Emission projections 2008–2012 versus national allocation plans II

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Abstract

We compare the national allocation plans (NAPs), proposed and submitted by EU Member States as of October 2006, with our estimations for CO_2 emissions by the installations covered by these NAPs. The collective allocations proposed under phase II NAPs exceed the historic trend of emissions extrapolated forward. Using our projections we find, depending on uncertainty in fuel prices, economic growth rates, performance of the non-power sector and CDM/JI availability, a 15% chance of a 'dead market' with emissions below cap even at zero prices. With an expected inflow of committed CDM/JI credits of 100 $MtCO_2$/year, allowance supply will exceed demand in 50% of cases without any carbon price, and in 80% of our €20/tCO_2 scenarios. Banking of allowances towards post-2012 conditions could create additional demand, but this is difficult to anticipate and conditional on policy evolution. The proposed phase II NAPs would result in low prices and only small volumes of CDM/JI would enter the EU ETS. CDM/JI would almost exclusively be public-sector funded, placing the cost of Kyoto compliance entirely upon governments.

Keywords: Emissions trading; Allocation plan; Europe; Projections

1. Introduction

This article projects the balance of supply and demand of allowances to emit CO_2 under the European emissions trading scheme (EU ETS) for the period 2008–2012. This balance will determine the scarcity, and hence the allowance price, during this period. Our aim is therefore to assess the collective implications of the proposed plans for the operation of the EU ETS in phase II.

Installations covered by the scheme have to provide CO_2 allowances for every tonne of CO_2 they emit. This forms the demand for allowances under the scheme. The supply to the market follows from tradable allowances allocated to existing or new installations or auctioned by governments as defined in the national allocation plans. The linking directive allows for some additional allowance supply to the EU-ETS market from project credits under the clean development mechanism (CDM) or joint implementation (JI) projects. To the extent that allowances from the

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period 2008–2012 are banked to future periods, this would create additional demand. It seems rather certain that no allowances from the period post-2012 can be borrowed to cover emissions in the period 2008–2012, so no additional supply from banking is expected.

In light of the NAPs that have been proposed by Member States for the second phase, this article aims to assess their aggregate impact on the market. We first collated the information in each plan – itself a complex exercise given some of the special provisions. Then we made different projections for the possible inflow of allowances from the CDM and JI project mechanisms. We start by comparing allocation against extrapolation of past trends. The main contribution of the article is a projection of the CO_2 emissions from installations covered by the European emission trading scheme. With the models we explore the implications of different price and growth scenarios.

In projecting these emissions we started from the verified emission data from the year 2005. For the non-power sectors we used two different modelling approaches to project the anticipated emissions in the period 2008–2012 on a sectoral level for each country. In the power sector, emissions are very sensitive to fuel and CO_2 prices. Therefore we applied a detailed power sector model developed by ICF International to project country-level emissions.

One inherent uncertainty in this field is caused by limited or restricted data availability. First, there is still some concern about the accuracy of monitoring of CO_2 allowances at the installation level – and future changes to the monitoring guidelines could alter the aggregate monitored emissions. Second, for three Member States, only limited information about verified emissions for our base year 2005 was available. If aggregate emissions of installations covered by ETS in these Member States were below our assumptions, then the gap between projected emissions and the cap could be bigger (and vice versa). In Section 6 we provide a more detailed discussion of the sensitivity of our modelling to various parameters and model choices.

We projected emissions and assessed the cap on a national level. We also verified our power sector model, the assumptions on the cap and the split between sectors on the national level. However, we did not have the resources to comprehensively compare our projections against all national projections.

2. Methodology and assumptions

To project future CO_2 emissions, we treat the power sector separately from other sectors covered by the ETS. For the power sector we examine emissions using the Integrated Planning Model (IPM) of ICF International, which simulates every European power station and investment decisions in new power stations. For the remaining sectors we use two approaches. First, we start from the verified emissions from 2005, adjust for the coverage of the ETS and then apply sector-specific growth rates from a recent DTI BAU study combined with country-specific CO_2 growth rates from OECD projections (OECD, 2006). The second approach to project emissions of the non-power sectors involves applying country- and sector-specific CO_2 growth rates as determined by the E3ME model of Cambridge Econometrics and calibrated for the Matisse FP6 project (Matisse, 2006), assuming CO_2 prices around €20/tCO_2. The detailed assumptions and our treatment of missing data are explained in Appendices 1 and 2.

To explore sensitivity to prices, we use four different fuel price assumptions from a recent UK Department of Trade and Industry study (DTI, 2006b) (see Appendix 3).

To determine the total cap, we use the publicly available data from NAPs, assuming that all New Entrant Reserves (NERs) will be issued. Some NAPs envisage that New Entrant Reserves will be

Table 1. Our estimations of CAP including inflows from JI and CDM projects ($MtCO_2$/year)

CAP	2074
CAP with NER	2178
CAP with NER, high CDM/JI inflow	2378

cancelled if not issued to new entrants.[1] Without any new build in these countries, the total EU cap would be reduced by 20 $MtCO_2$/year.

We furthermore take into account the potential inflow of allowances into the EU ETS from CDM and JI projects. Following a more detailed discussion in Grubb and Neuhoff (2006), we assume a potential range of between 0 and 1,000 $MtCO_2$ international project credits and allowances to enter the ETS during the period 2008–2012. The upper level is one-third lower than the total projected availability of CDM and JI for Europe, assuming that at least some of the inflow would be taken by government inflow in all cases; it is also roughly consistent with the 'supplementarity' constraint that many Member States have built into their plans in line with Kyoto commitments, representing, even at this maximum level, an inflow of less than 10% of allocated allowances. Indeed the EU Commission insisted in their decision on the first 10 second-phase NAPs (Nov 2006) that some Member States tighten their supplementary condition. Table 1 gives the range that we assume for cap and inflow (Appendix 4).

3. Emission projections in relation to historic trends

To verify our emission projections, we first compared them to historic emissions from 1990–2004 using data from the European Community GHG Inventory (EEA, 2006) as shown in Figures 1 and 2.

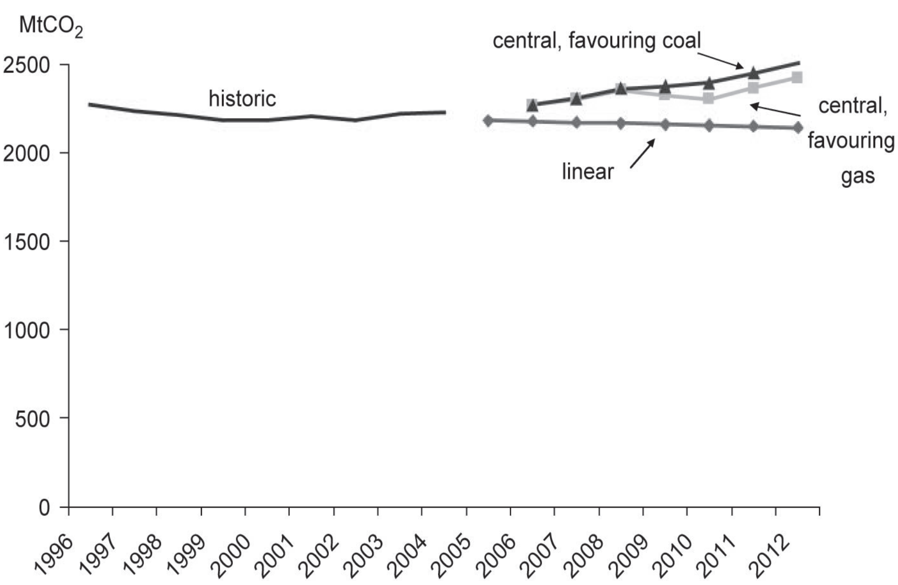

Figure 1. Linear trend of ETS emissions compared to simulation results for the case of zero CO_2 price and central fuel price assumptions.

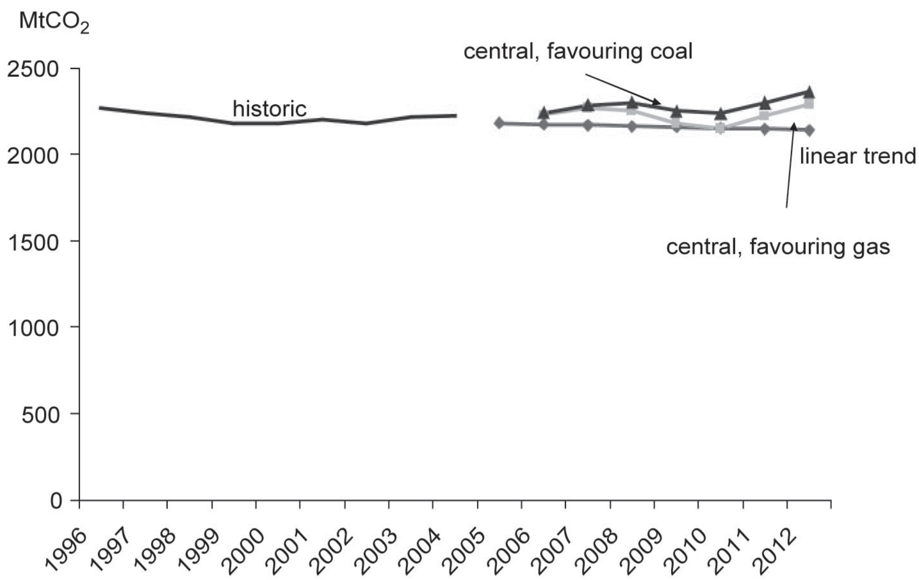

Figure 2. Linear trend of ETS emissions compared to simulation results for the case of a €20/tCO_2 price and central fuel price assumptions.

As the Inventory only provides data on the total national greenhouse gas emissions, we follow Georgopoulou et al. (2006) and assume that the share of emissions associated with ETS sectors stays constant. Fitting a linear trend to this historic emission from 1990–2004 (later start for accession countries), we then extrapolated the BAU development of emissions for 2005–2012 (Appendix 5).

Figures 1 and 2 illustrate that the emissions under this linear trend are lower than projected in the two central fuel price scenarios as defined by the UK Department of Industry (DTI, 2006a). The most likely reason for this, despite a decade of decline or stability, is that the model assumes a slowdown in the rate of energy efficiency improvements and a slowdown in the historic shift from coal towards natural gas, in the light of higher natural gas prices. We do, however, note a general tendency that models have previously projected emissions growth that has not materialized. As our model approach is also likely to underestimate emission reductions from unanticipated technological, institutional and behavioural changes, our results may be conservative – the excess allocation that we estimate for NAP IIs might in practice be even higher. To set this in the context of phase II allocations, the total phase II cap with NER implied by the proposed NAPs is slightly above the average emissions levels over the past 10 years.

Figure 2 illustrates that with a price of €20/tCO_2, emissions from the ETS sectors are projected to be roughly stable at current levels, still slightly above the historic trend.

4. Numerical results from simulations under uncertainty

Figure 3 compares the total NAP II allocation (the horizontal line spanning 2008–2012) against most recent emissions data (2005), the phase I cap, and a range of projections for emissions over the period assuming €0/tCO_2. We assume four different fuel price scenarios, three different economic growth rates, and apply two different models for the non-power sector. Thus the projection range

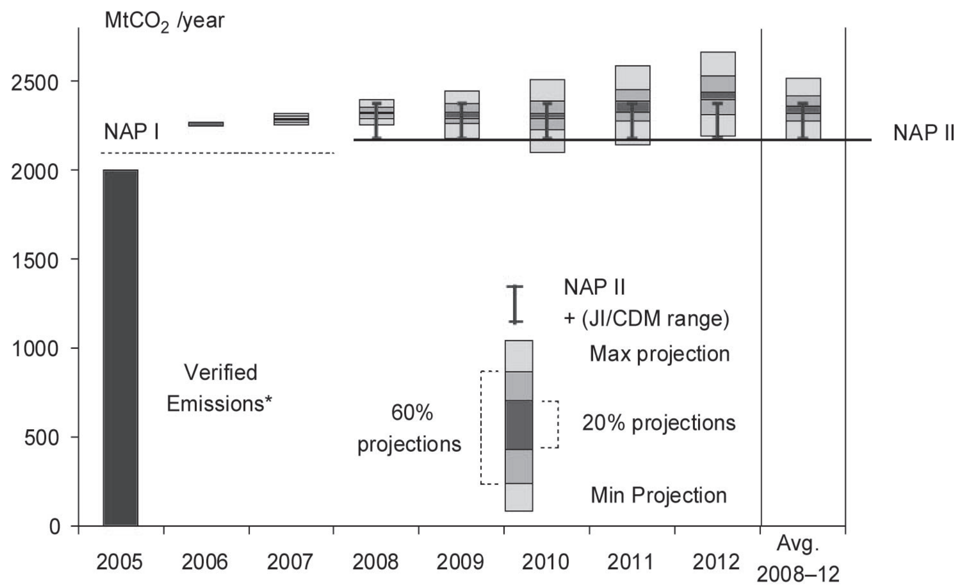

Figure 3. Projected CO_2 emissions versus cap for the BAU (assuming zero CO_2 price).

depicts the outcome of 24 different model scenarios. The vertical lines with T-endings show the range of potential inflow from JI and CDM credits into ETS.

Note that the phase I cap was significantly above the 2005 verified emissions, and the NAP II allocations in turn represent a significant increase over phase I. This suggests that Member States did not take on board the experience from the observed crash in CO_2 prices in May 2006 when proposing their NAPs for phase II.

Our model estimates of emissions for 2006 exceed the 2005 verified emissions, for four reasons. First, in the electricity modelling we do not reflect that some gas generation is operated, despite being more expensive than coal, because it is supplied under take-or-pay gas contracts. This would have decreased CO_2 emissions by 100 Mt. Second, the electricity model calculates aggregate CO_2 emissions for the year 2006 that exceed verified emissions in 2005 by 25 Mt. We decided against scaling the output to match the observed data, as the differences could equally be caused by slight variations in input prices and hydro availability. Third, with GDP growth, emissions from the non-power sector are expected to grow by 25 Mt. Fourth, 63.1 Mt of additional installations are covered under NAP II that either opted out of NAP I or where the coverage was extended.

The range of results for 2008–2012 illustrates that emission projections are subject to considerable uncertainty. Figure 3 shows the distribution in terms of five probability bands, with the central red illustrating the central 20% of scenario outcomes. The results show that, even with a zero carbon price (a 'no EU ETS' scenario):

– *Without any inflow of CDM and JI credits, allowance supply will exceed demand in 20% of our scenarios*. In other words, based on the proposed NAPs for the second phase and a range of other input assumptions, there is a one-in-five risk that the EU ETS would be unable to sustain any carbon market or incentive to abate, at home or abroad. We could only expect a positive price if banking moves a significant share of the allowances towards the post-2012 period.

– *If inflows from JI and CDM projects are high (200 MtCO$_2$/year), 80% of the projections result in excess supply*. Obviously, there is a certain paradox in a combination of high emission credit imports with an overall surplus market, but it illustrates that current phase II allocations are extremely unlikely to support private purchase of emission credits on the scale that suppliers may be hoping for, even at very low carbon prices.

Figure 4 illustrates the equivalent results if the power sector adjusts investment and operational decisions to reflect a carbon price of €20/tCO$_2$. Obviously, this reduces the total emissions in our 24 model scenarios, as depicted.

Figure 4 shows that:

– in 50% of the scenarios assuming an allowance price of €20/tCO$_2$, emissions would fall below the European cap even without any inflows of JI and CDM credits into the EU ETS;
– at the high level of credit inflow, the probability of sustaining a €20/tCO$_2$ price is very small, and even in our central case (100 MtCO$_2$/year), there is only a 20% chance of the market sustaining a price of €20/tCO$_2$.

This suggests that the currently published allocation levels of NAPs II are simply not consistent with sustaining CO_2 prices at significant levels.

The level of the CO_2 emissions in this projection suggests that if the European countries want to ensure CO_2 prices close to €20/tCO$_2$ then allocation has to be cut back significantly to reduce the aggregated EU cap. The implication based on our projections is that if a 200 Mt tightening were associated with a similar level of JI/CDM imports (200 Mt/year), there would then be roughly a 50% chance of the market sustaining a price of around €20/tCO$_2$ – before taking account of

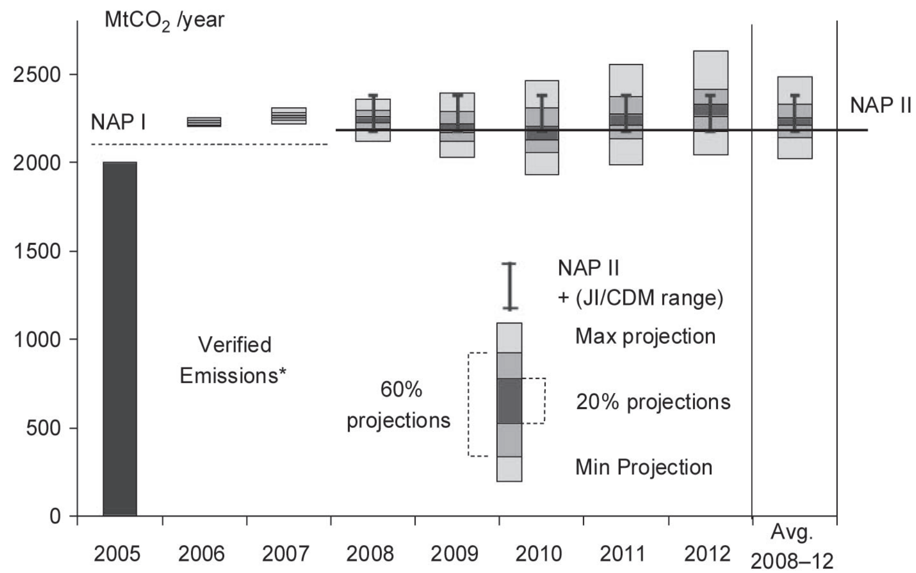

Figure 4. Projected emissions and cap, when the power sector is exposed to a price of €20/tCO$_2$.

responses outside the power sector. Subsequent to the initial publication of this article, the EU Commission has announced their decision on the first 10 NAPs. If the commission will apply the same methodology across all Member States, then this will, according to our calculations, result in a cut of 200 Mt/year.

5. Discussion

5.1. Implications for the NAP approval process

Comparing the projections for CO_2 emissions presented in this article to the proposed NAPs (before the Commission's decision), we concluded that they are unlikely to support a viable CO_2 market. These conclusions are consistent with those of Betz et al. (2006, this issue) and put a spotlight on the European Commission's NAP approval process. The Commission has to evaluate each NAP on its own merits, in relation to the criteria laid out in the Directive. Nevertheless, given the relative ambition of some of the NAPs (e.g. Spain, Italy, the UK) our collective result must imply that many other NAPs contain over-allocation based on emission projections which, at least when considered collectively, are implausible. This would contravene the relevant terms of the Directive.

A further basis on which the Commission might critically assess the national allocation plans are State Aid considerations. Johnston (2006) argues that free allowance allocation does constitute State Aid, which has to be notified according to the Directive. One relevant provision for the assessment of such State Aid could be the proportionality principle – the benefits from the free allocation should be proportional to the transition costs for companies from the introduction of emission trading.

Moreover, the weak allocations raise questions about the consistency of plans with national Kyoto targets, which is another criterion relevant to Commission assessment. In principle, countries could 'fill the gap' with purchases of JI/CDM, to which we now turn.

5.2. Implications for CDM/JI credits and government purchase

Weak allocations in the EU ETS do not necessarily imply a weak market for CDM/JI credits. As long as countries comply with Kyoto, the total demand for CDM/JI (or equivalent transfers of AAUs under Green Investment Schemes – an option not open to ETS private-sector participants) is set by the difference between national emissions and Kyoto targets over the period 2008–2012. The real implication of weak EU ETS allocations is on the cost of compliance to governments, specifically finance ministries and taxpayers, through three factors:

- *Substitution*: more allocations to ETS sectors mean that the private sector will have less need to purchase CDM/JI credits that would contribute to national compliance; governments must pay for these directly.
- *Increased total need*: a weak EU ETS price means that EU ETS sectors undertake less abatement, resulting in higher national emissions, and in aggregate a greater total need for CDM/JI credits. National governments could also decide to acquire additional credits (AAUs) from countries such as Russia and the Ukraine.
- *Price escalation*: the greater aggregate demand for CDM/JI credits might reasonably be assumed to have some impact on the overall CDM/JI market, increasing the price.

In short, the excessive allocations under the proposed national allocation plans mean that governments have to take up the slack, and substitute for less domestic abatement by funding additional abatement abroad at a higher unit cost to the taxpayer. This would imply that the Kyoto credits market will become a largely public-sector funded operation, rather than leveraging the private investment that many had originally envisaged.

The excessive EU ETS allocation would thus conflict with a desirable emissions pathway. It is also inconsistent with the principle that ETS sectors' share of the national emission budget should decline given large mitigation potentials, especially in the power sector.

5.3. Implications for auctioning and other mechanisms

This article has argued that the continuation of the EU ETS as an effective market during the Kyoto period requires that the currently proposed volume of total free allocations is reduced, probably by a couple of hundred $MtCO_2$ per year. However, our analysis has emphasized the high levels of uncertainty prevalent in emission projections. This suggests that Member States should consider carefully measures to increase price stability and thus improve investment certainty.

One option would be the increased use of auctions. Auctions in themselves could, in principle, provide a source of revenue for government purchases of Kyoto credits. In addition, if all Member States were to auction allowances within the 10% limit of the Directive (200 Mt/year) and the auctions were implemented with a price floor, then this would cover the range of uncertainty in the projections (Hepburn et al., 2006). This could ensure that, in the case of low emissions, a reduced inflow from the auctions would maintain prices, without distorting the demand/supply balance in the case of higher demand.

Banking of allowances to the period post-2012 could also help to support the price, if participants believe that the future allowance price will be higher. Banking has worked effectively in SO_2 and NO_x programmes in the USA (Ellerman, 2006). However, the same mechanism in the EU ETS would be subject to a high degree of uncertainty due to its iterative allocation approach and the complexity of post-2012 negotiations. These added uncertainties could subject the EU ETS to greater price volatility, and may thus reduce the effectiveness of banking as a mechanism to reduce investment risk.[2]

6. Caveats and sensitivities

It is important to note that this study does not calculate the impact of CO_2 prices on the CO_2 emissions of the non-power sector. It relies on (a) a DTI study (DTI/OEF, 2006), which assumes CO_2 emissions under a zero CO_2 price and then gives aggregate figures on the price response of the covered sector to allowance prices, and (b) the E3ME study (Matisse, 2006), which assumes a positive allowance price (increasing from €18 to €25/tCO_2 during phase II). Using data from the E3ME study, our emission projections for the non-power ETS sectors decrease by 75 Mt relative to our simulations based on DTI data. As both approaches differ in various dimensions, it is not clear to what extent this difference can be attributed to the emission reductions or are due to CO_2 prices. Therefore we did not differentiate between the two approaches, and depicted the results both for the €0 and €20/tCO_2 case as a component of the prediction uncertainty.

Table 2 illustrates how different assumptions affect the projected CO_2 emissions from the EU ETS sectors. As a basis for Figures 3 and 4 we calculated the impact of combining all these scenarios.

Table 2. Sensitivity of projected CO_2 emissions to model parameters

(Average 2008–2012)	Zero CO_2 price		€20/tCO_2	
	MtCO_2/year	Change	MtCO_2/year	Change
Central fuel price favouring gas, DTI	2352		2218	
Matisse study with E3ME for non power	2277	–3.2%	2143	–3.4%
Fuel price scenario, central favouring coal	2416	2.7%	2289	3.2%
Fuel price scenario, low fuel price	2316	–1.5%	2160	–2.6%
Fuel price scenario, high fuel price	2444	3.9%	2407	8.5%
GDP growth 0.75% higher/a (= CO_2 growth)	2424	3.1%	2286	3.0%
GDP growth 0.75% lower/a (= CO_2 growth)	2282	–3.0%	2152	–3.0%

7. Conclusions

We compared the volumes of EUA supply proposed in the NAPs to a range of emission projections to assess whether there will be scarcity and a thus a viable emissions trading market. For this purpose, we combined a detailed power sector model for all European countries with two approaches to project emissions of the non-power emissions covered by ETS, and simulated CO_2 emissions until 2012. We used the data from currently available national allocation plans and extrapolated to the outstanding plans to determine the currently envisaged emission cap under ETS for the period 2008–2012. We also made assumptions about the possible inflows of JI and CDM project credits into the ETS.

The results suggest that it is possible that emissions will be lower than the volume of issued allowances in the scheme in a scenario where we assumed zero CO_2 prices and it is very likely that emissions will fall short of allowances in the scheme in a scenario with €20 t/CO_2. Thus, very low CO_2 prices are likely to result from the currently proposed second-phase NAPs. In the current arrangement only extensive banking into the period post-2012 could ensure a significant positive CO_2 price. However, given the uncertainty about post-2012 arrangements, such banking is unlikely to attribute very high values to allowances, and given the complexity of political negotiations, such banking is likely to introduce large volatilities in the prices of ETS allowances throughout the period 2008–2012. Hence the future of EU ETS risks being heavily undermined by second-phase NAPs submitted to the European Commission, unless decisions are made to amend proposals in line with a tighter overall volume of allowance allocation. Since the initial publication of the study, the Commission has decided on the first 10 national allocation plans, and has requested that nine countries reduce the total volume of allocated allowances. The range of CO_2 emissions simulated for the year 2008–2012 illustrates how sensitive emissions can be to changing GDP growth rates, fuel prices and to energy intensity and technology development in all sectors. To increase the predictability of CO_2 prices in the light of this uncertainty, one might consider using the flexibility of the EU Directive and lessen free allocation to sectors that are not exposed to competition outside of the EU (e.g. the power sector). The allowances not issued for free could then be auctioned, e.g. 10% of the allowances issued per country. If a harmonized European price floor were to be used in these auctions, then this could help to manage the volatility inherent in any system in which cutbacks are modest compared with the intrinsic uncertainties in emission trends, and create confidence that the price will not drop below the price floor. This would facilitate investment in low-carbon technologies and energy efficiency.

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Notes

1 The NAPs specify that Cyprus, Denmark, Lithuania, Latvia, Malta and Portugal should not sell the excess NER back to the market. In the French NAP it has not been decided whether to cancel the excess NER or auction it, but for the purpose of calculating the maximum possible reduction of the cap, we assume that it will be cancelled.

2 Note also that, in the longer term, governments could issue option contracts for CO_2, also ensuring a price floor (Ismer and Neuhoff, 2006). European governments could thus guarantee buying back allowances until the scarcity of allowances is increased to the strike price of the option contracts.

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Appendix 1: Verified emissions

We started with verified emission data (EU Commission, 2006a, 27 September 2006) differentiated into iron and steel, cement, lime, glass, pulp and paper, ceramics, others, and primary aluminium. Based on WIFO (2006), we separated the classification combustion installations into power- and non-power-related combustion installations. Since we could not allocate the non-power combustion installations to specific sectors, we included them in the category 'others'.

For Poland, data on only 331 installations were available as of 27 September 2006, representing allocated allowances for 115.2 $MtCO_2$ out of a total NAP I of 239.1 $MtCO_2$. We assumed that the installations not reported in the CITL will have the same ratio to allocated emissions as the installations for which already reported data are available. Thus we assumed 189.0 $MtCO_2$ emissions for Polish installations covered by ETS in 2005 (implying a total national surplus of 50.1 $MtCO_2$). In our simulations of the European power sector, we calculated 132 $MtCO_2$ emissions for Polish power installations covered by ETS, and used this figure to separate between power- and non-power-related emissions.

For Cyprus and Malta no data were available and we assumed that they had the same ratio between verified emissions and NAP I allocation as the Member States for which full data were available. We did not have data available that allowed us to differentiate between power and non-power installations and thus applied a general emission growth trend to all emissions.

We added to these verified emissions the volume of new installations covered under NAP II that either opted out or were not covered under NAP I (5.3 $MtCO_2$ in Belgium, 11 Mt in Germany, 32 Mt in the UK, 6.6 $MtCO_2$ in the Netherlands, 5.5 in France, 0.7 in Portugal, 2 in Sweden).

Appendix 2: Projections for the non-power sector

To project the CO_2 emissions for the non-power sector, we first used an approach based on a recent DTI study (DTI, 2006a, 2000b) and then an approach based on a European model developed by Cambridge Econometrics.

For the first approach, we applied to the verified emissions per sector and country the sector-specific emission growth rates used by the UK DTI (DTI, 2006a; DTI/OEF, 2006), scaled by the differences in the expected national growth rates (Table 3). For example, the Spanish GDP is expected to grow 0.6% faster in 2006 than the UK GDP; thus we also assumed that emissions across the sectors increase 0.6% faster in Spain than in the UK. GDP growth projections for the period 2006–2007 are based on Eurostat (2006) and for the period 2008–2012 are based on OECD (2006) and IMF (2006).

Table 3. Assumed GDP growth rates

	2006	2007	2008–2012
AT	2.5%	2.2%	2.4%
BE	2.3%	2.1%	1.9%
CY	3.8%	3.8%	2.8%
CZ	5.3%	4.7%	3.8%
DE	1.7%	1.0%	2.0%
DK	3.2%	2.3%	1.1%
EE	8.9%	7.9%	4.6%
ES	3.1%	2.8%	2.5%
FI	3.6%	2.9%	1.5%
FR	1.9%	2.0%	2.1%
GR	3.5%	3.4%	3.1%
HU	4.6%	4.2%	3.0%
IE	4.9%	5.1%	3.6%
IT	1.3%	1.2%	1.4%
LT	6.5%	6.2%	4.6%
LU	4.4%	4.5%	4.0%
LV	8.5%	7.6%	4.6%
MT	1.7%	1.9%	4.6%
NL	2.6%	2.6%	2.1%
PL	4.5%	4.6%	4.5%
PT	0.9%	1.1%	2.0%
SE	3.4%	3.0%	1.8%
SI	4.3%	4.1%	4.6%
SK	6.1%	6.5%	5.5%
UK	2.4%	2.8%	2.5%

Sources: 2006–2007 data from Eurostat (2006)
2008–2012 data from OECD (2006), except for CY, EE, LT, LV, MT and SI (IMF, 2006).

The application of the DTI model outside of the UK makes the implicit assumption that the technological mix within a sector is roughly comparable across Europe. This is certainly a bold assumption, but we have no data available that allow us to assess what type of bias it introduces. By correcting for the relative size of different sectors, we intend to address the main concern of any such transfer – a different sectoral composition between countries.

The second approach uses sector- and country-specific growth rates computed from Cambridge Econometrics modelling. They represent those of the baseline scenario for the FP6 project Matisse using the E3ME model, covering the 2005–2010 period (Matisse, 2006). For the purposes of this article, we assume that the sector-specific growth rates are constant in 2011 and 2012. As the definitions of sectors under E3ME did not exactly match the classifications of verified emissions, we matched these sectors as described in Table 4.

Table 4. Mapping of E3ME model results to classification used for verified emissions

CITL	Matisse/E3ME
Refineries	2 – Other energy own use and transformation
Cement and lime	6 – Non metallic NES
Ceramics	6 – Non metallic NES
Glass	6 – Non metallic NES
Pulp and paper	10 – Pulp and paper
Iron and steel	3 – Iron and steel
Other	12 – Other industry

Note: NES = not elsewhere specified.

Table 5. Fossil fuel price assumptions from DTI (2006b)

	Central – Favouring GAS			Central – Favouring COAL		
	Oil ($/bbl)	Gas (p/therm)	Coal (£/t)	Oil ($/bbl)	Gas (p/therm)	Coal (£/t)
2005	55	41	33.6	55	41	33.6
2010	40	25.8	27.2	40	33.5	27.2
2015	42.5	27.3	26.1	42.5	35	26.1
2020	45	28.8	25	45	36.5	25
	High prices			Low prices		
	Oil ($/bbl)	Gas (p/therm)	Coal (£/t)	Oil ($/bbl)	Gas (p/therm)	Coal (£/t)
2005	55	41	33.6	55	41	33.6
2010	67	49.9	36.5	20	18	19
2015	69.5	51.4	36.5	20	9.5	16.8
2020	72	53	36.5	20	21	14.6

Appendix 3: Projections for the power sector

For our analysis of the European power sector, we use the Integrated Planning Model (IPM) developed by ICF International. The IPM is a linear programming model that selects generating and investment options to meet overall electricity demand today and on an ongoing and forward-looking basis over the chosen planning horizon at minimum cost. Further details about the model are available from the EPA website (http://www.epa.gov/airmarkets/epa-ipm/).

Table 5 gives the fuel price assumptions for which we followed the July study of the Department of Trade and Industry in the UK (DTI, 2006b). These prices were also applied to other European countries, correcting for location/transport costs and adjusting the differing intra annual price profile for gas between the UK and continental Europe. Demand projections are based on the UCTE forecasts for all Member States except the UK (based on DTI projections).

We assumed that the EU renewables target is satisfied. The model calculates the emissions for all power stations. For one central fuel price scenario, we determined the volume of emissions that results from installations with less than 20 MW thermal capacity (56.4 $MtCO_2$/year). As these installations are mainly heat-driven, we assumed the emissions to stay constant across the time frame considered and across fuel price scenarios.

For the simulations, we constrained new-build CCGT and coal plants to those already commissioned until 2013. The only plants coming on before 2013 are firm builds, unplanned CT units and unplanned wind installations (this reflects the idea that for a CCGT or coal plant to become operational by 2012 it will already have to be commissioned today). This might understate the potential for emissions reductions from a more rapid shift to gas through additional investment in gas generation. However, given that we already observe an increase in gas demand for power generation in Europe in the low fuel price scenario with ETS price (from 6,700 TBtu to 11,300 TBtu coverage exceeding ETS), it is reasonable to assume caution with additional shifts to gas generation.

Table 6 presents the aggregate CO_2 emissions for European emissions, using the DTI-based projection on emissions from the non-power sector.

When comparing the model results in 2006 with the 2005 verified power sector emissions, we observed that we exceeded these emissions. This is what we expected, as many gas power stations have long-term take-or-pay contracts and were thus operating despite the high 2005 gas prices. To test our model, we implemented a minimum run requirement on gas. On a country-by-country basis, the same amount of gas had to be used in the power sector in the 2006 as observed in 2003. Using this constraint, our 2006 simulated data for all countries excluding Poland, Malta and Cyprus exceeded the verified emissions data for the power sector of these countries by only 2%. Most deviations on a per-country basis could be explained by the specific climatic conditions in the year 2005. Therefore we were content to use the model for emission projections.

For our long-term projections, we did not apply the minimum gas consumption constraint. We assume that the take-or-pay contracts for gas that we reflected in this constraint will be resolved as part of the European liberalization or that new gas-powered stations will be exposed to the market price for gas.

Appendix 4: NAPs II

We used information on the second-phase cap from the national allocation plans submitted to the EU Commission (2006b), and from the NAP II drafts published for public debate by those countries that had not officially approved them yet, as they represent the most up-to-date data available.

Table 6. EU emission projections for power sector using IPM model ($MtCO_2$) and based on DTI sector projections for non-power sector

CO_2 price	Fossil-fuel price scenario	2006	2007	2008	2009	2010	2011	2012
€0/tCO_2	Central – Fav GAS	2268	2299	2351	2322	2301	2363	2423
	Central – Fav COAL	2268	2303	2361	2373	2392	2448	2505
	High Prices	2268	2301	2355	2389	2433	2493	2549
	Low Prices	2269	2302	2352	2286	2240	2314	2388
€20/tCO_2	Central – Fav GAS	2228	2269	2255	2177	2149	2220	2289
	Central – Fav COAL	2239	2283	2299	2251	2236	2298	2362
	High Prices	2251	2290	2325	2342	2394	2459	2515
	Low Prices	2225	2263	2216	2140	2064	2147	2232
€20/tCO_2	Central – Fav gas, minimum gas constraint	2128						

As the NAPs for DK and HU have not been published (as of 24 September 2006) we assumed the same ratio between their cap 2005–2007 and 2008–2012 as applicable to the average of the other Member States.

We included the entire New Entrant Reserve in the cap and also included the emissions that are currently envisaged for auctions (7% UK, 0.29% Belgium, 3.9 $MtCO_2$ Netherlands, 2.6 $MtCO_2$ Poland, 0.48 $MtCO_2$ Lithuania, 0.11 $MtCO_2$ Ireland, 0.4 $MtCO_2$ Austria, 0.19 $MtCO_2$ Luxembourg).

We assume that total available CDM and JI credits for the period 2008–2012 are between 800 and 2,200 $MtCO_2$, while Japanese demand could range between 250 and 1,000 $MtCO_2$ (Grubb and Neuhoff, 2006). Very high availability is unlikely to coincide with very low Japanese demand and vice versa. We also have to allow for demand from governments to cover excess emissions in the non-covered sector. Thus we assume that inflows into ETS in the period 2008–2012 could range between 0 and 1,000 $MtCO_2$. Table 1 summarizes our assumptions about the cap.

Appendix 5: Historical emissions and linear trends

We used data on the total per-country greenhouse gas emissions for the period 1990–2004 from the annual European Community GHG Inventory (EEA, 2006).

Projections for 2005–2012 have been obtained by linear regression of the available sample of total GHG emissions for each country. The initial analysis on a country-by-country basis pointed to the well-known strong decline in emissions in accession countries during their early transformation in the 1990s, and therefore we subsequently excluded data for the Czech Republic, Estonia, Hungary, Lithuania, Latvia and Slovakia for the years until 1992, 1993, 1992, 1998, 1995 and 1993 for the estimation of the linear trend.

We then used data on the ETS share of CO_2 emissions relative to the total GHG emissions from Georgopoulou et al. (2006) based on 2003 data, and thus were able to derive the linear trend for EU ETS BaU emissions projections.

By adopting this procedure the implicit assumption was made that the proportion of greenhouse gases from 'trading' and 'non-trading' sectors would remain unchanged. As emissions from some of the non-trading sectors, such as transport, are in fact expected to increase significantly, it is likely that our approach overstates the extrapolated CO_2 emissions of the covered sector. This indicates that our estimations of CO_2 emission reductions in the covered sector are conservative and might potentially be higher, e.g. even more stringent caps would be required to ensure a strong CO_2 price.

Appendix 6: CITL classifications

An analysis of the CITL raw data performed by Entec highlighted the existence of 'some fundamental errors with regard to classification in the EC database of sites by sector/activity', although the cause is 'not yet known' (Entec, 2006, p. 4). Some of the problems of misclassification are addressed in our projections:

– An analysis of the CITL classification compared to that of NAP I for Spain, Italy and the UK illustrates some differences, which are, however, not persistent across countries and sectors. For Italy, the discrepancy is minimal (with the maximum around 2%), while although it is more relevant for the UK and Spain, it is not in the same sectors. Therefore, on aggregate, they might to some extent average out.

– Thanks to more accurate aggregate country data for the power sector (including CHP) provided by WIFO, it has been possible to correctly distinguish non-power verified emissions from the CITL 'combustion' class, thus substantially reducing the possible distortion scope to only 44% of the total cap in terms of allocations.
– If remaining errors are in the order of 5% and imply misspecification between sectors that have different projected CO_2 growth rates of 2%, then the aggregate error (1.02^7 after 7 years, e.g. 15%) is 0.3%.

Appendix 7: Analysis – allocated versus verified

Based on the data available in the Community Independent Transaction Log we were able to compare for every installation the verified emissions with the allocated allowances for the year 2005 (EU Commission, 2006a). We grouped all installations where over/under-allocation fell within ranges of ±2.5% under/over allocation. The intervals were then labelled according to the middle value of the interval. The remaining installations were summarized in the +100% and –100% categories.

Figure 5 shows the distribution of total emission permits according to the extent of under/over-allocation at the installation level as a fraction of the allocation received. The distribution is bell-shaped with a mean higher than zero, reflecting the overall long position of the EU ETS. According to the CITL classification, non-combustion installations, in general, received more allowances compared to their needs than combustion installations, although the latter includes both power and non-power sector installations, thus distorting the analysis by adding over-allocated installations to the category.

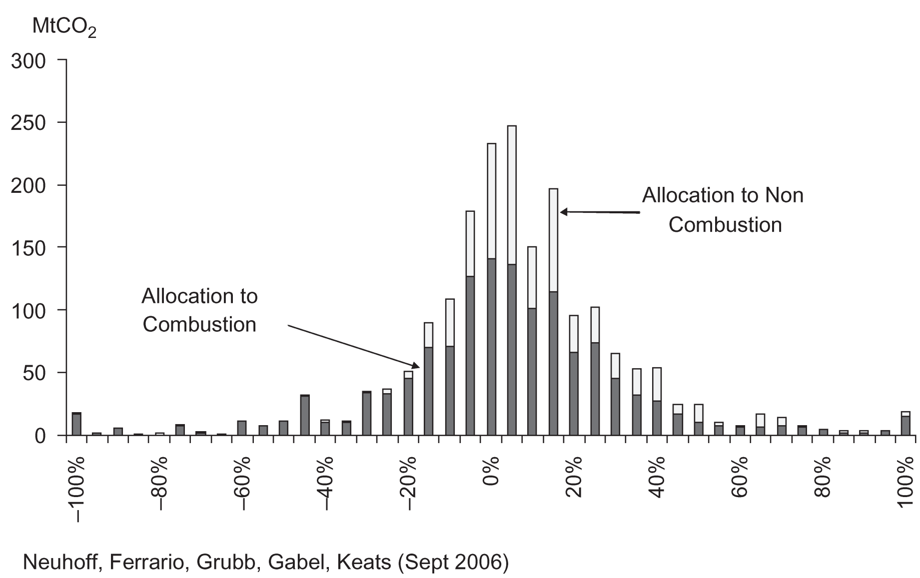

Figure 5. Relationship between verified emissions and allowances allocated to installations in 2005.

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