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Allocation of Carbon Emission Certificates in the Power Sector:

How generators profit from grandfathered rights

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The Cambridge-MIT Institute

*Massachusetts Institute of Technology
Center for Energy and
Environmental Policy Research*

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How generators profit from grandfathered rights

Kim Keats Martinez and Karsten Neuhoff[1]

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To meet its Kyoto requirements, the EU will establish an internal market for carbon dioxide allowances from 2005, the EU Emissions Trading Scheme (ETS). National governments are to allocate most of these allowances for free. The analysis shows that as a result the net value of both a typical pulverised coal-fired (PC) power station and a more modern gas-fired combined cycle gas turbine (CCGT) will increase. We show that in future allocation rounds a greater proportion of allowances can and should be auctioned. The paper also analyses the interactions with the Large Combustion Plant Directive, which limits SO_2 and NO_x emissions.

1 Introduction

In an effort to meet its Kyoto requirements, the EU will be establishing an internal market for carbon dioxide allowances from 2005, the EU Emissions Trading Scheme (ETS). This system will be based on the cap-and-trade model following successful experience with similar programmes for SO_2 and NO_x emissions in the US (Ellerman et al. 2000). Emission allowances will be allocated to participating installations in line with national Kyoto commitments. National governments have been given the responsibility of deciding how to organise the distribution of allowances amongst the market participants which will include power, ceramics, metal, paper and cement industries plus any other large combustion plant with a rated thermal capacity greater than 20MW.

In Section 2 we assess the impact of allowances and carbon prices on two representative power market participants in the UK – the standard UK base load pulverised coal-fired (PC) power station and a more modern gas-fired combined cycle gas turbine (CCGT). For this we simulate the dispatch of the UK power system using a long-term dispatch model, the Integrated Planning Model (IPM®). This allows us to draw some initial conclusions about the nature of over-compensation of freely distributed allowances. In Section 3 we examine

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issues that can arise when the baseline emissions period has to be updated. Section 4 examines the interaction between SO_2/NO_x and CO_2 emissions controls and in Section 5 we return to our issue of over-allocation and attempt to quantify this in the context of the UK power system.

2 Coal and Gas in a Carbon Constrained Environment

In the presence of emission certificates, fossil fuel generators will add the opportunity cost of emission certificates to their fuel costs to determine their marginal operating costs as illustrated in Table 1. Because emission rights can be freely traded, firms have the option to sell the allowances if the marginal cost of production and carbon dioxide exceeds the electricity price. In Section 3 we explore how the opportunity cost is affected by the manner in which emissions allowances are made available to market participants. Otherwise we assume that the opportunity cost of allowances will be equal to the price of the allowances and that no banking or borrowing is allowed.

Table 1: Comparing marginal costs of coal and gas-fired plant

	Pulverised coal plant	**Gas-fired CCGT plant**
Thermal efficiency (net HHV)	35%	50%
Fuel price (£/MMBTu)	1.20	2.30
Fuel cost (£/MWh)	11.70	15.70
VOM (£/MWh)	4.00	2.00
SRMC with out CO2 (£/MWh)	***15.70***	***17.70***
CO2 emissions (tCO2/MWh)	930	366
Allowance price (£/tCO2)	6.70	6.70
Allowance cost (£/MWh)	6.20	2.44
SRMC with CO2 (£/MWh)	***21.90***	***20.13***

Table 1 illustrates a typical merit order with PC plant achieving lower marginal costs than a CCGT plant in the absence of emission certificates. This situation changes in a carbon constrained world. With CO2 allowances trading at €10/tCO2 (£6.7/tCO2), the CCGT has lower marginal costs than the PC plant. This is due to the lower efficiency of the PC plant and the higher carbon content per unit of energy in coal relative to gas. Therefore, the PC plant will move down the merit order and run less relative to the unconstrained case.

Industry representatives frequently argue that higher marginal costs arising from carbon constraints will not feed through into higher product prices.[2] These arguments can be summarised under three headings, unfortunately none of these bear scrutiny in the case of electricity generation:

- *International competition*: Faced with viable international competition, companies impacted by carbon legislation would not be able to increase their prices as consumers would otherwise shift to imports from jurisdictions not impacted by the new legislation. However, this is less of an issue for electricity because the European Union and Accession Countries could satisfy less than 1% of demand with imports from North Africa, Ukraine and Belarus.

- *Price elasticity of demand*: If consumers were price sensitive, this would limit the ability of electricity producers to pass costs through. However, short-term demand elasticity for electricity is extremely low, and in the medium term higher electricity prices tend to have a greater impact on capacity investment than electricity utilisation by consumers.

- *Free allocation of allowances*: Under present plans a significant proportion of the carbon allowance requirements will be allocated to market participants for free. If costs have not increased, the argument goes, prices should not be affected. This fails to recognise the fact that freely allocated allowances have an *opportunity* cost equal to the revenue that would have been earned by selling them.

What are the implications of emission certificates on the profitability of the core thermal power stations, CCGT and PC plant? The effect of the emission certificates on profitability of the coal-fired power plant depends on the generation mix. However, using Table 1 as a guide, we can differentiate between three different scenarios each of which is present at different demand periods:

- First, during low demand periods the output of a PC plant, which would have been marginal, will now be provided by a CCGT. This change will be revenue neutral for the PC plant since at such times prices would be expected to only cover marginal production costs making such generators indifferent between generating and not generating.

[2] If wholesale market prices are regulated, as in parts of the US, then the regulator is unlikely to allow Utilities to pass through opportunity costs, and hence the subsequent argument would not apply. (See Burtraw e.a. 2002)

- Second, the effect of the carbon constraint during periods of medium demand means that PC plant will replace CCGT plant at the margin. During these periods prices would have exceeded the marginal costs of the PC plant, but in a carbon-constrained world the PC plant will be marginal, and no longer enjoy such benefit.

- Third, during the highest demand periods, the PC plant was and can be expected to remain infra-marginal. Typically the marginal plant will be an older fossil fuel plant characterised by lower efficiency and higher CO_2 emission intensity. Emission allowances will increase the marginal cost of such a plant by more than our reference PC plant. Therefore, by increasing the electricity price, the PC plant can expect to increase the level of compensation received.

In contrast to the PC plant the CCGT will profit from the introduction of emission certificates, even if they are auctioned, as can be seen by evaluating the possible scenarios:

- At low demand times, our merchant CCGT would not have been operating and will now be operating at the margin resulting in a zero change of net profits.

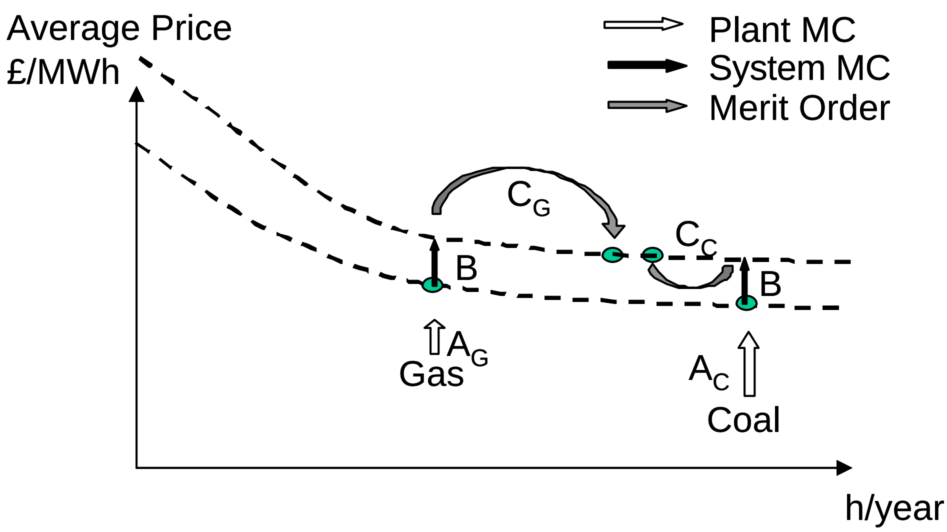
- In medium demand periods, the CCGT was marginal and is now infra-marginal, resulting in an increase in profitability.

- At times of high demand, the effect of the CO_2 allowances will be to increase the marginal costs of the higher cost marginal units by more than the cost increase incurred by the CCGT unit, once again increasing net profits of the CCGT.

The effects can be summarised using the average price duration curve, shown in Figure 1. The marginal cost curve can be used to derive the marginal price as function of demand $p(q)$. A typical representation of the load profile of a country is the load duration curve $q(t)$ which gives the number of hours t in a year during which demand is bigger or equal to q. Combining the marginal cost curve and the load duration curve we can construct the marginal price duration curve $p(t)$, which depicts the number of hours in a year during which the price is at least $p(t)$. A competitive generator will produce whenever the price matches or exceeds his marginal costs, MC. $p(T)=MC$ therefore characterises the numbers of hours a year T a generator will be producing.

The average price the generator obtains for his output will vary between $p(0)$ and $p(T)$. For the calculation of the annual revenue only the effective price $P(T)$ received by a generator producing during the T highest priced hours of a year matters. We can calculate $P(T)$ as the average of $p(t)$ for $0 \leq t \leq T$. The average price duration curve is depicted in Figure 1.

Figure 1: Average Price Duration Curve with and without CO2 emission costs



The introduction of carbon certificates will have three effects. The emission certificates increase the opportunity cost (or real cost in the case of auctioning) of production (A). The increase in marginal costs shifts the effective price duration curve upwards (B). The change of marginal production costs changes the merit order and therefore the number of hours the generator is producing per year (C).

2.1 Simulation modelling

Burtraw et.al. (2002) applied an investment planning model to the US electricity system and calculated the effects of Grandfathering and auctioning on the asset values. The authors argue that regulated utilities under cost-plus tariff regimes cannot include the opportunity costs of emission certificates in their cost base. They also calculate the impact on price if generation companies compete in liberalised markets and hence can include opportunity costs. Given that this is the case across most of Europe, under either auction or Grandfathering allocation systems, one expects opportunity costs to be passed though.

To assess the impact on the power sector, we propose to compare and quantify the impact on annual remuneration in the period 2008-2012 across three different emission allocation scenarios:

- Business-as-usual approach without CO2 constraints (*BAU*);
- Auctioning of all emission certificates by the Government (*Auctioning*);

- Grandfathering of emission allowances based on the emission levels in 1999-2002 (*Grandfathering*).

To support the numerical analysis we have used a dispatch model of the UK power system. The Integrated Planning Model (IPM®)[3] is a proprietary model that uses a linear programming formulation to select investment options and to dispatch generating and load management resources to meet overall electric demand today and on an ongoing basis over the chosen planning horizon. In modelling the impact of NO_x and SO_2 policies, we assume that the UK will adopt the cap-and-trade option in the Large Combustion Plant Directive[4] (LCPD) in line with the National Emission Reduction Plan (NERP) presented to the European Commission (EC) for approval at the end of November 2003.

The Business-As-Usual (BAU) case is modelled without CO_2 constraints. The carbon-constraints run includes a price of emission allowances of €10/tC02. Furthermore, we keep the resulting capacity expansion path from the BAU fixed until 2012. The impact on the electricity prices will be the same under auctioning and Grandfathering allocations. With CO2 allowance prices of €10/tC02, prices rise by £4.2/MWh in 2005-2007 and £3.1/MWh in the period 2008-2012 relative to the BAU case.

2.2 Allocation by auction alone

Table 2 illustrates the impact on sales and costs from a system where all emissions allowances must be purchased. For our reference CCGT plant, increased electricity prices and additional running hours increase sales revenues from 131£/kWyr to 164£/kWyr. On the cost side, additional generation increases fuel costs from 96£/kWyr to 107£/kWyr. Since operating and maintenance costs remain unchanged, sales margins increase from 35£/kWyr in the BAU to 58£/kWyr under the auctioning allocation scheme. With estimated annual emission of 1.4 million tCO2, the associated cost of CO2 emission allowances would be 18£/kWyr, less than the extra margin achieved on energy sales.

[3] ICF Consulting

[4] LCPD, 2001/80/EC

Table 2: Net cashflow impact with auctioned emission rights (2008-2012)						
All figures in £/kWyr	**Pulverised coal plant**			**Gas-fired CCGT plant**		
	BAU	**€10/tCO2**	***Change***	**BAU**	**€10/tCO2**	***Change***
(1) Energy sales revenue	117.8	134.9	*17.1*	131.1	164.5	*33.4*
(2) Fuel expense	70.8	69.9	*-0.9*	95.9	106.8	*11.0*
(3) O&M expense	33.1	33.1	*0.0*	21.7	21.7	*0.0*
(4=1-2-3) Energy sales margin	13.8	31.9	*18.1*	13.5	35.9	*22.4*
(5) Net purchases of CO2 allowances	0.0	33.1	*33.1*	0.0	17.5	*17.5*
(6=4-5) Operating margin	13.8	-1.2	*-15.1*	13.5	18.4	*4.9*
(7) Scarcity rent	13.7	13.7	*0.0*	13.7	13.7	*0.0*
(8=7+6) Total margin	27.5	12.4	*-15.1*	27.2	32.0	*4.9*

For our representative PC plant, the price increase results in an increase in sales revenue from 118£/kWyr to 135£/kWyr; an increase in the average realized price for energy sold is offset somewhat by a drop in generation. Slightly lower production means lower fuel costs, down from 71£/kWyr to 70£/kWyr while the cost of CO_2 emission certificates is 33£/kWyr in the carbon-constrained case. Hence, whilst energy margins would rise by 18£/kWyr, with the purchase of CO_2 certificates, the net remuneration for the coal plant would decrease by 15£/kWyr.

In addition to the energy sales revenue, both PC and CCGT plants are expected to receive scarcity rents during peak periods equivalent to 14£/kWyr. This reflects the additional revenue requirement to ensure that new investment can cover capital costs and, for modeling purposes, is equal in both BAU and carbon-constrained cases[5].

Moreover, auctioning will capture the value of emission certificates otherwise allocated for free to generators. Based on a US analysis, Crampton and Kerr (2002) conclude that an efficient design of such an auction would not pose difficulties. Hence, the state can use auction revenue to decrease distortionary taxes, compensate those sectors or consumers

[5] If new entrants had to acquire allowances from the market this would increase the scarcity rent payments necessary for them to break even. As it is, however, most EU Member States intend to provide new entrants with a sizeable CO2 allowance allocation for free.

most impacted by price increase, or recycle the funds to other types of energy efficiency projects. (Barket et al. 1993, Zhang and Baranzini 2003).

2.3 Grandfathering emissions rights

Toman et.al. (1998) show that under a Grandfathering scheme, the scarcity rent of CO2 allowances is passed onto owners of generation companies. Grandfathering emission certificates requires extensive information about past emissions and political negotiations on a number of issues including the treatment of new entrants, as described for the electricity sector by Harrison and Radov (2002), and the split between different sectors as considered by Sijm et. al. (2002).

For simulation purposes, our grandfathered case assumes that allowances equal to the annual average of CO2 emissions in the period 1999-2001 are allocated for free. Table 3 shows the financial results. Both plants' financial position improves markedly when compared to the auction allocation approach. We expect the PC plant to use fewer allowances than allocated. However, whilst annual generation does falls slightly under the carbon-constrained case from 5.6TWh to 5.5TWh, given the low level of operation in the baseline period, our reference plant remains a net buyer of allowances. The PC plant's total margin, nevertheless, increases from 12£/kWyr to 35£/kWyr. In the case of the CCGT plant, this increases from 32£/kWyr to 48£/kWyr. Annual dispatch increases from 3.2TWh to 3.6TWh, higher than in baseline period and requiring additional purchases of allowances over an above the free allocation.

Table 3: Net cashflow impact with grandfathered emission rights (2008-2012)						
All figures in £/kWyr	**Pulverised coal plant**			**Gas-fired CCGT plant**		
	BAU	**€10/tCO2**	***Change***	**BAU**	**€10/tCO2**	***Change***
(1) Energy sales revenue	117.8	134.9	*17.1*	131.1	164.5	*33.4*
(2) Fuel expense	70.8	69.9	*-0.9*	95.9	106.8	*11.0*
(3) O&M expense	33.1	33.1	*0.0*	21.7	21.7	*0.0*
(4=1-2-3) Energy sales margin	13.8	31.9	*18.1*	13.5	35.9	*22.4*
(5) Net purchases of CO2 allowances	0.0	10.3	*10.3*	0.0	1.6	*1.6*
(6=4-5) Operating margin	13.8	21.6	*7.8*	13.5	34.3	*20.8*
(7) Scarcity rent	13.7	13.7	*0.0*	13.7	13.7	*0.0*
(8=7+6) Total margin	27.5	35.3	*7.8*	27.2	48.0	*20.8*

What level of allocation would have been required to leave our representative plants equally well off under both BAU and carbon-constrained cases? Such an allocation could be perceived as a compromise within a political bargaining process (Bovenberg e.a. 2003). The results are shown in Table 4. Our representative PC plant would require an allocation equal to 66% of its baseline emissions. The profitability of the reference CCGT plant increases vis-a-vis the BAU case even in the auction case. Therefore, it does not need any free allocation. The UK has proposed allocating emission certificates based on the average of the highest four annual CO_2 emission quantities during the five year period 1998-2002.[6] This will then be scaled down by 22% to allow a reduction in national CO2 targets and to retain some allowances for new entrants. If all existing units, regardless of capacity type, receive a free allocation equivalent to about 78% of the emissions of the 1998-2002 base line, we can conclude that both types of generators will benefit from EU ETS.

[6]EU Emission trading Scheme, UK draft national allocation plan for 2005-2007, January 2004.

Table 4: Equivalence between auction and Grandfathering approaches (2008-2012)		
	Pulverised coal plant	**Gas-fired CCGT plant**
(1) Shortfall between BAU and €10/tCO2 scenarios under Auction approach (£/kWyr)	-15.1	4.9
(2) Number of allowances needed to cover shortfall (million tCO2)	2.31	-0.38
(3) Annual CO2 emissions (million tCO2)	5.08	1.39
(4=2/3) Shortfall measured as % of annual emissions	45.5%	-27.8%
(5) Allowance allocation equal to average emissions in 1999-2001 (million tCO2)	3.50	1.26
(6=2/5) Shortfall measured as % of baseline emissions	66.0%	-30.6%

The analysis suggests that the free allowance allocation would be excessive for all basic plant types and confirms the result of studies which look at the aggregate electricity sector (Dinan, 2003). Burtraw calculate for the US that 20.5% of allowances need to be allocated for free to ensure that firms will not incur losses due to the introduction of emission trading (2003). Hence, if industry succeeds in pushing for further free allocation of allowances in future commitment periods, then the overall share of allowances allocated for free can be reduced drastically. This would reduce the cost of implementing the CO2 trading scheme, as large handouts can be avoided. The analysis furthermore suggests, that it might be advisable to base the free allowance allocation on the plant type. As the power sector in Germany successfully convinced the German government to make the allocation of new allowances in future periods dependent on the fuel type (still pending EU approval) the power sector has disarmed the previous argument that such differentiation might be discriminatory. Free allocation of allowances is a bargaining game of interest groups lobbying for cash handouts, and should hence be exposed to more analysis and publicity in order to create a counterbalancing force.

3 Impact of Conditional Allocation and Updating

There are a number of reasons why policymakers may prefer allocation schemes where the allocation is made conditional on whether a power plant is operational. Even if free handouts of emission certificates to the larger historical emitters of CO_2 has disadvantages, from a practical perspective, this device can be used to support the reserve margin and hence increasing security of supply. This will be the case if the annual allowance value is large in comparison to the annual fixed operating and maintenance costs of a power station. This will incentivise owners of existing power plants to keep power stations open that would otherwise have been closed.

When allowances are grandfathered, the emissions baseline is usually based on a historical benchmark. However, as we look towards future allocations, there may be reasons why the baseline needs to be brought forward. When it is known that the baseline reference period will be moved forward to a period yet to elapse, we refer to this as updating. Knowing this information *ex ante*, market participants can adapt their behaviour today in an effort to influence the future allocation process. In the European context the question of updating could involve the allocation of allowances for the period 2008-2012 if these were to be based on emissions output in 2005-2007.

Member States and the European Commission have not provided any guidance as to how the allocation of emissions allowances will take place in the period after 2007. What would happen if industry anticipated that emission allowances for 2008-2012 were to be based on emission levels in 2005-2007? This approach can create both inter-temporal and inter-regional distortions.

The *inter-temporal* distortions are best described using a two-period example. Assume that the emission certificates awarded to generators in period t+1 are a fraction of emissions *u* generated in the first period, t. Then the net marginal emission cost c_t would be reduced by the value of the allowances allocated in future periods, discounted by the time value of money or discount factor *ß* which is derived from the interest rate *r* according to $ß=1/(1+r)$:

$$c_t = p_t - ß \cdot u \cdot p_{t+1} \qquad (1)$$

where p_t is emissions allowance the price in period t.

For illustration, assume the allowances for the year 2008-2012 were to correspond to 80% of the average emissions in the five-year period 2003-2007, with a constant allowance price and a discount rate of 10%, the effective cost of CO2 allowances in 2005-2007 would be reduced by 40% of the traded allowance price[7]. If the compliance period on which the allocation were to be determined was shortened to the three-year period 2005-2007, using the same assumptions, the effective cost of emitting one additional tonne in 2007 would be close to zero.

The appendix compares the impact of repeated updating where firms receive an allocation equal to the same fraction *u* of their emissions from previous periods to a simple grandfathering scheme. In all cases a fixed CO2 emission limit is set and no trading is allowed amongst regions. We also explore banking and non banking scenarios. These demonstrate that parity between grandfathering and repeated updating schemes can be achieved when the price of allowances in the latter case is 1/(1-u) times higher than prices in the former. The appendix also sets out the implications of implementing an updating mechanism after an emission-trading scheme is put into place using initially a grandfathering scheme.

Updating schemes can distort the allowance price relative to the opportunity costs for emission reductions. This will result in inefficiencies if allowances can be traded between different technologies, sectors or regions that face different allocation mechanisms or discount rates, as shall be now illustrated:

Consider two countries, which are symmetrical in all respects except for the allocation mechanism. Country A allocates allowances for forthcoming period t and the following period t+1 on the basis of historical emissions in the t-1 baseline. Country B uses the same methodology to determine the allocation for forthcoming period t but chooses to allocate all allowances in period t+1 based on emissions in period t. Assume that there is no cross-border emission trading and that each country has to meet the same national emissions cap. The price of allowances in country B would rise above that in country A. If the allowance price were to rise to P_A in country A, allowances prices in country B would have to rise to $P_A/(1- ß \cdot u)$, the level at which the net emission cost would be equal across both jurisdictions.

If we now allow for cross-border emission trading, market participants in country B would benefit from purchasing emissions allowances from country A, raising the net emissions cost in country A and reducing it in country B. As a result, more abatement would take place in

[7] 40% = 1 – $\mathbf{S}_{x=1,5}$**(0.2**0.78*0.91^{x}) Each base year influences the allocation in 5 years, we assume averaging over 5 base years (hence 0.2), 78% of emissions of the base years are allocated, and future emissions are discounted.

country A than in country B. This is inefficient; with identical upward sloping marginal abatement cost curves in each country, the efficient solution would have been an equal amount of emission reductions in both countries.

The inefficiencies occur because updating distorts the price signals in individual countries and trading results in the arbitraging based on a distorted price signal. One would expect consumption decisions to be directly impacted by the allowance price distortions created from updating. As power producers include the opportunity costs and benefits of current and future allowance certificates in their pricing decision, they equilibrium electricity price is not effected in a world with updating. However, it will be effected during the period when updating is introduced or phased out.

So far we have assumed that the value of emission certificates remains constant. This may not, however, be the case. If the forward curve for certificates were upward (downward) sloping then $ß \cdot u \cdot p_{c,future} >(<)\ p_{c,present}$, and this would aggravate (ameliorate) the situation described above. Even if certificates can be banked, which at the time of writing was only likely to be allowed within compliance periods and not across compliance periods, this would only limit the extend to which the forward curve can be upward sloping.

Updating can distort signals and introduce inter-temporal, inter-regional and inter-sectoral distortions resulting in an increase in abatement costs for all concerned. What possible lessons can be drawn for governments and others overseeing the allocation process? The choice of emissions baseline is clearly important. To avoid perverse incentives, overseers of the allocation process should make sure that the choice of baseline minimises the scope for perverse incentives. A coordinated approach across sectors and countries participating in the trading system would be useful but an easier approach would be to avoid updating entirely or implemented this in such a manner that the present value of any future allocation be negligible.

4 The interaction between CO_2 and SO_2/NO_x constraints

The LCPD sets new limits for combustion plants with a capacity greater than 50MW for the emission of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and fine dust particles. Rate limits apply to all “new” plants. For plants that were already commissioned or licensed before 1 July 1987, defined as “existing” plants, the new limits are not binding until 2016. Before this date each Member State has two options: to implement transitional rate limits on all units (Emission Limit Value approach) or implement a cap-and-trade scheme (National Emissions Reduction Plan). Under either scheme, an “existing” plant can choose to opt-out for a maximum of 20,000 hours in the period 2008-2015 after which it must close or install clean-up equipment that matches the new build standard. The UK government is most likely to choose the cap-and-trade scheme and we have modelled this option. Under this scheme, NOx and SO2 emission allowances will be allocated annually in the period 2008-2015 conditional on the power plant being operational. The amounts will be set with reference to plant level emissions in the period 1996-2000 and national targets.

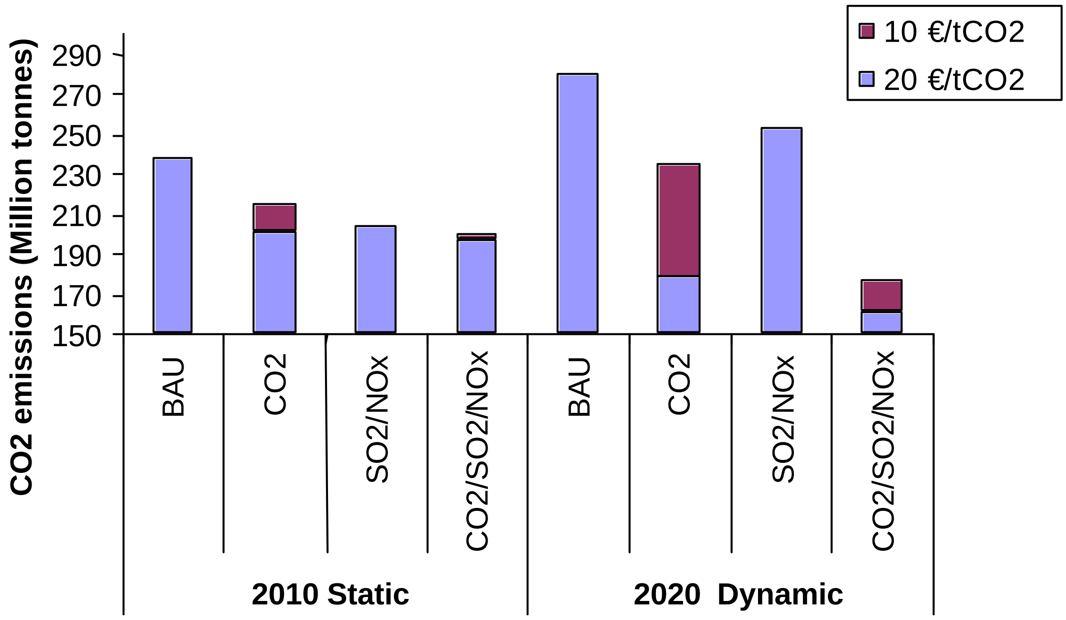
To assess the interaction between SO_2/NO_x and CO_2 policies on the power system emission levels we have simulated the development of the UK power market under four different scenarios:

- BAU – as defined above;
- CO_2 only – carbon-constrained case with CO_2 emissions allowances trading at 10€/tCO_2 and 20€/tCO_2;
- SO_2/NO_x only – policies consistent with meeting the NERP requirements as described above; and,
- Combined CO_2 and SO_2/NO_x policies – combined impact of EU ETS with allowances at 10€/tCO_2 and 20€/tCO_2 together with NERP implementation of the LCPD.

The BAU case still defines the capacity expansion path until 2012 in all cases. Since beyond 2012 the model is allowed to optimise capacity expansion and retirement decisions in manner that minimises the NPV of system costs, the resulting capacity mix in 2020 will differ between scenarios. In 2010, the results will be based on applying alternative policies to the same capacity mix. Therefore, the 2010 results give a feel for the impact of policies without taking dynamic efficiency into account whilst the 2020 results will allow such effects to take root.

Our simulation results are summarised in Figure 2. Emissions of CO_2 in the BAU were estimated to be 238.4 million tonnes in 2010. Assuming a CO_2 allowance price of 10€/tCO_2 reduces the generation from coal plants significantly and this is accompanied by a reduction in CO2 emissions of 22.9 million tonnes. However, the impact of the SO_2/NO_x regulations alone is enough to result in a fall in CO_2 emissions of 34.4 million tonnes. In combination, both policies reduce emissions of CO_2 by 37.5 million tonnes. A CO_2 allowance price of 20€/tCO_2 reduces the generation from more carbon-intensive plants even more and this is accompanied by a reduction in CO_2 emissions of 37.2 million tonnes. This is larger than the sole impact of the SO_2/NO_x regulations. The combination of high CO_2 price and SO_2/NO_x regulations results in a drop of CO_2 emissions of 41.0 million tonnes.

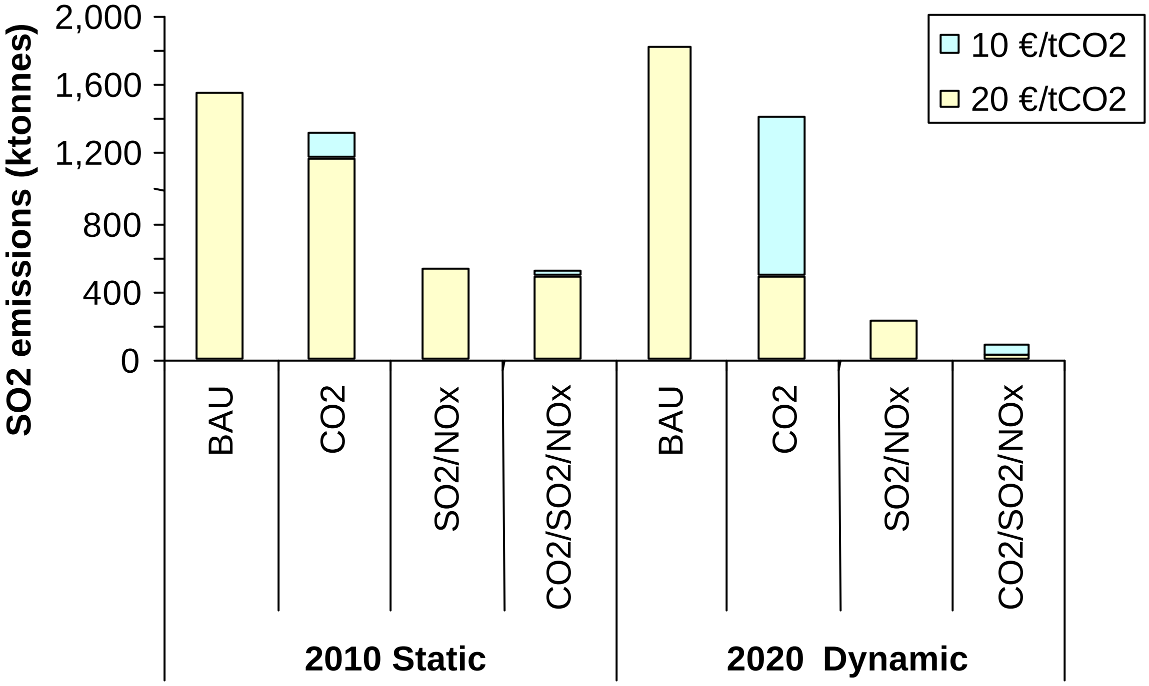
Figure 2: CO2 emissions from interaction between CO2 and SO2/NOx constraints



CO_2 emissions in 2020 are estimated at 280.1 million tonnes. An allowance price of 10€/tCO_2 reduces CO_2 emissions by 45.6 million tonnes which represents a greater drop than the impact of the SO_2/NO_x regulations alone at 34.4 million tonnes. However, in combination, both policies reduce emissions of CO_2 by 102.1 million tonnes. With an allowance price of 20€/tCO_2, CO_2 emissions fall 101.1 million tonnes, nearly four times greater than applying SO_2/NO_x regulations alone. The combination of high CO_2 price and SO_2/NO_x regulations results in a drop of CO_2 emissions of 119.1 million tonnes.

Our simulation results regarding SO_2 emissions are summarised in Figure 3. In 2010, emissions in the BAU were estimated to be 1,551 ktonnes. A CO_2 allowance price of 10€/tCO_2 reduces the generation from coal plants significantly and this is accompanied by a reduction in SO_2 emissions of 217 ktonnes. This impact is similar to that of SO_2/NO_x regulations alone, which result in a fall in SO_2 emissions of 1,015 ktonnes. In combination, both policies reduce emissions of SO_2 by 1,037 ktonnes. A CO_2 allowance price of 20€/tCO_2 reduces the generation from more carbon-intensive plants even more and this is accompanied by a reduction in SO_2 emissions of only 369 ktonnes. This is far smaller than the sole impact of the SO_2/NO_x regulations. The combination of high CO_2 price and SO_2/NO_x regulations, however, results in a drop of SO_2 emissions of 1,068 ktonnes.

Figure 3: SO2 emissions from interaction between CO2 and SO2/NOx constraints



SO_2 emissions in 2020 are estimated at 1,817 ktonnes. An allowance price of 10€/tCO_2 reduces SO_2 emissions by 399 ktonnes which represents a smaller drop than the impact of the SO_2/NO_x regulations alone at 1,582 ktonnes. However, in combination, both policies reduce emissions of CO_2 by 1,720 ktonnes. With an allowance price of 20€/tCO_2, SO_2 emissions fall 1,325 million tonnes, still less effective than applying SO_2/NO_x regulations alone. The combination of high CO_2 price and SO_2/NO_x regulations results in a drop of SO_2 emissions of 1,791 million tonnes.

What are the implications of these results for power companies? The capacity expansion path, fixed until 2012, includes LCPD compliance with no regard for the costs of CO2. Under this BAU assumption, if we compare the emissions levels of CO_2 and SO_2 in 2010, when carbon prices are low the constraints associated with the implementation of the LCPD are binding on the power sector. This suggests that programmes designed to reduce non-CO_2 emissions will be commercially attractive (based on a static, short term assessment).

However, in the same time frame, as the carbon constraint is tightened further (€20/tCO_2), the CO_2 price becomes binding: CO_2 and SO_2 emissions are lower in the combined SO_2/NO_x and tight CO2 case than under the SO_2/NO_x constraint alone. At the industry level, therefore, the higher the price of CO_2, the greater the switch from coal plants to gas-fired CCGT and the smaller the need for SO_2/NO_x clean up equipment. Whilst we have not sought to identify this point exactly, our results suggest that there comes a point where the load factor of coal-fired plant falls so much due to the CO2 constrain that it makes investing in flue gas clean-up equipment commercially unattractive[8].

Addressing the long-term result, our 2020 results show that when the capacity mix is allowed to vary between scenarios, even a small CO_2 constraint is enough to bring about a significant change in the capacity mix. Once again CO_2 is the binding constraint.

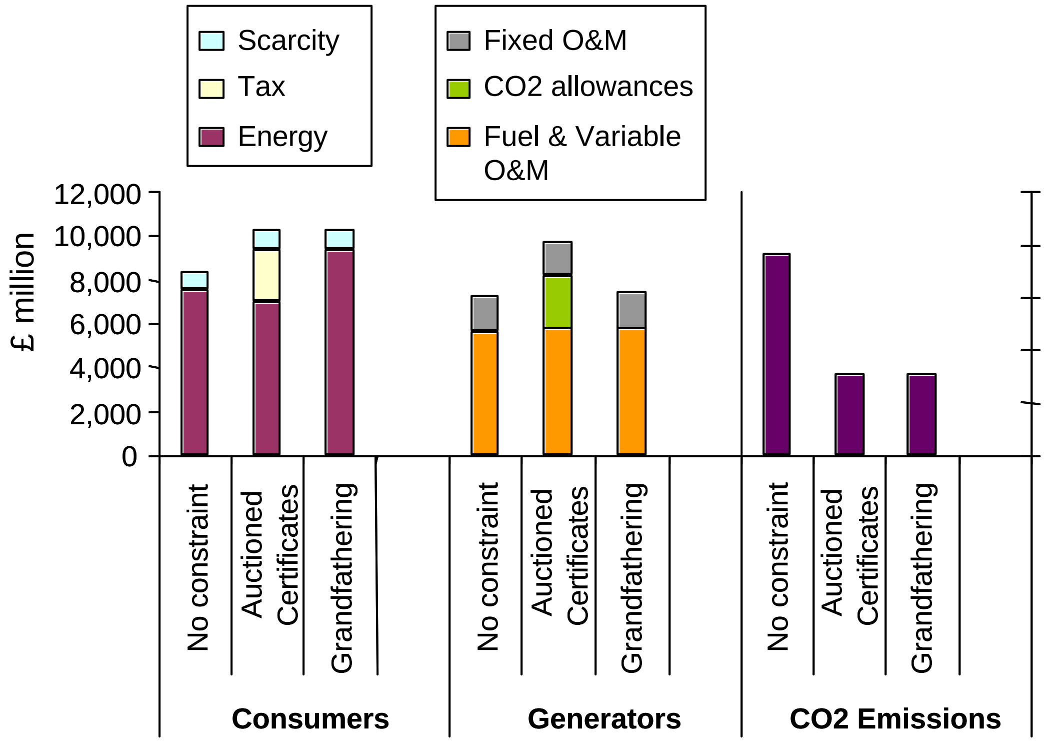
Therefore, when considering both 2010 and 2020 results in parallel, given the uncertainty surrounding actual CO2 prices, owners of existing plant in the UK may be better off postponing retrofit programmes at existing coal-fired plant. Carbon constraints significantly reduce the attractiveness of flue gas clean up investments in favour of developing new higher efficiency gas-fired plants.

5 Costs of Implementing Carbon Constraints

Our simulation analysis also confirms the view that European power producers are most likely to benefit from the implementation of tradable CO_2 allowances under the EU ETS. Figure 4 shows that UK's total expenditure of private and industrial consumers on electricity (excluding transmission and distribution charges), and hence revenue for electricity generators as a whole, increases by £1,840 million irrespective of whether allowances are auctioned or allocated for free. At the same time total generation costs have only increased by £60 million as less coal and more gas is used, resulting in an increase in net revenues of £1,780 million. The value of the carbon liability is only £1,385 million. Therefore, the aggregate power sector would be more than capable of meeting the CO_2 emission costs without any need for free allowances (see section 2 for power plant specific assessment).

[8] Although not presented here, this result was confirmed separately by running a simulation allowing the capacity expansion path to be endogenously determined throughout the forecast horizon. Far less investment in FGD, for example, was observed in this case than under the BAU case.

Figure 4: Annual expenditure on electricity, costs of production and CO2 emissions (2008-2012)



This can be compared to the results obtained by Smith and Ross (2002) for the US power sector where it was found that 9% of all allowances would need to be grandfathered to make the introduction of CO_2 emission certificates equity value neutral. This may reflect a higher incidence of coal-fired power plants and less nuclear than in the UK.

If CO_2 constraints (e.g. 10€/tCO_2) are implemented together with SO_2/NO_x constraints, our analysis shows that annual energy expenditure by consumers and hence revenue of power plants increases by £2,800 million while variable costs only increase by £160 million. The increase in revenues is far greater than the carbon liability of £1,291 million and therefore the sector as a whole would require no free allocation. This ignores the investment costs for SO_2 scrubbers and other clean up equipment that may well explain and justify some free allocation of CO_2 allowances. Investment costs might be lower if, like in the US, reductions can be achieved by shifting to low sulphur coal (as were ca. 66% of SO_2 reductions achieved in the US according to Ellerman 2003) or if plants operate under the 20,000-hour derogation allowed for under the LCPD.

In any case, in future emission allowance allocation rounds it would be advisable to auction larger fraction of allowances in order to collect the scarcity rent paid by consumers and use it to reduce alternative tax burdens. Smith and Ross (2002) use a general equilibrium model to show that the macroeconomic costs of the CO_2 control program are 80% higher under Grandfathering than when all allowances are auctioned and recycled through marginal personal income tax rate cuts. It is unlikely that the money will be directly recycled, and more likely that it will be used to avoid alternative tax increases at times when increasing capital mobility seems to limit the scope of national governments for capital and firm profit taxation.

6 Conclusion

Using the UK as a guide, we show that under present CO_2 emission allowance allocation guidelines, power companies in the EU will be over-compensated. A far greater fraction of available CO_2 emissions allowances could have been auctioned in the first phase of the EU ETS and should be auctioned in future allocations without reducing the net value of power companies' existing assets.

Second, we have highlighted the possible perverse incentives that arise when the allocation is based on emissions in a forthcoming period. An updating allocation methodology can give rise to inter-temporal, inter-regional and inter-sectoral distortions and this suggest that EU Member States should commit to cooperating in defining the allocation methodologies to be used for future trading periods, namely 2008-2012. At best, updating should be avoided completely or implemented in such a manner that the present value of any future allocation be negligible.

Finally when considering the cumulative impact of SO_2/NO_x and CO_2 constraints, we find that power companies may be better off postponing flue gas clean up programmes in favour of developing new higher efficiency gas-fired plants.

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Annex: Impact of updating on allowance prices

Usually a mechanism for free allocation of allowances is used to buy-off industry opposition to the implementation of emission trading schemes. This annex examines the distortions that updating schemes can have on the price of emission allowances when compared to auction or perfect grandfathering allocation option examined. The auction or perfect grandfathering allocation option is examined in case A below. We examine the impact of updating on the allocation of allowances for the second compliance period in cases B and D. For completeness, cases C and E present the results on allowance prices and dispatch of a continuous updating scheme.

Let us assume that the total level of emissions is capped, and therefore that the total amount of allowances to be issued, T_c, is fixed. For simplicity we assume a linear relationship between marginal abatement costs c_t and aggregate emissions T() where the marginal costs of reducing CO_2 emissions increase as CO_2 emission targets are tightened:

$$T(c_t)=T_0-b\cdot c_t \text{ , where } b>0. \qquad (1)$$

(A) Single period

In an auction or given a perfect grandfathering of allowances, the marginal abatement costs c_t would be equal the allowance price p_t. By assumption this is the price level required to achieve the target emissions level. Hence,

$$T(p_1)=T_{c,t}$$

$$\Rightarrow \; p_t = c = \frac{T_0 - T_{c,t}}{b} \qquad (2)$$

(B) Two periods, without banking or borrowing

In period two, generators receive allowances corresponding to a fraction *u* of their emissions in period one. As described in the main text, updating schemes result in generators offsetting the value of future allowance allocation against today's allowances price. Since no third period exists in the model, allowances prices in period two will be determined by the marginal abatement costs such that $p_2=c_2$. In period one, however, the allowance price is determined by the marginal abatement costs, c_1, plus the value of future allowances allocated through updating and discount factor *ß* which is derived from the interest rate *r* according to $ß=1/(1+r)$:

$$p_1 = c_1 + ß \cdot u \cdot p_2$$

Combining with the physical constraint on emissions that determines the marginal abatement costs (2) gives:

$$p_1 = c_{opt,1} + ßuc_{opt,2} = (1+ßu)\frac{T_0 - T_{c,1}}{b} = (1+ßu)c_1 \qquad (3)$$

The allowance price would be higher in period one than under (A). With no banking, this will not affect the inter-temporal allocation. However, inefficiencies can arise across jurisdictions or sectors if different generation technologies, sectors or countries face different updating proportions u or discount factors ß. In these cases, different producers will take differing abatement decisions even if they face the same marginal abatement cost.

(C) Many periods, without banking or borrowing

Now assume that players anticipate that updating will occur not only in the second period, but that allocations in any subsequent period are based on the emissions in the preceding period. To simplify the calculations we assume a constant emission target $T_{c,t}=T_c$ and therefore constant marginal abatement costs $c_t=c$.

$$p_1 = c + ßu(c + ßup_3) = \ \dots \ = c\sum_{n=0}^{\infty}(ßu)^n = \frac{T_0 - T_c}{b(1 - ßu)} \tag{4}$$

If the scheme is implemented for an indefinite amount of time then the same formula applies to all periods, and the updating will result in a higher price level for allowances in all periods. The price level will exceed the allowance price in period one in (B) above. This divergence of allowance price and opportunity costs of allowances will result in the same type of distortions across technologies, sectors and regions as discussed in (B).

(D) Two periods, with banking and borrowing

When banking is allowed, the objective is to achieve the total amount of emission reductions over the observation horizon. If T_t is the emissions quantity in period t then total emissions are constrained by

$$\sum_{t=1}^{n}\left(T_t - T_{c,t}\right) = 0 \tag{5}$$

Substituting the opportunity costs of emissions (1) into (5) gives:

$$T_0\text{-}b\cdot c_1+T_0\text{-}b\cdot c_2=T_{c,1}+ T_{c,2} \tag{6}$$

Assuming allowances can be banked at no cost then financial arbitrage will determine the price path such that:

$$p_t= ß\ p_{t+1} \tag{7}$$

As in (B) the allowance price in the second period will equal the marginal abatement cost such that $p_2 = c_2$. In the first period, the allowance price will equal marginal costs plus the benefit of future allowance allocations $p_1 = c_1 + ßup_2$. Substituting these two equalities for c_t into (6) and using (7) gives:

$$\begin{aligned} &p_1 = \frac{1}{1+1/ß - u}\frac{\sum_{t=1,2}\left(T_0 - T_{c,t}\right)}{b} \qquad p_2 = c_2 = \frac{1}{1+ß - ßu}\frac{\sum_{t=1,2}\left(T_0 - T_{c,t}\right)}{b}, \\ &c_1 = \frac{1-u}{1+1/ß - u}\frac{\sum_{t=1,2}\left(T_0 - T_{c,t}\right)}{b}. \end{aligned} \tag{8}$$

The results reveal two effects: in the absence of updating, $u = 0$, and given positive interest rates, $r>0$ and therefore $ß<1$, the opportunity to bank will result in a reduction in allowance prices and marginal emission reduction costs in the first period. The effect will be increased emissions in period one and emission reductions in period two relative to (A).

With banking, *u > 0*, the value of future allowance allocations will increase the allowance price in period one and decreases the cost of the marginal emission reduction c_1. Thus, updating encourages emissions to be switched from the second to the first period.

If *ß(1-u) =1* then the updating and banking effects will balance each other out. Emissions trading between technologies, sectors and countries with different updating mechanisms will result in inefficient allocation of abatement effort.

If borrowing is not allowed, the financial arbitrage constraint (7) is replaced by the market clearing condition $T(c_t)=T_{c,t}$. In this case we can envisage three possible solutions:

- First, when allowance prices resulting in case (B) can be profitably arbitraged by banking allowances from the first to the second period such that if $p_1 < ßp_2$. Then resulting allowance prices will be described by equation (8).
- Second, where allowance prices in (B) are consistent with $p_1=ß\, p_2$, then case (3) and (8) will coincide.
- Third, when borrowing would otherwise be profitable, $p_1 > ß\, p_2$, allowance prices will also be described by equation (3).

Results from the banking without borrowing case, therefore, encompass those from the without banking or borrowing as well as the banking and borrowing cases. The following table summarises the impact of increases of the updating rate and interest rate on allowance price, cost of the marginal emission reduction and emission quantities. The reader can judge how the binding no-borrowing constraint will affect prices, opportunity costs and emission levels.

Table 5: Impact of interest rate increase *r* and updating proportion *u* on key variables

	p_1	c_1	T_1	p_2	c_2	T_2
No banking, n=2	u (+)					
No banking, n=8	u (+)			u (+)		
Banking, n=2	u (+), r (-)	u (-), r (-)	u (+), r (+)	u (+), r (+)	u (+), r (+)	u (+), r (-)

(E) Many periods, banking and borrowing

Using the price path of allowances (7) and the relationship between allowance price and marginal costs of emission reductions $p_t = c_t+ßup_{t+1}$ gives:

$$p_t = \frac{c_t}{1-u} \tag{9}$$

Substituting (9) and (7) into (5) gives:

$$\sum_{t=1}^{n} \left(T_0 - b(1-u)p_1 b^{1-t} - T_{c,t}\right) = 0 \tag{10}$$

For r>0 and ß<1 and assuming, as in (4), constant $T_{c,t}$, the sum in (10) does not converge when the number of periods *n* increase towards infinity. This is because the model allows participants to borrow an increasing number of allowances from future periods. This would reduce the marginal costs of emission reduction and increase the level of emissions in earlier periods. To prevent such an effect, most banking schemes typically do not allow for borrowing of allowances. If we set ß=1 to remove the incentives to borrow, then solving (10) for p_t gives the same allowance price and relationship to marginal abatement costs as observed in case (C).