Deutsches Institut für
Wirtschaftsforschung

DIW BERLIN

Discussion Papers

1097

Michael Pahle • Lin Fan • Wolf-Peter Schill

How Emission Certificate Allocations Distort Fossil Investments
The German Example

Berlin, January 2011

IMPRESSUM

DIW Berlin
German Institute for Economic Research
Mohrenstr. 58
10117 Berlin

Tel. +49 (30) 897 89-0
Fax +49 (30) 897 89-200
http://www.diw.de

ISSN print edition 1433-0210
ISSN electronic edition 1619-4535

Papers can be downloaded free of charge from the DIW Berlin website:
http://www.diw.de/discussionpapers

Discussion Papers of DIW Berlin are indexed in RePEc and SSRN:
http://ideas.repec.org/s/diw/diwwpp.html
http://www.ssrn.com/link/DIW-Berlin-German-Inst-Econ-Res.html

How emission certificate allocations distort fossil investments: the German example[1]

Michael Pahle[a], Lin Fan[b], Wolf-Peter Schill[c]

[a] Potsdam Institute for Climate Impact Research, Telegrafenberg A51, 14473 Potsdam, Germany, michael.pahle@pik-potsdam.de
[b] Department of Geography of Environmental Engineering, The Johns Hopkins University, 3400 North Charles Street, Baltimore, MD, 21218, U.S.A, lfan@jhu.edu
[c] DIW Berlin, Department of Energy, Transportation, Environment, Mohrenstraße 58, 10117 Berlin, Germany, wschill@diw.de

Abstract
Despite political activities to foster a low-carbon energy transition, Germany currently sees a considerable number of new coal power plants being added to its power mix. There are several possible drivers for this "dash for coal", but it is widely accepted that windfall profits gained through free allocation of ETS certificates play an important role. Yet the quantification of allocation-related investment distortions has been limited to back-of-the envelope calculations and stylized models so far. We close this gap with a numerical model integrating both Germany's particular allocation rules and its specific power generation structure. We find that technology specific new entrant provisions have substantially increased incentives to invest in hard coal plants compared to natural gas at the time of the ETS onset. Expected windfall profits compensated more than half the total capital costs of a hard coal plant. Moreover, a shorter period of free allocations would not have turned investors' favours towards the cleaner natural gas technology because of pre-existing economic advantages for coal. In contrast, full auctioning of permits or a single best available technology benchmark would have made natural gas the predominant technology of choice.

Keywords: Emissions trading; Allocation rules; Power markets; Investments

JEL: Q48, Q54, Q58

[1] We would like to thank Jochen Diekmann for insightful comments.

1. Introduction

During the last years considerable investments in new coal capacities were brought on the way in the German electricity sector. In total ten plants are currently under construction, which after completion will add around 11.3 GW to the market (BUND, 2010). Besides, there are plans for more than 12 additional plants. Taking together all projects – the majority of them hard coal – possible expansions amount to approximately 32% of German peak electricity demand in 2008 (Bundesnetzagentur, 2009). Realizing that for several years after liberalization in 1998 natural gas was the predominant option (Brunekreeft and Bauknecht, 2006), this development constitutes a dramatic shift in technology choice.

In a hierarchical analysis, Pahle (2010) explores drivers and decision factors that may have given rise to this “dash for coal”. Several factors are identified which suggest themselves as necessary conditions or drivers. Among them, the German national allocation plans (NAPs) of the EU Greenhouse Gas Emission Trading System (ETS) have presumably played an important role by providing free certificates for new entrants according to fuel specific benchmarks – see overviews by DEHSt (2005) for NAP I and Schleich et al. (2009) for NAP II. For conventional fossil fuels this implies that the “dirtier” technology coal received a higher absolute allocation than its “cleaner” competitor natural gas. Electricity generators were able to pass through opportunity costs for free certificates and earned additional windfall profits – see for example Sijm et al. (2006) and Zachmann and von Hirschhausen (2008). Accordingly, investment incentives were biased towards the dirty technology. This distortion has been widely acknowledged in the literature, for example by Ellerman (2008), Neuhoff et al. (2006a) and Neuhoff et al. (2006b). In this article, we use a numerical model to quantify the effects of German allocation rules on thermal investment decisions in Germany around the year 2005. We find that the windfall profits created by NAP I have further increased an already existing preference for coal investments compared to natural gas. In contrast, counterfactual allocation rules like full auctioning of permits or a single best available technology benchmark would have substantially increased natural gas investment incentives.

Research to assess and quantify the created economic incentives has been surprisingly sparse so far. Kemfert et al. (2006) analyze several environmental and economic effects of European emissions trading. However, they do not explicitly examine power sector investment incentives. In an interview-based study of investment decisions in the German power sector, Hoffmann (2007) draws an ambiguous picture of the EU ETS influences. On the one hand, investments still depend on fundamentals, in particular on fuel prices and respective scenarios. On the other hand, there is evidence that “current projects are only profitable due to the development of the EU ETS” and “did not work out in 2003 due to the […] non-existence of the EU ETS”. Additional support comes from numerical models, albeit applied to other countries (cp. Burtraw and Palmer, 2008). For the UK Neuhoff et al. (2006a) confirm additional coal power plant investments, but also acknowledge that results may invert if assumptions on gas prices and investor expectations are changed. Laurikka and Koljonen (2006) compare investment opportunities for gas and coal plants in Finland under uncertainty, using stochastic electricity and certificate prices. They conclude that the allowance market can have significant impact on the expected profitability of gas plants, whereas the value of new coal plant investment remains mainly unaffected. Because they do not take account of passed-through opportunity costs and windfalls profits, their results fall short of assessing the above mentioned investment distortion. One of the few contributions so far explicitly integrating windfall profits is Taschini and Urech (2009), who analyze how expected windfall profits will affect operation and profitability of different technologies. They find that when opportunity costs are internalized, there is a shift towards coal-fired generation somewhat contrary to intuition. However, they use a rather stylized model and a fixed allocation regime not adapted to any particular market. In summary, the distortionary effect of a fuel-specific new entrant reserve and windfall profits on investment and technology has not been quantified for Germany so far (cp. Hentrich et al., 2009), where perverse outcomes have been most evident. This article aims to fill this literature gap for Germany, where the above described “dash for coal” suggests that respective distortions in fact played an important role.

Our analysis is based on a discounted cash flow (DCF) model similar to Laurikka & Koljonen (2006) who use a stochastic price distribution. Investment options are evaluated by their overall performance in the market according to the net present value (NPV) criteria. Related literature applies real options methods (see for example Reedman (2006), Blyth et al. (2007), Reinelt and Keith (2007), Szolgayova et al. (2008), Patiño-Echeverri et al. (2009)), which considers the value from obtaining information on future uncertainty. But they rely on an exogenous stochastic price process. In contrast, we deterministically compute both the price of electricity and the quantity a plant can sell endogenously, based on a detailed representation of demand and supply (merit order). A comparable method has been used for example by Weigt and von Hirschhausen (2008) for an analysis of short term market power in the German wholesale market. Other applications include the impact of carbon pricing on cycling costs (Denny and O'Malley, 2009). In this case, combining DCF with a merit order representation poses the distinctive advantage to have a bottom-up representation of fuel costs and allocation schemes. Due to this prices and cash flows can be determined by means of fundamentals, which is an essential requirement in face of our research question.

We retrospectively look at the year 2005 when the ETS became effective. From this point of reference, we analyze the bias created by free allocation of certificates for either hard coal or natural gas towards the choice of a pending capacity investment. Doing so implicitly assumes that both technologies are the only viable alternatives[2]. Effectively, this breaks down to a comparison of relative rather than absolute profitability, which proves to have important influence on methodology and calibration. An important point in this regard is that we do not intend to capture actual investment decisions, but rather quantify the relative impact on profitability of different technologies.

We also investigate the impact of the length of the period with free allocation on investment decisions. In particular, we are interested in how its length will affect the investment value through the cash flow over the plant’s lifetime. A crucial role is played by the discount factor, which determines how important the investor considers future

[2] For further argumentation that this indeed applied to the German situation see Pahle (2010).

revenues. For example, a high discount factor enforces the effect of an initial free allocation period because the investor puts less weight on future gains, and vice versa. Bergerson and Lave (2007) compare investment values under different schedules for carbon taxation and discount rates (private, social). In accordance to their findings our results also suggest that the interplay of discounting and transitional policy periods may be of high importance for power sector investments. Nonetheless, we find that shorter free allocation periods would not have been sufficient to reverse the economic preference for coal under initial allocation rules (NAP I).

Although our analysis has a retrospective focus, we touch a very topical issue here as several currently unresolved questions could benefit from hindsight. For example, the discussion about initial allocation and efficiency of a trading scheme currently seems to gain new momentum (Hahn and Stavins, 2010). However, sound scientific evidence of this issue is yet far from comprehensive, and mostly early and partly preliminary results dominates the discussion like for example in Convery (2009). Especially inframarginal rents due to free allocation as well as the particular rationality of certificate costs pass-through are still only roughly quantified and vaguely understood (Keppler and Cruciani, 2010). Our findings may thus sharpen understanding and provide helpful information for the design of future allocation schemes.

The remainder is structured as follows. Section 2 introduces the methodology and the model. Section 3 includes all relevant data and parameters. Section 4 discusses the results. The last section summarizes and concludes.

2. Methodology & Model

2.1 Investment rationale

We model the investment decision of a generator building a new centralized fossil power plant of typical size (1000 MW). The technologies (k) under comparison are hard coal (HC) and natural gas (NG). The preferred technology is determined by the relative difference of the net present values (NPV) over the financial lifetime (T_{FL}) between either option.

The primary cash flow of the plant is determined by two factors: the overall number of hours the plant can sell to the market (full load hours) and the price of electricity p_{el} in respective periods[3]. The electricity price is derived endogenously from the merit order based on generators' supply bids and (exogenous) demand in the market[4]. Demand is represented by different periods j subsuming hourly fluctuations over the year. It is characterized by demanded quantity in $d(j)$ in GW and duration $hr(j)$ in hours. We assume marginal cost pricing, thus in each of these periods the electricity price equals the generating costs of the marginal plant. In consequence the new plant sells to the market if

[3] We assume that the plant just sells electricity to the German wholesale market. We neglect possible additional revenues from the balancing market, as this market is beyond the scope of the article.
[4] We only consider the wholesale market that is completely separated from the balancing market in Germany.

demand exceeds its specific position in the merit order, i.e. when it is submarginal as specified in the generation subset of demand (*GEN*). Thus the generator acts as a price-taker implying that the new capacity is small compared to the overall market and not part of a larger portfolio which could offer strategic options[5]. Other operating constraints like ramping times are excluded for sake of simplicity.

The cost of generating electricity consists of two parts. First, variable costs depending on the fuel price p_{fuel}(k,t) and the price of CO_2 certificates p_{CO2}. And second, capital costs per unit c_{cap}(k) for the initial investment and fixed O&M costs $c_{OM,k}$(k) per year. Yet only the variable costs do affect price formation. To compute fuel and emissions costs, the thermal efficiency $\eta(k)$ of the technologies is required. Moreover, the number of CO_2 certificates required for compliance is determined by the carbon emission factor *cef*(k), which specifies emissions per unit of fuel used. We allow for asymmetric cost pass-through by differentiating between actual costs of generation – which include full carbon costs – and generators' supply bids *bid(k,t)* to the wholesale market. A generator's bid only includes a fraction of the full CO_2 costs given by the pass-trough rate *ptr(k,t)*. We provide further explanation of asymmetric cost pass-through in section 2.2.

Another essential feature of the model is the inclusion of two succeeding periods of emission trading: at first, for a certain time span T_{FA}, permits are allocated for free according to a certain scheme which quantifies the allocation *alloc(k)* per MW installed capacity and year (see Section 3)[6]. This endowment – multiplied by plant size and CO_2 price – constitutes an additional positive cash flow. During the second period, extending over the remaining years (T_{AUC}), permits are auctioned and must fully be bought from the permit market, which implies a purely negative secondary cash flow and thus no windfall profits.

The NPV is evaluated over the financial lifetime of the potential plant. It comprises the initial capital expenditure as project costs and the sum over the future discounted profits as cash flow. The discount rate δ used is understood as a specific mark-up inherent to the project that resembles the associated risks and thus the investor's myopia. The overall model reads (see Table 2.1 for a description of sets, indices, parameters and variables):

$$
\begin{aligned}
NPV(k) = \; & -cap(k)\cdot c_{cap}(k) \\
& -\sum_{t\in T_{FL}} cap(k)\cdot c_{OM}(k)\cdot(1+\delta)^{-t} \\
& +\sum_{t\in T_{FA}}\left\{\sum_{j\in GEN(k,t)}[p_{el}(j,t)-c_{el}(k,t)]\cdot cap(k)\cdot hr(j)+alloc(k)\cdot cap(k)\cdot p_{CO2}(t)\right\}\cdot(1+\delta)^{-t} \\
& +\sum_{t\in T_{AUC}}\left\{\sum_{j\in GEN(k,t)}[p_{el}(j,t)-c_{el}(k,t)]\cdot cap(k)\cdot hr(j)\right\}\cdot(1+\delta)^{-t}
\end{aligned}
$$

[5] This corresponds best to an independent power producer operating a single merchant plant.
[6] We assume free allocation without ex-post correction. Generators receive a certain amount of certificates which is not adjusted later on according to actual electricity generation.

where

$$c_{el}(k,t) = \left[p_{fuel}(k,t) + p_{CO2}(t) \cdot cef(k) \right] / \eta(k)$$

$$bid(k,t) = \left[p_{fuel}(k,t) + ptr(k,t) \cdot p_{CO2}(t) \cdot cef(k) \right] / \eta(k)$$

$$GEN(k,t) = \left\{ j \mid p_{el}(j,t) > bid(k,t) \right\}$$

Table 2.1: Sets, indices, parameters and variables

	Description	Unit
Indices		
t	Year index relative to base year (2005)	
k	Technology index: hard coal (HC), natural gas(NG)	
j	Demand period index	
T_{FL}	Time span in years over which the NPV is evaluated	
$T_{FA} \subseteq T_{FL}$	Subset of T_{FL} in which certificates are allocated for free	
$T_{AUC} \subseteq T_{FL}$	Subset of T_{FL} in which certificates are auctioned	
Exogenous Parameters		
cap(k)	Capacity of the model plant	MW
d(j)	Demand	GW
hr(j)	Number of hours per year in which demand equals d(j)	hr
$c_{cap}(k)$	Capital costs	€/kW
$c_{OM}(k)$	O&M costs	€/(MW*a)
$p_{fuel}(k,t)$	Fuel price	€/MWh_{th}
$p_{CO2}(t)$	Price of CO_2 certificates; corresponds to pass-through in T_{GF} and full market price in T_{AUC}	€/t
$c_{el}(k,t)$	Variable costs of electricity	€/MWh_{el}
alloc(k)	Annual free allocation of certificates	t/MW
$\eta(k)$	Thermal plant efficiency	
cef(k)	Carbon emission factor	t/MWh_{th}
δ	Discount rate	
ptr(k,t)	Technology-specific pass-through rate of CO_2 costs	
Endogenous Variables		
$p_{el}(j,t)$	Electricity price set by variable costs with mark-up of carbon costs (pass-through) of marginal plant in each demand period	€/MWh
bid(k,t)	Supply bid to market	€/MWh
GEN(k,t) $\subseteq$ j	Subset of all demand periods where new capacity can sell to market	

2.2 Price formation, generation & CO_2 cost pass-through

An important feature of our analysis is the endogenous determination of electricity prices and full load hours to compute the NPV of a new plant. In order to do so, we make use of a detailed structural representation of the underlying market to create the merit order, i.e. the aggregated supply curve of all power plants. Figure 2.1 shows the stylized German merit order and demand distribution in the reference year for given fuel prices (see Section 3 for data and assumptions). It comprises all available generation capacities according to their short-run marginal costs, from renewables on the left to peaker plants on the right side.

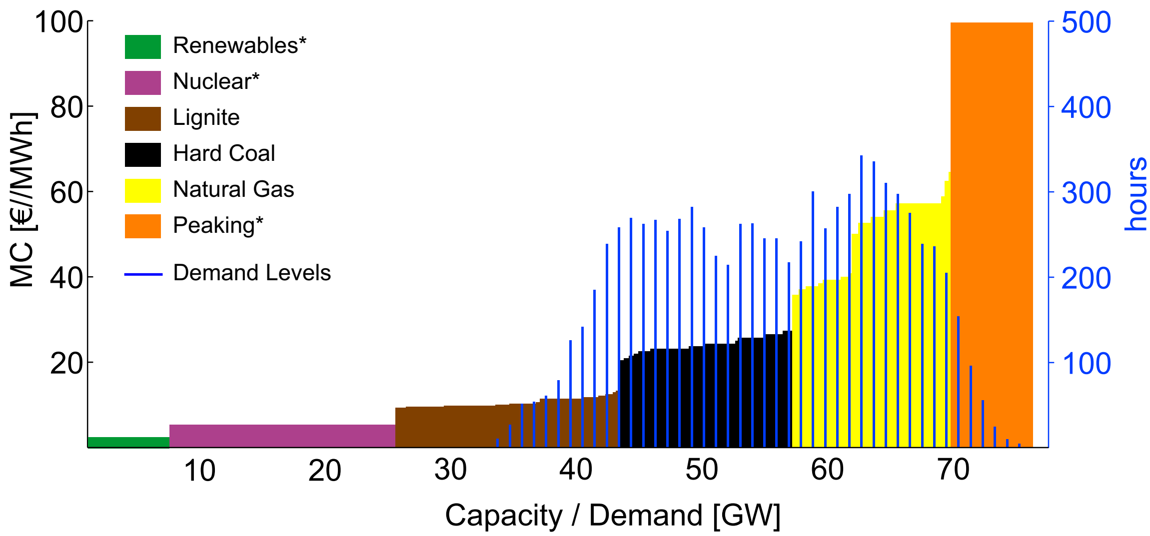

Figure 2.1: Stylized German merit order and demand distribution in reference year; w/o carbon costs; *stylized representation; (UBA 2009, ENTSO-E 2010, own calculations)

Over the course of a year demand varies to a considerable extent. Blue lines in Figure 2.1 represent all levels of demand thus indicating annual fluctuations. Due to the marginal cost pricing assumption a plant sells to the market during all periods in which demand exceeds its specific position in the merit order. In turn, given the frequencies of occurrence for different demand levels, this determines the number of full load hours.

Both electricity prices and plant-specific full load hours are thus highly dependent on the merit order. One of its essential characteristics in this regard is the stepped shape due to the different technologies with distinct cost structures. All capacities of equal technology are represented by a plateau that gradually rises from left to right, corresponding to a decreasing efficiency from new plants (left edge) to older plants (right edge). Less efficient capacities require a higher amount of fuel per unit output equating to higher marginal costs[7]. If a market based regulation of CO_2 is introduced, compliance costs are added to marginal costs. Figure 2.2 shows the modified German fossil merit order[8] with a carbon price of 15 €/t, which is fully added to variable costs (lighter shades indicate CO_2 costs).

[7] Natural gas plants include both gas turbines and combined cycle natural gas, which explains the jump in marginal costs within the gas block.
[8] In the following we will concentrate on the relevant fossil section of the merit order (lignite, hard coal, natural gas) were all relevant effects take place.

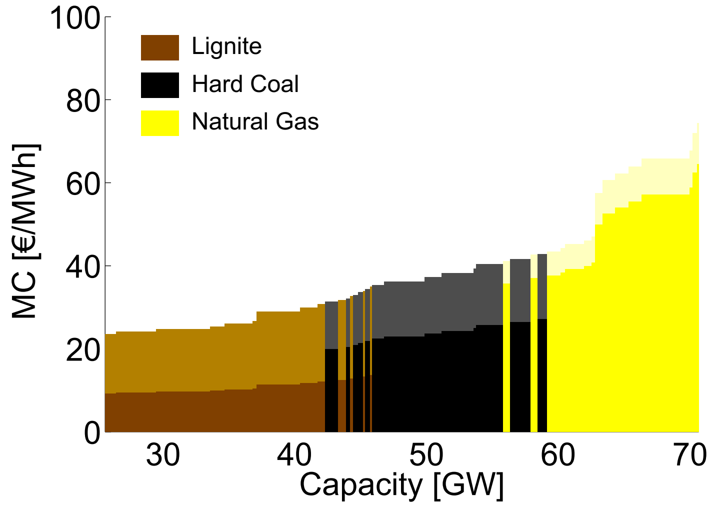

Figure 2.2: German fossil merit order (2005) with carbon costs of 15 €/t (lighter shades)

It can be seen that the strict separation into coherent blocks dissolves. This happens because technologies with low fuel costs are disproportionally affected by CO_2 costs due to higher emission intensity, in particular lignite and hard coal. As a result, the least efficient plants of one technology block “change positions” with the most efficient plants of the block to the right. That is, old lignite overlaps with new hard coal, and old hard coal with new natural gas. In consequence, the general shape of the merit order also becomes flatter, and the discontinuities between different technologies dissolve.

Under this situation relevant changes accrue to (a) the overall price formation in the market, and (b) the extent to which every single plant can sell to the market. The effect on prices (a) is global and emerges out of the increase of marginal costs in disproportion to fuel costs: the average level rises whereas the overall range is reduced due to the now flatter supply curve. The effect on generation (b) however is plant-specific: the modified marginal costs under CO_2 regulation may lead to a change of position of this plant in the merit order as explained above. In consequence, it can either increase or decrease its generation with a leftward or rightward shift respectively.

Figure 2.3 and Figure 2.4 show the effect of new capacities in more detail. They depict the position of the assumed model plant alternatives in the merit order (red outlines). Without CO_2 pricing (Figure 2.3), both plants are located at the left outer edge of their respective technology blocks and are relatively far apart. With CO_2 pricing however (Figure 2.4), blocks dissolve and the distance is reduced. This corresponds to a lower difference in annual full load hours (Δflh), depending on the exact distribution of demand in between. Moreover, the flatter shape of supply under CO_2 pricing also reduces the total marginal cost differential (Δmc) between the two options.

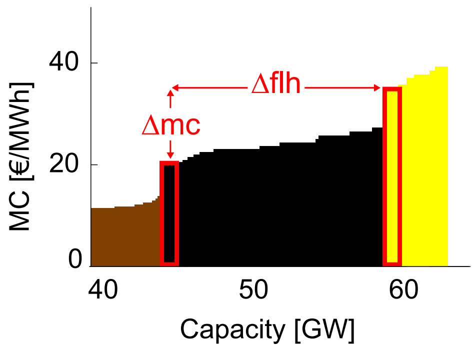

Figure 2.3: New plants w/o CO_2 costs

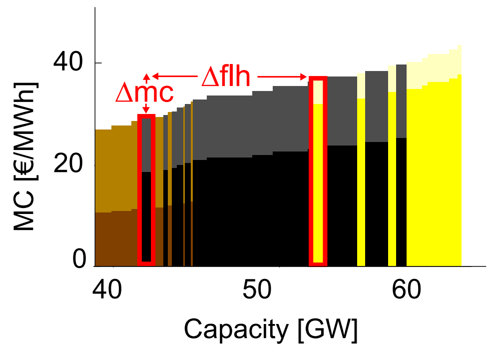

Figure 2.4: New plants with CO_2 costs

This situation would arise if carbon prices were fully added to variable generation costs. If we neglect strategic behaviour or inter-period constraints in electricity generation, it can be expected that rational market players pass through CO_2 costs completely to electricity prices. This holds for the case in which certificates are auctioned, but also in a setting where permits are grandfathered or allocated for free in another way (without ex-post correction). A profit-maximizing generator has to decide between (a) not generating electricity and selling the permits on the market, and (b) generating electricity and using the permits as a production factor. Generation will thus be an optimal choice only if the profit of generating electricity in case (b) does not fall below the profit of selling the permits in case (a). Accordingly, full pass-through is in principle a fully rational strategy, if some peculiarities of electricity generation are neglected.

Nonetheless, empirical analyses draw a different picture. For example, Sijm et al. (2006) show that pass-through rates in Germany reached 100% in peak times, but only around 60% in off-peak times[9]. In fact, agreement on the guiding rationalities for pass-through at lower rates than 100% is still pending; for a recent overview of arguments see Keppler and Cruciani (2010). Power plant owners may have a preference for generating electricity rather than selling permits, even if it is the less profitable alternative. Another possible answer is that rates were chosen according to technical constraints, namely operating constraints and related costs. Whereas natural gas plants are very flexible, coal plants generally have considerable ramping and start-up constraints which also affect total plant lifetime (Nollen 2003). A coal generator may find it more profitable to sell electricity below marginal costs in a given period than to stop generation during this period and face the ramping-related costs. In order to fully capture this effect, it would be necessary to use a bottom-up electricity generation model which includes inter-period constraints. As this is beyond the scope of this article, we make the simplifying assumption of technology-specific average pass-through rates that are constant over all hours of a year.

Following this line of argument, we assume that coal generators have a preference to retain their "old" position in the merit order. Lignite and hard coal operators set pass-

[9] Fell (2010) conducts an empirical estimation for the Nordic electricity market and finds that – in the short run – pass through rates are close to 100% also in off-peak times.

through rates such that technology blocks persist and fuel switch is avoided. This corresponds to a merit order as shown in Figure 2.5, in which shares not passed-through are indicated in light grey. It has been calculated by using the following heuristic: all gas plants are perfectly flexible and thus apply pass-through rates of 100%. The least efficient hard-coal plant chooses its pass-through rate such that it stays left of the most efficient gas plant. All other hard coal plants adjust their pass-through rates such that they stay left of the least efficient hard coal plant. The same procedure applies to the lignite plants. Performing this calculation for 2005 results in pass-through rates of 77% for lignite and 89% for hard coal[10]. Accordingly, generation technologies with lower technical flexibility have lower pass-through rates. Note that our rationale for asymmetric pass-through rates is based on technical considerations, not on market imperfections (cp. Fell, 2010).

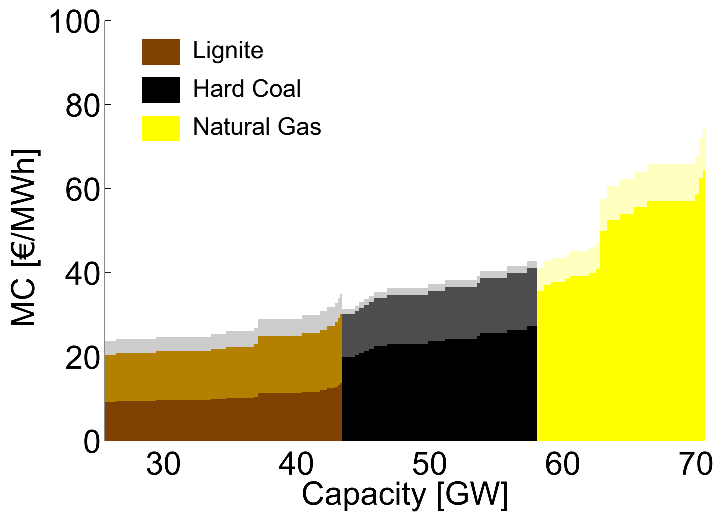

Figure 2.5: German merit order (2005) with carbon costs of 15 €/t and flexibility-constrained cost pass-through

The heuristic results in the merit order shown by Figure 2.5. It is used to calculate future prices and generation, which are important determinants of the NPV cash flow. In addition, we conduct a sensitivity analysis in section 4.5 in which the pass-through rate is equal to 100% for all technologies. By doing so, we assess the sensitivity of results to our assumption on technology-specific pass-through rates.

2.3 Limitations

The main benefit of our approach lies in making several quantities endogenous, which both is a requirement for our research questions and increases plausibility. Nonetheless, the overall methodology has some essential shortcomings. There are a number of influencing factors not taken account of that affect generation, price formation and investment rationales in electricity markets. First, as Blyth (2010) and Pahle (2010) point out, in practice the uptake of a certain technology may be influenced by other factors like technological spillovers, additional regulatory biases, or the adherence to an established

---

[10] Thus rates found are here are somewhere between the findings of Sijm et al. (2006) and full pass through. A higher CO_2 price assumption would result in lower rates closer to Sijm et al.

industrial structure. Second, on short time scales capacity outages, intermittent renewable generation, and ramping constraints lead to contractions and left-/rightward shifts of the fossil block in the overall merit order; also compare Weigt and Hirschhausen (2008). Third, over the course of the NPV evaluation period the market structure and generation mix is not static, but develops over time as new plants are built or old plants are decommissioned. Taking account of this would require a market investment model, which is both beyond the scope of this article and in many ways still considered a challenge (see for example Lise and Kruseman, 2008). Consequently we only operate with a static snapshot of the generation mix in 2005, leaving future investments – even foreseeable ones – aside. And fourth, if the new plant would be built by a generator owning additional plants, then the investment would be optimized given the whole portfolio. Such an investment decision is fundamentally different from the rational we consider. We acknowledge this by restricting our model to only capture a single merchant plant as explained above.

In summary, claiming that the resulting NPVs would be the only criterion for deciding on an investment of a certain technology is beyond the potential of our approach. Rather, NPV differences can be understood as one of many contributing factors that we measure by means of the described methodology and its restrictions. Notwithstanding these limits, our intention is not only to quantify the overall outcome, but also to shed light on the micro dynamic effects within the merit order out of which the NPV differences emerge. In fact, because of the investment assessment in relative rather than absolute terms, we level out several of the described distortions as they apply to both hard coal and natural gas capacities. By doing so, we reduce the main element of our analysis to the section of the merit order that separates the potential new hard coal plant from the potential new natural gas plant[11], namely the segment serving intermediate load. It is essentially this section that determines the difference in NPVs and thus the primary impact of free allocation vs. auctioning.

3. Model application

3.1 EU ETS and German allocation rules

EU ETS allocation rules were implemented by National Allocation Plans (NAP) for Phase I (2005-2007) and II (2008-2012) respectively[12]. In Germany a so called “new entrant” reserve provided certificates to newly built capacity based on technology-specific benchmarks derived from the “best available technology” (BAT)[13]. Both NAP I and NAP II define benchmarks of 0.75 tCO_2/MWh for hard coal and 0.365 tCO_2/MWh for natural gas respectively (Bundestag, 2004, 2007). However, designs differ considerably with regard to how many years a new plant is entitled to receive free allocation. NAP I grants free certificates for 14 years after commissioning (see Åhman et

[11] In Figure 2.1and Figure 2.5 for example, that section is identical to the full block of hard coal capacities.
[12] Ziesing et al. (2007) and DEHSt (2009) provide excellent overviews of the development of German allocation rules and the related political debate.
[13] This approach contrasts with the grandfathering mechanism, which has been used for existing power plants, drawing on historic emissions.

al., 2007)[14], whereas NAP II restricts provisions to Phase II regardless of when exactly the plant started operation; it thus covers a maximum of five years only. In addition, the NAPs differ in their assumptions on plant utilization, which has an important impact on the actual number of certificates allocated to a plant. NAP I basically guarantees coverage of total annual emissions from power generation by considering the expected yearly production of a plant (Bundestag 2004). Accordingly, new coal power plants receive more certificates than new natural gas plants not only explicitly due to higher technology-specific benchmarks, but also implicitly because of higher full load hours. In contrast, NAP II follows a non-discriminatory approach by assuming 7500 full load hours per year for either technology. Table 3.1 provides an overview of the allocation for the model power plants (1000 MW)[15].

Table 3.1: Annual allocations for model power plants (1000 MW) under NAP I and II

	NAP I	NAP II
Hard coal	5,25 Mt/a for 14 years (0.75t/MWh*7000h*1000MW)	5,625 Mt/a for up to 5 years (0.75t/MWh*7500h*1000MW)
Natural gas	2,0075 Mt/a for 14 years (0.365t/MWh*5500h*1000MW)	2,7375 Mt/a for up to 5 years (0.365t/MWh*7500h*1000MW)
Distortion towards coal	3,2425 Mt/a	2,8875 Mt/a
Assumptions drawing on Konstantin (2007)		

Considering that the value of emission certificates will be (partly) passed-through to customers, the new entrant provisions break down to a considerable economic advantage for hard coal due to the higher absolute allocations. The distortion was even higher in NAP I than in NAP II because of a longer duration and an allocation based on actual emissions. The relevant question thereby is whether the NAP revision induced a change in technology preference or retained the original one.

As said the German ETS was initiated with a pledge to generators guaranteeing free permit allocation to new plants for 14 years according to production needs (NAP I). Even though planning and constructing a power plant takes several years, early action and rapid realization could well have led to timely commissioning. Consequently, we use the total length (14 years) in the model application. Yet we do not restrict the analysis to the effects of the factual NAP I allocation, but also investigate investment incentives under the assumption that NAP II would have been applied from the beginning instead of NAP I. We also study the implications of two other counterfactual allocation rules: full auctioning (AUC) of all permits as well as the application of a single best available technology benchmark (SBAT), which explicitly favors carbon-efficient installations (Schleich et al. 2009). Under SBAT allocation rules, the extent of free permit allocation is determined by the requirements of the lowest-emission technology, i.e. natural gas

[14] Later on, the European Commission decided that free allocation provisions of NAP I had to be restricted to the first ETS period. Nonetheless, we assume that investors in 2005 assumed 14 years of free allocation. We further assume that there was no ex-post correction of free allocation, although this issue was not settled in Germany around the year 2005.

[15] We assume that new hard coal plants typically supply base load (about 7000 full load hours per year) and natural gas plants supply intermediate load (5500 full load hours per year), drawing on Konstantin 2007.

plants. Such an approach was initially planned to be implemented in Germany, but policy makers finally decided to apply a technology-specific benchmark in NAP I, largely because of industry concerns (Ziesing et al., 2007). In addition, we analyse a case without CO_2 regulation (NoREG) in order to establish a reference case.

Under any allocation mechanisms, the price for CO_2 certificates is both an important model parameter and relevant for determining windfall profits. For our ex-post analysis, it is important which expectations investors had at the base year 2005 about the long-term price development. As the market was newly created and subject to many distortions, it all but provided a stable signal and forecasts were rather vague. In this regard Capoor and Ambrosi (2006) report that during 2003 and 2004 "forward trading mostly responded to political and regulatory expectations rather than to market fundamentals". In fact, early estimates mainly relied on what the EU was envisaging and communicating to stakeholders. In 2003 Point Carbon (2003) reported that the EU Commission indicates a level of 15 €/t. However, during the first emissions trading year 2005 it actually turned out that prices stabilized at 20-25 €/t. Regarding price development, Point Carbon (2006) concluded at the end of 2005 that the market already responded to the fundamentals of power generation, which possibly indicated future price increases in the same order of magnitude as in the case of. As investors may well have anticipated additional pressure on the price through tighter political targets in the future, even higher expectations on price increases appear justified.

Following this argument and taking account of early signals, we assume an initial price of 20 €/t in 2005 and a yearly real growth rate of 2% in the baseline (cp. Table 3.4). In alternative scenarios, we assume a lower price path (15 €/t in 2005, +1% p.a.) and a higher one (25 €/t in 2005, +3% p.a.). These paths should cover many of the scenarios that actually existed on the investors' side. In particular, the implied extreme cases of around 18 and 45 €/t in 2025 represent the range of possible future emission prices widely discussed. It also should be noted that according to 2005 regulations we exclude the possibility of banking and borrowing certificates. Banking would have allowed investors to save up certificates that could be sold later in times of higher CO_2 prices. However, as discounting devalues banked certificates at higher rates (5-10%) than the increasing price of CO_2 would increase their value of (1-3%), banking would not have been an economic alternative whatsoever.

3.2 Fuel costs

Besides the costs of carbon, investment profitabilities are highly sensitive to fuel costs. In 2005 border trade prices for hard coal and natural gas were around 8 € and 16 € per MWh_{th} respectively (BMWi, 2010). Transport and trading mark-ups added, final costs for power generation amounted to 9.1 € and 20.0 € per MWh_{th} (Konstantin, 2007). Regarding forecast, costs had already increased around 50% for both fuels between 2000 and 2005. According to the IEA World Energy Outlook (WEO), an increasing spread between coal and gas in long run price scenarios was expected around the year 2005. In the WEO 2004 reference scenario, hard coal prices were thought to increase by 16% until 2030 (annual price increase of +0.6%), while natural gas prices were projected to grow by around +27% during the same time (+0.9% p.a.) (IEA, 2004). Only one year later, IEA's expectations on hard coal prices dropped significantly to -7% until 2030 (-0.3% p.a.), while natural gas prices were projected to grow by even +33% during the same period (+1.1% p.a.) (IEA, 2005). We use these different price projections in alternative scenarios applying average yearly growth rates of +0.15% p.a. for coal and +1.0% p.a. for natural gas in the baseline (cp. Table 3.4). Pahle (2010) found that the relative impact of decreasing real hard coal price expectations was probably a major decision factor for the extensive investments made in hard coal capacity. Different fuel price scenarios allow scrutinizing and quantifying this finding.

As for other technologies than hard coal and natural gas, we assume zero fuel costs for renewable energy sources. This ensures that available renewable capacities are always running (must-run) and represents priority feed-in according to the German Renewable Energy Sources Act (EEG). For peaker plants, which consist of oil and diesel plants as well as pumped hydro storage, we assume fuel costs of 100 €/MWh_{el} (compare Konstantin, 2007)[16]. As a consequence, renewable sources are located at the very left side of the merit order, whereas peaker plants are at the very right side. Fuel cost for nuclear and lignite plants are around 3.5 €/MWh_{el} and 4.0 €/MWh_{th}, respectively[17]. We assume fuel costs for other technologies than hard coal and natural gas to be constant in all scenarios.

3.3 Capital & OM costs

While economic conditions for fuel costs turned in favor of hard coal around 2005, capital costs developed in the very opposite direction. In 2004, specific investment costs were around 400 €/kW for natural gas and around 800 €/kW for hard coal capacity (Konstantin, 2007). Only two years later, costs had increased to around 500 €/kW for gas and 1100 €/kW for coal plants, mainly due to high global demand for power plants and increased prices for steel and copper (Konstantin, 2009). According to a study by trend:research, new hard coal capacity was even estimated to be as expensive as 1500 €/kW by 2007 (Flauger, 2007). This disproportionate growth in costs may have decreased the relative attractiveness of hard coal, and a number of projects especially by smaller suppliers have indeed been cancelled due to this reason (see Pahle, 2010). The relevance of this development is also analyzed by sensitivity analyses in Section 4, where we quantify the effect of increased capital costs (+50% for hard coal, +25% for natural gas).

It should be noted that our above assumptions refer to overnight costs, which do not comprise costs of financing due to either advance expenditures before construction (turn-key costs) or annuity based payoff (fixed charge rates). Both schemes imply additional interest on capital, and thus would require calculating final investment costs based on the discount rate. Even though this is in general more realistic, it is also very specific to both projects and investors and thus hard to implement properly (see Section 3.6). That said, and in face of our focus on allocation schemes, we ignore the details on how the investors

[16] The exact price level is not relevant for the modeling results as it levels out by only looking at relative NPVs.
[17] Note that fuel costs for peaker technologies and nuclear power plants are related to electricity generation, while fuel costs for all other technologies are related to the thermal energy content.

finance the project and thus how the capital cost is paid off. Our approach is in line with standard cost assumptions for electricity modelling.

Aside from investment costs, we consider fixed costs for operation and maintenance (O&M) in the model application. We assume yearly O&M costs of 37.8 €/kW for hard coal and 30.3 €/kW for natural gas in the baseline run (Konstantin, 2007). These values include maintenance, staff, insurance, operating supplies and waste disposal.

3.4 Generation capacities

For the conventional fossil supply structure of the German market, we draw on public data by UBA (UBA, 2009)[18]. We exclude combined heat and power plants for which the merit order dispatch mechanism is not applicable due to heat-controlled operation. In total we consider 150 conventional fossil plants, out of which 52 are lignite, 50 are hard coal, and 48 are natural gas. The overall installed gross capacities are 20.8 GW, 19.0 GW and 12.8 GW respectively. We derive net available generation capacities drawing on average plant availabilities and other technology-specific factors provided by Konstantin (2007). The thermal efficiency is derived on a plant-by-plant basis according to an age-efficiency correlation established by Schröter (2004).

In addition to fossil capacities, the overall supply structure also includes nuclear, renewable and peaker plants. We derive the nuclear capacity of 2005 and its average net availability from the sources mentioned above (Konstantin, 2007; UBA, 2009). As for renewables, their overall installed capacity amounted to 27 GW in 2005 (BMU, 2006). Due to the high share of wind, we only consider average annual availability, which amounts to approximately 7 GW. Peaking capacity consisted mainly of oil and pumped hydro plants (UBA, 2009). Table 3.2 lists the available net generation capacities of all included technologies. These capacities form the merit order based on ranked short-run marginal costs, which is shown in Figure 2.1.

Table 3.2: Net available capacities of different generation technologies

Technology	Capacities (in GW)	Cumulated capacities (in GW)
RES	7.1	7.1
Nuclear	18.4	25.6
Lignite	17.8	43.3
Hard coal	13.7	57.0
Natural gas	12.6	69.6
Peaker	8.4	78.0
Total	**78.0**	

[18] We only consider plants that were commissioned before 2005.

3.5 Demand

For demand assumptions we draw on load data provided by ENTSO-E (2010)[19]. Figure 3.1 shows both the distribution of hourly loads in the German network and cumulated load hours for different demand levels. Demand ranged from around 33 GW to a peak value of 78 GW. In order to determine the marginal plant and thus the price of electricity for every hour of the year, we align the load distribution and the merit order derived from the generation capacities listed in Table 3.2. We find that demand fluctuations span from lignite over hard coal and natural gas up to the peaker plants. Thus RES, nuclear and some lignite plants are always in operation, which resembles the real market very well. To compare our model with empirical operational characteristics of fossil power plants, we use cumulated load frequencies to estimate average full load hours for the installed plant capacity of each technology. As shown in Table 3.3, they fit empirical values for 2004 provided by VDEW (cited in VGB PowerTech, 2005)[20] quite well.

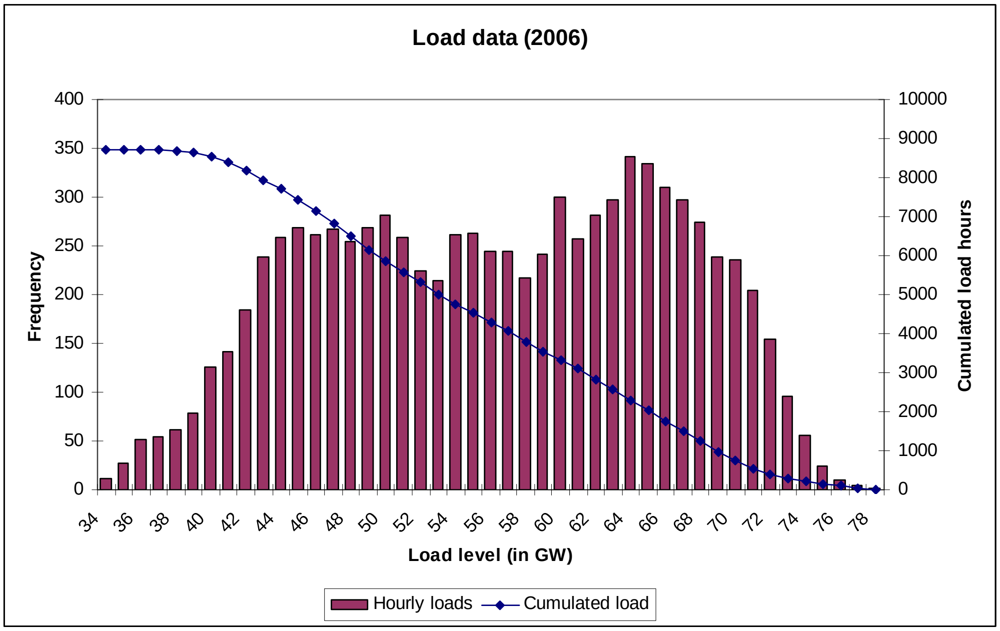

Figure 3.1: Load distribution in 2006 (ENTSO-E, 2010)

Table 3.3: Estimated model full load hours and empirical values for 2004 for different fossil technologies

	Model full load hours (averages)	Empirical full load hours 2004 (VGB PowerTech, 2005)
Lignite	7410	7230
Hard coal	4748	4460
Natural gas	2424	2730

[19] We use data for 2006, since data for 2005 is not available. It is reasonable to assume that German electricity demand pattern did not change significantly between 2005 and 2006. ENTSO-E was formerly known as the Union for the Co-ordination of Transmission of Electricity UCTE.

[20] We use data for 2004 because from 2005 on empirical full load hours already reflect the impact of certificate pricing.

Due to unavailability of data for all hours of the year we excluded cross-border trade with other countries; both exports and imports in 2005 were in the order of 10% of total generation, while the net balance was small. However, this should pose only a minor problem since we focus on the relative profitability of two investments, such that deviations from the real world cancel out. Including trade would be much more relevant in an analysis that aims to reproduce real hourly market outcomes, as for example in Weigt and Hirschhausen (2008). Furthermore we explicitly aimed to improve the methodology used in similar studies in the grey literature. For example, Garz et al. (2009) only make use of five characteristic demand levels, by which they try to capture daily fluctuations. In doing so they neither describe a method for finding particular levels, nor do they crosscheck resulting full load hours to empirical data. In contrast to this approach we conjecture our representation as considerably more grounded in empirical facts.

With regard to the future development, we assume that demand persist at the 2005 levels for mainly two reasons. First, we can only speculate about growing or falling demand for the next years. There are good reasons for future trends in both upward (economic growth, substitution of other energy carriers by electricity) and downward (energy efficiency, elasticity to higher prices) direction. Second, even if demand changes to some extent, it is very unlikely to affect our results, because we only look at NPV differences. These differences are solely determined by section of the demand distribution that is located between the coal and the gas plant. As indicated by Figure 2.1, coal and gas are located at the center of the demand distribution that is relatively flat-top. Hence a moderate shift in one or the other direction would not change prices much.

3.6 Discount rates and financial lifetime

Net present value calculations require using a discount rate. It reflects the time value of money or the rate of return if the capital is invested in alternative projects, and also comprises a project specific risk mark-up. Thus it depends on specific projects and is generally hard to estimate empirically (Rust 1987, Timmins 1997, Ishii and Yan 2004). In this context, we draw on a standard discount rate assumption for investments in electricity generation capacities of 7.5%. It represents the mean value of 5% and 10%, which are used by the International Energy Agency (2010). These rates seem commonly agreed; for instance Fleten et al. (2007) and Patiño-Echeverri et al. (2009) use 5%, whereas Gross et al. (2010) use 10%. The financial lifetime, over which cash flows are considered, is assumed to be 20 years in the baseline (compare Lindenberger and Hildebrand, 2008)[21].

Table 3.4 provides a summary of all model parameters. Fixed costs (specific investment and O&M costs) are listed only for hard coal and natural gas plants, as we analyse investments in these technologies only. Fuel costs are provided for lignite, hard coal, and natural gas. For renewable, nuclear and peaker technologies, we use overall variable cost of electricity generation (c_{el}) in order to simplify the analysis.

[21] For reasons of comparison, we neglect the fact that gas plants generally have lower financial life times than hard coal plants.

Table 3.4: Overview of model parameters. Real numbers, monetary value 2005.

Parameter	Baseline	Alternative scenarios	Source
T_{FL} in years	20		Own assumptions drawing on Lindenberger and Hildebrand (2008)
$T_{FA} \subseteq T_{FL}$ in years	NAP I: 14 NAP II: 5	0-20 years of free allocation, full auctioning (AUC) or single best available technology (SBAT)	Bundestag (2004, 2007)
$T_{AUC} \subseteq T_{FL}$ in years	NAP I: 6 NAP II: 15		
cap(k) in MW	Hard coal: 1,000 Natural gas: 1,000		Own assumptions
c_{cap}(k) in €/kW	Hard coal: 800 Natural gas: 400	Hard coal: 1,200 (+50%) Natural gas: 500 (+25%)	Rounded from Konstantin (2007), own assumptions (see Section 4)
c_{OM}(k) in €/kW	Hard coal: 37.8 p.a. Natural gas: 15.5 p.a.		Konstantin (2007)
c_{el}(k,t) in €/MWh$_{el}$	RES: 0 Nuclear: 3.5 Peaker: 100.0		Konstantin (2007), IEA (2004, 2005), own assumptions
p_{fuel}(k,t) in €/MWh$_{th}$	Hard coal: 9.1 (2005), +0.15% p.a. Natural gas: 20.0 (2005), +1.0% p.a. Lignite: 4.5 (2005), 0% p.a.	Hard coal: +0.6% / -0.3% p.a. Natural gas: +0.9% / +1.1% p.a.	
p_{CO2}(t) in €/t	20.0 (2005), +2% p.a.	15.0 / 25.0 (2005), +1% p.a. / +3% p.a.	Point Carbon (2006), own assumptions
η(k)	Existing hard coal plants: 32.7-44.3% Model hard coal plant: 46% Existing natural gas plant: 31.2-56.0% Model natural gas plant: 58.0%		UBA (2009), Schröter (2004), Wietschel et al. (2010)
cef(k) in t/MWh$_{th}$	Hard coal: 0.342 Natural gas: 0.202 Lignite: 0.410		Konstantin (2007)
δ	7.5%	5% / 10%	IEA (2010)

4. Results

4.1 Overview

We first compare investment incentives in the reference case without regulation (NoREG) with the factual allocation rules (NAP I) and three possible counterfactuals, all evaluated over 20 years: NAP II, full auctioning (AUC) and a technology neutral single best available technology benchmark (SBAT). Considering later developments and insights by policy makers, it is useful to contrast the results of the factual allocation to the results of counterfactual allocation rules. Second, we investigate the sensitivity of results to fuel prices and capital costs. Third, we compare the interdependent effects of free allocation period length and size of the discount rate on NPVs. And finally, we examine the sensitivity of results to our assumption of asymmetric cost pass-through.

4.2 CO_2 regulation under different allocation rules

A baseline run without any carbon regulation (NoREG) shows that a hard coal plant is € 283 million more profitable than a natural gas plant. Thus hard coal plants would have been the preferred investment choice around 2005. The situation changes considerably after the introduction of the ETS, as shown in Figure 4.1. In the NAP I case, which represents the factual allocation rules by then, hard coal's NPV edge over natural gas increases substantially relative to the reference case. Under baseline assumptions (red dots), a hard coal plant is € 717 million more profitable than a comparable natural gas plant. The respective increase in the NPV difference of € 434 million originates from disproportionate windfall profits related to technology-specific allocation rules[22]. Applying the counterfactual NAP II allocation rule, the NPV difference increases less pronounced than under NAP I rules to only € 452 million. This is essentially due to the non-discriminatory full load hour approach of NAP II (compare Section 3.1). In the counterfactual case with full auctioning (AUC), the picture changes. The natural gas plant now has a comparative advantage of around € 136 million. We find the same NPV difference for the SBAT case, in which a single best available technology benchmark is applied. In contrast to AUC, SBAT creates windfall profits. However, it does so in the same extent for both technologies. Hence absolute NPVs increase, but the difference remains equal.

Additional model runs show that some allocation rules are highly sensitive to CO_2 price assumptions as shown in Figure 4.1. Whereas the NAP I and NAP II cases are relatively robust, the AUC and SBAT regimes are strongly affected by varying assumptions on CO_2. For example, in a scenario with very low CO_2 prices, the relative NPV advantage of hard coal under AUC/SBAT is € 102 million. Under the same allocation rules, natural gas investments achieve a NPV edge of € 411 million over hard coal in the case of a high CO_2 price path. In general, increasing CO_2 prices support natural gas investments under AUC/SBAT – as intended by carbon regulation. Yet under NAP I, higher carbon prices slightly increase hard coal's NPV advantage due to higher windfall profits. Our results

[22] Note that € 434 million account for around half the capital costs of the model hard coal plant.

show that the introduction of emissions trading may lead to perverse outcomes if allocation rules are not carefully chosen.

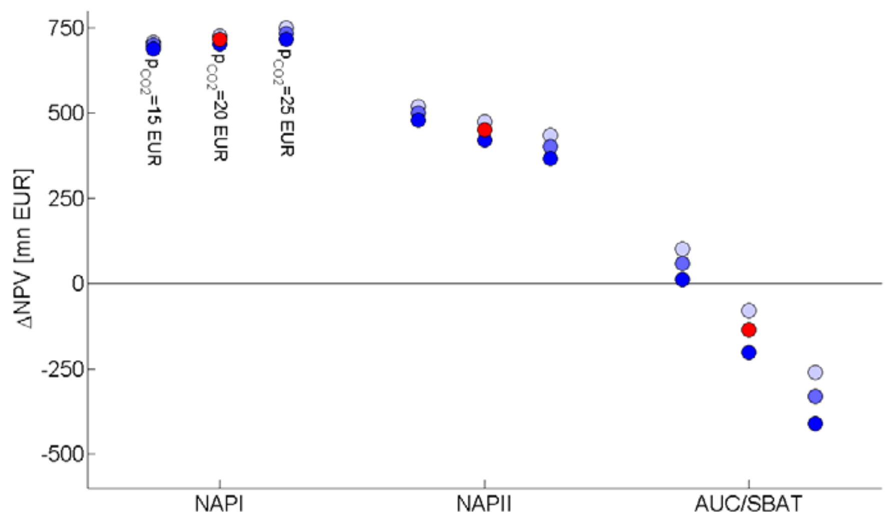

Figure 4.1: NPV differences between hard coal and natural gas investments for different allocation rules and CO_2 price expectations. Lighter shades indicate lower annual CO_2 price increases.

A more general finding is that both hard coal and gas investments are profitable in absolute numbers. NPVs for a single plant investment are positive in all cases analyzed here. This result may depend on our assumption on peak prices (100 €/MWh) to some extent. Yet it seems to be plausible given the fact that the German power plant fleet is quite old on average. New, efficient plants have a competitive edge in such an environment. In other words, market prices generally provided incentives to invest in thermal generation.

4.3 Sensitivity to fuel prices and capital costs

As expected, results are also sensitive to fuel price paths with the effect that higher fuel prices for a particular technology decrease the NPV difference to this technology's disadvantage (see Table 4.1). Under NAPI and NAPII, different fuel price assumptions do not challenge hard coal's NPV edge over gas investments. Yet in the AUC and SBAT cases, varying fuel price assumptions can result in a change of investment decisions, but only when the lowest CO_2 price path applies (changing sign in the rows of Table 4.1).

We now look at overall sensitivities of results to fuel and CO_2 prices. Under NAP I and NAP II, even the most extreme values for the NPV difference are relatively close to the baseline outcome and are well in the positive range. That is, the investment preference for hard coal under NAP I and II is very robust. In contrast, fuel and CO_2 price sensitivities in the AUC and SBAT cases are both much larger and lead to sign changes of the NPV difference. As a matter of fact, emission regulation only unfolds its intended incentives in these schemes. And, given the range of sensitivities under either scheme, CO_2 prices pose a higher risk on profitability than fuel prices, which were the previously dominant factors in this respect.

Finally, we examine the effect of increasing capital costs on NPV results. Capital costs of thermal plants have risen considerably during the last years, in particular for coal (see Section 3.3). Higher capital costs partially offset windfall profits gained through free allocation. We quantify this effect by for increased capital costs of +50% for hard coal, and +25% for natural gas. As investment costs are fixed and incur only at the initial period, the sensitivity analysis is straight forward. Under the new assumptions, the difference in total capital costs is increased by € 300 million, which directly translates into an NPV difference of equal size. As Table 4.1 shows, this reduces the relative advantage of hard coal over gas projects to € 417 million under NAP I baseline assumptions. Even in the worst case, the NPV difference is still very large (€ 313 million). That is, hard coal projects retain a considerable NPV edge over natural gas even under the assumption of higher capital costs. Yet under alternative allocation regimes like AUC and BAT, higher capital costs would have made natural gas plants the preferred investment choices in all scenarios analyzed here.

Table 4.2: NPV differences between coal and natural gas plants in million € for different allocation rules and price assumptions (bases cases in bold)

			Annual hard coal price inc. [%] -0,3			0,15			0,6		
	CO2 price (2005) [€]	*Annual CO2 price inc. [%]*	*Annual natural gas price inc. [%]* 0,9	1	1,1	0,9	1	1,1	0,9	1	1,1
NAP I	15	1	738	759	782	686	707	729	631	653	675
	15	2	730	751	773	677	699	721	623	644	667
	15	3	719	741	763	666	689	711	613	634	656
	20	1	759	780	802	706	727	750	652	674	695
	20	2	748	770	791	696	**717**	739	641	663	684
	20	3	733	754	777	682	701	725	627	649	670
	25	1	778	800	822	726	749	772	672	694	715
	25	2	765	787	809	713	734	756	660	681	702
	25	3	747	769	791	696	717	740	641	663	685
NAP II	15	1	550	571	593	497	519	540	443	465	486
	15	2	530	552	574	478	500	522	424	445	467
	15	3	508	530	552	456	478	500	402	424	446
	20	1	507	529	550	455	476	498	401	423	444
	20	2	483	504	525	430	**452**	473	375	398	419
	20	3	453	473	497	401	421	444	346	368	389
	25	1	464	486	508	412	435	458	358	380	401
	25	2	434	456	477	381	402	425	328	349	370
	25	3	396	418	441	345	366	389	290	312	334
AUC & SBAT	15	1	133	154	176	80	102	123	26	47	69
	15	2	90	111	133	38	59	81	-17	4	27
	15	3	42	64	86	-10	12	34	-64	-42	-20
	20	1	-49	-27	-6	-101	-80	-58	-156	-134	-112
	20	2	-105	-83	-62	-157	**-136**	-114	-212	-190	-169
	20	3	-169	-148	-125	-221	-201	-178	-275	-253	-232
	25	1	-232	-209	-187	-283	-260	-237	-337	-316	-294
	25	2	-301	-279	-258	-353	-332	-310	-407	-386	-364
	25	3	-380	-359	-336	-432	-411	-388	-487	-464	-443

4.4 Free allocation period length and discount rate

Finally, we investigate the influence of discounting and the length of the free allocation period. More specifically, a higher discount rate puts more weight on early cash flows, thus reducing the benefits of long-term support. For example, in this case with a payoff time of 20 years, 5% and 10% discounting lead to a cumulated weighted cash flow of 62% and 72% respectively after ten years already. Or in other words, for a 10% discount rate, around three quarters of the overall unit returns fall into the first ten years of operation. Accordingly, there is a joint impact of free allocation period length and discount rate on profitability. The length of the free allocation period was a highly discussed police variable at the time of NAP I discussions. The question arises if there is a turning point in duration from which on the investment distortion may invert. For the case of Germany this implies an answer to the question if a shorter free allocation period, probably in combination with higher discounting, could have created a dedicated incentive for natural gas. As pointed out earlier, analysis of this issue is rather sparse until now.

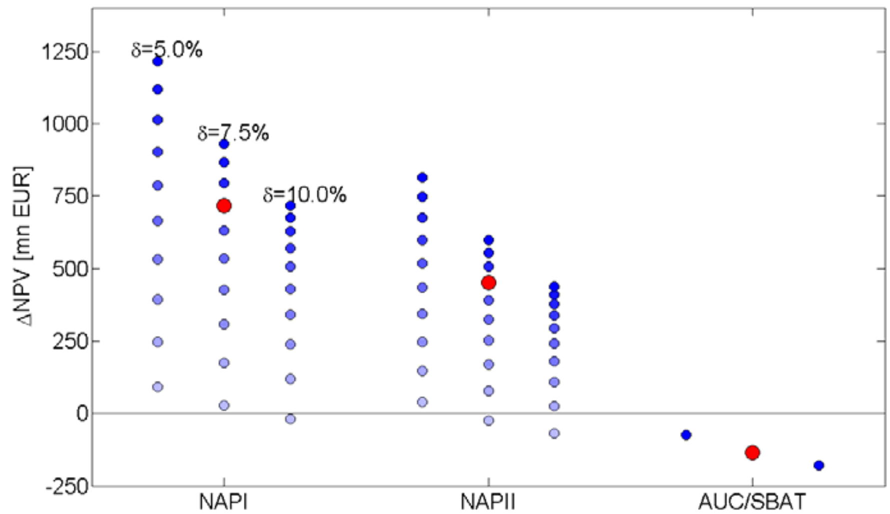

Figure 4.2: NPV differences between hard coal and natural gas investments for different allocation rules, allocations lengths and discount rates (base case assumptions for fuel and CO_2 prices)

Figure 4.2 shows the results for varying discount factors and allocations lengths (2, 4, 6, …, 20 years, lighter to darker shades). An apparent observation is the respectable impact of different lengths in the NAP I and NAP II case, which result in much larger NPV variations than the previously analyzed CO_2 and fuel price sensitivities. The length of the free allocation period has a substantial impact on the NPV difference between coal and gas investments: in the most extreme cases it rises as high as € 1216 million (NAP I, 20 years, 5%) and as low as € -69 million (NAP II, 2 years, 10%). Altogether, the NPV difference is always positive for NAP I and NAP II except for three extreme cases. Accordingly, hard coal investments are more profitable than natural gas investments in almost all NAP I/NAP II variations. Shorter free allocation periods would hardly have created incentives for natural gas.

Higher discount rates shrink the span of different free allocation lengths and at the same time reduce the overall levels of NPV differences. Both effects – more distinct for NAP I than for NAP II – meet expectations in the light of the previous discussion: shorter periods of free allocation effectively reduce windfall profits, which are higher for coal than for gas, and thus reduce coal's NPV edge over gas. Higher discount rates generally decrease the NPV difference between coal and gas plants as coal investments are more capital-intensive compared to gas, but also lead to higher revenue streams. Increasing discount rates do not influence upfront capital costs, but decrease the value of future revenues and thus decrease coal's NPV edge over gas.

Finally, we look at the AUC/SBAT cases. Here it turns out that the length of the free allocation period (SBAT) does not matter. The reason is basically the same as given above for why AUC and SBAT produce identical NPV differences: due to equal allocations, both technologies profit to the same extent, regardless of allocation period length. The discount rate plays a role though, but only a minor one. Higher discounting somewhat devalues free allocations over time compared to lower discounting. Hence the distinct investment incentive for natural gas provided by AUC/SBAT remains unchanged.

In summary, varying policy length has a considerable impact on relative profitability of out two investment options, if certificates are allocated in a technology-specific way (NAP I, NAP II). In contrast, there is no influence at all if allocation is technology neutral (SBAT). In the German case, a different allocation period length under NAP I would not have not mattered eventually, as preexisting economic advantages for hard coal were too strong.

4.5 Sensitvity to asymmetric pass-through rates

The results discussed so far draw on technology-specific pass-through rates, which are heuristically determined as explained in Section 2.2. We assess the sensitivity of results to the assumption of asymmetric pass-through rates by assuming full pass-through and re-running the model. Figure 4.3 shows the resulting NPV differences: the main outcomes do not change. However, the relative profitability of hard coal plants increases in all cases compared to asymmetric cost pass-through (compare Figure 4.1). That should be expected, as hard coal plants are no longer “forced” to sell electricity at prices slightly lower than their full marginal costs – including opportunity costs of emission permits – during some periods. As a consequence, natural gas’ NPV edge over hard coal vanishes under full auctioning or SBAT.

The results show that adjusting pass through rates to avoid fuel switch is actually not an optimal strategy for hard coal generators. Under NAP I allocation rules and baseline assumptions, for example, using asymmetric pass-through rates instead of full pass-through leads to losses of € 157 million over the evaluated period of 20 years. Still, as discussed earlier, there is empirical evidence that asymmetric pass-through occurred. A possible rationale are ramping-related technical constraints which incur additional costs (see Section 2.2).

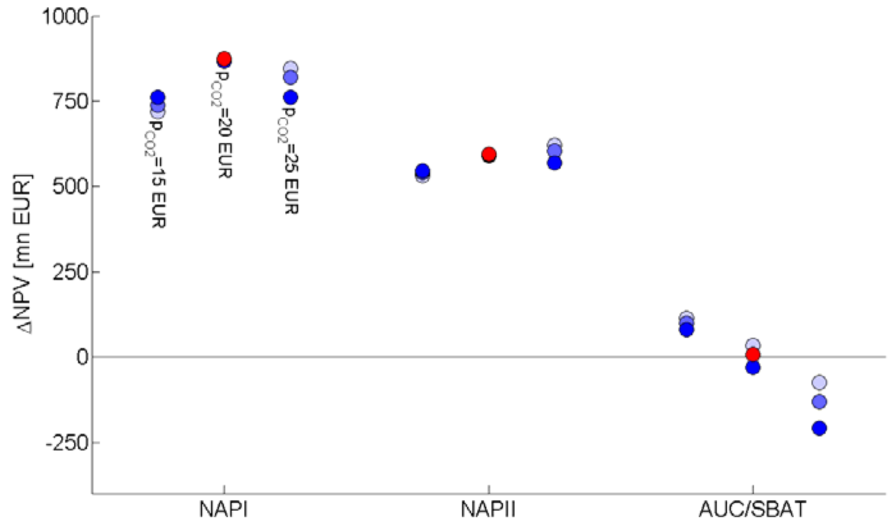

Figure 4.3: NPV differences between hard coal and natural gas investments for full cost pass-through

5. Conclusions

We have studied the distortionary effect of different emission permit allocation rules on fossil power plant investment choices in Germany. We explicitly take into account windfall profits and perform sensitivity analyses regarding fuel prices, capital costs, the length of the free allocation period, and discount rates. To our knowledge, this article is the first to quantify the investment distortion towards hard coal created by the German NAP I implementation. We also make a methodological contribution to the literature by combining DCF analysis with a merit order approach, which allows determining electricity prices and plant utilization endogenously. Furthermore, we explicitly consider technology-specific asymmetric pass-through rates.

We find that without carbon regulation, investments into hard coal power plants had a significant NPV edge over natural gas investments in 2005. This finding may explain why so many hard coal projects were initiated in the first place. Introducing regulation has a large impact on NPVs of fossil investments in general, but magnitude and direction of effects heavily depend on allocation rules. Under the factual scheme of 2005 (NAP I), the preference for emission-intensive coal investments, which was prevalent even without carbon regulation, was greatly increased by expected windfall profits. We further find that the length of the free allocation period – heavily discussed at that time – has an important impact on the relative profitability of coal and gas investments. Nonetheless, even the shortest lengths would not have provoked a change in technology choice, notwithstanding three extreme cases. This finding is especially helpful to reconcile that the particularly long period of free allocations granted in NAP I played a less important role than initially assumed.

Our investigation of counterfactual allocation rules shows that an alternative implementation of NAP II in 2005 would not have changed the overall picture. In contrast, applying full auctioning of emission permits or a single best available technology allocation scheme – as initially planned – could have halted or even reversed the "dash for coal", depending on fuel and CO_2 price paths. While both options lead to the same relative outcomes, they differ with regard to absolute investment incentives. According to our results, full auctioning would have substantially decreased the profitability of hard coal projects compared to the case without carbon regulation. In contrast, single best available technology allocation would have increased the profitability of both hard coal and gas projects due to windfall profits, while natural gas would have benefited more.

We conclude that the German NAP I did not cause the "dash for coal" in the first place, but greatly spurred and sustained it. While German policy-makers intended not to hamper investments in the power sector by carbon regulation (Matthes & Schafhausen 2008), they designed an allocation scheme which in the end created perverse incentives and massively promoted investments into emission-intensive hard coal plants. Obviously, policy makers failed to take the effects of free allocation-related windfall profits on coal profitability into account. We have thus shown that the details of implementing carbon regulation can be extremely important in a dynamic perspective. Different allocation regimes may not just have distributive effects, but also important consequences for investment choices.

Although the analysis has a retrospective focus, our findings are relevant in support for current policy-making. We conclude that by introducing full auctioning of emission permits from 2013 on (NAP III) Germany is providing the right incentives from an environmental perspective. However, the new coal capacity brought on the way has created a heavy burden for ambitious future transition to lower carbon intensity.

References

Åhman, M., Burtraw, D., Kruger, J., Zetterberg, L., 2007. A Ten-Year Rule to guide the allocation of EU emission allowances. Energy Policy 35, 1718-1730.

Bergerson, J.A., Lave, L.B., 2007. Baseload Coal Investment Decisions under Uncertain Carbon Legislation. Environmental Science & Technology 41, 3431-3436.

Blyth, W., 2010. The Economics of Transition in the Power Sector, Information Paper. International Energy Agency, Paris.

Blyth, W., Bradley, R., Bunn, D., Clarke, C., Wilson, T., Yang, M., 2007. Investment risks under uncertain climate change policy. Energy Policy 35, 5766-5773.

BMU, 2006. Erneuerbare Energien in Zahlen - nationale und internationale Entwicklung. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit. Berlin, May 2006.

BMWi, 2010. Entwicklung von Energiepreisen und Preisindizes. Energiedaten Tabelle 26. 17.03.2010. http://www.bmwi.de/BMWi/Redaktion/Binaer/Energiedaten/energiepreise-und-energiekosten1-entwicklung-energiepreise-preisindizes.xls Last accessed 21 December 2010.

Brunekreeft, G., Bauknecht, D., 2006. Energy policy and investments in the German power market, in: Sioshansi, F.P., Pfaffenberger, W. (Eds.), Electricity Market Reform: An International Perspective. Elsevier, Oxford, pp. 235–263.

BUND, 2010. Geplante und im Bau befindliche Kohlekraftwerke. BUND für Umwelt und Naturschutz Deutschland e.V. Berlin, 4 May 2010.

Bundesnetzagentur, 2009. Monitoringbericht 2009. Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen. Bonn.

Bundestag, 2004. Gesetz über den nationalen Zuteilungsplan für Treibhausgas-Emissionsberechtigungen in der Zuteilungsperiode 2005 bis 2007 (Zuteilungsgesetz 2007 – ZuG 2007), Bundesgesetzblatt Jahrgang 2004 Teil I Nr. 45, ausgegeben zu Bonn am 30. August 2004.

Bundestag, 2007. Gesetz zur Änderung der Rechtsgrundlagen zum Emissionshandel im Hinblick auf die Zuteilungsperiode 2008 bis 2012, Bundesgesetzblatt Jahrgang 2007 Teil I Nr. 38, ausgegeben zu Bonn am 10. August 2007.

Burtraw, D., Palmer, K., 2008. Compensation rules for climate policy in the electricity sector. Journal of Policy Analysis and Management 27, 819-847.

Capoor, K., Ambrosi, P., 2006. State and Trends of the Carbon Market 2006, Washington, D.C.

Convery, F.J., 2009. Reflections - The Emerging Literature on Emissions Trading in Europe. Review of Environmental Economics and Policy 3, 121-137.

DEHSt, 2005. Implementation of Emissions Trading in the EU: National Allocation Plans of all EU states. Brief fact sheets of EU member state allocation plans. Deutsche Emissionshandelsstelle (DEHSt) im Umweltbundesamt. Berlin, November 2005.

DEHSt, 2009. Emissionshandel: Auswertung der ersten Handelsperiode 2005-2007. Deutsche Emissionshandelsstelle (DEHSt) im Umweltbundesamt. Berlin, January 2009.

Denny, E., O'Malley, M., 2009. The impact of carbon prices on generation-cycling costs. Energy Policy 37, 1204-1212.

Ellermann, D.A., 2008. New Entrant and Closure Provisions: How do they Distort? The Energy Journal Special Issue, 63-76.

ENTSO-E, 2010. Hourly load values of a specific country for a specific month. European Network of Transmission System Operators for Electricity. https://www.entsoe.eu/db-query/consumption/mhlv-a-specific-country-for-a-specific-month/. Last accessed 21 December 2010.

Fell, H., 2010. EU-ETS and Nordic Electricity: A CVAR Analysis. The Energy Journal 31, 1-26.

Flauger, J., 2007. Kraftwerks-Projekten droht das Aus. Handelsblatt, 04.09.2007.

Fleten, S.E., Maribu, K.M., Wangensteen, I., 2007. Optimal investment strategies in decentralized renewable power generation under uncertainty. Energy 32, 803-815.

Garz, H., Ötsch, R., Haas, A., Wirtz, P., Zank, S., 2009. German power utilities - caught in the CO2 trap?. Düsseldorf, September 2009.

Gross, R., Blyth, W., Heptonstall, P., 2010. Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs. Energy Economics 32, 796-804.

Hahn, R.W., Stavins, R.N., 2010. The Effect of Allowance Allocations on Cap-and-Trade System Performance. NBER Working Papers. National Bureau of Economic Research. Cambridge, March 2010.

Hentrich, S., Matschoss, P., Michaelis, P., 2009. Emissions trading and competitiveness: lessons from Germany. Climate Policy, 316-329.

Hoffmann, V.H., 2007. EU ETS and Investment Decisions: The Case of the German Electricity Industry. European Management Journal 25, 464-474.

IEA, 2004. World Energy Outlook 2004 Edition. International Energy Agency. Paris, 2004.

IEA, 2005. World Energy Outlook 2005 Edition. International Energy Agency. Paris, 2005.

IEA, 2010. Projected Costs of Generating Electricity. International Energy Agency. Paris, 2010.

Ishii, J., Yan, J., 2004. Investment under regulatory uncertainty: U.S. electricity generation investment since 1996. Center for the study of energy markets working paper series. Berkeley, March 2004.

Kemfert, C., Kohlhaas, M., Truong P. T., Protsenko, A., 2006, The Environmental and Economic Effects of European Emissions Trading. Climate Policy 6 (2006), 4, 441-455.

Keppler, J.H., Cruciani, M., 2010. Rents in the European power sector due to carbon trading. Energy Policy 38, 4280-4290.

Konstantin, P., 2007. Praxisbuch Energiewirtschaft, 1. Auflage. Springer. Berlin, Heidelberg, 2007.

Konstantin, P., 2009. Praxisbuch Energiewirtschaft, 2. bearbeitete und aktualisierte Auflage. Springer. Berlin, Heidelberg, 2009.

Laurikka, H., Koljonen, T., 2006. Emissions trading and investment decisions in the power sector--a case study in Finland. Energy Policy 34, 1063-1074.

Lindenberger, D., Hildebrand, B., 2008. Studie Energiewirtschaftliches Gesamtkonzept. BDEW. Berlin, 31 March 2008.

Lise, W., Kruseman, G., 2008. Long-term price and environmental effects in a liberalised electricity market. Energy Economics 30, 230-248.

Neuhoff, K., Åhman, M., Betz, R., Cludius, J., Ferrario, F., Holmgren, Pal, G., Grubb, M., Matthes, F., Rogge, K., Sato, M., Schleich, J., Sijm, J., Tuerk, A., Kettner, C., Walker, N., 2006b. Implications of announced phase II national allocation plans for the EU ETS. Climate Policy 6, 411-422.

Neuhoff, K., Keats Martinez, K., Sato, M., 2006a. Allocation, incentives and distortions : The impact of EU ETS emissions allowance allocations to the electricity sector. Climate Policy 6, 73-91.

Pahle, M., 2010. Germany's dash for coal: Exploring drivers and factors. Energy Policy 38, 3431-3442.

Patino-Echeverri, D., Fischbeck, P., Kriegler, E., 2009. Economic and Environmental Costs of Regulatory Uncertainty for Coal-Fired Power Plants. Environmental Science & Technology 43, 578-584.

Point Carbon, 2003. Carbon Market Europe. June 2003.

Point Carbon, 2006. Carbon 2006. Hasselknippe, H. and Røine, K. (eds.). 28 February 2006.

Reedman, L., 2006. Using a real-options approach to model technology adoption under carbon price uncertainty: an application to the Australian electricity sector. Economic Record 82, S64.

Reinelt, P.S., Keith, D.W., 2007. Carbon Capture Retrofits and the Cost of Regulatory Uncertainty. Energy Journal 28, 101-127.

Rust, J.P., 1987. Optimal replacement of GMC bus engines: an empirical model of Harold Zurcher. Econometrica 55, 999-1033.

Schleich, J., Rogge, K., Betz, R., 2009. Incentives for energy efficiency in the EU Emissions Trading Scheme Energy Efficiency 2, 37-67.

Schröter, J., 2004. Auswirkungen des europäischen Emissionshandelssystems auf den Kraftwerkseinsatz in Deutschland., Institut für Energietechnik, Fachgebiet Energiesysteme. Technische Universität Berlin, Berlin.

Sijm, J., Neuhoff, K., Chen, Y., 2006. CO2 cost pass-through and windfall profits in the power sector Climate Policy 6, 49-72(24).

Szolgayova, J., Fuss, S., Obersteiner, M., 2008. Assessing the effects of CO2 price caps on electricity investments - A real options analysis. Energy Policy 36, 3974-3981.

Taschini, L., Urech, S., 2009. The Real Option to Fuel Switch in the Presence of Expected Windfall Profits Under the EU ETS. The Journal of Energy Markets 31, 1-21.

Timmins, C.D., 1997. Price as a policy tool for dynamic resource allocation: the case of the municipally owned water utility. Standford University.

UBA, 2009. Datenbank „Kraftwerke in Deutschland“, 10.07.2009. Umweltbundesamt. http://www.umweltbundesamt.de/energie/archiv/kraftwerke_in_deutschland.pdf. Last accessed 21 December 2010.

VGB PowerTech, 2005. Zahlen und Fakten zur Stromerzeugung 2005. Essen 2005.

Weigt, H., Hirschhausen, C.v., 2008. Price formation and market power in the German wholesale electricity market in 2006. Energy Policy 36, 4227-4234.

Wietschel, M., Arens, M., Dötsch, C., Herkel, S., Krewitt, W., Markewitz, P., Möst, D., Scheufen, M., 2010. Energietechnologien 2050 - Schwerpunkte für Forschung und Entwicklung. Fraunhofer ISI, Karlsruhe.

Zachmann, G., von Hirschhausen, C., 2008. First evidence of asymmetric cost pass-through of EU emissions allowances: Examining wholesale electricity prices in Germany. Economics Letters 99, 465-469.

Ziesing, H.-J., Diekmann, J., Kohlhaas, M., Betz, R., Bradke, H., Köwener, D., Rogge, K., Schleich, J., Walz, R., Cames, M., Matthes, F.C., 2007. Entwicklung eines nationalen Allokationsplans im Rahmen des EU-Emissionshandels. Texte 17|07. Dessau, June 2007.