse effects of passing through the opportunity costs of freely allocated CO_2 emission allowances, such as the incidence of windfall profits among power producers or higher electricity prices for major industrial consumers. This analysis includes the impact of these policy options on the competitiveness of major power consumers and producers, with special attention to the position of the Combined Heat and Power (CHP) sub-sector in the Netherlands. These policy options - which fit into the present framework of the EU ETS directive and a liberalised power market - concern particularly:

- A more stringent allocation of CO_2 emission allowances to the power sector together with a more lenient allocation to other industries participating in the EU ETS.
- A (partial) auctioning of the CO_2 emission allowances, especially to the power sector, and recycling the auction revenues to those industries most affected by EU ETS induced increases in power prices.

Both options will be considered from two perspectives, namely:

- The policy options will be implemented in both the Netherlands and neighbouring countries affecting the competitiveness of the Dutch power producers.
- The policy options will be implemented in the Netherlands only.

4.1 General considerations

Major initial assumptions

For both policy options, it is assumed that the size of the national caps - and, hence, the total amount of CO_2 emission allowances within the EU ETS - does not change and that a change in the allocation of these caps does not change the price of these allowances.[12] Moreover, in first instance, it is also assumed that a change in allocating CO_2 emission allowances to the power sector does not affect the price of electricity. This assumption is based on the consideration that, regardless the allocation method used, power producers will always *pass on* 100 percent of the CO_2 costs to their bid prices when making operational decisions, and that the extent to which these costs actually *work on* (higher) power prices depends on a complex set of market forces (but not on the allocation of CO_2 emission allowances).

Based on these assumptions, the following considerations and implications can be made.

Consequences for major power producers

Firstly, for the power producers, the allocation method does not affect their operational decisions as neither their marginal (CO_2) costs nor their marginal (power) revenues are changed. However, a change in the allocation to the power sector - either through a more stringent allocation of free allowances or by auctioning a part of the allowances needed - does reduce their

[12] It should be acknowledged, however, that the way emission allowances are auctioned may affect the price of these allowances, depending on the impact of specific forms of auctioning on the incidence of risks and (imperfect) information regarding emissions trading. This potential price effect, however, is neglected because the way in which CO_2 emissions allowances may be auctioned is still unknown (and, hence, the size of this effect is also unknown). Moreover, the amount of allowances auctioned is likely to be small during the second trading phase (2008-2012) since the share of allowances auctioned will be 10 percent or less of the national cap during this phase, while the number of countries opting for auctioning (the maximum amount of) emission allowances will likely be restricted. Therefore, the impact of auctioning on the price of a CO_2 emission allowance will probably be (negligibly) small.

windfall profits.[13] Therefore, in the long run, (changes in) the allocation of CO_2 emission allowances to the power sector may affect their investment decisions, particularly in three ways, i.e. (i) the total amount invested in new or upgraded generation capacity, (ii) the fuel mix of the new investments, and (iii) the location of the new investments, depending on whether installations in neighbouring, competing countries are subject to similar (changes in) allocation practices, as well as on the transmission capacity and costs for trading power between the countries involved.

By changing the incidence of windfall profits and, hence, investment patterns, a change in allocating CO_2 emission allowances - i.e. less grandfathering to the power sector - may in the long run lead to higher power prices due to (i) less generation capacity and, hence, a higher scarcity rent to power production, (ii) higher transmission costs, if power is imported, and/or (iii) higher capital costs (since less profitable companies have to finance a larger part of their investments by external loans and, hence, have to pay a higher interest rate on their capital investments). However, these long-run or dynamic effects are, in principle, independent of the *specific* allocation method (i.e. auctioning versus stringent allocation) as long as the price of a CO_2 emission allowance and the amount of allowances grandfathered to power companies do not depend on the specific allocation method used.

Consequences for power intensive industries

Similarly, for the power intensive industries and other major electricity users participating in the EU ETS, the specific allocation method used does, in first instance, not affect their operational decisions as long as the CO_2 and power prices remain the same. The overall profits of these users, however, depend on the allocation method, including the way they are compensated for the pass through of CO_2 costs to power prices. If major power users are compensated by a lenient allocation - in the sense that they get extra allowances - their profits will improve compared to a less lenient allocation. Whether the additional allowances granted will compensate for the extra costs of ETS-induced increases in power prices depends on the revenues of the allowances (i.e. additional amount times CO_2 price) and the higher costs of power use (i.e. total consumption times price increase).

A potential drawback of compensating power users for ETS-induced increases in electricity prices by a lenient allocation of emission allowances may be that power users who can easily pass on their higher electricity costs into their outlet prices will be compensated twice, while users who can not pass on these costs may be undercompensated. Moreover, power users who can easily pass on their higher electricity costs are most likely also able to pass on the opportunity costs of their grandfathered allowances (and, hence, realise windfall profits accordingly). It may be questioned why power users who can pass on electricity (and CO_2) costs should be compensated for higher power prices by means of a lenient allocation of CO_2 emission allowances.

A related disadvantage of compensating major power users by means of a lenient allocation is that high emitters, but low power users, may be overcompensated while low emitters, but high power users, may be undercompensated. On the other hand, allocating allowances in proportion to power consumption may provide a perverse incentive to higher electricity use. Another drawback is that major power users *not* participating in the EU ETS - notably the aluminium producers - do not get any compensation for higher power prices since they do not receive any allowances at all.

Moreover, in principle, allocation is not meant as an instrument to compensate industries for higher power prices (apart from the fact that higher power prices are an intended, rational and efficient effect of climate policy in general and emissions trading in particular, regardless the

[13] Assuming some 40 Mt of CO_2 emissions by the Dutch power sector per year and an average CO_2 price of 15 €/tonne, 10 percent less grandfathering implies a cost and, hence, a loss (or less windfall profits) of 60m Euro if CO_2 and power prices do not change due to a change in allocating the national cap (compared to an initial windfall profit of 300m Euro, assuming 100 percent grandfathering and a pass-through rate of 50 percent).

allocation method used). Therefore, using a lenient allocation to major power users in order to compensate them for ETS-induced increases in power prices does not seem be an appropriate approach and can be highly questioned for a variety of reasons.

On the other hand, if major power users are compensated by recycling the revenues of allowances auctioned to power generators, the net impact of the EU ETS on the performance of these users depends on the induced higher costs of electricity consumption, the amount of grandfathered emission allowances, the extent to which they can pass on CO_2 and power costs to their outlet prices, the mechanism by which the auction revenues are recycled, and the target groups of these revenues. Depending on these variables, some groups of power users may be overcompensated, while others may be undercompensated or not compensated at all.

The major advantage of compensating through recycling auction revenues is that, in principle, all (major) power consumers can be compensated - including those outside the EU ETS - and that the mechanism to compensate these consumers can be rather general and simple, without perverse incentives on energy use or CO_2 emissions, for instance by using the auction revenues to lower general income and business tax rates. However, if only a small amount of emission allowances is auctioned, the revenues will most likely not be sufficient to fully compensate all (major) electricity consumers, while the energy/power-intensive industries will probably be undercompensated and benefit more from another, more targeted approach (for instance, either by targeting auction revenues only to those industries or by compensating these industries by means of the previously mentioned approach of a lenient allocation of emission allowances to these industries).

In addition, recycling auction revenues by lowering general income and business tax rates would also - or even mainly - benefit high income groups and relatively profitable firms which hardly suffer from higher electricity prices, such as banks or insurance companies. An alternative would be to recycle auction revenues by lowering the energy tax (called 'EB'). This option, however, would mainly favour small power consumers, notably low-income households, but not offer a solution to major industrial users since they are exempted from paying the EB.

More generally, similar to the case of compensation by means of a lenient allocation, it may be questioned why major power users should be compensated at all for ETS-induced increases in power prices as these increases are an intended and rational effect of the ETS to reduce CO_2 emissions in an optimal way, while some power users may be able to pass on power (and CO_2) costs into their outlet prices (and, hence, realise windfall profits due to grandfathering).

Four analytical cases

The considerations and implications outlined above are based on the initial assumption that power (and CO_2) prices are not affected by changes in the allocation of the overall cap of the EU ETS. However, as already observed, power prices may become relatively higher in the long run due to the dynamic effects of less grandfathering to the power sector on its investments in new or upgraded generation capacity. Moreover, the empirical knowledge on the (static) relationship between allocation and power prices is still weak and, hence, it could also be assumed that less grandfathering to the power sector will result in a higher *'work-on'* rate of CO_2 costs and, therefore, higher power prices. If this would indeed be the case, granting less free allowances to the power sector - either through a more stringent allocation or by auctioning part of the allowances needed - will result in an (additional) welfare transfer from power consumers to producers compared to a situation in which a change in allocation does not lead to higher power prices.

Overall, if it is assumed that the *specific* method to allocate less grandfathered allowances to the power sector (i.e. stringent allocation versus auctioning) does not have a specific impact on power prices - and, therefore, can be analysed similarly - four different cases can be distinguished with regard to the implications of a change in allocating CO_2 emission allowances for the main groups of stakeholders in the Netherlands:

- Case A: less grandfathering to the power sector in both the Netherlands and competing, neighbouring countries, with no impact on power prices.
- Case B: less grandfathering to the power sector in the Netherlands only, with no impact on power prices.
- Case C: less grandfathering to the power sector in both the Netherlands and competing, neighbouring countries, with induced higher power prices in these countries.[14]
- Case D: less grandfathering to the power sector in the Netherlands only, with induced higher power prices in this country.

These cases are analysed in the following section, notably with regard to the implications of changes in the allocation of CO_2 emission allowances for the major groups of stakeholders in the Netherlands, i.e. major electricity users versus power producers participating in the EU ETS. Within the latter group of power producers, special attention is paid to the implications of less grandfathering for the operators of so-called Combined Heat and Power (CHP) installations as they represent a significant, politically sensitive part of the power sector in the Netherlands (see Appendix C for some specific information on the relationship between CO_2 emissions trading and the CHP sector in the Netherlands).

4.2 Specific cases of policy options and implications

Case A
Less grandfathering to the power sector in both the Netherlands and competing, neighbouring countries, with no impact on power prices

In brief, the major implications of this case for the main groups of stakeholders in the Netherlands include:

A.1 Major power producers
In this case, as outlined above, major power producers in the Netherlands - and competing, neighbouring countries - will loose part of their (windfall) profits due to less grandfathering. While this will probably hardly affect their short-run operational decisions, it may have an impact on the investment decisions in new or upgraded generation capacity. Table 4.1 provides an overview of present investment schemes by Dutch-based power generators, while Table 4.2 presents an estimate of the annual CO_2 emissions of these schemes.

[14] It is assumed that the induced increase in power prices is more or less equal in all countries considered. If this increase differs significantly between the countries involved, the implications for the main groups of stakeholders may be similar - although less outspoken - to those of case D.

Table 4.1 *Investment schemes by major power generators in the Netherlands*

Company	Site	Type of plant	Size	In operation (planned)
Delta	Sloe area	Gas Combined Cycle	820 MW_e (2 units of 410)	2008
Essent	Maasbracht	Gas Combined Cycle (in combination with old unit)	+280 MW_e (upgrade existing plant plus lifetime extension)	2008
E.ON	Maasvlakte	Pulverised coal	1100 MW_e	2012
Electrabel	Flevopolder	Gas Combined Cycle	800-900 MW_e (2 units)	2009
	Rotterdam	Coal/biomass fired plant	600-800 MW_e	2011-2012
Eneco	Rotterdam	Gas Combined Cycle	840 MW_e	2009
Nuon	Still unknown	Integrated Coal Gasification Combined Cycle (IGCC, multi-fuelled: coal, biomass, gas)	1200 MW_e	2011

Table 4.2 *Estimated annual CO_2 emissions of new investment schemes in the Netherlands*

Company	Project	Capacity [MW]	Biomass capacity factor	Full-load hours	Non-biomass Production [GWh]	Emission factor [tCO_2/GWh]	Efficiency	CO_2 emissions [ktonne/a]
Nuon	Magnum	1200	0.3	6900	5796	341	0.47	4205
Electrabel	Flevo Centrale	800	0	6500	5200	202	0.58	1811
Electrabel	Coal/Bio	600	0.3	7200	3024	341	0.45	2291
Delta	Sloecentrale	820	0	6500	5330	202	0.58	1856
Eneco	New gas	840	0	6500	5460	202	0.58	1901
Essent	Claus-upgrade	280	0	6500	1820	202	0.58	634
E.on	Maasvlakte	1100	0	6800	7480	341	0.46	5544

The impact of emissions trading in general and the allocation of CO_2 allowances in particular on investments in new or upgraded generation capacity depends on the amounts of CO_2 emissions of the new installation, the CO_2 price of an emission allowance on the EUA market, the extent to which CO_2 costs are passed on to higher power prices, the allocation of emission allowances to newcomers, and - above all - the *expectations* of potential investors/newcomers with regard to these factors, given the long-term character of the new investment schemes and the large uncertainties concerning these factors (besides the role and uncertainties regarding other factors such as future fuel costs or power prices).

In theory, the best allocation option would be to grant no free allowances at all to new investments as this would provide the most optimal incentive to reduce CO_2 emissions in the long run. The second-best option would be to grant free allowances to newcomers based on a certain CO_2 benchmark as this would favour less carbon-intensive investments. Based on current practice, however, it is assumed that grandfathering to new investments in the Netherlands will be fuel-specific, i.e. carbon-intensive plants will receive proportionally more free allowances than carbon-extensive installations. This implies that, with 100 percent grandfathering, NUON's Magnum project will receive an annual equivalence of 4.2 Mt of CO_2 allowances for free, while ENECO's new CCGT installation will get 1.9 Mt of CO_2 allowances and Delta's intended nuclear plant will acquire nothing (see last column of Table 4.2).

Based on the emission estimates of Table 4.2, 10 percent less grandfathering implies that NUON's Magnum project will get less allowances for free, equivalent to an amount of 0.39 Mt CO_2. At an assumed average CO_2 price of 15 €/t, this implies a cost (or loss) of almost € 6 million per year. Although this is a substantial amount, for an investment project of 1 billion Euro - with an assumed rate of return before taxes of 12-15 percent and fuel costs of about half a million Euro *per day* - one may wonder whether it really jeopardizes such a project.

However, as noted above, investment decisions are usually not based on actual values of present policies and related factors, such as the present share of grandfathering in total allocation, but rather on investors' expectations regarding these factors. If it is assumed that less grandfathering meets the expectations of investors, it will not affect their planned investments. However, given the long-term character of investments in new generation capacity and the large uncertainties regarding future allocation, CO_2 prices, pass-on rates, etc., it is more reasonable to assume that investors hardly or not account for these issues and just base their investment decisions on non-/pre-ETS factors such as fuel costs and power revenues (or highly discount potential CO_2 costs and revenues after 2012). In that case, less grandfathering is not (or hardly) accounted for, implying that it will raise cost and reduce profits once it becomes due and, hence, having an adverse - but probably small - impact on new investments, as discussed above.

Finally, even if less grandfathering leads to less new investments in generation capacity, this impact will probably be temporarily since less investments implies more future scarcity and, hence, higher power prices, inducing more future investments. Therefore, less grandfathering will at the most lead to some delay of new investments in generation capacity but most likely not to a cancellation of these investments.

It should be emphasised, however, that the reasoning above is partly speculative as presently little is known on investors' expectations and decision-making under uncertain climate policy decisions.

A.2 CHP operators

In general, CHP operators participating in the EU ETS will face similar effects due to less grandfathering as the major power producers noted above. In order to encourage CHP production in the Netherlands, however, operators get a subsidy per MWh generated, which is partly dependent on the allocation of CO_2 emission allowances in the sense that benefits due to the overallocation of such allowances is partly - i.e. 50 percent - accounted for when determining the subsidy per MWh of CHP generated electricity (for details see Appendix C). Therefore, if less CO_2 emission allowances are grandfathered to CHP operators they will be compensated for 50 percent by higher subsidies.

However, the present CHP subsidy scheme is under discussion, which may result in a new scheme, for instance a CHP subsidy system that is restricted to newcomers only (or that does not account for the impact of allocating CO_2 allowances allocation on CHP's financial performance). In that case, less grandfathering to CHP producers will not be partly compensated by higher subsidies, resulting in less profits for CHP producers and, hence, less output and/or investments by these producers. If one wants to avoid these adverse effects on the CHP sector, operators in this sector can be exempted from the policy option to grandfather less allowances to the power sector as a whole (although CHP generators - just as other power producers - also benefit from the ETS-induced higher electricity prices and the resulting windfall profits).

More generally, one can state that the primary intention of the EU ETS is to reduce CO_2 emissions at the lowest social costs, while the primary aim of the CHP subsidy scheme is to encourage a socially optimal level of CHP production. Therefore, if one is interested to support the CHP sector - besides the already higher power prices and resulting windfall profits induced by emissions trading based on grandfathering - it is generally better to rely on (higher) direct output subsidies than on a lenient allocation of CO_2 emission allowances to this sector.

A.3 Major power users

Major power users can be compensated for the ETS-induced higher electricity prices by either a more lenient allocation of CO_2 emission allowances to these users - as far as they participate in the EU ETS - or by recycling the revenues of allowances auctioned to power producers to these users (although both options can be questioned, as outlined in Section 4.1). Even if in both policy options the amount of compensation is the same for the group of major power users as a whole, different sub-groups of these users may prefer one of these options (or even different variants within each of them), depending on whether it serves their interest or not. In general, one can say that high emitters, but low power users participating in the EU ETS will prefer a general lenient allocation of emission allowances while low emitters, but high power users - notably non-participants of the EU ETS - will prefer a recycling of auction revenues. The specific implications of the two policy options for different sub-groups of major power users, however, depend on the details and specific implications of each option.

Case B
Less grandfathering to the power sector in the Netherlands only, with no impact on power prices

B.1 Major power producers
The major difference of this case compared to case A is that it will deteriorate the position of Dutch-based generators related to their foreign competitors as these generators have to buy more CO_2 allowances to cover their emissions and, hence, make less (windfall) profits. Less grandfathering to Dutch-based power producers, however, does not affect their (short-run) operational decisions since CO_2 and power prices do not change. In addition, it is unlikely that it will have a decisive, lasting impact on their investment decisions (as discussed under case A.1 above), let alone on the location of new investments in the sense that these investments would be relocated to neighbouring countries and the generated power exported to the Netherlands, mainly for three reasons.

Firstly, additional power exports to the Netherlands is restricted by available transmission capacities at the Dutch border. Secondly, additional (windfall) profits due to a higher rate of grandfathering in neighbouring countries are reduced by the transmission costs of exporting power to the Netherlands (these extra costs are likely even higher than the profits concerned). Finally, it is highly uncertain whether a higher rate of grandfathering in neighbouring countries will last for a significant part of the lifetime of investments in new generation capacity and, hence, investors would probably not account for such a constant higher rate.

B.2 CHP operators
Compared to the major power producers, CHP operators will suffer less from less grandfathering to the power sector in the Netherlands only since (i) less grandfathering to CHP operators is partly compensated by higher subsidies to these operators in the present scheme, and (ii) even if the present CHP subsidy scheme is abolished for incumbent operators, it will most likely be maintained for newcomers, i.e. operators investing in new or upgraded CHP capacity. Therefore, the impact of less grandfathering on new investments by CHP operators is probably small.

B.3. Major power consumers
Compared to case A, the implications of case B for the major power consumers are likely to be zero since it is assumed that there is no change in CO_2 and power prices, while the way these consumers are compensated does not change either.

Case C
Less grandfathering to the power sector in both the Netherlands and competing, neighbouring countries, with induced higher power prices in these countries.

C.1 Major power producers
The crucial difference of this case, compared to case A, is that a change in the allocation of CO_2 emission allowances will lead to higher power prices, either by inducing a higher 'work-on' rate of CO_2 costs to power prices or by reducing new investments in generation capacity, resulting in (temporarily) higher power prices due to a higher scarcity rent. The major implication for the power producers is that this price increase will (partly) nullify the effects of less grandfathering

as they will get higher revenues and, hence, additional (windfall) profits. The extent to which this may happen is difficult to say as there is hardly any empirical evidence on this issue. However, if one assumes that 10 percent less grandfathering (say from 95 to 85 percent of the allowances needed) leads to a 5 percent higher ‘work-on’ rate (say from 45 to 50 percent), then the overall effect of less grandfathering on windfall profits in the present case is only half compared to cases A or B.

C.2 CHP operators
The implications of case C for the CHP operators in the Netherlands depend largely on the specifics of the (new) CHP subsidy system. In the present system, changes in power prices are accounted for when determining CHP subsidies (for both incumbents and newcomers). So, if a change in the CO_2 allocation system leads to higher power prices, it results in lower subsidies. Hence, there is hardly any change in the overall performance of CHP operators (both incumbents and newcomers). However, if the new CHP subsidy is restricted to new entrants only, then the implications of case C for the incumbent CHP generators will basically become the same as for the major power producers outlined in the previous Section C.1.

C.3. Major power consumers
It will be clear that the implications for major power consumers of a higher electricity price due to less grandfathering to the power sector are opposite to those for the producers: because of the higher electricity prices major power users are faced by higher costs, which - depending on the extent to which they can pass on these costs - will result in less profits (or higher losses) than in cases A or B.

Case D
Less grandfathering to the power sector in the Netherlands only, with induced higher power prices in this country

D.1 Major power producers
The major implication of this case, compared to case B, is that potential adverse effects of less grandfathering - if any - on the amount/timing of new investments will be reduced. However, similar to case C, the extent of this reduction is hard to say due to lack of empirical data on this issue, but if one assumes that 10 percent less grandfathering leads to a 5 percent higher work-on rate, then the overall effect of less grandfathering on windfall profits - and, hence, new investments - is only half the effect of case B.

It should be noted, however, that while during peak hours the power price in the Netherlands is set by a domestic marginal generator, during off peak hours it is often determined by power imports. Therefore, if the policy option of less grandfathering is restricted to the Netherlands only, it can be reasonably assumed that it may increase (temporarily) peak power prices in the Netherlands, but not that it may increase off peak prices similarly.

D.2 CHP operators
The impact of case D on the financial performance of CHP generators is most likely even smaller than outlined above in case B, although in the end it depends mainly on the specifics of the CHP subsidy system, as discussed in case C above.

D.3. Major power consumers
The implications of case D for the major power consumers in the Netherlands include particularly that the off-peak prices may increase less compared to case C.

4.3 Summary and conclusions

In order to reduce the adverse effects of passing through the opportunity costs of grandfathered CO_2 emission allowances, notably the incidence of windfall profits to power producers and higher electricity prices to power consumers, two related options can be considered, i.e. less grandfathering to the power producers by either a more stringent allocation of CO_2 emission allowances to these producers - resulting in more purchases of allowances on the market - or auctioning a part of their allowances needed, and compensating power users for ETS-induced increases in power prices by either a more lenient allocation of CO_2 emission allowances to these users - resulting in less purchases or more sales of allowances on the market - or recycling to these users the revenues of allowances auctioned to the power producers. The major considerations and implications of these options for the major stakeholders involved can be summarized as follows:

Major power producers

Less grandfathering to power generators implies less windfall profits to these generators. However, assuming that less grandfathering to power producers does not affect CO_2 and/or power prices, it does not affect their (short-run) operational decisions, as their operational profits do not change. On the other hand, if it is assumed that less grandfathering leads to higher power prices, the impact on operational/windfall profits and, hence, operational decisions is affected accordingly (i.e. profits and production will be higher). Moreover, less grandfathering to power producers may affect their investment decisions - through its impact on power prices and/or (windfall) profits - but its impact is likely (negligibly) small and temporary, notably if CO_2 prices are low or the reduction in grandfathering is relatively small, since:

- Investment decisions are primarily based on other, more important factors such as long-term power prices and fuel costs.
- Issues such as CO_2 prices, pass-through rates to power prices, allocation of CO_2 emission allowances, etc., are probably abstracted from or highly discounted for future years given the long-term character of investments in new generation capacity and the present high uncertainties regarding future climate policies in general and emissions trading in particular.
- Even if less grandfathering leads to fewer investments in generation capacity, this impact will probably be temporary since less investments now will lead to more scarcity and higher prices on the power market, inducing more investments in the future.

Therefore, less grandfathering will at the most lead to some delay of new investments in generation capacity but most likely not to a cancellation of these investments.

Finally, if less grandfathering to the power sector is only implemented in the Netherlands - and not in neighbouring, competing countries - the impact on relocating investments from the Netherlands to these countries (and exporting power from these countries to the Netherlands) is most likely very small or even absent. Besides the reasons mentioned above, this can be attributed to the consideration that potential differences in windfall profits due to differences in grandfathering among countries are nullified by transmission costs, other (physical or institutional) constraints and uncertainties whether these differences in grandfathering - or other policy induced CO_2 issues - will last in the future. This applies particularly when the difference in rate of grandfathering between the Netherlands and competing countries is small (say 10-20 percent of total allowances needed). The potential impact on relocating investments may be more significant, however, if the difference in grandfathering between the countries concerned becomes more substantial (say, 50 percent or more), and the transmission constraints and costs of exporting power are reduced significantly.

CHP operators

In first instance, the impact of less grandfathering on CHP operators in the Netherlands is similar to its general impact on major power producers outlined above. In second instance, however, its impact depends particularly on the specifics of the (new) CHP subsidy scheme as the impact of less grandfathering on overall (windfall) profits and power prices may be accounted for when determining CHP subsidies to incumbent and/or new operators. Moreover, policy makers can decide to exempt CHP operators from measures to reduce grandfathering to the power sector in general and continue a policy of lenient allocation of CO_2 emission allowances to CHP operators. This option may be questioned, however, since (i) CHP operators - just like the major power producers - also benefit from ETS-induced increases in power prices, grandfathering and resulting windfall profits, (ii) the primary aim of allocating CO_2 emission allowances is to enhance the social benefits and credibility of the ETS and not to favour the financial interests of specific groups, and (iii) if policy makers choose to support CHP, it is generally better to use a specific, well-defined and targeted subsidy scheme than to rely on a general, lenient allocation of CO_2 emission allowances to (incumbent and new) CHP operators.

Major power users

As said, major power users may be compensated for ETS-induced increases in power prices by either a lenient allocation of CO_2 emission allowances to these users or by recycling to them the revenues of allowances auctioned to power producers. In general, both compensation options can be questioned since:

- Higher power prices are an intended, rational effect of emissions trading to reduce CO_2 emissions in an optimal way - regardless the allocation method used - and, hence, there is no general need to compensate these higher power prices.
- some major power users may be able to pass on higher power prices - and CO_2 costs of their grandfathered allowances - and, hence, there is no need to compensate these users.

More specifically, compensation through a lenient allocation to power users may be further questioned because of some additional, specific considerations, including:

- High emitters, but low power users, may be overcompensated while low emitters, but high power users, may be undercompensated.
- Allocating allowances in proportion to power consumption may provide a perverse incentive to higher electricity use.
- Major power users *not* participating in the EU ETS - notably the aluminium producers - do not get any compensation for higher power prices since they do not receive any allowances at all.
- Allocation is not meant as an instrument to compensate industries for higher power prices.

On the other hand, the major advantage of compensating through recycling auction revenues is that, in principle, all (major) power consumers can be compensated - including those outside the EU ETS - and that the mechanism to compensate these consumers can be rather general and simple, without perverse incentives on energy use or CO_2 emissions, for instance by using the auction revenues to lower general income and business tax rates. However, if only a small amount of emission allowances is auctioned, the revenues will most likely not be sufficient to fully compensate all (major) electricity consumers, while the energy/power-intensive industries will probably be undercompensated and benefit more from another, more targeted approach.

In addition, recycling auction revenues by lowering general income and business tax rates would also - or even mainly - benefit high income groups and relatively profitable firms which hardly suffer from higher electricity prices, such as banks or insurance companies. An alternative would be to recycle auction revenues by lowering the energy tax (called 'EB'). This option, however, would mainly favour small power consumers, notably low-income households, but not offer a solution to major industrial users since they are exempted from paying the EB.

Therefore, to conclude, options to compensate major power users for ETS-induced increases in electricity prices may be questioned as each option has certain shortcomings and drawbacks. In practice, a mix of different options may be preferable to compensate different target groups of electricity consumers, thereby partly mitigating the shortcomings and drawbacks of each option separately, for instance by a lenient allocation of CO_2 emission allowances to industrial power users and a lowering of energy taxes for households and other small consumers of electricity.

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Appendix A Statistical estimates of pass through rates

This appendix presents the results of several approaches to estimate the pass through rates of CO_2 emissions trading costs to the price of electricity, for the years 2004 and 2005 separately, based on year-ahead prices (see Tables A.1 up to A.4). In addition, this appendix explains the approaches that have been undertaken to the analysis of the empirical data to investigate the evidence of a statistical relationship between power prices and the costs of CO_2 associated with the production of power. Due to its technical nature, this may seem a less accessible discussion on the approaches applied. To facilitate accessibility for a less technical audience intuitive explanations have been provided in frames.

A.1 Mathematical model

The basic model assumption applied in the analysis of power sector data consists of the fact that power prices can be decomposed into various cost components. Firstly it is assumed that the CO_2 cost is a highly variable cost component of power production. Further it is assumed that fuel cost is a highly variable cost component. In the first part of the analysis it is assumed that fuel costs are fully covered by the power price (univariate analysis) while in the second part it is assumed that fuel costs are only partially reflected in the power prices (multi-variate analysis). Finally it is assumed that all other costs are constant in time. This component covers operational costs, costs associated with maintenance and the like. Note that profit margins may be a component of power prices, which are assumed constant over time as well.

A.2 Time windows

An important consequence of the model proposed above is that variations in the components that are assumed to be stable may compromise the mathematical analysis. As the likelihood of violations of these assumptions increases with an increasing period of analysis or time window - for example changes in profitability due to changing supply and demand relations, market concentration etc. - the validity of the analysis is increasingly compromised as well. This implies that the time windows considered should not be too wide.

On the other hand statistical estimates involve estimates based on datasets assumed to behave according to some functional relation with some uncertainty. The more uncertainty applies to these data points, the more uncertainty applies to the estimated parameters. To decrease uncertainty one needs to consider more data points, thus increasing the dataset and thus widening the time window considered. The dataset or time window to which the analyses are applied should be carefully selected against the background of this trade-off.

A.3 Univariate analysis

Application of univariate analysis assumes that power prices are determined by one driver with unknown impact, in this case CO_2 costs associated with power production. The analysis aims to find the impact of the CO_2 costs on the power price, ergo the amount of the CO_2 cost that is added to the power price. This amount is expressed in the average percentage of the CO_2 cost added to the power price and is called the pass through rate of CO_2 costs.

Fuel prices have an impact on the power prices as well, but it is assumed that this impact is known a priori. Notably it is assumed that the pass through rate of fuel cost variations is 100%. As this impact is known it can simply be subtracted from the power price yielding the spark or dark spread. Therefore the following analysis does not relate the power price to CO_2 costs, but instead aims to find the relation between spark/dark spread and CO_2 prices.

A.3.1 Time series analysis

The initial approach to the estimation of CO_2 pass through rates was developed within the framework of time series analysis. Time series analysis in general targets the estimation of inherent patterns in a particular time series, like stationarity, trends, seasonality and the like. Effectively one does not articulate the assumption that a particular driver (for example gas prices) is present but assumes that some recurring patterns are typical to the time series at hand. Two typical classes of such patterns are patterns recurring over time in absolute and relative sense. Absolute recurrence is shown for example by a time series that is constant over time, increasing with a constant rate over time or showing recurring fluctuations over time (low in summer, high in winter). These are all examples of stationary series with a trend. Relative recurrence relationships relate behaviour of the time series at some point in time to some other point in time. For example if the time series shows a high value at time t given by S_t, than S_{t+1} will also be high. In both cases the dataset is assumed to be ordinal, ergo some data point of the time series is related to one or more other data points in the time series.

The equation describing the spark/dark spread S_t as a function of CO_2 costs C_t^{CO2} and some constant component is given by:

$$S_t = \beta_1 + \beta_2 C_t^{CO_2} + \varepsilon_t$$

Since time series analysis is fit for the estimation of the relationship between two time series, the method has been applied to the single time series of the spark/dark spread minus the CO_2 costs, i.e. the clean spark/dark spread:

$$(S_t - \beta_2 C_t^{CO_2}) = \beta_1 + \varepsilon_t$$

At this point the contribution β_2 of C_t^{CO2}, i.e. the pass through rate, is not known. It is assumed that a clean or carbon corrected spark spread is stationary however, while the individual series do not need to be stationary, so we are possibly dealing with two cointegrated variables. In other words the pass through rate β_2 is given by the linear estimation of the clean spark spread that is constant in time. The procedure to estimate such a pass through rate effectively involves adjusting the pass through rate until stationery has been reached. The estimation can be performed by a least squares approach.

Intuition: If the clean spark spread can be represented by a straight line in time, the correct pass through rate will yield a horizontal straight line.

The approach sketched above has some limitations. Firstly it assumes that the clean spark/dark spread can be modelled by a linear function in time. A measure of the extent to which this assumption is valid is given by the R^2-values of the linear estimates of the clean spark/dark spreads. In the former analysis in Sijm et al. (2005) these values were generally within acceptable ranges, but in the current framework of the full 2005 time window, the R^2-values decreased significantly as the assumption of linear behaviour of the clean spark/dark spread was less applicable.

Intuition: If the clean spark spread cannot be represented by a straight line in time, the representative slope of the line is difficult to assess and is therefore not trustworthy. Estimating the pass through rate that yields a horizontal line representing the clean spark spread in time may not be trustworthy either.

A.3.2 Cross sectional analysis

Cross sectional analysis relaxes the assumption of ordinality of the time series involved. In other words the analysis no longer assumes a specific relation between members of the dataset. On the other hand it is assumed that some members of the dataset are partially or fully determined by one or more members of some other dataset or some members of various other datasets.

Intuition: Assume that power prices are high if the CO_2 costs are high, whereas power prices are low when CO_2 costs are low. The slope of the line passing through both points is defined by P^{high}-P^{low} divided by C^{high}-C^{low}, which is equivalent to the pass through rate of the CO_2 costs.

The mathematical model of the relationship between spark/dark spread on the one hand and the costs of CO_2 on the other does not change structurally upon this framing. However the data points are no longer interpreted as members of a time series but as members of a dataset, hence the index of the data points changes from *t* to *n*:

$$S_n = \beta_1 + \beta_2 C_n^{CO_2} + \varepsilon_n$$

The model assumes a linear relationship between spark spread and the cost of CO_2 as before. However, instead of assuming a linear relationship in time it assumes a linear relationship between the associated members of the two datasets. In other words, if the linear relationship is positive, ergo β_2 is higher than zero, S will be relatively high if C_n^{CO2} is relatively high, and S_n will be relatively low if C_n^{CO2} is relatively low. The estimation of the linear relationship is conducted by means of the ordinary least squares method (OLS)

An important drawback of pure cross sectional analysis is encountered in datasets that show heteroskedasticity. This phenomenon can be characterised as differing variance per data point. In the particular case of spark spreads or power prices a specific form of heteroskedasticity is present, namely first-order serial correlation, which is described as the case in which errors in one time period are correlated directly with errors in the ensuing time period:

$$\varepsilon_t = \rho\varepsilon_{t+1} + \upsilon_t$$

Where $0 < \rho < 1$

Various tests for such correlation exist, like for example the Durbin-Watson test. It involves a test on the residuals resulting from the OLS on the cross-sectional data. In all cases the DW-test shows strong evidence of the presence of first-order serial correlation.

Intuition: The cross sectional analysis assumes no time dependence of any of the datasets involved. However if power price is high at time *t* it is often also high at time *t+1*. Ignoring this fact leads to underestimation of the uncertainty in the derived pass through rate.

A.3.3 Cross sectional analysis with corrections for serial correlations

One approach to solve the problem of first-order serial correlation concerns the Cochrane-Orcutt procedure or the closely related Prais-Winston procedure. These methods sequentially estimate the OLS estimate of the cross-sectional data set followed by an estimation of ρ by regressing the residuals on their respective predecessors. Based on the estimate of ρ the original cross sectional data can now be corrected and the procedure is repeated. Repeatedly applying this procedure converges to a stable ρ and estimate of the parameter at hand, which indicates that a solution has been found.

Intuition: If time dependence exists this may be corrected so that the actual uncertainty in the pass through rates can be assessed.

Another commonly used approach used to solve the problem of serial correlation involves application of OLS to the first differences of the cross sectional data. This approach inherently assumes $\rho = 1$, which is generally not known to be the case a priori.

A.4 Multi-variate regression

The former applications inherently assumed a fuel pass through rate of 100%. For a number of reasons this assumption may be violated (in part these relate to the reasons leading to a CO_2 cost pass through rate of less than 100%).

Intuition: In the former section the pass through rate of fuel cost was set to 100%. In this section it is assumed that this pass through rate may be lower and both the pass through rates of fuel and CO_2 costs are estimated.

Multi-variate analysis allows for the estimation of pass through rates of multiple costs components. In this case the equation becomes:

$$S_n = \beta_1 + \beta_2 C_n^{CO_2} + \beta_3 C_n^{fuel} + \varepsilon_n$$

Where β_3 is the pass through rate of the fuel costs.

Application of multi-variate regression yields intuitively unlikely results of pass through rate above 100% for one driver whereas the other shows very low pass through rates, or the other way around, most notably in case of Dutch power prices during the peak hours on the one hand and gas prices and CO_2 costs on the other. Further these pass through rates are highly unstable in the sense that for different cross sections of the datasets analysed the pass through rates can differ heavily. This suggests the existence of collinearity between the two drivers at hand, namely gas prices and CO_2 costs. In other words these series are correlated, which may follow from the correlation matrix.

As a rule of thumb multicollinearity exists if correlation between the two drivers is higher than the correlation of either of the two variables with the dependent variable. Particularly for the case of Dutch peak hour power prices on the one hand and gas prices and CO_2 costs on the other this was indeed confirmed.

Intuition: As gas prices and CO_2 costs are so much alike there are no mathematical grounds to state if some change in power price is a consequence of changes in the gas price or of the comparable changes in the CO_2 costs and, hence, the approach provides no reliable estimates of the pass through rates.

A.5 Conclusions

Various approaches have been presented in the former sections with the intention to sketch their strengths and weaknesses for a broad audience. Based on these arguments, the most representative estimate can be identified.

Due to spurious correlations multi-variate analysis effectively disqualifies as a methodology and one will have to rely on the assumption that fuel costs are passed through for the full 100%. This can only be an overestimation, at cost of the estimated pass through rate of the CO_2 costs, particularly in case of spark spread analysis. Recall that gas prices and CO_2 costs are strongly related in mathematical sense, so that overestimation of the one implies underestimation of the other.

Finally, regarding the various approaches to univariate analysis assuming full pass through of fuel costs, the cross sectional analyses corrected for the serial correlations are the most reliable approaches.

Table A.1 *Estimates of pass through rates in Germany and the Netherlands, based on absolute values of the variables regressed*

Line no.	Period	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	Off-peak [%]	Germany Peak [%]	Off-peak [%]
1	2004	OLS		27	-12**	91**	-19**
				(0÷54)	(-20÷-3)	(79÷104)	(-29÷-9)
2		PW		-6	-9	12	0
				(-40÷28)	(-19÷15)	(-4÷28)	(-8÷8)
3		OLS	√	114**	21**	70**	10**
				(88÷141)	(12÷30)	(59÷81)	(0÷20)
4		PW	√	112**	18**	37**	56**
				(83÷141)	(8÷28)	(22÷54)	(-9÷20)
5	2005	OLS		19	71**	113**	64**
				(-14÷54)	(68÷75)	(105÷120)	(61÷68)
6		PW		144**	43**	63**	50**
				(114÷173)	(36÷50)	(50÷76)	(44÷58)
7		OLS	√	78**	74**	117**	67**
				(65÷91)	(68÷79)	(105÷129)	(61÷73)
8		PW	√	80**	72**	60**	46**
				(65÷96)	(67÷78)	(48÷74)	(38÷54)

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.

Table A.2 *Estimates of pass through rates in Germany and the Netherlands, based on first differences of the variables regressed*

Line no.	Period	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	Off-peak [%]	Germany Peak [%]	Off-peak [%]
1	2004	OLS		11	9	5	5
				(7÷31)	(-6÷24)	(-13÷24)	(-4÷15)
2		PW		-2	8	-1	6
				(-41÷37)	(-6÷22)	(-17÷16)	(-3÷15)
3		OLS	√	7	9	5	5
				(-51÷65)	(-10÷29)	(-16÷27)	(-12÷22)
4		PW	√	2	7	-1	5
				(-55÷59)	(-12÷27)	(-21÷20)	(-12÷22)
5	2005	OLS		203**	46**	64**	35**
				(132÷274)	(28÷66)	(34÷94)	(19÷52)
6		PW		205**	48**	64**	36**
				(134÷276)	(30÷66)	(34÷95)	(20÷52)
7		OLS	√	106**	36**	61**	42**
				(64÷147)	(27÷45)	(47÷73)	(33÷51)
8		PW	√	106**	36**	61**	42**
				(67÷144)	(27÷45)	(47÷74)	(33÷50)

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.

Table A.3 *Estimates of pass through rates in Germany and the Netherlands, based on absolute values of the variables regressed*

Line no.	Period	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	The Netherlands Off-peak [%]	Germany Peak [%]	Germany Off-peak [%]
1	January-July 2005	OLS		139**	51**	86**	46**
				(116÷161)	(46÷57)	(78÷95)	(42÷50)
2		PW		151**	49**	69**	48**
				(128÷175)	(43÷55)	(60÷78)	(43÷52)
3		OLS	√	40**	52**	72**	42**
				(32÷49)	(49÷55)	(68÷76)	(40÷45)
4		PW	√	42**	46**	68**	43**
				(31÷49)	(40÷51)	(60÷75)	(39÷46)
5	August-December 2005	OLS		150	10	-100**	-39**
				(-110÷310)	(-24÷43)	(-187÷-13)	(-74÷-4)
6		PW		200**	47**	62**	34**
				(134÷267)	(29÷66)	(32÷91)	(20÷50)
7		OLS	√	-130	-8	-150**	-65**
				(-270÷10)	(-46÷30)	(-253÷48)	(-111÷-19
8		PW	√	109	42	52*	28
				(24÷195)	(23÷62)	(17÷88)	(9÷47)

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.

Table A.4 *Estimates of pass through rates in Germany and the Netherlands, based on first differences of the variables regressed*

Line no.	Period	Regression method OLS/PW[a]	Fuel = 1[b]	The Netherlands Peak[c] [%]	The Netherlands Off-peak [%]	Germany Peak [%]	Germany Off-peak [%]
1	January-July 2005	OLS		126**	38**	61**	49**
				(96÷156)	(29÷47)	(48÷75)	(39÷59)
2		PW		126**	38**	61**	46**
				(95÷156)	(29÷47)	(48÷75)	(37÷55)
3		OLS	√	100**	34**	60**	45**
				(61÷147)	(25÷43)	(48÷74)	(34÷55)
4		PW	√	100**	34**	61**	42**
				(63÷141)	(25÷43)	(48÷74)	(33÷52)
5	August-December 2005	OLS		203**	46**	64**	35**
				(132÷274)	(28÷66)	(34÷94)	(19÷52)
6		PW		205**	48**	64**	36**
				(134÷276)	(30÷66)	(34÷95)	(20÷52)
7		OLS	√	111*	44**	62**	33**
				(16÷205)	(24÷65)	(30÷93)	(16÷51)
8		PW	√	115*	46**	61**	33**
				(24÷207)	(26÷67)	(30÷92)	(15÷51)

a) OLS = Ordinary Least Squares; PW = Prais-Winston.
b) Fuel=1 (i.e. √) refers to regression equation in which the coefficient of fuel cost pass through is assumed to be 1.
c) * = Statistically significant at 5% level; ** = statistically significant at 1% level. Figures between brackets indicate confidence interval.

Appendix B Impact of CO_2 emissions trading on wholesale power market shares in the Netherlands during different load periods

Apart from the consequences for the profitability of producing and selling electricity, a change in the cost structure of power generation due to CO_2 emissions trading may lead to changes in the market shares for the producers involved. This appendix elaborates on the discussion presented in Chapter 3 on the potential changes of wholesale market shares in the Netherlands for the power companies concerned as a consequence of the opportunity cost of CO_2 emission allowances.

While Chapter 3 has analysed changes in wholesale market shares concerning total annual power sales in the Netherlands, the present appendix is based on a more detailed market representation distinguishing three different load periods (or 'products' offered on the market), called 'off peak', 'shoulder' and 'peak'.[15] These periods represent each about one-third of the total production hours in a year. As these load periods are characterised with different typical demand levels, different subsets of the production merit order are dispatched to meet these demand levels.

The justification for such a more detailed market analysis is two-fold. It can be argued that different load periods refer to different markets. Aggregating these markets into a single one may lead to a biased, less informative analysis as the volumes produced during peak hours are generally much higher than the volumes during off peak hours. Moreover, the various producers considered can be characterised as typical base load or peak load producers due to the nature of the technologies spanning their respective production portfolios. Effectively, this implies that the producers can be identified to be particularly active on the base load or peak load market (or both). Shifts in market share should hence be considered against this background of different load periods.

The analysis below covers six scenarios based on the COMPETES model.[16] These scenarios refer to two basic or 'extreme' market structures, i.e. perfect competition (PC) and oligopolistic competition (ST), each distinguished by three scenarios, including:

- A scenario without emissions trading, i.e. the price of CO_2 is zero (PC0 and ST0).
- A scenario with emissions trading at a price of 20 €/tCO_2 and a price elasticity of demand of 0.2 (PC20 and ST20).
- A scenario with emissions trading at a price of 20 €/tCO_2 and a zero elasticity of demand in the PC scenario (PC20-ze) and a low elasticity of 0.1 in the ST scenario (ST20-le).

In the sections below, changes in Dutch market shares are analysed for all power companies in the region covered by the COMPETES model (i.e. Belgium, France, Germany and the Netherlands). Relative market shares are considered and, hence, it should be realised that in case of changing total demand, absolute market shares may be retained while relative market shares change. In addition, it should be noted that analysis of relative market shares provides no insight into the profitability of the electricity sales concerned.

[15] In addition, the COMPETES model - on which the analysis is based - distinguishes a fourth load period, i.e. the so-called 'super peak' period, consisting of the 200 hours in a year with the highest sum of the loads for the four countries covered by the model (i.e. Belgium, France, Germany and the Netherlands). This super peak period is less relevant to the market share analysis outlined in the present appendix - and, hence, not included - as during this period most production capacity is needed to match demand and, therefore, the market shares during the super peak are highly determined by the available capacity (and hardly by the price of CO_2).

[16] See Sijm et al. (2005) and references cited there.

B.1 Perfect competition

Figure B.1 presents changes in relative market shares for all power producers serving the Dutch wholesale market during the off peak, shoulder and peak hours. The market shares are annualised for the various load periods considered. Particularly for the off peak and shoulder hours, it can be observed that due to CO_2 pricing EON, Electrabel and ENBW increase their market shares significantly at the expense of NUON and the competitive fringes in France, Germany and the Netherlands.

The companies that lose market share may be characterised as peak producers in accordance to the relatively strong presence of gas-fired production facilities in their respective portfolios and as such these portfolios are less competitive during off peak and shoulder hours. Therefore, though losses of market share are significant during peak hours, the production of these companies is less sensitive to CO_2 costs during the more profitable peak hours when power prices are relatively high.

Compared to the 0.2 elasticity scenarios, Electrabel is able to expand its market share more significantly during off peak and peak hours in the PC20-ze scenario (i.e. the perfect competition scenario with a CO_2 price of 20 €/t and a zero demand elasticity). As the company is generally the marginal bidder in both periods on the basis of its nuclear and gas-based production, respectively, it takes advantage of higher levels of demand during these hours due to the assumed lower elasticity of demand in this scenario

B.2 Oligopolistic competition

The second set of scenarios, presented in Figure B.2, assumes strategic behaviour of all power producers in the COMPETES region, except the so-called 'competitive fringes' of the countries covered by the model. In case of strategic bidding no significant differences between the load periods can be observed, while the shifts in load-differentiated market shares are grossly speaking similar to the shifts in the aggregated production market shares as analysed in Chapter 3.

In contrast to the perfect competitive scenarios, under oligopolistic market conditions it is not attractive for companies with substantial nuclear-based technologies in their respective portfolios to significantly expand their market shares during the shoulder and off peak hours as these (profit-maximising) companies rely on withholding generation capacity and, hence, increasing power prices (rather than increasing market shares at lower prices). Accordingly, the capacity of the competitive fringes is used during these load periods to meet power demand, most notably the capacity of the Dutch competitive fringe, as illustrated in Figure B.2, particularly in the ST20-le scenario.

B.3 Conclusion

A load-differentiated analysis of market shares under various model scenarios indicates that particularly the shoulder and off peak hours offer opportunities for nuclear power producers to expand their respective market shares in response to higher CO_2 prices. These opportunities will be exploited notably under perfect competition scenarios (with market prices given for all companies), while under oligopolistic conditions these opportunities will only be partially used by strategically operating companies as they rely on withholding production capacity and, hence, increasing power prices in order to maximise profits (rather than increasing market shares at lower prices).

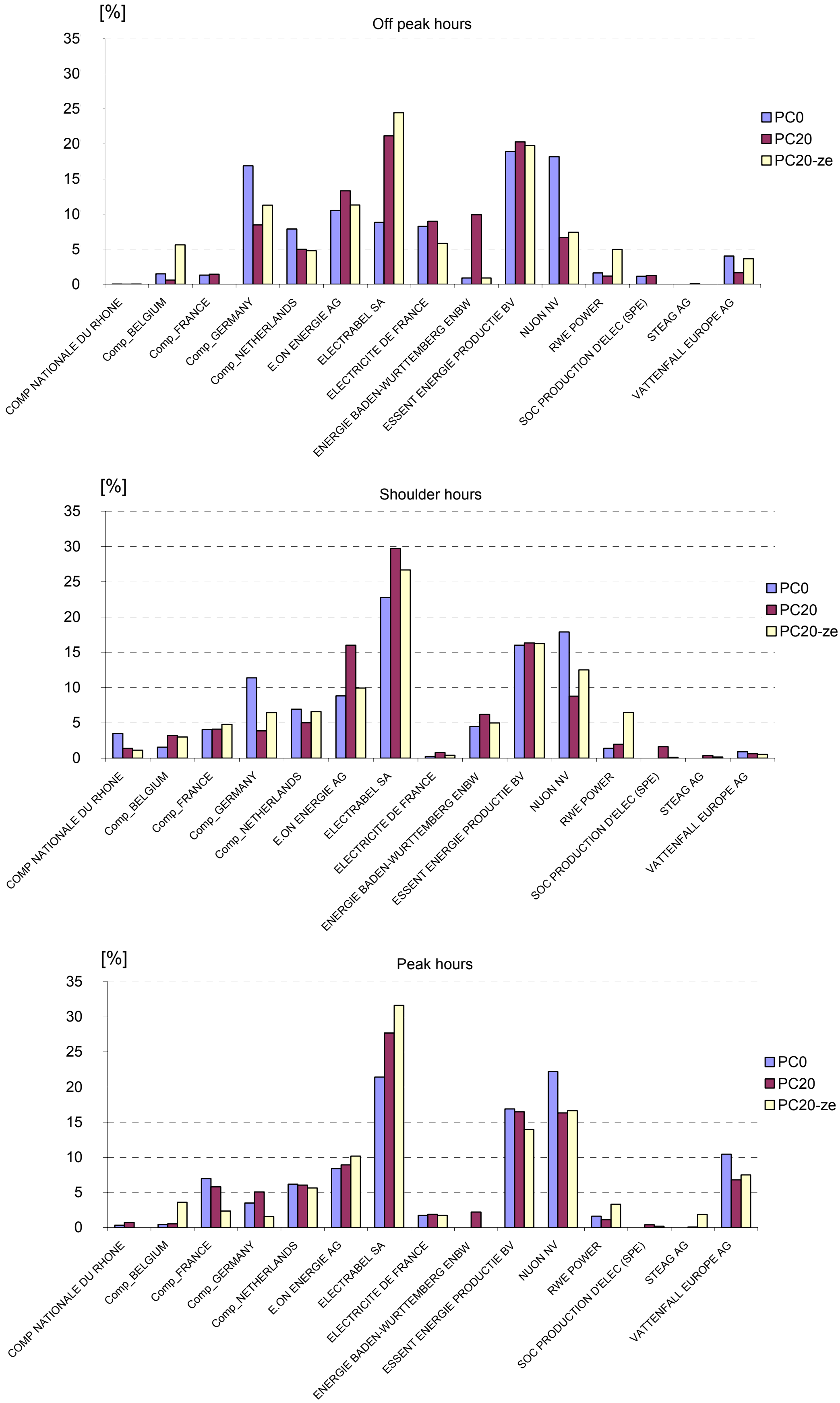

Figure B.1 *Changes in wholesale market shares in the Netherlands for different load periods under different perfect competition scenarios*

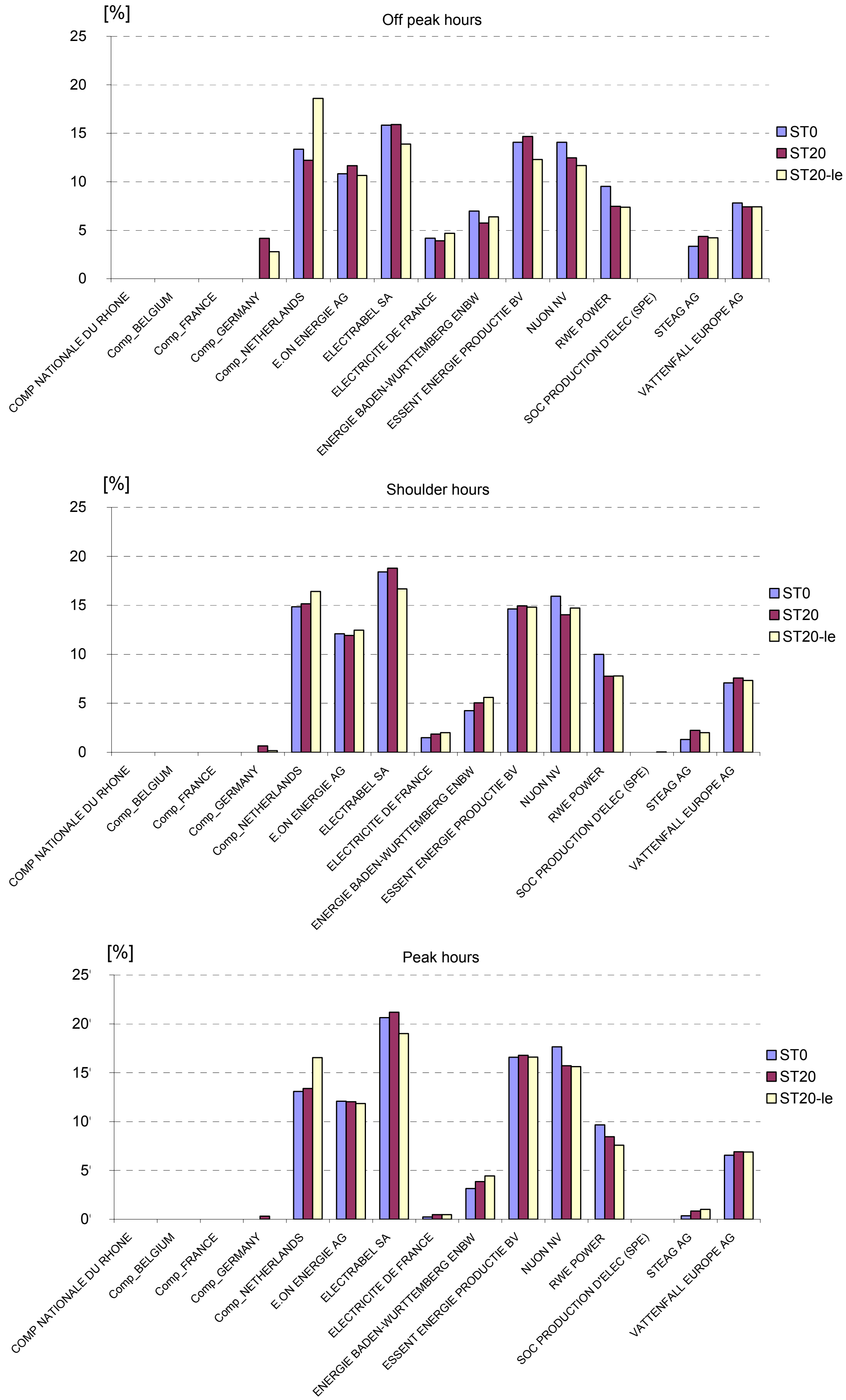

Figure B.2 *Changes in wholesale market shares in the Netherlands for different load periods under different oligopolistic competition scenarios*

Appendix C The impact of CO_2 emissions trading on the Combined Heat and Power (CHP) sector in the Netherlands

In the Netherlands, Combined Heat and Power (CHP) production plays a major role in the national electricity supply. About 40% of electricity is produced in CHP plants. Of the 21,500 MW of electric power capacity installed, 8,550 MW was in the form of CHP installations (2004 data).

The liberalisation of the electricity market in the Netherlands starting around 1999 caused some major problems for CHP. The original system of fixed prices for CHP power supplied to the grid was replaced by one where generated electricity is sold at actual market prices. The relatively low price of electricity in the off-peak periods combined with the high price of gas, affected the profits of many CHP systems. The rapid increase of CHP during the nineties practically came to a standstill. Most CHP units remained in operation, but a significant decrease in operational hours was experienced.

From 2003 onwards, electricity prices (mainly in peak periods) started to rise again, slightly improving the situation for CHP. Since early 2005, however, gas prices started to increase rapidly. As natural gas is the major fuel for CHP, this potentially worsens the financial situation of many CHP installations. Crucial, however, is the development of the spark spread for gas-fired installations, which has decreased slightly since 2003 but has increased significantly during the latter part of 2005 (see Chapter 2, Figure 2.6).

Some new CHP plants have been built between 2003 and 2005. This mainly included small gas engines (few MW each) in horticulture and a few large CHP plants. The largest, the 'Rijnmond Energiecentrale' (825 MW_e) was put into operation end of 2004. This plant is actually a power plant but supplies a relatively small amount of heat. It is therefore still a CHP plant, but it cannot be considered as the optimal solution with regards to energy efficiency (van Dril and Elzenga, 2005).

In mid-2004, the so-called MEP feed-in system for CHP was introduced in the Netherlands. The MEP scheme provides a reward for the supplementary kWhs of electricity produced by CHP units when compared to separate production of heat and power. This means that through the MEP the additional 'CO_2-free kWhs' produced by CHP units are rewarded, providing the biggest incentive for the most energy efficient CHP units. For each CHP installation, the so-called *CO_2-index* is determined. This is a percentage that shows the amount of supplementary kWhs produced. This percentage differs per CHP technology and is within the range of 15-30%.

The difference between electricity (output) and gas (input) prices remains the most important factor for a cost efficient operational of CHP units. It will become more and more important to be able to respond flexibly to price changes. On balance, the trend in gas and electricity prices has been favourable to CHP between 2003 and 2005, owing mainly to the higher price of both peak and off-peak electricity and relatively stable gas prices. Since early 2005 gas prices started to increase again. However, as electricity prices in the Netherlands depend to a large extend on the price of natural gas, the large electricity producers will pass through higher gas prices in the electricity price meaning a higher electricity market price that might also benefit CHP.

C.1 CHP in the Netherlands - Statistics

Below some basic statistics on CHP are given based on CBS data of 2004 (source: http://statline.cbs.nl):

- About 42% of electricity production in the Netherlands is generated by CHP plants.
- Of the 21,500 MW of electric capacity installed, 8,550 MW was in the form of CHP installations (2004 data).
- Total electricity production in 2004 was 102.15 TWh of which 43.25 TWh of electricity was produced in CHP plants.[17]
- The distribution over sectors is approximately as follows:
- Industry ~ 4100 MW
- Central CHP capacity (district heating + central power plants with heat supply) ~ 2600 MW
- Other sectors ~ 1850MW

A large part of this capacity is above the 20 MW_{th} emission trading threshold, exceptions are:

- Gas engines, most gas engines are units below 1-2 MW, no gas engines above 20 MW_{th} are installed in the Netherlands. The total installed capacity of gas engines is 1580 MW. Mainly installed in horticulture and tertiary sector.
- Part of the gas turbine park (approx. 600 MW of a total of 2160 MW). Mainly installed in tertiary sector, a few in industry.

A large share of the CHP plants is so-called 'must-run facilities' that are operating due to a constant heat demand and cannot freely move production to peak hours. Operational hours differ per application (Ten Donkelaar et al., 2004):

- CHP capacity in industry (4100 MW), need to run because of process heat production - average no of operational hours per year - 6000-6800
- Of central CHP capacity about 1900 MW is in the district-heating sector (heat supply to third parties, mainly household consumers) with approx. 4000-4500 operational hours a year.

C.2 CO_2 allowances and CHP

From January 1, 2005 onwards, CHP installations with a thermal output above 20 MW are part of the CO_2 emission trading scheme. Emission trading will have a number of effects on the exploitation of CHP units. Most CHP installations can more efficiently produce electricity and heat than is done by reference installations. Therefore, CHP installations have received a relatively generous allocation of emission rights, meaning that a certain surplus of these rights can be sold. This also influences the amount of operational support CHP electricity received from the Dutch government, as this is based on a certain financial gap.

To determine the need for additional support to CHP, ECN has calculated the financial gap of CHP exploitation for the years 2004 to 2006. This financial gap is defined as the difference between the (higher) production costs in €/MWh and the (lower) market price in €/MWh. Since 2005 the influence of CO_2 emissions trading has been taken into account when calculating this financial gap. In this calculation the value of the CO_2 allowances (or the CO_2 market price) is of major importance.

For the annual calculation of the financial gap of CHP in year X it was agreed to calculate with the average forward price for natural gas and electricity as have been traded for year X during the period October year X-2 until September year X-1. For CO_2 forward prices the same period was taken (data were taken from www.emissieprijzen.nl or the 'EU monthly CO_2 emissions trade marker' (Platts)). These average forward prices for 2005 were 6.5 €/tCO_2, wile for 2006 they increased to 14.9 €/tCO_2.

[17] 2003 data: electric power capacity installed 20,900 MW_e with a production of 98.14 TWh, and 7600 MW_e CHP capacity with a production of 39 TWh.

C.3 Calculation of emission allowances

The actual allocation of emission allowances to CHP plants has been calculated based on the Calculation Rules for Allocating CO_2 Emission Allowances (SenterNovem, 2004). In these calculation rules installations being more energy efficient than the benchmark, receive extra CO_2 emission allowances and this is also the case for CHP plants. Allowed CO_2 emissions for the period 2005-2007 have been calculated ex-ante.

Calculations made by ECN, based on actual gas consumption of a number of standardised CHP plants (CCGT units and gas turbines) compared to the benchmark efficiencies of electricity and heat production showed that these CHP plants are 12 to 20% more efficient. As more efficient installations are rewarded for taking 'early action' this could mean an overallocation for these CHP plants in the order of 12 to 20%. One has to realise however that each CHP production site is allocated separately. Situations of single plants can differ, some can be far more efficient, reaching values of 20% and more, others, mainly older installations may reach only additional efficiencies of a few percent.

However, according to the calculation rules, the allocation benefit (overallocation) for energy efficiency measures like CHP is maximised at 10% (according to the so-called *10% rule*). CHP installations can therefore maximally sell 10% of their CO_2 emission allowances.

When calculating the financial gap of a CHP installation it is important to calculate the extra emission allowances a CHP installation received. The obtained CO_2 emission allowances represent a value equal to the market price for CO_2 and when selling these on the market the financial gap can potentially be lowered.

C.4 Impact due to allocation of CO_2 rights

The original ECN study on CO_2 price dynamics shows that a significant part of the costs of freely allocated allowances is passed through to power prices (Sijm, et al., 2005). The study also emphasised, however, that the rates and amounts of passing through CO_2 costs do not necessarily apply to all installations and during all load periods considered. On the contrary, notably the CHP gas installations in the Netherlands must run during off-peak hours, even if it is not profitable, as seems to be the case under forward 2006 price conditions. Under these conditions, such *price-following* installations are not able to cover the opportunity costs of grandfathered allowances, let alone to realise 'windfall profits' due to emissions trading.

On the other hand, it should be recognised that - besides potential revenues from heat production - these installations may earn significant profits during peak load hours (when prices are relatively high) and that without emissions trading power prices might have been lower during the off-peak hours given the average pass-through rates and the average high CO_2 prices considered. As was shown before, due to a certain overallocation of CO_2 emission allowances, an additional revenue can be gained from selling emission allowances on the carbon market.

C.5 Current situation of CO_2 allowance allocation (first trading period)

During the first trading period and as long as CHP support exists in the form of the MEP feed-in tariffs, the issues of CHP support and CO_2 allowance allocation are interrelated:

- CHP is more energy efficient in comparison with separate production of heat and power. Therefore, CHP installations produce less CO_2 and, hence, they received a generous amount of CO_2 allowances.

- For its calculation of the financial gap op CHP generation, ECN assumes a maximum overallocation of CO_2 allowances in the CHP sector of 10 percent.[18] For the less efficient CHP installations this percentage could be lower.
- Overallocated tonnes of CO_2 are an additional revenue to the CHP operator and can be sold on the carbon market. The level of revenue depends on the CO_2 price that showed a significant increase during 2005. Forward prices of CO_2 credits for the years 2005 and 2006 amounted to, on average, 6.5 and 15 €/tonne, respectively. While 2005 forward prices had little effect on the cost-effectiveness of running CHP plants, with 2006 forward prices being almost three times as high, this situation may be rather different.
- CHP is supported through the MEP feed-in tariff. Subsidies under the MEP are based on the financial gap between actual revenues and cost efficient exploitation. This financial gap is covered for 50% by the feed-in system.[19] As noted before, the average CHP installation will receive additional revenues from selling CO_2 credits. In case these CO_2 credits are not sufficient for covering the financial gap, the MEP tariff will cover 50% of this additional gap.
- This means that high revenues for selling CO_2 credits lowers the financial gap meaning less financial support required through the MEP. The other way around, with little revenues for selling CO_2 credits the financial gap remains high which requires more financial support through the MEP.
- The conclusion is that under the current system where CO_2 emissions trading and financial support to CHP are interrelated, more or less CO_2 allowance allocation has a limited influence on the operational efficiency of CHP as financial losses are covered up to 50% by the MEP feed-in system.

The situation becomes different when no support is granted to CHP. CHP has been fully supported under the MEP between July 2004 and December 2005. The Ministry of Economic Affairs plans to cut back on this system however. For 2006 it was already decided to provide support only to CHP installations that are less than 10 years old. The reason is that the older installations do not require additional support as capital costs are usually paid off and only operational costs remain for the CHP operator. The same level of support will most likely be provided for 2007 also.

From 2008 onwards a radical shift in policy may take place. The Ministry of Economic Affairs may stop supporting the operation of incumbent CHP installations and only provide investment support to new CHP installations. The rationale behind this shift is to only support new and more energy efficient CHP installations reducing more CO_2 emissions than existing installations. The opinion of the Ministry is that existing installations do not require additional support due to increasing electricity prices. According to calculations made by ECN this may be the case for older (paid off) installations with only operational costs, but not for those that still have to pay off their investments (Harmsen, 2005). Moreover, the price of gas (fuel for most CHP installations in the Netherlands) has also increased, substantially increasing operational costs.

C.6 Changing the CO_2 allowance allocation (second trading period)

In the situation that the Dutch government will put an end to the feed-in system, a change in allocation of CO_2 allowances may substantially influence the cost-effective operation of CHP.

Continue with grandfathering - stricter emission caps for the power sector:

- In case of stricter emission caps the overallocation level for CHP installations will decrease. This will first of all lead to lower revenues for CHP from selling emission allowances.

[18] There is a maximum overallocation of CO_2 emissions of 10%. Actual overallocation for certain types of CHP installations could be even higher (up to 20%) for very efficient plants. For less efficient installations, the overallocation can of course be less than 10%.

[19] A higher percentage of financial support is not allowed under the EC regulation for environmental support.

- It may mean that CHP installations, at least the less efficient ones, will have to buy additional emission allowances on the carbon market, meaning less (windfall) profits.
- Most CHP installations are smaller than traditional power plants and many of them are must-run installations. Therefore, CHP installations can be considered as price takers on the electricity market. CHP operators are not in the position to pass through CO_2 costs to the power price of their installation. However, as many large power producers can pass through the CO_2 costs, market prices for electricity will generally increase, creating a potential benefit for CHP operators selling their electricity on the market.

Auctioning part of the CO_2 emission allowances

This will mean that e.g. 90 percent of the emission allowances will be grandfathered and the remaining 10 percent will be auctioned. If a CHP installation has to buy part of its required allowances at an auction rather than selling an overallocated surplus on the market, it implies a higher financial gap for such an installation. Depending on the existence and specifics of a CHP support system during the second phase of the EU ETS, this higher financial gap may be partly - for instance 50 percent - covered by this support system.

Example - influence of 10%, 5% and 0% overallocation on the financial gap of CHP

Below a simple calculation is given showing the influence of the overallocation of CO_2 emission allowances for CHP on the financial gap of three standardised CHP installations:

- The financial gap is calculated as: capital costs + operational costs - revenues (electricity + heat + CO_2 allowances). *A positive sign here means that there is a certain financial gap.*
- Operational costs and revenues are based on forward prices of electricity, gas and CO_2 allowances as have been traded for year X during the period October year X-2 until September year X-1. E.g. the price of CO_2 credits for 2006 taken here is 15 €/ton.
- Capital costs of the given installations are based on average investment costs of the respective type of technology.
- Overallocation percentages have to be reduced by a c*orrection factor* of 3%, more precisely by a factor 0.969. According to the Dutch Allocation Plan (SenterNovem *et al,*, 2004) all emission quota available to the participants in the emissions trading scheme have to be reduced by this factor. This way the total emission quota for the Netherlands are scaled down to reach the Dutch climate objective. CHP plants with an overallocation of 10% actually receive the following allocation percentage: 110% × 0.969 = 106.6%.

The calculations in Table C.1 show a certain influence of the amount of CO_2 allowances allocated on the financial gap of operating a CHP installation. At a CO_2 price of 15 €/tonne, however, this influence is generally small and is not decisive whether a CHP installation operates efficiently or not. The revenues are at a price of 15 €/tonne not that significant that the CO_2 allocation would decide between cost-efficient operation or not.

In Table C.2, the financial gap is calculated for a hypothetical CO_2 price of 30 €/t. As expected, at higher CO_2 prices, the differences in this gap become more significant with changing percentages of allocation.

Table C.1 *Financial gap of CHP operation for different installations at different CO_2 allocation percentages (in ct/kWh, CO_2 15 €/tonne)*

% allocation (before correction)	Gas turbine ($25\ MW_e/36.5\ MW_{th}$)	CCGT ($80\ MW_e/200\ MW_{th}$)	CCGT ($250\ MW_e/226\ MW_{th}$)
10	0.80	0.55	0.13
5	0.85	0.61	0.17
0	0.89	0.67	0.21
-5	0.94	0.73	0.24

Table C.2 *Financial gap of CHP operation for different installations at different CO_2 allocation percentage (in ct/kWh, CO_2 price 30 €/tonne)*

% allocation (before correction)	Gas turbine ($25\ MW_e/36.5\ MW_{th}$)	CCGT ($80\ MW_e/200\ MW_{th}$)	CCGT ($250\ MW_e/226\ MW_{th}$)
10	0.74	0.46	0.08
5	0.83	0.59	0.16
0	0.92	0.71	0.23
-5	1.02	0.83	0.31