DISCUSSION PAPER

Multi-Period Emissions Trading in the Electricity Sector - Winners and Losers

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ABSTRACT

Emission trading has become recently more and more import in environmental regulation. In the context of controlling greenhouse gas emissions, the directive on a Europe-wide trading scheme for large immobile sources may be perceived as one of the most important milestones in recent years. Prior to its start, however, a number of very specific design features have to be agreed upon. In the political discussion, the question of how to allocate emission rights is considered as one of the most important issues. So far, a distribution (almost) free of charge is the option of choice. An aspect that has interestingly attracted little attention in the past is the question of how to allocate emission rights over time. This may for example be done on the basis of a constant reference metric, as for example emissions in a certain fixed year, or on the basis of a rolling metric as for example emissions in the previous year. The following paper analyses four different allocation options in multi-period emissions trading that are currently discussed in the European context. The four options are applied for the electricity sector. A power market close to reality with five different types of power plants (hydro, nuclear, lignite, coal and gas) is simulated over two periods. The paper distinguishes between a market effect of emissions trading on the one hand and compliance costs for meeting the emission reduction obligation on the other. The market effect results from a price increase which is due to the fact that opportunity costs for using allowances, though received free of charge, must be considered. However, only compliance costs and not opportunity costs materialise as costs in the profit and loss account of utilities. It turns out that the electricity sector as a whole gains from the introduction of the instrument due to the increase of the electricity price. With regard to the different allocation options, it is found that utilities have different preferences depending on the fuel used.

Key words: abatement costs, allocation of GHG allowances, benchmark, compliance costs, electricity sector, multi-period emission trading

JEL-classification: H 23, H 25, L 20, L 52, L 94, Q 25, Q 28

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1 Introduction

In the context of environmental regulation emissions trading has gained acceptance and support in the past (Stavins 2003). With regard to the fight against global warming, trading greenhouse gas (GHG) emission entitlements has first been introduced on state level in the Kyoto-Protocol in 1997. Subsequently, it was implemented on entity level in the UK and Denmark. The most important example, however, may be the directive on a Europe-wide emissions trading scheme adopted in 2003 (EU 2003). According this directive certain installations, i.e. major immobile sources of GHGs, are obliged to participate in a cap and trade scheme from January 1, 2005. The allocation of emission entitlements, in the European context called allowances, is perceived as very important issue from the companies' point of view. Though a number of different options exist two approaches have been in the focus during the discussion between governments and participants, namely an allocation based on emissions in a reference year and the use of a benchmark. With both options allowances are distributed free of charge. Interestingly, the question on how to design the allocation over time, i.e. in subsequent periods, has only attracted little attention. The impact of different alternative allocation options on the single installations has not been addressed so far. Existing literature, which is briefly reviewed below, either concentrates on the sector level or provides a pure analytical discussion. During the negotiations of the national allocation plans within the EU Member States this issue has either been overlooked or has not been discussed in public so far. Nevertheless, this question will be answered in some way – possibly without knowing the exact implications.

Against this background this article deals with the analysis of the impact of different allocation options on installations in the electricity sector. Electricity generation has been chosen as it is a major source of GHG emissions in Europe and as it plays an important role in the planned trading scheme. The focus is on the relative impacts of the allocation on different power generation technologies rather than on absolute effects of the allocation on this sector compared to other sectors covered by the scheme. The analysis is based on a simulation of an artificial but realistic electricity market. As the focus is on the impacts of the allocation, only a few technical issues are considered. Transmission losses, for example, are fully neglected. The analysis is limited to a short-term perspective only. On the one hand, this is due to the fact that politically a short term perspective is likely to influence current legislation the most. On the other hand the path for auctioning the allowances is already slightly paved in the European scheme.

With a 100 percent auctioning, however, the problem discussed below, do not exist anymore.

The paper first discusses the impact of emissions trading on firms from a theoretical perspective. Section three reviews different options for allocation allowances free of charge. Multi-period emissions trading in the electricity sector is analysed in detail in section four. Section five concludes.

2 Emission trading and its impact on firms

Emission trading is a market based instrument that allows a cost-efficient achievement of an emission target through the equalisation of marginal abatement cost. Participants in the trading scheme are not prescribed any specific abatement options. The only obligation they face is to surrender as much emission allowances at the end of a period as they released emissions into the atmosphere in this period. Therefore, they can decide whether to abate emissions in-house or to buy allowances[1] on the market. The decision to buy allowances is driven by the question of whether internal marginal abatement costs[2] are lower than the allowance price.

The implementation of an emissions trading schemes requires a number of decisions to be taken with regard to the design, as for example the compliance period, the units traded, monitoring rules, liability etc. (for a more detailed discussion see AGE 2001, AGO 1999, Boemare et al. 2002, CCAP 1999, CCAP 2002, WBCSD 2001, p. 8, UNEP and UNCTAD 2002). Another important aspect is the allocation of the allowances. Generally, allowances may either be provided free of charge or only be issued to participants against a fee. For trading at the company level, economists have argued in favour of a fee-based allocation or more precisely an auction as distributing the allowances for free would result in extra revenue for the recipients of the allowances and in reduced efficiency on a macro-economic level (Cramton and Kerr 2002, Field 2000 p. 31, Speck 1999, Woerdman 2000 p. 620). A more detailed analysis follows below. However, it has been argued that this question can only be answered when comparing the concrete design of an auction[3] and a free of charge scheme respectively (for example Bohm 2002). Burtraw et al. (2001) compare three different allocation

[1] The term emission right and allowance are used interchangeably.
[2] Costs resulting from in-house abatement are referred as abatement costs in this paper. Compliance costs by contrast are the sum of abatement costs and expenses from buying or selling allowances on the market.
[3] For example "How is the revenue from the auction recycled?"

options for the electricity sector in the US and find that the costs to society are about one-half with auctioning compared to the two free of charge option.[4]
On the other hand, emitters ask for an allocation free of charge arguing that the additional financial burden of paying the fees would be too high. They have till now generally succeeded. The directive on GHG trading in the EU prescribes [5] an allocation almost free of charge [6] and Stavins (2003) reports the same for the relevant non-GHG trading schemes in the US.

The argument of the additional financial costs is, however, only partly true. One also has to look at the other side of the coin. It is reasonable to assume that allowances are scarce, at least at the start of the scheme. Otherwise there would be no reason to introduce the instrument apart from obfuscation of a do-nothing strategy. In this case there will be a price for allowances. Thus, although allowances are allocated for free, their use for production involves an opportunity cost; they could have been sold in case of non-production. According to cost theory, producers will consequently raise the product prices according to the product's emission intensity and the costs for emitting carbon.

The effect on the market can be studied in comparison to a per unit tax (for general example see Pashigian 1995, pp. 313-316; for the specific comparison Goulder 2002). Assume a competitive market for a certain product and denote the demand curve for the product by D and the supply prior to the implementation of the trading scheme by S_1 (see Figure 1). The equilibrium price p^* and the corresponding quantity q^* arise from the intersection of the two curves. Furthermore, assume that a competitive allowance market emerges. The CO_2 price is than determined by the overall emissions budget and the individual participants' abatement costs. All participants face the same CO_2 price which translates into opportunity costs within the firms' cost and price strategy. In case all producers have the same emission intensity per unit of output, the additional opportunity costs for CO_2 emissions result in an upwards shift of the supply curve (see S_2 in Figure 1). This shift in turn results in a new equilibrium with the equilibrium quantity $q^\#$. Consumers now face the price $p^\#$. In case a per unit (CO_2) tax had been introduced, then the producers would face the price $p^\sim$ and the government would receive a transfer from consumers and producers equal to the rectangles b and c. The

[4] The authors use the revenue from the auction in the least efficient way discussed in literature, namely the direct redistribution to households.
[5] For their position during the legislation process see Com (2001), p. 2.
[6] More precisely: At least 95% of allowances have to be allocated free of charge for the initial period 2005-2008 and at least 90% for the subsequent period (EU 2003).

triangles e and f are the deadweight losses that result from the reduction of output. In case of emissions trading the price increase is due to the fact that producers take opportunity costs into account. As a consequence they can receive additional revenues. The magnitude of the latter depends on the slope of the supply and that of the demand curve. If price elasticity of demand is low, revenues increase strongly. To prevent producers from benefiting too much, partial auctioning of the allowances would be sufficient. Goulder (2002) analysed this issue for the US fossil fuel industries and finds that only about 13 percent of allowances need to be distributed free of charge in order to avoid losses of profit for these industries. Regarding the EU trading scheme, current legislation already provides the possibility for such a change.[7]

As mentioned above, transferring these revenues to the government with subsequent tax reduction can reduce total costs of the regulation to society. Apart from these economic aspects Parry (2002) points out that the higher revenues result in increased equity values which lead to more income for shareholders. As "…stock ownership is skewed towards the rich…" (Parry 2002, p. 7) there is a strong case for auctioning also on distributional grounds.

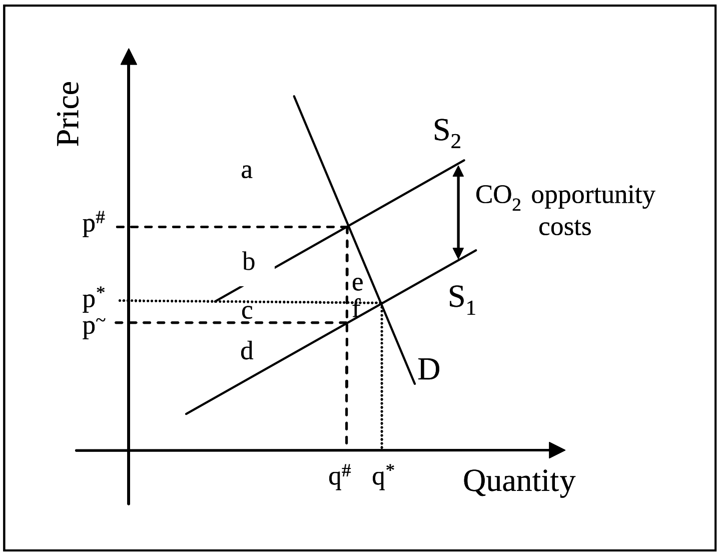

Fig. 1: Impact of a per unit tax or consideration of opportunity costs of emitting CO_2 by producers

While some emitters theoretically may get surplus allowances, most emitters will have to invest in either in-house abatement or to purchase emission rights on the market as total emissions are to be reduced. As a consequence the majority of emitters will face at

[7] See previous footnote.

least some compliance costs. Summarising these two aspects, i.e. the market effect and the compliance costs, one can see that the total financial impact on an individual installation can be calculated by subtracting the compliance costs from the additional revenues resulting from the price increase.

With regard to the allocation discussed in the next section one should note that, with the assumptions made above, the market effect is not linked to the allocation and vice versa. The price increase always takes place, either due to the opportunity costs as discussed above or due to real costs in case (parts of) the permits are auctioned. Depending on the CO_2 costs, the merit order curve, which is introduced below, may change and some installations may be driven out of the market – regardless of the initial allocation. The latter only affects the participants' compliance costs and thus their liquidity.

3 Options for allocating under a "free of charge" scheme

While the theoretical analysis of the change in the producer rent has generally been done on the sector level, the allocation of the allowances free of charge is a matter to be dealt with at the installation level. A wide basket of options for this allocation exists (AGE 2001, AGO 1999, Boemare et al. 2002, CCAP 1999, CCAP 2002, Holmes et al. 2000, Mies, 2000, Nera 2002, NZME 1998). In the existing schemes in Denmark or the US and in the current discussion (PWC 2003), however, the following two approaches have been favoured:

- an allocation based on emission in a certain period (what is referred to as emission based allocation below)
- the use of a benchmark, i.e. specific emission factor.

The latter has to be multiplied with the reference figure of the benchmark in order to get an emission figure. Formulae are given below. However, as Bode (2003) showed, the use of a general, i.e. non-installation specific, benchmark with an absolute cap as foreseen by the emission targets of the Kyoto Protocol, results in an allocation in proportion to output only. The line of argumentation is given in the annex. Thus, there is no need to put any effort on the determination of any benchmark. Furthermore, one should be aware that an output-based allocation provides an incentive to increase output

(Fischer 2001). However, in this short-term analysis it is assumed that the output is only determined by the producers' marginal production costs.[8]

A number of analyses of free of charge allocation schemes exists. The majority, however, is either a pure analytical exercise or concentrates on the sector or society level and does not explicitly analyse the individual electricity generator's perspective, at least with regard to the options politically discussed in Europe.

Böhringer et al. (2003) for example analyse an emission and an output based allocation in order to analyse the trade-off between a compensation of energy intensive industry for the adverse impacts from regulation and economic efficiency. They conduct a comparative static CGE analysis and find that the trade-off depends strongly on the allowance price on the international market. With regard to the concrete allocation scheme the first and the second best design depends on the fact whether the system studied is open or closed.

Other studies focus more on the electricity sector. The Balmorel project (Balmorel 2001) resulted in a detailed model of the electricity and combined and heat power market in the Baltic Sea region. It provides a long-term analysis of the price for heat and power until 2030. The price increase found is explained by the restructuring of the supply system and increases in fuel prices. Costs for emissions are not mentioned. Emission trading is only assumed for deriving an aggregate abatement costs curve for this region. No different allocation schemes are studied. Hauch (2003) focuses on electricity trade and CO_2 reduction in the northern European power market. He finds that trade in electricity in addition to allowances trading can reduce compliance costs and that the burden sharing agreement in the EU implies different costs for different Member States. The investigation is restricted to country level. Munksgaard et al. (2002) analyse the impact of internalising external costs in the northern European power market using the same model as the previous author. They show how cross-border trade and prices are affected in different scenarios as for example a coordinated and a national approach. In order to regulate the power sector a tax is applied and the authors point out that the model is appropriate for long-term analyses.

As mentioned above, Burtraw et al. (2001) study the electricity market in the US. In a paper that follows (Burtraw et al. 2002) the authors introduce "the auction paradox" according to which generators as whole would be better off under an auction than with a

[8] Efforts to increase market share by, for example additional marketing measures, may be effective only in the mid-term.

generation performance standard[9] as electricity prices are higher in the former case. The concrete distributional effects depend on the fuel use in the power plant analysed and the fact whether or not a plant is entering the market. They do not compare different approaches for allocation free of charge.
UBS (2003) provides an analysis of the German electricity market until 2010. Apart from three different allocation schemes they also consider other issues as the phase out of nuclear energy and the aging of plants etc. so that a clear understanding of the impact of the allocation is not possible.

Against this background, the impact of different allocation options in multi-period emissions trading for the electricity sector, or more precisely on single installations as prescribed in the EU directive on emissions trading, is analysed in the next section.

4 Multi-period emissions trading in the electricity sector

The electricity sector generally accounts for a high percentage of CO_2 emissions from fossil fuel combustion. This is why it is has been the major focus of regulating GHG emissions. As power generation usually takes place in big plants, i.e. large immobile source, lots of features of regulation (incl. monitoring) are especially suited for emissions trading.

4.1 Some explanatory remarks - supply and demand side characteristics

The electricity market has special characteristics. The product is homogenous whiles for the production process a number of options exist which involve different quantities of GHG emissions per unit produced. Lignite fired power plants incur the highest specific emissions. Apart from the fuel used, the efficiency of the power plant is also relevant. In the lower range, there are a number of zero emission technologies as for example nuclear power plants or renewable energies. Storage of electricity is possible, though much more complicated and expensive, when compared to other goods.
It goes without saying that both short-term and long-term marginal production costs also differ. Figure 2 gives a schematic overview for different production techniques and their characteristics as it can be seen in western European countries. As the paper focuses on the short-term implications and as the short-term market economics are

[9] The generation performance standard corresponds to the output-based allocation used in this paper.

determined by marginal costs (UBS 2003, p. 29), only short-term marginal costs[10] are considered.

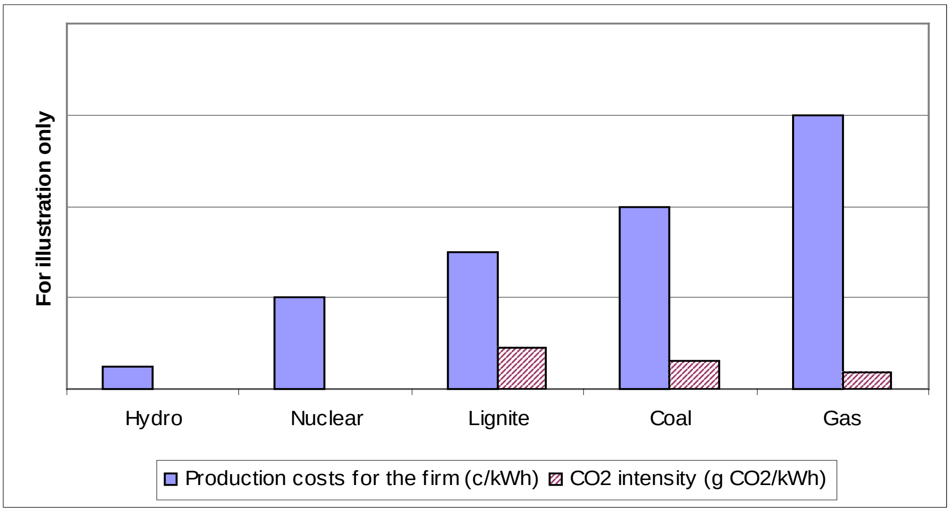

Fig. 2: Schematic production costs and CO_2 intensities for different production techniques (figures are given in Table 1)

Apart from the economic and emission-related aspects, there are other differences between the technologies. Most important for this paper is the operational flexibility. While gas fired plants, for example, can be started and stopped quite fast, lignite fired or nuclear power plants require more time for both processes. Thus they are differently suited for satisfying peak load demand which is discussed below.

The main characteristics for the demand side is it variation over the day as depicted in Figure 5 in the data section below. Demand in modern societies is low during the night when most of the people sleep and peaks about noon. Furthermore, there are changes in the demand curve depending on the season.

When supply and demand match in functioning markets, system economics will determine that the lowest marginal cost plant will be operated first (UBS 2003, p. 32). Thus, a merit order curve as shown in Figure 3 develops. As demand changes over the day, the equilibrium price, which is determined by the marginal plant, also changes during the day. Peak load prices are much higher than base load price.

[10] Most important parts of short-term marginal production costs are fuel costs and operation and maintenance (e.g. fuel handling) Balmorel (2001, p. 20).

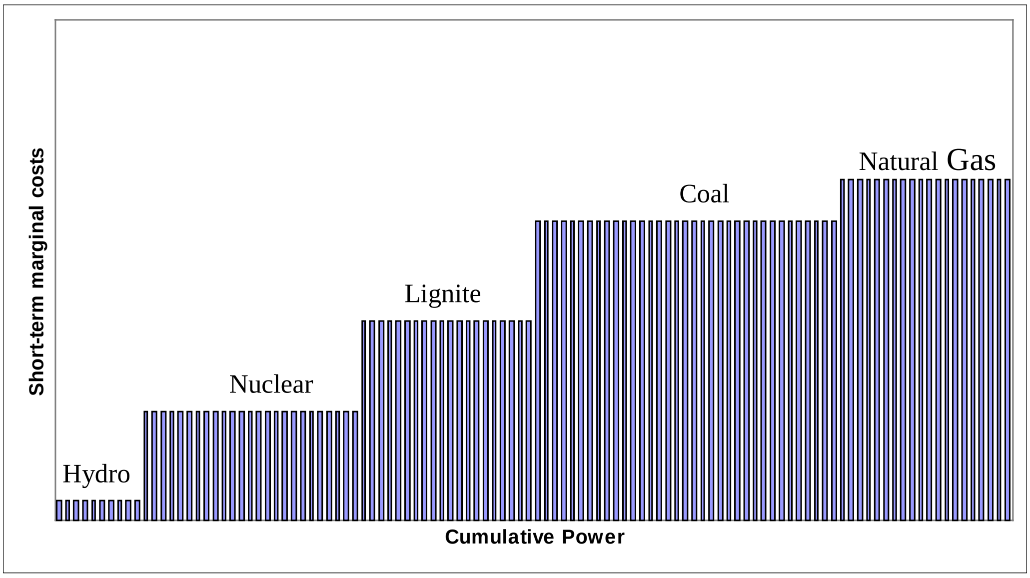

Fig. 3: Schematic depiction of short-term marginal electricity production costs depending on the fuel used (no CO_2 costs included)

The impact of CO_2 costs

Even though CO_2 emissions imply external costs[11] they are rarely included in the current production costs due to lack of appropriate regulation. However, in case this is done, production costs rises depending on the emission intensity and the costs of an allowance. Depending on the additional costs, the merit order curve may change (see Figure 4) and as a consequence the equilibrium price may also change. Some installations may be driven out of the market even though being fully economically viable if emissions face no costs.

[11] See for example Com (2003).

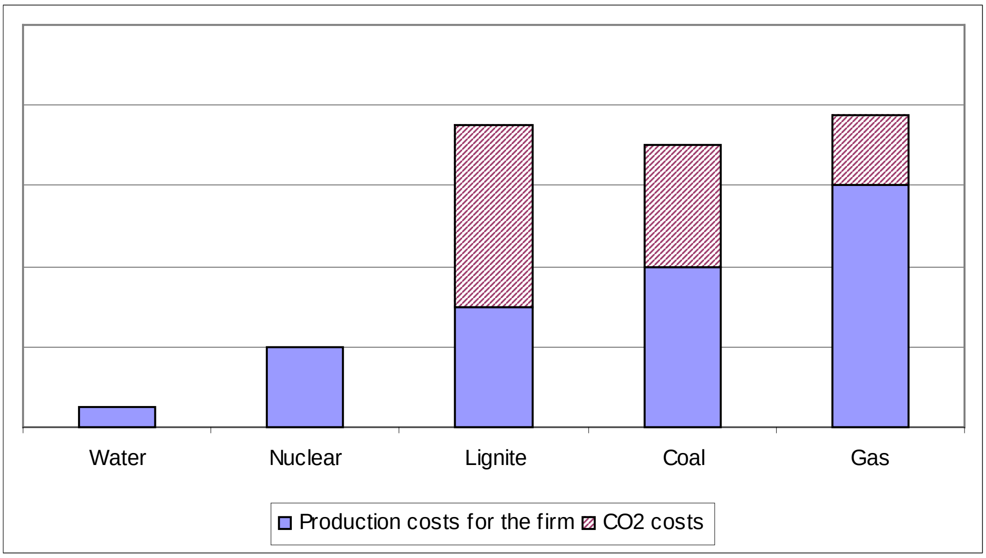

Fig. 4: Exemplary change in merit order due to impact of additional CO_2 costs

It this context it should be noted that primary objective of emissions trading is not to drive coal and lignite fired power plant out of the market as stated by UBS (2003). It is rather to meet a given target cost-efficiently. This driving out may be a result but not an objective of the instrument. If for example operators of a high emission intensive plant manage to establish "pure" production costs at a certain level so that total costs (incl. CO_2 costs) are lower than those of competing less emission intensive plants, the instrument could still be judged to be successful in the sense that the total emission target is met.

4.2 The Model

To analyse the impact of different allocation option in multi-period emission trading in the electricity sector a power market is simulated. Effects outside the power sector, as for example effects on the labour market, are not considered.

The market[12]

Two periods (years) are studied. The market is perfectly competitive. The supply side consists of i = 1, 2, …N installations which are run by either water, uranium, lignite, coal or gas.

[12] Specific characteristics are provided in the data section that follows.

The individual supply curve for hour t is as follows:

$S^i_{t,r} = (c^i_r + k^i_r) q^i_{t,r}$ if $(c^i_r + k^i_r) \leq p_{t,r}$ (1a)

$S_{i,t} = 0$ if $(c^i_r + k^i_r) > p_{t,r}$ (1b)

s.t. $q^i_{t,r} \leq q^i_{\max}$ (2)

with $k^i_r = e^i p^{CO_2}_r$

Where $S^i_{t,r}$ = supply of installation i in hour t in period r (MW), which results in a corresponding production of (MWh), c^i_r = short term marginal costs of installation i in period r (Euro/MWh), k^i_r = specific CO_2 costs for installation i in period r (Euro/MWh), $q^i_{t,r}$ = power of installation i in hour t in period r (MW), $p_{t,r}$ = electricity price in hour t and period r (Euro/MWh), e^i = emission intensity of installation i (t CO_2/MWh), $p^{CO_2}_r$ = costs of CO_2 allowances in period r, which is equal to the market price (Euro/t CO_2), $q^i_{\max}$ = nameplate power of installation i (MW)

Adding up the individual supply curves we get the cumulative supply:

$$S_{t,r} = \sum_i S^i_{t,r} \quad (3)$$

Where $S_{t,r}$ = cumulative supply in hour t and period r (MW)

Demand in this short-term study is assumed to be inelastic. Modern societies depend on electricity and substitutes are hard to find and hard to be implemented in the short-run. People will continue to switch on their fridges to cool their food in the near future even if prices increase. Bower et al. (2001, p. 998) assume an inelastic demand for electricity prices below 125 Euro / MWh which is already very high. The inelastic, exogenously given demand is denoted by $D_{t,r}$.

As the short-term market is analysed, supply and demand are balanced hourly as for example in Bower et al. (2001). As no storage option is considered we get the equilibrium for each hour directly as follows:

$$S_{t,r} = D_{t,r}$$

There is only one market considered. No distinction between industrial and private consumers is made. Furthermore, neither transmission fees nor taxes are considered.

The allocation

The allocation of allowances is restricted to CO_2 emitting plants.[13] Two different allocation options are applied: an emission based and a benchmark based approach. Remember that a benchmark is identical to an output based allocation. Furthermore, both approaches are distinguished regarding the design over time. More precisely, a constant and rolling approach are proposed. A constant allocation means that emissions rights in both periods are allocated on the basis of (the same) data of the reference period. On the other hand, the distribution is always based on the data of the previous period in a rolling allocation. The allowances are given to the installation for the whole year and are also calculated on this level. Thus, in total we get four different allocation possibilities for a single installation i that translate into formula as follows:

Emission based constant

$$A_r^i = \frac{\sum_t e_{t,0}^i q_{t,0}^i}{\sum_i \sum_t e_{t,0}^i q_{t,0}^i} * A_r \qquad (5)$$

Emission based rolling

$$A_r^i = \frac{\sum_t e_{t,r-1}^i q_{t,r-1}^i}{\sum_i \sum_t e_{t,r-1}^i q_{t,r-1}^i} * A_r \qquad (6)$$

Benchmark constant

$$A_r^i = \frac{\sum_t q_{t,0}^i}{\sum_i \sum_t q_{t,0}^i} * A_r \qquad (7)$$

Benchmark rolling

$$A_r^i = \frac{\sum_t q_{t,r-1}^i}{\sum_i \sum_t q_{t,r-1}^i} * A_r \qquad (8)$$

where A_r^i = allocation to installation i in period r, A_r = total quantity of allowances to be distributed in period r

Emission abatement

Emission abatement options and costs differ widely among installations. Apart from the fuel applied, the age and retrofit measures taken in the past are important factors. However, as the focus is on the multi-period allocation and the market effect, no concrete abatement costs are considered when calculating the profit below. An arbitrary assignment of different mitigation options to the single plant has not been judged reasonable. Rather the same costs - the carbon price on the allowance market – are used for all installations. This implies a worst case analysis as the market price is the highest

[13] This does not seem to be obviously. Burtraw et al. (2002) allocate allowance to non-hydro renewable sources, too.

cost a firm will have to bear. In case its abatement costs are below the market price, compliance costs would be lower. The firm can abate more than necessary to meet its target and sell allowances one the market. This worst case analysis would be the realistic scenario in case the sector as a whole would buy emission rights from cheaper abatement options from outside the sector, as for example by investing in CDM projects.

The overall financial impact

Finally, the financial impact consisting of the market effect and the compliance costs can be calculated as follows:

$$P_r^i = \sum_t (p_t - c_r^i) q_{t,r}^i - (e^i q_{t,r}^i - A_r^i) p_r^{CO_2} \qquad (9)$$

Where P_r^i = profit of installation i in period r (EUR)

The second product on the r.h.s. of the equation constitutes the compliance costs discussed above.

4.3 The Data

On the supply side 110 power plants have been introduced. Table 1 gives an overview on type, capacity, specific emissions and costs. The latter are constant over the two periods.

Tab. 1: Portfolio of power plants used in the simulation[*)]

Type of plant	Number	Net-capacity (MW)	CO_2 intensity (kg CO_2/MWh)	Short-term marginal costs for the producer (EUR/MWh): Literature [**)]	Used in the simulation
Hydro	10	100	0	0 - 4,4	2
Nuclear	25	800	0	0 - 15	5
Lignite	20	350	1000	10 - 21	12
Coal	35	300	800	5 - 22	15
Natural Gas	20	150	350	10 - 37	20

[*)] Based on Balmorel (2001), Bower et al. (2001), Rowland et al. (2003), Leyva et al. (2003), UBS (2003), UCTE (2002).
[**)] Differences can be explained by different definitions. Lowest figures only comprise fuel costs whereas higher ones contain all costs of keeping the plant running. Not all studies provide cost data for each type of plant. Regardless of absolute differences, all studies but one result in the same merit order curve as depicted in Figure 3.

On the demand side three seasons are distinguished: Summer, winter and transition (see Figure 5). The two former comprise 90 days each and the later 180. The trend is based on UCTE (2002). Thus, total annual energy demand amounts to 275 TWh. Maximum demand is 39479 MW in the winter between 11 and 12 am. As the focus in on the allocation and market effect, the same annual demand is assumed for all years.

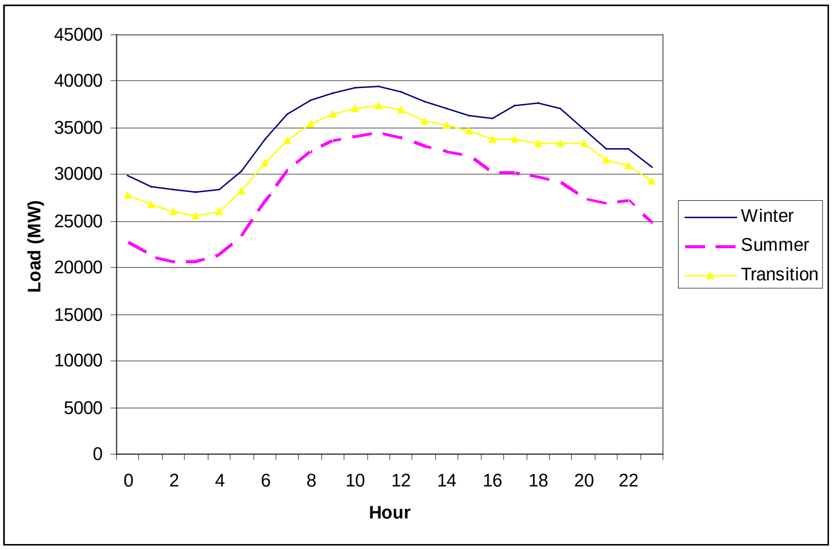

Fig. 5: Load curves as used in the simulation

There are a lot of studies dealing with the carbon prices for different kinds of trading schemes. An overview of model results is given by Springer (2003). Prices for Annex B trading CO_2 only are reported to range from 3 to 71 US$/t CO_2. Allowance prices for the EU trading scheme are currently about 12 EUR / t CO_2 (Point Carbon 2004) and CER from CDM projects, which are likely to be eligible within the EU scheme sell at about 5 EUR. Thus, two different carbon prices are studied, 5 and 20 EUR/ t CO_2.

The total allowance budget is set in such a way, that emissions decline compared to the reference period by 5 % in the first and by 10 % in the second period.

4.4 Results

In order to be able to better compare the different allocation schemes a reference scenario with two periods and no carbon costs has been studied. To give a first idea of the impact of the model assumptions, Table 2 shows the change of the merit order and the resulting change in electricity generation for different plant types. As can be seen, with the assumptions made, there are no changes with a carbon price for CO_2 of 5 EUR/t. However, with a carbon price of 20 EUR/t the total production alters. As one would have expected there are no changes for the emission-free plants, i.e. hydro and nuclear plants. Regarding the CO_2-emitting installations, one can see that production is shifted from the emission intensive to the less intensive.

Tab. 2: Electricity generation with different carbon costs cumulated over two periods

Type of plant	Production of all plants; carbon costs: 0 EUR/t CO_2 (GWh)	Production of all plants; carbon costs: 5 EUR/t CO_2 (GWh)	Production of all plants; carbon costs: 20 EUR/t CO_2 (GWh)
Hydro	17280	17280	17280
Nuclear	345463	345463	345463
Lignite	110196	110196	12423
Coal	76634	76634	125391
Gas	427	427	49443
Total	550000	550000	550000

As mentioned in the analytical section above there will be a price effect that affects all plants regardless of the emission intensity. Table 3 and 4 show this effect in detail. The row “Change in gross margin” refers to the market effect only and describes the change regarding the variable gross margin (see also the minuend in equation 9). The row “Compl. Costs” on the other hand describe the compliance costs for meeting the emission target (see also subtrahend in equation 9). The net-effect can be determined by subtracting the compliances costs from the absolute change. (In case the figure is positive, the group of plants as a whole has realised windfall profits)

As can be seen, the total changes are always the same, i.e. the electricity sector as a whole benefits from the introduction of the scheme. In contrast, plant-type specific changes depend on the allocation rule. Remember that the absolute figures are a consequence of the assumptions stated above as for example a completely inelastic demand in the short-term market. Thus, it is should be interpreted more qualitatively.[14]

[14] The fact that the gas-fired power plants do not realise any gross margin in the reference case is due to the fact that they represent the marginal plant and that all plants are assumed to have the same marginal costs. With more differentiated cost assumptions this would change. However, the objective of the paper is to study the group of plants as a whole.

As mentioned above, different allocation rules do have distributional effects on certain plant types that depend on the costs for emitting CO_2. Non-emitting plants always face the same changes. They earn only windfall profits due to the introduction of the trading scheme.[15] As carbon costs of 5 EUR/t CO_2 do not have an impact on the total production of certain type of plant (i.e. hydro, lignite etc.), there is no difference between a constant and rolling approach for the same class of allocation, i.e. the emission-based and the benchmark approach. However, there is a difference between the classes.

It is conspicuous that gas-fired power plants realise negative compliance costs with a benchmark allocation. As has been mentioned above, a benchmark allocation only refers to output and not to emissions. Obviously, gas-fired plants receive more allowances than they need to be compliant.

The picture changes slightly with higher emission costs. As could be seen in Table 2 lignite fired plants lose market shares. This is why they can sell surplus allowances that in turn result in negative compliance costs. Contrary to the case with low costs, there are now differences between the constant and the rolling approach within the two allocation classes. The concrete impact depends on whether the plants' production increases or decreases. The installations preferences are depicted in Table 5.

[15] More precisely they earn windfall profits as long as the marginal plant is a fossil-fuelled one.

Tab. 3: Model results over two periods for the four different allocation rules and a carbon price of 5 EUR/ t CO_2

	Reference (no CO_2 cost)	Emission based constant			Emission based rolling			Benchmark constant			Benchmark rolling		
Type of plant	Total variable gross margin (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)
Hydro	214	69	32	0	69	32	0	69	32	0	69	32	0
Nuclear	3251	1390	43	0	1390	43	0	1390	43	0	1390	43	0
Lignite	309	221	72	224	221	72	224	194	63	251	194	63	251
Coal	38	165	436	125	165	436	125	191	506	98	191	506	98
Gas	0	0.4	/	0.3	0.4	/	0.3	1	/	-0.4	1	/	-0.4
Total	3812	1845		349	1845		349	1845		349	1845		349

Tab. 4: Model results over two periods for the four different allocation rules and a carbon price of 20 EUR/ t CO_2

	Reference (no CO_2 cost)	Emission based constant			Emission based rolling			Benchmark constant			Benchmark rolling		
Type of plant	Total variable gross margin (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)	Change in gross margin (Mill. EUR)	Change (%)	Compl. Costs (Mill. EUR)
Hydro	214	280	131	0	280	131	0	280	131	0	280	131	0
Nuclear	3251	5598	172	0	5598	172	0	5598	172	0	5598	172	0
Lignite	309	999	324	-1059	457	148	-518	890	288	-950	373	121	-433
Coal	38	746	1974	1279	1157	3060	868	852	2255	1173	1110	2938	915
Gas	0	212	/	344	343	/	213	215	/	341	475	/	82
Total	3812	7835		564	7835		564	7835		564	7835		564

Tab. 5: Preference of different type of plants for different allocation rule as a function of the carbon costs

Type of plant	Preference	Carbon costs (EUR / t CO_2) 5	20
Hydro		Indifferent	indifferent
Nuclear		Indifferent	indifferent
Lignite	1.	Emission based	Emission based constant
	2.		Benchmark constant
	3.	Benchmark	Emission based rolling
	4.		Benchmark rolling
Coal	1.	Benchmark	Emission based rolling
	2.		Benchmark rolling
	3.	Emission based	Benchmark constant
	4.		Emission based constant
Gas	1.	Benchmark	Benchmark rolling
	2.		Emission based rolling
	3.	Emission based	Benchmark constant
	4.		Emission based constant

As can be seen in Table 5, the preferences vary strongly among the different fossil-fuelled plants. With the carbon prices studied, the lignite-fired power plant operators would always prefer the emission based constant approach, whereas the gas-fuelled plant operators would prefer the rolling benchmark as basis for the allocation. Operators whose plants use coal do not have a clear preference. Plant operators may take these results in mind when lobbying for a certain design of the trading scheme. On the other hand, politicians may use it when framing their general energy policy.

5 Conclusion

Emission trading offers the opportunity to limit GHG emissions into the atmosphere cost-efficiently. This is one reason why the EU decided to implement a Europe-wide trading scheme for major source such as combustions plants with a thermal power larger than 20 MW. Thus, the majority of the electricity sector must participate. However, a lot of detailed design issues have not been decided yet. The question of how to allocate emission allowance over time is one of them.

This paper has analysed this point using the electricity sector as an example. Using a stylised power market, four different allocation options have been used to analyse the resulting impact on different types of plant. It turned out that the electricity sector as a whole is likely to benefit from the introduction of the trading scheme as long as the allowances are distributed free of charge. The results, however, must be interpreted with some caution as some simplified assumptions were made.

Non-emitting facilities as for example hydro or nuclear plants are indifferent with regard to the allocation rule. They always realise windfall profits as long as the marginal plant is fossil-fuelled. With regard to the later group of plants, it was shown that the preferences depend on the fossil fuel used as well as on the carbon costs. The result may serve decision makers in industry and policy during the negotiations on the design of the scheme.

Future work will use more specific data on both supply and demand side. Furthermore, the time period may be extended to allow new plants to enter the market. A more detailed distinction on installation level between abatement costs and compliance costs is also of interest though such data may be hard to get.

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7 Annex

How does a benchmark based allocation work?

In this analysis the term "benchmark" is used in the sense of a specific emission factor, i.e. $\frac{emissions}{output}$.[16]

The allocation based on a general benchmark could be calculated as follows

$$A_r^i = s_{r-j} q_{r-j}^i \qquad (10)$$

where A_r^i = allocation to installation i in period r, s_{r-j} = benchmark in period r-j, q_{r-j}^i = output of installation i in period r-j

An alignment between a bottom-up (benchmark) approach and a top-down constraint as set by the Kyoto targets requires the consideration of the constraint given in inequality (6). A straightforward approach would be the introduction of a period-specific correction factor c_r as discussed for example in PwC (2003) and AGE (2001)

$$c_r = \frac{A_t}{\sum_i A_r^i} \qquad (11)$$

Taking into account this factor, (10) changes to

$$A_r^i = s_{r-j} q_{r-j}^i c_r \quad \Leftrightarrow A_r^i = s_{r-j} q_{r-j}^i \frac{A_r}{\sum_i A_r^i} \quad \Leftrightarrow A_r^i = s_{r-j} q_{r-j}^i \frac{A_r}{\sum_i s_{r-j} q_{r-j}^i}$$

$$\Leftrightarrow A_r^i = \frac{q_{r-j}^i}{\sum_i q_{r-j}^i} A_r \qquad (12)$$

A_r = total quantity of allowances to be distributed in period r

As one can see, a benchmark based allocation which takes into account the national budget (e.g. the Kyoto Commitment), results in an individual allocation which is only proportional to a participant's output in a certain period and not at all related to emission intensities. This might be somewhat surprising as the intention of the use of a benchmark is generally to consider the specific emissions.[17]

[16] Theoretically, any benchmark as, for example, labour productivity or turnover could be used for allocation. For an emission benchmark, other reference figures than the output could also be used.
[17] Compliance costs may of course differ.