Splitting the EU ETS: strengthening the scheme by differentiating its sectoral carbon prices

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Abstract

The current EU ETS faces a dilemma. To induce low-carbon investments in the power sector, higher carbon prices are needed, while low carbon prices are needed to reduce the risk of carbon leakage and loss of industrial competitiveness. This study analyses the effects and implications of two alternative policy options to address this price dilemma, i.e. (i) splitting the ETS into two separated sector regimes: one more ambitious regime with a relatively high carbon price for the power sector and a less ambitious regime with a relatively low carbon price for the other sectors covered by the EU ETS (called 'industry'), and (ii) imposing a carbon tax on power sector emissions additional to a single ETS carbon price for both industry and the power sector. The study uses modelling scenarios and qualitative assessments to analyse the effects and implications of these policy options. It concludes that, in a world with unequal carbon prices, there is a case for differentiating ETS sectoral carbon prices and that the first-best option to achieve this differentiation is to impose a carbon tax on power sector emissions additional to a single ETS carbon price.

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Summary

Background
The current international climate policy situation is characterised by unequal or differentiated carbon prices as some countries or regions – including the EU – have implemented climate policies, such as the EU ETS, to restrict and price their GHG emissions while most of the other countries and regions in the world have not or have hardly done so. This situation has led to a dilemma, or even an impasse, with regards to the further development and strengthening of these policies, in particular of the EU ETS, aggravated by the current economic problems facing the EU.

On the one hand, the current ETS carbon reduction ambition and, in particular, the current and expected ETS carbon prices up to 2020 are too low to give an adequate incentive for long-term, capital-intensive investments in low-carbon technologies, notably in the power sector, in order to reach the ambitious targets of the EU to reduce its overall GHG emissions by 80-95% in 2050, compared to 1990 levels.

On the other hand, the industry sector covered by the ETS and exposed to non-EU competition is in favour of an international level playing field and, therefore, opposed to enhancing the ETS abatement ambition and raising the ETS carbon price beyond comparable commitments in non-EU, competing countries unless it is compensated for the resulting difference in carbon costs between EU and non-EU countries.

One of the options to deal with the dilemma outlined above is to split the ETS into two separate regimes, each with its own abatement ambition and carbon price, i.e. on the one hand a more ambitious regime with a relatively high carbon price for the power sector that provides adequate incentives for investments to decarbonise the power sector by 2050 and, on the other hand, a less ambitious regime with a relatively low carbon price for industry that keeps pace with international climate policy developments.

An alternative option is to keep a single ETS covering both the power sector and industry – with a single, relatively low carbon price that keeps pace with international climate policy developments – but to also impose an additional, EU-wide carbon tax on

power sector emissions that, together with the ETS carbon price, provides adequate incentives for investments to decarbonise the power sector by 2050.

Actually, both policy options are similar instruments to differentiate abatement ambitions and carbon prices between the power sector and the other sectors covered by the EU ETS (called 'industry'). Both options can be implemented in such a way that they result in similar outcomes at the sectoral and macroeconomic levels. Hence, in terms of differentiating ETS sector carbon prices and also in terms of environmental-economic effects, both options can be regarded as similar, identical instruments. However, in terms of policy implementation, feasibility, acceptability or other policy considerations, the two options may be seen as two different instruments, each with its specific pros and cons.

Main objectives
Against this background, the main objective of the present study is to analyse the major effects and implications of splitting the EU ETS, i.e. differentiating its abatement ambitions and carbon prices between the power sector and the other ETS sectors ('industry'). The second objective is to evaluate the two alternative policy options to achieve such a differentiation, i.e. by either (i) splitting the ETS into two separated sector regimes, or (ii) imposing a carbon tax on power sector emissions in addition to a single ETS regime covering both the power sector and industry.

Overall approach
In order to reach the objectives and research questions mentioned above, we have designed several modelling scenarios and assessed these scenarios using the '*Energy-Environmental-Economy Model for Europe'* (E3ME). In addition, we have conducted a brief case study for the Netherlands in order to analyse the implications of splitting the EU ETS in some more detail. Finally, we have performed some qualitative assessments, in particular to evaluate the pros and cons of the two alternative policy options to differentiate ETS sector carbon prices, i.e. 'ETS splitting' versus 'carbon taxation'.

Modelling approach
In order to analyse the performance of splitting the ETS, we have designed a variety of modelling scenarios that are distinguished by different policy options with regard to splitting the ETS and different ambition levels to reduce CO_2 emissions by the ETS up to 2050. More specifically, this study analyses three policy options with regards to the EU ETS:

1. *Current, non-splitting option*, i.e. continue the current ETS up to 2050, characterised by one single cap and one single ETS carbon price for all sectors covered by the scheme.
2. *Splitting option, i.e. s*plit the current EU ETS into two separate regimes, each with its own cap and its own carbon price: a more ambitious regime with a relatively high carbon price for the power sector and a less ambitious regime with a relatively low carbon price for all the other ETS sectors, except aviation (called 'industry').
3. *Alternative, non-splitting option with carbon taxation*, i.e. continue the current ETS (one cap, one single ETS price for all sectors covered by the scheme) but introduce carbon price differentiation between the power sector and industry by implementing an additional, EU-wide tax on the CO_2 emissions of the power sector.

For each option, we have distinguished three different ambition levels to reduce the ETS cap:

A. *Current ambition,* i.e. the cap declines by the current reduction factor of 1.74% per annum up to 2050 (compared to 2008-2012).
B. *High ambition,* i.e. starting from 2021 the cap declines by 2.25% per annum up to 2050.
C. *Low ambition,* i.e. starting from 2021 the cap declines by 1.25% per annum up to 2050.

Under all three ambition levels of policy options 2 and 3 the power sector is assumed to reduce its emissions to zero by 2050 (full decarbonisation of the power sector) while industry is assumed to meet the remaining part of the overall ETS ambition level. This implies that the required reduction in emissions for industry is actually zero under ambition level C (low), rather moderate under ambition level A (current), but quite stringent under ambition level B (high).

Multiplying the three policy options by the three ambition levels results in nine ETS policy scenarios. However, as the modelling results of the three ambition scenarios of policy option 3 (non-splitting + carbon taxation for the power sector) are similar to those of policy option 2 (ETS splitting), in the modelling we focus our attention on the results of the three ambition scenarios of policy option 1 (no ETS splitting) versus policy option 2 (ETS splitting) only.

Modelling results

Table 1 presents a summary of the main differences in the modelling results of policy option 2 (ETS splitting) compared to policy option 1 (non-splitting) at different ETS ambition levels grouped according to favourable outcomes of splitting ('pros') and unfavourable outcomes ('cons'). For instance, it shows that ETS splitting at its current ambition level reduces the abatement costs for industry by € 5.4 billion in 2050. On the other hand, it increases abatement costs in the power sector by € 11.8 billion in 2050.

Based on the modelling results, the study concludes that in a world of unequal or differentiated carbon prices, there is a case for splitting the EU ETS – i.e. differentiating its sectoral carbon prices and ambition levels – in order to reduce the risk of carbon leakage resulting from an ETS-induced loss of industrial competitiveness and, simultaneously, to enhance the incentive for low-carbon investment by the power sector in order to reach ambitious, EU-wide GHG reduction targets by 2050.

At each ETS ambition level, however, there is always a trade-off between favourable effects ('pros') and unfavourable effects ('cons') of ETS splitting and, therefore, there is no unambiguous case for ETS splitting. In any case, at each ETS ambition level, the abatement costs under ETS splitting will be higher compared to the costs under non-splitting, i.e. the current ETS. As a percentage of GDP, however, these costs are rather small, while they are offset by favourable effects such as either higher investments in low-carbon technologies, higher industrial output/GDP or a mixture of these effects.

Table 1: Summary of main differences in modelling results between ETS splitting (policy option 2) and non-splitting (policy option 1) at different ETS ambition levels grouped according to favourable outcomes ('pros') and unfavourable outcomes ('cons') of ETS splitting

	Pros	Cons
Current ambition level (scenarios 2A – 1A):	• Abatement costs: lower in industry (2050: € 5.4 billion). • CCS: higher in power sector (2050: +64 $MtCO_2$) and total ETS (2050: +14 $MtCO_2$). • RES-E: higher in power sector (2050: +6 percentage points). • Output: higher in industry (2050: +0.5%). • GDP: higher in EU27 (2050: +0.3%).	• Abatement costs: higher in power sector (2050: € 11.8 billion) and total ETS (€ 6.4 billion). • CCS: lower in industry (2050: -50 $MtCO_2$).
High ambition level (scenarios 2B – 1B):	• Abatement costs: lower in power sector (2050: € 7.8 billion) • CCS: higher in industry (2050: +43 $MtCO_2$) and total ETS (2050: +20 $MtCO_2$).	• Abatement costs: higher in industry (2050: € 8.9 billion) and total ETS (€ 1.1 billion). • CCS: lower in power sector (2050: -24 $MtCO_2$). • RES-E: lower in power sector (2050: -2 percentage points). • GDP: lower in EU27 (2050 -0.1%).
Low ambition level (scenarios 2C – 1C):	• Abatement costs: lower in industry (2050: € 0.5 billion). • CCS: higher in power sector (2050: +221 $MtCO_2$) and total ETS (2050: +221 $MtCO_2$). • RES-E: higher in power sector (2050: +7 percentage points). • ETS emissions: lower in total ETS (2050: -134 $MtCO_2$).	• Abatement costs: higher in power sector (2050: € 16.3 billion) and total ETS (€ 15.8 billion). • Output: lower in industry (2050: -0.1%). • Electricity prices: higher (2050: +6 €/MWh).

Note: The outcomes above do not refer to absolute results but to relative differences between respective splitting and non-splitting scenarios. For instance, in the row “Current ambition level (scenarios 2A - 1A)” and the column “Pros”, the statement “RES-E higher in power sector (2050: + 6 percentage points)” implies that in 2050 the share of renewables in total power generation (RES-E) is 6 percentage points higher in splitting scenario 2A (current ETS ambition) compared to the baseline scenario 1A (non-splitting; current ambition).

The case for ETS splitting seems to be strongest at the current ETS ambition level as in this case the favourable effects seem to outweigh the unfavourable effects. At higher (than current) ETS ambition levels, there is a weaker argument for ETS splitting in order to enhance the incentive for low-carbon investments by the power sector but a stronger argument for ETS splitting in order to reduce the risk of carbon leakage resulting from an ETS-induced loss of industrial competitiveness. Paradoxically, however, there is also a higher risk that, due to splitting, carbon prices for industry become higher rather than lower (and even higher than carbon prices for the power sector under splitting, as happens in scenario 2B). This risk can be avoided by allowing one-way EUA trading by industry under ETS splitting, implying that at all ETS ambition levels carbon prices for industry will always be lower – or, at best, similar – under ETS splitting compared to non-splitting.

Reversely, at lower (than current) ETS ambition levels, there is a weaker argument for ETS splitting in order to reduce the risk of carbon leakage but a stronger argument for ETS splitting in order to enhance the incentive for low-carbon investments by the power sector. At lower ETS ambition levels, however, there is also a higher risk that indirect carbon costs – and even total carbon costs – for electricity-intensive industries increase due to higher electricity prices resulting from ETS splitting. This risk can be reduced, however, by compensating these industries for ETS-induced increases in electricity prices.

Case study: implications of ETS splitting for the Netherlands

The case study on the implication of splitting the ETS for the Netherlands confirms that splitting can reduce the risk of carbon leakage and increase the incentive to switch to zero-carbon and low-carbon electricity generation. It shows also, however, that ETS splitting can lead to suboptimal decisions on investments and the allocation of fuels. The carbon price in industry can remain too low for capture and storage of industrial CO_2 emissions. Substituting fossil fuels by electricity becomes more difficult and generating electricity in non-ETS sectors can gain a competitive advantage.

Qualitative assessment of policy options

Table 2: provides a summary of the qualitative assessment of the different policy options analysed in this study. More specifically, the upper part of **Table 2**: presents the major pros and cons of policy option 2 (ETS splitting) versus policy option 1 (non-splitting, i.e. the current ETS). As indicated above, splitting the ETS results in (i) lower risks of carbon leakage and loss of industrial competitiveness, and (ii) stronger incentives for low-carbon investments in the power sector. In addition, splitting the ETS may improve the credibility of the scheme by overcoming the current ETS sectoral price dilemma, in particular by encouraging more low-carbon investments in the power sector.

On the other hand, besides being more costly, ETS splitting also has some other disadvantages ('cons'), compared to non-splitting. In brief, these disadvantages include:

- ETS splitting requires a change of the ETS Directive, which may be a thorny, time-consuming process.
- ETS splitting implies operating two separated regimes, which enhances administrative demands.
- ETS splitting implies a major change of the system, which may reduce its reliability among ETS stakeholders and EUA market participants.
- ETS splitting reduces the liquidity of the EUA market which enhances the risks of more price volatility, market concentration and misuse of market power.

The lower part of **Table 2**: compares the two alternative policy options of differentiating ETS sector carbon prices, i.e. (i) splitting the ETS into two separated sector regimes (policy option 2), and (ii) imposing a carbon tax on power sector emissions in addition to a single ETS covering both industry and the power sector (policy option 3). The table shows that each option has its specific pros and cons (as the pros and cons of policy option 2 can be regarded as the mirror image of the pros and cons of policy option 3). Hence, there is no unambiguous case for one of the two options as the ideal option to differentiate sector carbon prices as there is always a trade-off between the pros and cons of each option.

Table 2: Summary of qualitative assessment: major pros and cons of different policy options

	Pros	Cons
ETS splitting (policy option 2) compared to non-splitting (i.e. current EU ETS ; policy option 1):	• Lower risks of carbon leakage and loss of industrial competitiveness. • Stronger incentives for low-carbon investments in power sector. • May enhance credibility of the scheme.	• Requires change of ETS Directive. • Higher administrative demands. • Lower policy consistency/reliability. • Lower EUA market liquidity.
Differentiation of ETS sectoral carbon pricing by imposing an extra carbon tax on power sector emissions (policy option 3), compared to price differentiation by splitting the ETS (policy option 2)	• No change of ETS/Directive. • Higher EUA market liquidity. • Combines environmental effectiveness and investment (price) security. • Carbon price for power sector is always higher than for industry. • Can be implemented by individual Member States or group of like-minded countries. • More flexibility (to adjust carbon tax/sectoral carbon pricing).	• EU-wide resistance against 'carbon tax'. • EU-wide carbon tax requires unanimity among all Member States. • "Right tax level' may be hard to determine. • No guarantee that a specific abatement target will be reached by the power sector, e.g. full decarbonisation by 2050.

On balance, however, when qualifying and weighing the pros and cons of the two options, imposing an additional, EU-wide carbon tax on power sector emissions seems to be the first-best policy option to differentiate sector carbon prices. To some extent, however, this qualifying, weighing and selecting of policy options is a political issue. The major drawbacks of the preferred, first-best policy option is the expected socio-political resistance against a carbon tax and that the introduction of an EU-wide carbon tax requires unanimity among all Member States.

The carbon tax, however, applies to the power sector only (no trade distortions) and does not imply higher carbon costs to the power sector or higher electricity prices to end-users, compared to the alternative policy option 2 (ETS splitting). Moreover, the resistance against an additional carbon tax on power sector emissions may be reduced or perhaps even overcome by an open-minded discussion on the pros and cons of this policy option versus other options to deal with the policy dilemma of lower or even zero carbon prices outside the EU and its implications for EU-internal, sectoral carbon pricing.

If the resistance to an EU-wide carbon tax on power sector emission cannot be overcome, a second-best option to differentiate ETS sector carbon prices is splitting the ETS in separated sector regimes. If this second-best option is also not feasible, a third-best, alternative option to an EU-wide carbon tax on power sector emissions next to the EU ETS is the introduction of such a tax by either individual countries – as recently occurred in the UK – or by a group of like-minded countries which are committed to or interested in decarbonising their power sector in the coming decades, while reducing the risk of carbon leakage due to an ETS-induced loss of industrial competitiveness.

1 Introduction

Background

The current international climate policy situation is characterised by unequal or differentiated carbon prices as some countries or regions – including the EU – have implemented climate policies, such as the EU ETS, to restrict and price their GHG emissions while most of the other countries and regions in the world have not or have hardly done so. This situation has led to a dilemma, or even an impasse, with regards to the further development and strengthening of these policies, in particular of the EU ETS, aggravated by the current economic problems facing the EU.

On the one hand, the current CO_2 price of the EU ETS is too low to provide an adequate incentive for long-term, capital-intensive investments in low-carbon technologies needed for the transition to a low-carbon economy in the EU. It is expected that this price will remain low in the foreseeable future. Moreover, the current CO_2 reduction ambition of the ETS is not yet in line with the overall ambition to reduce its total GHG emissions by 80-95% in 2050 compared to 1990 levels. Hence, a further strengthening of the ETS ambition and, consequently, raising its carbon price are needed to meet long-term EU climate goals.

The transition to a low-carbon economy needs to happen primarily in the power sector. More specifically, in order to reach the overall EU GHG objective by 2050 the power sector has to move towards near full decarbonisation of its electricity generation across the EU, requiring adequate and timely incentives to induce the necessary long-term, capital-intensive investments for such a transition. In general, the power sector supports, or in any case does not oppose, efforts to strengthen the EU ETS and to raise its carbon price as the power sector is not exposed to non-EU competition and is able to pass through the costs of a higher carbon price into higher end-users' electricity prices.

On the other hand, industries covered by the ETS and exposed to international competition are opposed to raising the ETS carbon price as it would reduce their competitiveness and result in carbon leakage, i.e. less industrial output and emissions within the EU but more output and emissions outside the EU. More precisely, ETS industry exposed to non-EU competition is in favour of a level playing field and, therefore, opposed to strengthening the EU ETS or increasing its ambition beyond comparable commitments in non-EU, competing countries unless it is compensated for the resulting differences in carbon prices and costs between EU and non-EU countries.

One of the options to deal with the dilemma outlined above is to split the ETS into two separate regimes, each with its own abatement ambition and carbon price, i.e. on the one hand a more ambitious regime with a relatively high carbon price for the power sector that provides adequate incentives for investments to decarbonise the power sector by 2050 and, on the other hand, a less ambitious regime with a relatively low carbon price for industry that keeps pace with international climate policy developments.

An alternative option is to keep a single ETS covering both the power sector and industry – with a single, relatively low carbon price that keeps pace with international climate policy developments – but imposing an additional carbon tax on power sector emissions that, together with the ETS carbon price, provides adequate incentives for investments to decarbonise the power sector by 2050.

In economic terms, both policy options are similar instruments to differentiate abatement ambitions and carbon prices between the power sector and the other sectors covered by the EU ETS (called 'industry'). Both options can be implemented in such a way that they result in similar outcomes at the sectoral and macroeconomic levels. Hence, in terms of differentiating ETS sector carbon prices and its environmental-economic effects, both options can be regarded as similar, identical instruments. However, in terms of policy implementation, feasibility, acceptability or other policy considerations, the two options may be seen as two different instruments, each with its specific pros and cons.

Main objectives
Against this background, the first objective of the present study is to analyse the major effects and implications of splitting the EU ETS, i.e. differentiating its abatement ambitions and carbon prices between the power sector and the other ETS sectors ('industry'). The second objective is to evaluate the two alternative policy options to achieve such a differentiation, i.e. by either (i) splitting the ETS into two separated sector regimes, or (ii) imposing a carbon tax on power sector emissions in addition to a single ETS regime covering both the power sector and industry.

Specific research questions
In addition to the overall objectives above, the major specific research questions of the present study include:

1. *Is it possible to split the ETS into an ambitious regime for the power sector and a less ambitious regime for industry after 2020?*

2. *If so, how can this be best achieved?*
   a) For instance, can we have two separate caps within the ETS, i.e. one stringent for the power sector, and one less stringent for industry? Can they mutually interact and if so, under what conditions? More specifically, can there be trading in EUAs/offset credits between the two regimes if the carbon price

must be different? Or should industry be placed completely outside of the scope of the ETS and follow a completely different regime?

b) Where can we draw the line for which installation belongs in which regime? Should the entire industry fall under the less ambitious regime or just the industry that is confronted with the risk of carbon leakage? And how could we deal with for instance electricity that is generated by industry or heat that is generated by the power sector? How is it best to treat the aviation sector under the ETS?
c) Assuming that splitting the ETS sectors can only be done after 2020 and that industry only temporarily requires a less ambitious regime, what are the implications and best modalities for splitting the ETS sectors in such a way that they can eventually be merged again?
d) What is the effect of splitting the ETS on the performance of the EUA market?
e) What are the effects of an ambitious ETS cap for the power sector in the EU in general and for Member States with relatively a lot of coal, such as Poland? What are the effects on electricity generation from renewable energy sources (RES-E) and are additional policies to stimulate RES-E still needed under an ambitious ETS regime for the power sector?
f) What is the impact of ETS splitting with a high ambition for the power sector, i.e. full decarbonisation by 2050, on the electricity price in 2030 and 2050?
g) How much of the ETS induced increase in electricity costs will be passed through to industry (i.e. indirect carbon costs to industry)? What are the specific sectors that are vulnerable to the risks of carbon leakage due to the pass through of higher electricity costs to industry? Should there be compensation in order to avoid these risks and, if so, to which specific industries and in what way?
h) More generally, what are the effects of splitting the ETS on industry?
i) What are the macroeconomic effects of splitting the power sector and industry? Will it make the reduction of CO_2 emissions more expensive?

3. *If splitting of the ETS system is feasible, does it solve the problem? In other words, can we have a CO_2 price for the power sector that will ensure the necessary stimulus in low-carbon investment in power generation?*

Overall approach
In order to address the objectives and research questions above, we have designed a set of modelling scenarios and assessed these scenarios using the '*Energy-Environmental-Economy Model for Europe'* (E3ME). In addition, we have conducted a brief case study for the Netherlands in order to analyse the implications of splitting the EU ETS in more detail. Finally, we have performed some qualitative assessments, in particular to evaluate the pros and cons of the two alternative policy options to differentiate ETS sector carbon prices, i.e. 'ETS splitting' versus 'carbon taxation'.

Outline of study
First of all, Chapter 2 outlines the methodology applied by the modelling part of the present study, including descriptions of the scenarios and the model used to assess these scenarios. Subsequently, Chapter 3 presents and analyses the modelling results for the ETS sectors and the EU27 economy as a whole. Chapter 4 discusses some implications of splitting the ETS for the Netherlands in some more detail at the ETS

sectoral level. Finally, Chapter 5 presents a detailed evaluation and summary of policy options to differentiate ETS sector carbon prices and abatement ambitions.

Appendix A of this study provides additional, detailed statistical results of the modelling scenarios at the EU27 macroeconomic, national and sectoral levels. Appendix B gives a list of the energy and climate policies included in the modelling scenarios. Finally, Appendix C presents a review of recent issues and studies on carbon leakage.

2

Methodology

This chapter provides a brief explanation of the methodology applied in this study, in particular of the modelling scenarios that have been used to assess different policy options with regards to splitting the EU ETS (Section 2.1). In addition, it gives a brief description of the model used to assess these scenarios (Section 2.2).

2.1 Scenario descriptions

2.1.1 Summary of modelling scenarios

In order to analyse the performance of splitting the EU ETS between different sectors, this study has designed and applied a variety of modelling scenarios that are distinguished by different policy options for splitting the ETS and different ambition levels to reduce CO_2 emissions in the ETS up to 2050.

More specifically, this study analyses three policy options for the EU ETS:
1. *Current, non-splitting option*, i.e. continue the current ETS up to 2050, characterised by one single cap and one single ETS carbon price for all sectors covered by the scheme.
2. *Splitting option, i.e. s*plit the current EU ETS into two separate regimes, each with its own cap and its own carbon price: a more ambitious regime with a relatively high carbon price for the power sector and a less ambitious regime with a relatively low carbon price for all the other ETS sectors, except aviation (called 'industry').
3. *Alternative, non-splitting option with carbon taxation*, i.e. continue the current ETS (one cap, one single ETS price for all sectors covered by the scheme) but introduce carbon price differentiation between the power sector and industry by implementing an additional tax on the CO_2 emissions of the power sector.

For each option, we have distinguished three different ambition levels to reduce the cap:

A. *Current ambition.* This ambition level follows and continues the current practice in which the cap for the installations covered by the ETS during its third trading period is lowered each year by a fixed reduction factor of 1.74% per annum, compared to the average cap/emissions of these installations during the second trading period.[1] It is assumed that this annual cap reduction factor is continued beyond 2020 up to 2050. Hence, over the 40-year period 2010- 2050 the cap is reduced by 40 * 1.74% = almost 70% compared to '2010' (i.e. the average cap/emissions over the years 2008-2012).
B. *High ambition.* For this ambition level it is assumed that up to 2020 the cap is lowered by the current reduction factor (i.e. 1.74% p.a.) but starting from 2021 up to 2050 this factor is increased to 2.25% per year (compared to '2010'). Therefore, over the 10-year period 2010-2020, the cap is reduced by 17.4%, while it is further reduced by 30 * 2.25% = 67.5%, resulting in an overall reduction of the cap over the period 2010-2050 of almost 85%. The main motivation for increasing the cap reduction factor beyond 2020 is that with the current rate (1.74%) it is almost impossible to reach the overall EU GHG reduction target for the year 2050, i.e. minus 80-90% compared to 1990 for all sectors, including both ETS and non-ETS sectors.
C. *Low ambition.* For this ambition level, it is assumed that up to 2020 the cap is reduced by the current factor but starting from 2021 up to 2050 this factor is lowered to 1.25% p.a. Hence, over the whole period 2010-2050 the cap is reduced by almost 55%. The main reason for considering this lower ambition level is that an international climate agreement may be lacking beyond 2020 and that, consequently, EU Member States and/or ETS industrial sectors may argue successfully to lower the annual reduction factor for the ETS cap in order to protect their economic interests.

The three different ambition levels for the ETS as a whole are translated into the above-mentioned policy options as follows:

1. *Current, non-splitting option.* In this option, translating the different ambition levels is quite straightforward. As there is only one single cap in this option, the ambition levels are translated into the policy options by reducing the cap according to the rates and periods as specified above for each ambition level.
2. *Splitting option.* In this option, translating the overall ETS ambition levels is a bit more complicated as, starting from 2021, there are separated caps for the two different ETS sectors (power and industry), while the CO_2 reduction ambition is differentiated between these two sectors. Basically, the approach runs as follows. Firstly, the single ETS cap for the year 2020 is split into two separated caps for the two different sectors based on their respective shares in total ETS emissions in the baseline scenario over the years 2010-2020.[2] Subsequently, starting from 2021, the cap for the power sector is reduced linearly each year in order to become zero by 2050 in all scenarios concerned, regardless the overall ETS ambition level. Finally for each ambition level (low, current, and high) the cap for industry is derived by subtracting the annual cap for the power sector from the overall ETS cap as specified

1 Some installations covered by the ETS during its third trading period were not yet included in the scheme during the second trading phase. Therefore, as these installations were not part of the cap during this phase, an adjustment has been made by adding the average emissions of these installations over the years 2008-2012 to the cap over this period.

2 These shares amount to 62.2% and 37.8% for the power sector and industry, respectively (see Section 3.1).

for each ambition level above.[3] This implies that the reduction target for industry is relatively weak in the low ambition scenarios and more stringent in the more ambitious scenarios – in particular in the high ambition case – while the mitigation target for the power sector is similar, i.e. full decarbonisation by 2050, across the three ambition levels for the ETS as a whole.

3. *Alternative, non-splitting option with carbon taxation.* In this option, it is assumed that at each ETS ambition level, the power sector and industry will reach the same sectoral reduction target as under policy option 2. This time, however, these targets are not achieved by splitting the ETS – resulting in separated caps and differentiated ETS carbon prices for industry and the power sector – but rather by differentiating sectoral carbon pricing through the introduction of an EU-wide carbon tax on the CO_2 emissions of the power sector additional to the single ETS carbon price for both the power sector and industry. Methodologically, i.e. in modelling terms, this option is quite straightforward as the carbon tax in the power sector for each ambition level is equal to the difference in carbon prices between the power sector and industry of each respective ambition scenario of option 2 (while the cap in the different ambition scenarios of policy 3 is similar to the cap in the respective scenarios of option 1).[4]

In practice, however, setting the 'right carbon tax' in policy option 3 may be more complicated as data on (differences in sectoral) carbon price in separated ETS markets are not known, while data on (future) marginal abatement costs for industry and the power sector are scarce and uncertain. A practical solution/approach might be to (i) estimate these cost on the best information and modelling tools available, (ii) set the carbon tax based on these cost estimates, and (iii) adjust the tax periodically, e.g. every five years, based on updated information and clear, transparent rules.

Basic modelling scenarios

Multiplying the three policy options by the three ambition levels results in nine ETS policy scenarios. The main features of these scenarios are summarised in **Table 3** and labelled according to their position in this table. For instance, scenario 1A refers to policy option 1 (non-splitting) with ambition level A (current), scenario 2C refers to policy option 2 (splitting) with ambition level C (low) and scenario 3B to policy option 3 (non-splitting + carbon tax) with ambition level B (high).

The nine scenarios mentioned in **Table 3** have been specified and assesed with the E3ME model (see Section 2.2). The quantitative results of these modelling scenarios are presented, analysed and discussed in Chapter 3, while the three basic policy options underlying these scenarios are further assessed in Chapter 5 in more qualitative terms, including a brief evaluation of the major pros and cons of each option.

3 This approach has been used to guarantee that the policy options result in the same overall ETS ambition level in order to make these options better mutually comparable at different specific ambition levels.

4 For instance, if the carbon price in scenario 2A is 100 €/tCO_2 for the power sector and 40 €/tCO_2 for industry, the carbon tax for the power sector in scenario 3A is simply 100 - 40 = 60 €/tCO_2.

Table 3: Summary of modelling scenarios

Ambition levels:	Policy options:		
	1: Current single ETS cap setting extrapolated to 2050	**2: ETS splitting (two separate sectoral caps), starting from 2021**	**3: Single ETS cap + carbon tax in power sector, starting from 2021**
A. Current ETS ambition: -1.74% p.a. until 2050	Scenario 1A (BAU): Single ETS cap declining by 1.74% p.a. until 2050	Scenario 2A: Power sector cap: declines linearly to reach 100% reduction in 2050 Industry cap: remaining part to reach overall ETS ambition level A in 2050	Scenario 3A: Single ETS cap + carbon tax for the power sector to reach sectoral ambition levels of scenario 2A
B. High ETS ambition: -2.25% p.a. until 2050, starting from 2021	Scenario 1B: Single ETS cap declining by 2.25% p.a. until 2050, starting from 2021	Scenario 2B: Power sector cap: declines linearly to reach 100% reduction in 2050 Industry cap: remaining part to reach overall ETS ambition level B in 2050	Scenario 3B: Single ETS cap + carbon tax for the power sector to reach sectoral ambition levels of scenario 2B
C. Low ETS ambition: -1.25% p.a. until 2050, starting from 2021	Scenario 1C: Single ETS cap declining by 1.25% p.a. until 2050, starting from 2021	Scenario 2C: Power sector cap: declines linearly to reach 100% reduction in 2050 Industry cap: remaining part to reach overall ETS ambition level C in 2050	Scenario 3C: Single ETS cap + carbon tax for the power sector to reach sectoral ambition levels of scenario 2C

2.1.2 Baseline scenario

In our study, scenario 1A is the so-called baseline or 'business-as-usual' (BAU) scenario. As indicated above, the main distinguishing feature of this scenario in the present study is that it includes the current basic structure of the ETS with its current CO_2 reduction ambition, i.e. a single fixed cap for its major sectors (power, industry) which – starting from 2013 – is reduced by 1.74% per annum compared to the average cap/emissions of these sectors during its second trading period.[5]

The baseline scenario 1A has been calibrated to the so-called ‘PRIMES projections’ that are published by the European Commission (DG Energy) in its *EU energy trends to 2030* (EC, 2010a). We have used the 2009 update of these projections, which are based on current EU and Member States’ policies up to April 2009 and economic expectations by that time. PRIMES 2009 projections, however, have been slightly further updated for this study by including additional economic data for 2009-10, giving a better short-term representation of the recession.

The PRIMES baseline projections include the effects of the ETS and other current policies up to April 2009, notably policies in the fields of energy savings, renewables and GHG reductions in non-ETS sectors. According to these projections, the 2020 target is met for the EU ETS – more or less by definition by assuming compliance to the cap – but not for these other fields of energy and climate policies (EC, 2010a).[6]

As E3ME solves on an annual basis it is necessary to interpolate between the five-year time step periods used in the PRIMES model projections. A simple algorithm is used to carry out this procedure. It is also necessary to extrapolate trends beyond 2030 up to 2050. In general a linear approach is used, although there are some cases (for example the rapid development of new technologies) where we have slowed the trend rates of growth.

Moreover, the figures that are published in the PRIMES projections have been adapted to be consistent with the sectoral classifications used in the E3ME model. For example, it is necessary to split up the service sector from the DG Energy figures into the 36 service sectors used in E3ME. Generally an extrapolation of historical trends is used for this calculation.

All other scenarios included in **Table 3** are similar to the baseline scenario, with the exception of their distinguishing features mentioned in this table.

2.1.3 Common basic scenario assumptions and input variables

The main assumptions and input variables for all the scenarios described above include:

- *GDP/sectoral growth rates:* in all scenarios, assumptions on GDP/sectoral growth rates have been derived from and calibrated to DG ECFIN’s economic projections up to 2050 in the 2012 Aging Report (EC, 2012a). For the period 2010-2050, the resulting growth rates are recorded in the upper part of **Table 4**.

5 Aviation is another major sector covered by the EU ETS since 2012, but it has been excluded from the baseline and other modelling scenarios in our study as it follows a slightly different regime in terms of cap setting and trading of allowances (see Section 2.1.4 below).

6 Besides the baseline scenario, the PRIMES 2009 projections also cover a so-called ‘reference scenario’ which includes additional policies adopted between April 2009 and December 2009. This reference scenario assumes that the two binding EU targets for 2020 will be met (i.e. the 20% renewable energy target and the 20% GHG reduction target). The results for the reference scenario turn out that only half of the third, non-binding target will be achieved (i.e. 9.5% rather than the target of 20% energy savings by 2020). For more details on the PRIMES 2009 baseline and reference scenario projections, see EC (2010a).

- *Fuel prices*: assumptions on fuel prices up to 2030 are derived from the IEA's 'Current Policies Scenario' published in its World Energy Outlook 2011 (IEA, 2011). Extrapolations were used to estimate fuel prices beyond 2030. For the period 2010-2050, the resulting fuel prices are recorded in the lower part of **Table 4**.

Table 4: Key scenario assumptions on economic growth rates and fuel prices, 2010-2050

	2010-2020	2020-2030	2030-2040	2040-2050
Growth rate (average % per annum):				
EU27 GDP	1.6	1.6	1.5	1.5
• Industry	0.7	1	0.9	1.0
• Transport	3.4	3.7	2.3	1.7
• Services	1.7	1.7	1.5	1.5
Fuel prices:	2020	2030	2040	2050
Oil (2010$/barrel)	118.1	134.5	145.8	158.2
Gas (2010$/MBtu)	11.0	12.6	13.7	14.8
Coal (2010€/tonne)	109.0	115.9	125.6	136.3

Source: EC (2010a and 2012a), and IEA (2011).

- *Other policies besides ETS*: we include current policies up to April 2009 that are included in the PRIMES baseline case (for a list of these policies, see Appendix B).
- *Climate policies outside the EU*: in all scenarios, we have assumed that countries outside the EU take no action beyond their existing policies and GHG reduction targets (from the Copenhagen summit). The current version of E3ME does not model explicitly non-European countries, but if the targets for non-EU countries were converted to carbon prices they would be low to zero. There is no feedback modelled from Europe to the rest of the world. This implies that, in all scenarios, international energy/commodity prices are the same and policies in non-EU countries remain identical.
- *Allocation of EU emission allowances (EUAs):* for reasons of simplicity, it is assumed in our modelling scenarios that, starting from 2013, all EUAs for the power sector are auctioned and all EUAs for the other (industrial) sectors are allocated for free.[7] It is assumed, however, that the free allowances are allocated on a lump sum basis (i.e. not related to current or updated production). Therefore, using these free allowances is regarded as spending so-called 'opportunity costs' and, hence, these costs are passed on to higher output prices, depending on the demand responsiveness, competitiveness and other market conditions of the industries concerned.
- *Banking and borrowing of EUAs:* we have assumed no borrowing, but banking is allowed over the whole period 2013-2050.
- *Revenues from EUA auctioning and carbon taxation of the power sector:* assumed to be recycled through lowering of income taxes.

7 In reality, however, allocation is more complicated as the power sector in ten Eastern European countries is allowed to receive a (declining) share of its EUAs for free while some industries – not regarded to be exposed to the risk of carbon leakage – have to buy a (growing) share of their EUAs at an auction. For specific details on EUA allocation issues, see the website of the DG CLIMA (EC, 2013).

- *Compensation of indirect carbon costs:* for the nine basic scenarios, we have assumed that energy-intensive industries are not compensated for the ETS carbon costs passed through to the electricity prices for industrial end-users (see also Section 2.1.5 where we discuss an additional, so-called 'compensation scenario'.
- *Use of offset credits:* we have assumed that ETS sectors are allowed to use CDM/JI credits to cover their emissions additional and equivalent to 7.5% of their cap.[8]
- *EUA trading between separated sectors (in policy option 2):* in first instance, we assume that EUA trading is not allowed between separated sectors in policy option 2 in order to see which carbon prices result for these sectors and to determine the carbon tax for the power sector in policy option 3. In some cases, however, this may result in higher carbon prices for industry than for the power sector under policy option 2, implying that under policy 3 either the power sector receives a carbon subsidy or the industry has to pay a carbon tax equal to the sectoral price difference. As all these outcomes may appear to be undesirable or unfeasible, an alternative opportunity or assumption for policy option 2 would be to allow industry to buy EUAs from the power sector, but not the other way around, i.e. no selling by industry to the power sector. If this one-way EUA trading is indeed assumed to be allowed, the carbon price for industry may be substantially lower than the carbon price for the power sector but will never become higher. If one-way trading is allowed and actually takes place under policy option 2, the carbon price of industry will be equal to the carbon price of the power sector (equivalent to the single carbon price under policy option 1), implying that the carbon tax under policy 3 will be zero.
- *Electrification of the transport sector:* in all scenarios, it is assumed that there is only limited further electrification in the transport sector. If there was large-scale electrification of vehicles, this would increase demand for electricity and push up ETS prices for the power sector. However, this effect would be constant in all the scenarios, so does not have a large impact on the study conclusions.

2.1.4 Sectoral coverage in the ETS policy scenarios

In the modelling scenarios of option 1, the sectoral coverage of the ETS is similar – except aviation (see below) – to the coverage of the ETS during its third trading phase as specified in the EU ETS Directive of 2009, i.e. including the power sector and energy-intensive industries such as iron and steel, refineries, paper and pulp, glass, bricks, cement, aluminium and some chemical installations. Moreover, in addition to the CO_2 emissions of these installations, the scenarios also include the other GHGs specified by the 2009 ETS Directive (EC, 2009a and 2013).

In the modelling scenarios of policy options 2 and 3 a distinction is made between the power sector on the one hand and 'industry' on the other. The power sector covers all installations larger than 20 MW that generate power, regardless whether the electricity is delivered to the grid or used for own consumption (industrial CHP). All other installations covered by the ETS are simply labelled 'industry' in this study.

8 The figure of 7.5% is based on the average share of CDM credits allowed over the years 2008-2020 related to the ETS cap over this period (EC, 2012b).

Aviation, however, is excluded from all scenarios, mainly because it has a different regime in terms of cap setting and trading of allowances.[9] Aviation has a separate cap from power stations and other fixed installations because different types of allowances are issued for the two parts of the EU ETS. Allowances issued for fixed installations are general allowances (EUAs), while the aviation has aviation allowances. Airlines can use both types of allowances for compliance purposes, but fixed installations cannot use aviation allowances (EC, 2013).

Moreover, unlike the cap for fixed installations, the aviation sector cap remains the same in each year of the 2013-2020 trading period (EC, 2013). Although in principle it would be possible to include aviation in the modelling scenarios, it would complicate the analysis while, most likely, not adding much to the overall findings on the ETS splitting options.

2.1.5 Compensation scenario

In addition to the nine basic scenarios described above, which – as mentioned – do not assume compensation of industries of indirect carbon costs – we have designed and briefly analysed an alternative scenario in which energy-intensive industries are compensated by means of rebates for 75% of the ETS carbon costs passed through to their electricity prices. This compensation scenario is otherwise equivalent to scenario 2B (splitting; low ambition), which has been chosen as the reference case because it turns out to have the highest ETS-induced increase in electricity prices.

The main results of this compensation scenario, labelled 2BR, are outlined in Section 3.4.3 as part of discussing the modelling results for industry in Section 3.4 as a whole.

2.1.6 Treatment of CCS in the modelling scenarios

As part of this study, cost curves for the potentials of carbon capture and storage (CCS) have been designed and applied within the E3ME model.

There is considerable uncertainty regarding the amount of CCS that could be expected in both the power sector and ETS industry up to 2050. However, the amount of CCS implemented would be expected to increase if there were higher carbon prices (meaning more CCS sites became cost effective) so this is relevant for both the baseline and the other scenarios.

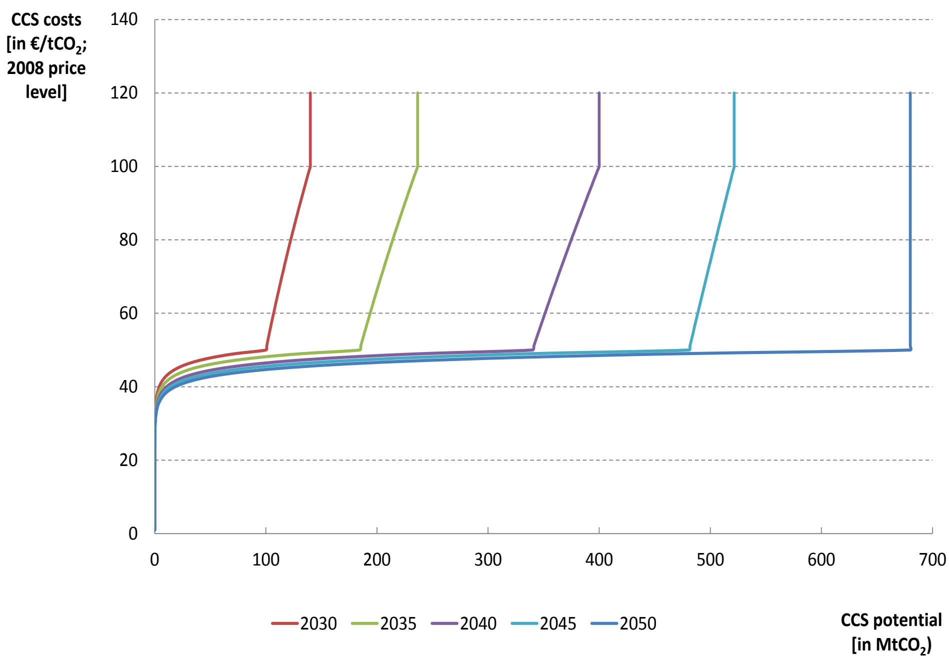
The approach in this study has been to take aggregate figures for Europe as a whole from the CCS Technology Roadmap of the IEA (2009) and to use these data to construct CCS cost curves over the years 2030-2050 for each of the two main ETS sectors, power and industry. The cost curves were then applied in each of the scenarios to analyse the interaction between carbon prices, CCS and other abatement options.

9 Moreover, ETS design options with regards to aviation may change, or even abandoned, due to international negotiations or pressure from outside countries.

The resulting CCS cost curves over the period 2030-2050, with an interval of 5 years, are presented in **Figure 1** and **Figure 2** for the power sector and industry, respectively. These graphs illustrate that applying CCS in the power sector and industry becomes only economically attractive if the carbon price is at least 40-50 €/tCO_2. In addition, they show that in the 2030s CCS potentials are still limited (due to various technical, infrastructural or other capacity constraints) and that CCS costs in terms of €/tCO_2 increase steeply once these capacity constraints are reached. Over time, however, CCS potentials grow significantly due to capacity investments and technical learning, resulting in major cost savings and a shift of the CCS cost curves to the right of the graphs. For instance, at a cost (or carbon price) level of 60 €/tCO_2 CCS potential in 2030 is only about 100 MtCO_2 in the power sector, whereas it amounts to almost 700 MtCO_2 in 2050 (**Figure 1**).

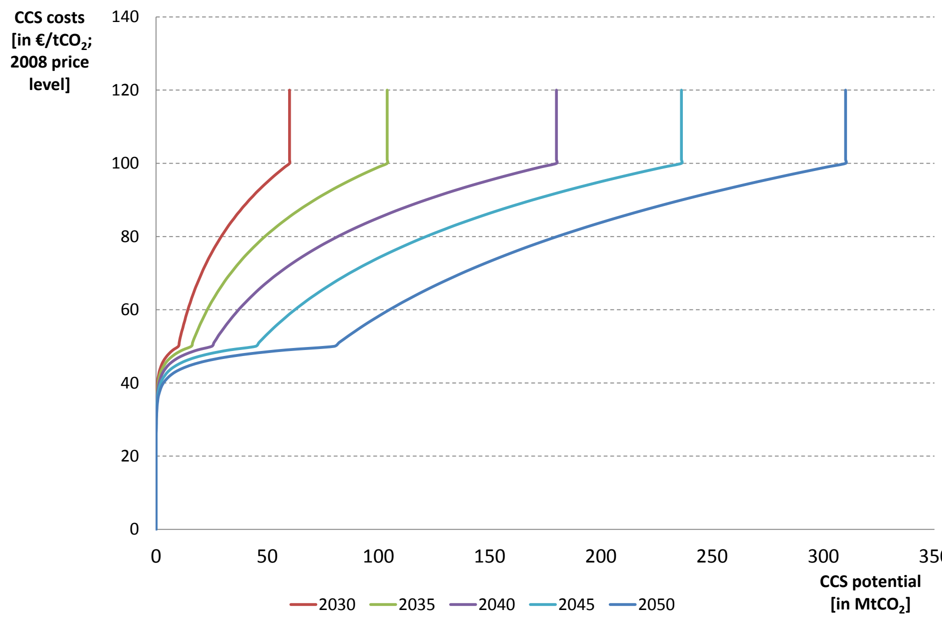
It should be noted that the share of CCS is a major long-term assumption in the baseline and other modelling scenarios as it plays an important role in determining future carbon prices; without CCS the model results suggest we could expect a carbon price in the region of €400/tCO_2 by 2050 in several scenarios. When comparing these scenarios, however, the CCS assumptions are less important because the amount of CCS in the power sector is largely unchanged, notably among the splitting scenarios (see Section 3.3.2). Nevertheless, there are some differences in power sector CCS levels between the respective splitting and non-splitting scenarios as well as in industrial CCS levels between all scenarios considered (see Section 3.4.2). This reduces the other differences between scenarios, i.e. if there was no CCS the range of carbon prices would be higher.

Figure 1: EU27: Cost curve of CCS potential in the power sector, 2030-2050



Source: Derived and interpolated from IEA (2009).

Figure 2: EU27: Cost curve of CCS potential in industry, 2030-2050



Source: Derived and interpolated from IEA (2009).

2.1.7 An alternative policy option: output-based allocation

An alternative policy option to address the issue of carbon leakage is output-based allocation of free ETS allowances rather than lump-sum allocations such as grandfathering (based on historical emissions) or benchmarking (i.e. free allocation of allowances based on an emissions benchmark times historical production levels). As this option is largely beyond the scope of the present study – and hard to model – we will not assess it as part of the modelling results in chapter 3 but rather assess in qualitative, comparative terms in chapter 5 as part of evaluating different policy options to improve the ETS in general and to address the issue of carbon leakage in particular.

2.2 The Energy-Environmental-Economy Model for Europe (E3ME)

E3ME is a computer-based model of Europe's economic and energy systems and the environment. It was originally developed through the European Commission's research framework programmes and is now widely used in Europe for policy assessment, forecasting and research purposes.

The structure of E3ME is based on the system of national accounts, as defined by ESA95, i.e. the Eurostat System of Accounts 1995 (EC, 1996), with further linkages to energy demand and environmental emissions. The labour market is also covered in detail, with estimated sets of equations for labour demand, supply, wages and working hours. In total there are 33 sets of econometrically estimated equations, including the components of GDP (consumption, investment, and international trade), prices, energy demand and materials demand. Each equation set is disaggregated by country and by sector.

E3ME's historical database covers the period 1970-2010 and the model projects forward annually to 2050 (Chewpreecha and Pollitt, 2009). The main data sources are Eurostat, DG ECFIN's AMECO database and the IEA, supplemented by the OECD's STAN database and other sources where appropriate. Gaps in the data are estimated using customised software algorithms.

The other main dimensions of the model are:
- 33 countries (the EU27 Member States plus Norway, Switzerland and 4 EU candidate countries, i.e. Croatia, Iceland, Macedonia and Turkey).
- 69 economic sectors, including disaggregation of the energy sectors.
- 43 categories of household expenditures.
- 21 different users of 12 different fuel types.
- 14 types of air-borne emission (where data are available) including the six greenhouse gases monitored under the Kyoto protocol.
- 13 types of households, including income quintiles and socio-economic groups such as the unemployed, inactive and retired, plus an urban/rural split.

Typical outputs from the model include GDP and sectoral output, household expenditure, investment, international trade, inflation, employment and unemployment, energy demand and CO_2 emissions. Each of these is available at the national and EU level, and most are also defined by economic sector.

The econometric specification of E3ME gives the model a strong empirical grounding and means it is not reliant on the assumptions common to Computable General Equilibrium (CGE) models, such as perfect competition or rational expectations.

In summary the key strengths of E3ME lie in three different areas:[10]
- The close integration of the economy, energy systems and the environment, with two-way linkages between each component.
- The detailed sectoral disaggregation in the model's classifications, allowing for the analysis of similarly detailed scenarios.
- The econometric specification of the model, making it suitable for short and medium-term assessment, as well as longer-term trends.

As with all models, there are some limitations and assumptions that must be observed. These principally relate to the available data. In particular, the ETS is modelled on a sectoral, rather than installation, basis. This is a reasonably accurate representation but does not take into account some of the finer details (e.g. small installations and co-generation).

[10] For further details on the model, including a full manual, see the E3ME website: http://www.e3me.com

3

Modelling results

This chapter presents and analyses the modelling results of the scenarios, as outlined in the previous chapter, according to the following structure. First, Section 3.1 discusses the results for the ETS in terms of the cap of EU emission allowances (EUAs) and the CO_2 emissions of the ETS sectors over the years 2010-2050, while the evolution of ETS carbon prices across the scenarios is outlined in Section 3.2. Next, Section 3.3 discusses the implications of splitting the ETS in terms of ETS carbon abatement costs. Sections 3.4 and 3.5 present and analyse some more specific results for the two ETS sectors distinguished in this study, i.e. power generation and industry. Finally, Section 3.6 discusses some macroeconomic results of the modelling scenarios in terms of their implications for GDP, employment, trade etc. at the EU27 and Member State levels.

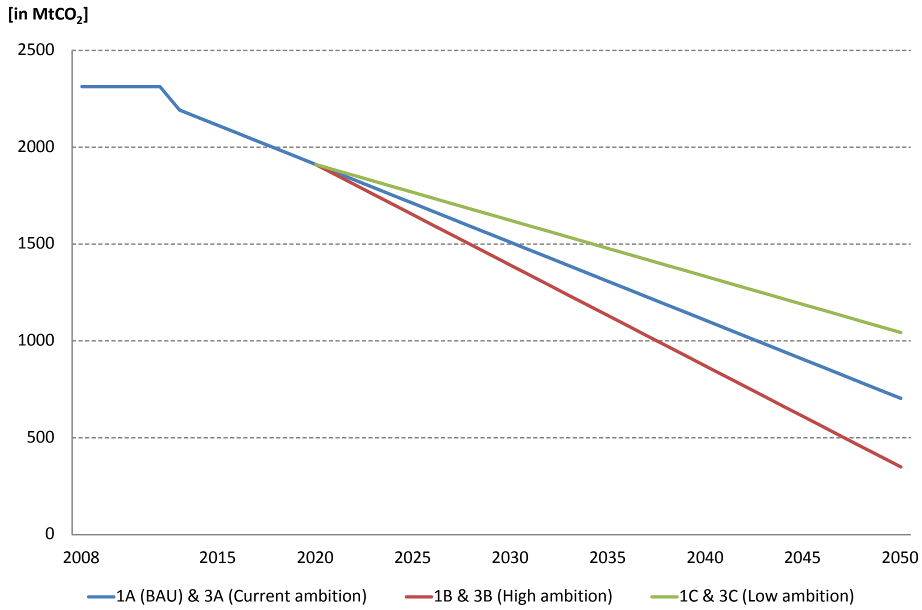
This chapter is focused on presenting and analysing the major quantitative results of the nine modelling scenarios outlined in the previous chapter, i.e. the three policy options – (1) non-splitting, (2) ETS-splitting, and (3) non-splitting + carbon tax – multiplied by the three ambition level for the ETS as a whole: (A) current ambition, (B) high ambition, and (C) low ambition. However, as the modelling results of the scenarios for policy option 3 are similar to those of the respective ambition scenarios of either policy option 1 or 2, for reasons of clarity and compactness the results of policy option 3 scenarios are usually grouped together in the text, tables and figures below with those of their similar, respective policy 1/2 scenarios and receive less specific attention (with the major exception of the sections on carbon pricing and carbon taxation in the power sector).[11]

[11] More specifically, the ETS caps in the alternative, non-splitting scenarios 3A, 3B and 3C are similar to the caps in the respective, current non-splitting scenarios 1A, 1B and 1C. In terms of all other modelling results, however, scenarios 3A and 3C are similar to 2A and 2C, while scenario 3B is similar to 1B (as will be further outlined and explained in the main text below).

3.1 ETS cap and CO_2 emissions

Figure 3 shows the evolution of the ETS cap over the years 2008-2050 for the non-splitting scenarios (i.e. policy options 1 and 3), while **Figure 4** presents the cap for the ETS sectors industry and power generation separately for the splitting scenarios (policy option 2). Note that in this study – unless specified otherwise – the cap not only refers to the amount of EU emission allowances (EUAs) allocated annually but also includes an additional number of CDM credits equal to 7.5% of the annual amount of EUAs (as explained in the previous chapter).

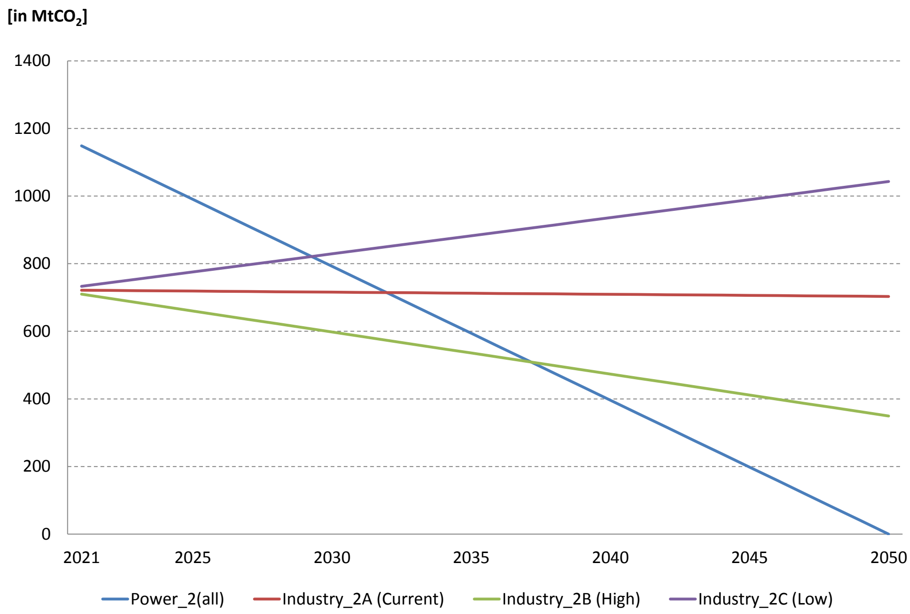
Figure 3: Non-splitting scenarios: ETS cap (including CDM), 2008-2050



Up to 2020, the evolution of the ETS cap is similar in all scenarios, i.e. the total cap for all installations covered by the ETS during its third trading period (2013-2020) is decreased by a reduction factor of 1.74% per annum compared to the average cap/emissions of these installations during the second trading period (2008-2012). As a result, the annual cap during the third phase declines from 2192 $MtCO_2$ in 2013 to 1910 $MtCO_2$ in 2020.[12] This cap refers to all installations and GHG emissions covered by the EU ETS during its third trading period, with the exception of the aviation sector.

[12] The total cap/emissions of all installations covered by the ETS during its third trading period – i.e. excluding aviation – is estimated by the E3ME model at, on average, 2313 $MtCO_2$ for the years 2008-2012 (including CDM). Hence, an annual reduction factor of 1.74% implies a lowering of the cap by 40.25 $MtCO_2$ per year. In line with the revised EU ETS Directive of 2009 and the methodology for setting the cap during the third trading period (EC, 2009a and 2010b), the average cap/emissions during the period 2008-2012 (2313 $MtCO_2$) is set representative for the middle year of this period, i.e. 2010. This implies that the cap for the year 2013 has been reduced by three times the annual reduction factor, i.e. by 3 x 1.74% = 5.22% (or by 121 $MtCO_2$ compared to '2010'), leading to a cap of 2192 $MtCO_2$ in 2013. Similarly, for the year 2010, it implies that the cap has been lowered by ten times the annual reduction rate, i.e. by 10 x 1.74% = 17.4% (or by 403 $MtCO_2$ compared to '2010'), resulting in a cap of 1910 $MtCO_2$ in 2020. For detailed results on the annual ETS caps over the period 2008-2050, see **Table 24** in Appendix A.

Figure 4: Splitting scenarios: ETS cap (including CDM), industry and power sector, 2021-2050



Starting from 2021, however, the evolution of the ETS cap is different across the scenarios, depending on whether the ETS is split or not into separated sectors as well as on the ambition level of the scenarios to reduce CO_2 emissions up to 2050 either for the ETS as a whole (non-splitting scenarios) or for each of the separated sectors (splitting scenarios).

Within the set of non-splitting scenarios, the baseline scenario 1A – as well as scenario 3A – continues the current CO_2 reduction ambition level for the ETS up to 2050, i.e. lowering the cap by 1.74% per annum, compared to '2010'.[13] This results in a cap for these two scenarios steadily falling by 40.25 $MtCO_2$ per annum to 703 $MtCO_2$ in 2050, i.e. almost 70% lower compared to 2010 (see **Figure 3** as well as **Table 5**).

In addition to scenarios 1A and 3A, **Figure 3** also presents the evolution of the cap for the other non-splitting scenarios up to 2050, based on different CO_2 reduction ambition levels (as discussed in Section 2.1). As expected, compared to the current ambition scenario, the decrease of the cap is more (less) steep in the high (low) ambition scenario.

A summary of the cap in specific years is provided in **Table 5**. It shows that in the high ambition scenarios the ETS cap is reduced to some 350 $MtCO_2$ in 2050, i.e. 85% lower compared to 2010 (against 70% reduction in the current ambition scenario). In the low ambition scenario, however, the total reduction rate over the period 2010-2050 amounts to 55%.

[13] The year '2010' refers to the average cap/emissions of the period 2008-2012.

Table 5: ETS cap (including CDM), non-splitting scenarios (policy options 1 and 3), 2010-2050 (in $MtCO_2$)

	1A (BAU) & 3A (current)[a]	1B & 3B (high)	1C & 3C (low)
2010	2313	2313	2313
2020	1910	1910	1910
2021	1870	1858	1881
2050	703	349	1043
Reduction 2020-2050 (in %)	63	82	45
Reduction 2010-2050 (in %)	70	85	55

a) Caps under the scenarios of policy options 1 and 3 are similar because they are both non-splitting options (one single cap) with similar, respective ETS reduction ambitions.

For the splitting scenarios, **Figure 4** presents the evolution of the cap over the years 2021-2050 for the two ETS sectors concerned, i.e. power and industry. To set this cap for each sector and for each year in each scenario, first of all the overall ETS cap for the year 2020 in the baseline scenario (1910 $MtCO_2$) has been split between the power sector and industry, based on their average share in total ETS baseline emissions over the period 2010-2020, resulting in an 'imaginary 2020' cap for the power sector of 1188 $MtCO_2$ and for industry of 722 $MtCO_2$ (including CDM).[14] Subsequently, the cap for the power sector has been reduced linearly over the years 2021-2050 to become zero by 2050 in all splitting scenarios (i.e. a 100% decarbonisation target for the power sector in 2050). Finally, for industry, the 2020 cap has been adjusted annually over the years 2021-2050 for each splitting scenario by the rules and targets outlined in Section 2.1 (see particularly **Table 3**).

Table 6: ETS cap (including CDM), splitting scenarios (policy option 2), 2020-2050 (in $MtCO_2$)

	Power	Industry		
	All Scenarios	2A (current)	2B (high)	2C (low)
2020[a]	1188	722	722	722
2021	1149	721	710	733
2050[b]	0	703	349	1043
Reduction 2020-2050 (in %)	100	3	52	-44

a) These are 'imaginary, base-year' caps for the year 2020 in order to calculate the caps for 2021 and beyond.

b) Note that when the cap of the power sector is added to the cap of the industrial sectors in the respective splitting scenarios, the cap for the ETS sectors as a whole is similar to the ETS cap in the respective non-splitting scenarios and, hence, the overall CO_2 reduction ambition of the splitting scenarios is similar to the ambition of the non-splitting scenarios as expressed in **Table 5**.

[14] The shares of the power sector and industry in total ETS emissions over the years 22010-2020 amount to 62.2% and 37.8% respectively. For specific emissions data, see Appendix A (**Table 25**, **Table 26** and **Table 27**).

Table 6 shows that of the overall CO_2 reduction ambition for the ETS as a whole, a substantial amount is realised by the power sector over the years 2020-2050 in all splitting scenarios (i.e. a fixed amount of 1188 $MtCO_2$). The other or remaining part of this ambition to be achieved by industry varies by splitting scenario. In the splitting scenario 2A (current ambition), the cap for industry declines slowly from 722 $MtCO_2$ in 2020 to 703 $MtCO_2$ in 2050, i.e. a decrease by 3% over this period. In splitting scenario 2 B (high ambition), however, the cap for industry is reduced substantially from 722 $MtCO_2$ in 2021 to 349 $MtCO_2$ in 2050. In splitting scenario 2C (low ambition), on the contrary, industry is even allowed to increase its emissions as its cap is raised from 722 $MtCO_2$ in 2020 to 1043 in 2050.

CO_2 emissions

Figure 5 presents the evolution of the CO_2 emissions for the ETS as a whole, as well as for the power sector separately, over the period 2010-2050 for some selected scenarios (1A, 1B and 1C). In addition, **Table 7** provides data on CO_2 emissions of both the power sector, industry and the ETS as a whole in the years 2010 and 2050 for all scenarios. It can be observed that while emissions at the sectoral and aggregate levels are similar in 2010, they vary widely in 2050 depending on the scenario considered. For instance, CO_2 emissions in the power sector in 2050 range from 273 $MtCO_2$ in scenario 1B to 657 $MtCO_2$ in scenario 1C (see **Figure 5** and **Table 7**).

Table 7: CO_2 emissions in ETS sectors, 2010-2050

	Power		Industry		Total ETS	
	2010	2050	2010	2050	2010	2050
1A (BAU): Current	1204	493	728	554	1932	1048
1B & 3B: High	1204	273	728	434	1932	707
1C: Low	1204	657	728	678	1932	1336
2A & 3A: Current	1204	352	728	736	1932	1088
2B: High	1204	355	728	378	1932	733
2C & 3C: Low	1204	353	728	746	1932	1099

It should be noted, however, that due to banking of EUAs over the period 2013-2050, the evolution of CO_2 emissions over this period differs substantially from the evolution of the cap (as discussed above).[15] This is illustrated in **Figure 6** for the ETS as a whole in the baseline scenario 1A (current ambition) and in **Figure 7** for the power sector in splitting scenario 2B (high ambition).

Figure 6 shows that the ETS cap in the baseline scenario declines steadily from 2192 $MtCO_2$ in 2013 to 703 $MtCO_2$ in 2050. Up to 2037, however, CO_2 emissions are projected to be below the cap, resulting in the banking of EUAs equivalent to a cumulative amount of about 2.4 $GtCO_2$ over the years 2013-2036. This amount is used to cover emissions above the cap during the period 2037-2050. Due to this banking of

15 Banking means that EUAs are saved in a period in which EUAs are less scarce and hence, relatively cheap in order to be used in a later period in which EUAs are more scarce and, therefore, relatively expensive. The major advantage of banking is that it saves costs and, hence, enhances overall efficiency. In addition, it reduces emissions below the cap in earlier periods and lowers carbon prices in later periods. On the other hand, banking enhances carbon prices in earlier periods and increases emissions above the cap in later periods.

allowances, CO_2 emissions of the ETS sectors in the baseline scenario amount to more than 1000 $MtCO_2$ in 2050 while the cap is only about 700 $MtCO_2$ in this year.

Figure 5: CO_2 emissions in ETS (total) and power sector, 2010-2050, in non-splitting scenarios 1A (BAU; current ambition), 1B (high ambition) and 1C (low ambition)

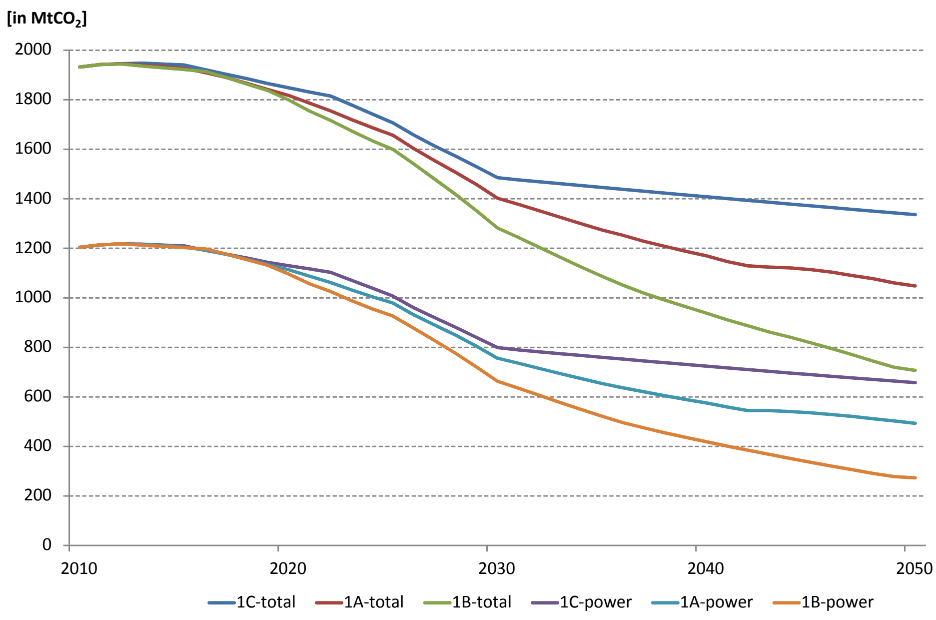


Figure 6: Impact of banking: ETS cap versus CO_2 emissions, baseline scenario 1A (current ambition), 2013-2050

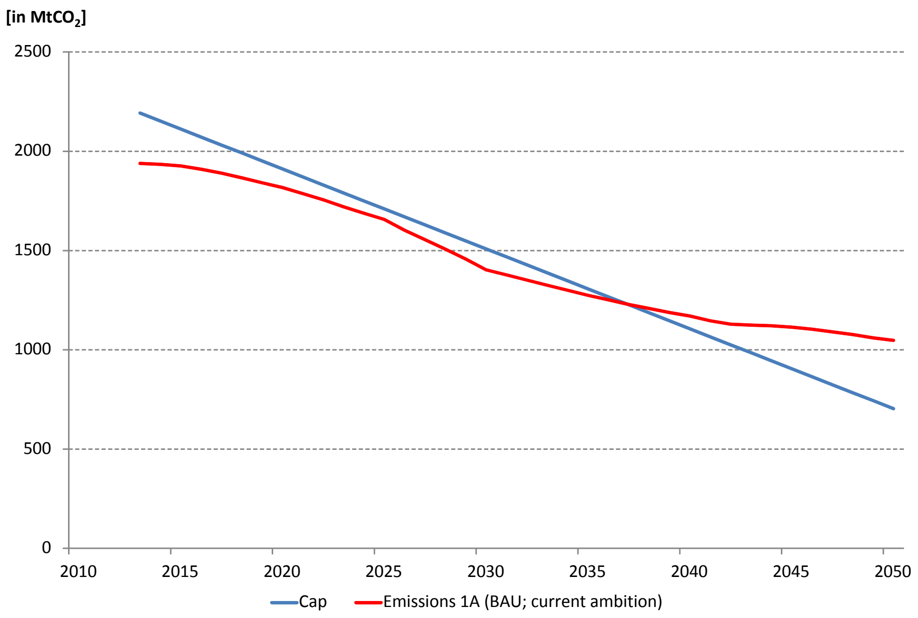
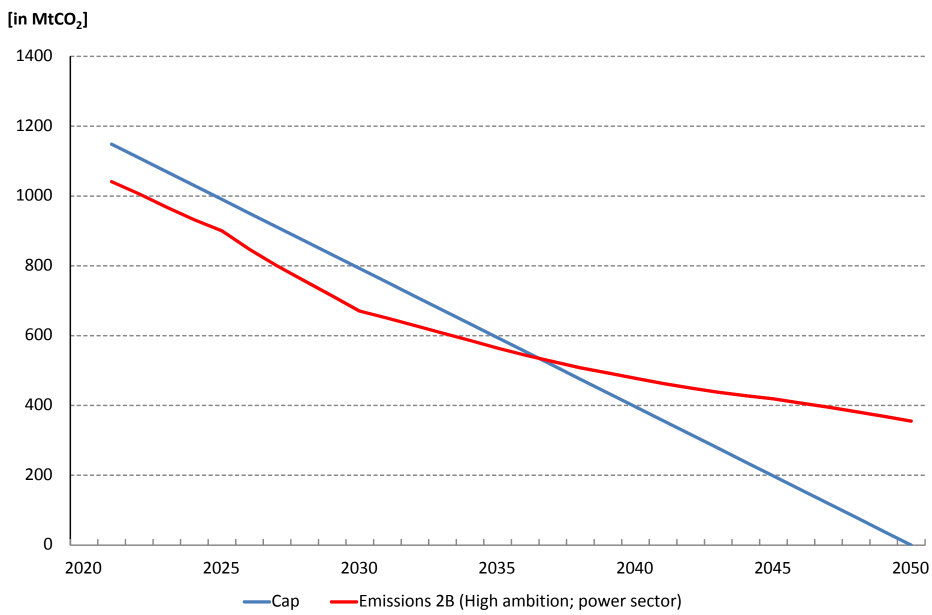


Figure 7: Impact of banking: ETS cap versus CO_2 emissions in the power sector, scenario 2B (splitting, high ambition), 2021-2050



Similarly, **Figure 7** illustrates the impact of banking on CO_2 emissions by the power sector in the splitting scenario 2B. In this scenario, the cap for the power sector decreases steadily from 1149 $MtCO_2$ in 2021 to zero in 2050. Without banking, a cap moving to zero would most likely result in rather high carbon prices by the end of this period as the latest marginal units to abate CO_2 are usually rather expensive. It has been assumed, however, that banking is allowed over the period 2013-2050. Consequently, EUAs are banked substantially by the power sector up to 2036, to a cumulative amount of approximately 2.5 $GtCO_2$, which is used to cover emissions above the cap in the years 2038-2050.[16]

Owing to banking, (very) high carbon prices in the power sector can be avoided by the end of the period up to 2050 and overall efficiency is improved. On the other hand, however, due to banking of EUAs emissions by the power sector are still substantial during these years while the cap is already significantly lower. For instance, the cap for the power sector has reached zero by 2050 while, due to banking, its CO_2 emissions in scenario 2B still amount to some 360 $MtCO_2$ in this year. Therefore, although total emissions of the power sector over the years 2013-2050 do not surpass its total cap during this period, due to banking the target of full decarbonisation of the power sector will not be reached in 2050.

It should be noted, however, that the substantial amount of banking is to a large extent due to the modelling approach and underlying assumptions with regard to banking by ETS sectors. Banking of allowances is introduced in the model to smooth the carbon

16 About 40% of this amount has been banked by the power sector during the non-splitting period 2013-2020. Actually, as EUAs are auctioned to the power sector (starting from 2013), they may not be banked by (only) the power sector itself but (also) by other sectors (industry), banks or other financial institutions and, at a later stage, sold to the power sector.

price trajectory over the period considered, i.e. to reduce significant year-to-year fluctuations in the carbon price in general, to avoid peak prices in particular and, hence, to make it easier and more cost-effective for ETS participants to achieve the emissions cap.

In addition, the large amount of banking results from underlying assumptions such as the availability of unlimited funds to finance banking and the absence of regulatory risks or other uncertainties. In reality, however, funding is limited and there are all kinds of uncertainties and risks regarding future carbon prices, abatement costs, climate policies, etc. Although uncertainties on EUA prices may even enhance the need for banking, in reality the amount of banking is most likely substantially lower than assumed in our scenarios and, hence, actual emissions by the power sector in 2050 will likely be lower in the years up to 2050 than indicated by **Figure 7** and **Table 7**.

Moreover, we have assumed that banking is allowed only up to 2050 and does not consider or make explicit assumptions for the period beyond 2050. In reality, however, banking of EUAs beyond 2050 is likely to be allowed. Therefore EUAs before 2050 will probably be banked and used in the years after 2050 and, hence, emissions by the power sector will probably be even further reduced in the years up to 2050 than indicated above.

Finally, although the underlying assumptions of banking and its impact on ETS carbon prices and CO_2 emissions over the years 2013-2050 may be questioned, it should be noted that the central aim of this study is not to make exact assessments of CO_2 emissions and carbon prices over the years 2013-2050 but rather to compare the performance of different ETS splitting options. As the banking (and other modelling) assumptions are similar to all options and scenarios considered, these assumptions hardly affect this comparison of ETS splitting options.

Comparing CO_2 emissions between the splitting and non-splitting scenarios

When comparing sectoral emissions in 2050 between the splitting and non-splitting scenarios, it can be observed that power sector emissions are lower under splitting scenarios 2A and 2C (compared to non-splitting scenarios 1A and 1c, respectively), but higher under 2B (compared to 1B). This implies that power sector emission *reductions* are higher under 2A and 2C but lower under 2B. An opposite pattern in emission reductions can be observed for industry, i.e. higher emission reductions under 2B compared to 1B.

These patterns result from the sectoral ambition levels for each scenario as defined and explained in Section 2.1.2 (**Table 3**), implying that within a similar total ETS reduction target (for instance, ambition level A: current) the power sector faces a higher ambition under 2A than under 1A and industry a lower ambition (while the reverse applies for ambition level B: high).

Overall, however, the total amount of CO_2 emissions – and, hence, the total amount of emission reductions – is more or less similar at the current and high ambition levels. For instance, total ETS emission in 2050 amount to 707 $MtCO_2$ in non-splitting scenario 1B and 733 $MtCO_2$ in splitting scenarios 2B (the small difference is due to differences in banking of emission allowances, as explained below).

In splitting scenario 2C (low ambition), however, total ETS emissions in 2050 are significantly lower than in 1C, i.e. 1099 and 1336 $MtCO_2$, respectively. Apart from some banking under 1C (which raises emissions in 2050), this is mainly due to the fact that under 2C the cap for industry is so relaxed – see **Table 6**– that its emissions remain far below its sectoral cap. Although power sector emissions under 2C are severely restricted by its sectoral cap, total ETS emissions remain far below the aggregated sum of the (separated) sectoral caps. In contrast, under non-splitting scenario 1C, there is only one single (overall restrictive) cap and total ETS emissions largely follow this cap (apart from some banking). Therefore, although the total ETS cap is similar under 1C and 2C (low ambition), total ETS emissions follow this cap under non-splitting scenario 1C while they remain far below this cap under splitting scenario 2C due to the relaxed, non-binding sectoral cap for industry under this scenario.

Table 8: Average annual emission by ETS sectors, 2013-2050 (in $MtCO_2$)

	Power sector	Industry	Total ETS
Non-splitting scenarios:			
1A (current)	805	641	1446
1B (high)	702	597	1299
1C (low)	886	697	1582
Splitting scenarios:			
2A (current)	729	714	1442
2B (high)	729	573	1301
2C (low)	729	720	1448
Difference between splitting and non-splitting scenarios:			
2A – 1A (current)	-76	73	-3
2B – 1B (high)	26	-25	2
2C – 1C (low)	-157	23	-134

Table 8 presents the average annual emissions by ETS sectors over the period 2013-2050 for the non-splitting scenarios (policy option 1) and the splitting scenarios (policy option 2) as well as for the differences between these respective scenarios. It shows, for instance, that the average annual emissions for the power sector over this period are similar under all three splitting scenarios (i.e. 729 $MtCO_2$), while they vary for industry from 573 $MtCO_2$ in splitting scenarios 2B (high ambition) to 720 $MtCO_2$ in splitting scenario 2C (low ambition).

In terms of differences between the splitting and non-splitting scenarios, **Table 8** shows that under ambition level A (current), annual CO_2 emissions by the power sector over the period 2013-2050 are, on average, 76 $MtCO_2$ lower in splitting scenario 2A, compared to non-splitting scenario 1A, i.e. under 2A the power sector reduces its average annual emission by and additional amount of 76 $MtCO_2$. In splitting scenario 2B (high ambition), however, annual CO_2 emission by the power sector are, on average, 26

$MtCO_2$ higher than in non-splitting scenario 1B as the power sector benefits from the fact that under 2B its reduction target is less stringent than under 1B.

For industry, the differences in average annual emissions between the splitting and non-splitting scenarios have opposite signs compared to those for the power sector, while the size of the sectoral differences is more or less similar under ambition levels A and B. This implies that total ETS emissions are more or less similar between the respective scenarios of these ambition levels and that the differences in emissions between the respective splitting and non-splitting scenarios is nearly zero (see **Table 8**).[17]

The above observations, however, do not apply for ambition level C. Under this low overall ETS ambition level, annual CO_2 emissions by the power sector over the period 2013-2050 are, on average, 157 $MtCO_2$ lower in splitting scenario 2C, whereas they are only 23 $MtCO_2$ higher for industry. As a result, total annual ETS emissions are, on average, 134 $MtCO_2$ lower in splitting scenario 2C than in non-splitting scenario 1C, although the overall ETS ambition level or cap reduction factor is similar under both scenarios, i.e. declining by 1.25% per annum, starting from 2021. This is due to the fact that under this overall (soft) ambition level the power sector faces a similar stringent ambition target under 2C as under the other splitting scenarios (2A and 2B), i.e. full decarbonisation by 2050, whereas the resulting ambition target for industry is so relaxed under 2C that its annual emissions remain far below its sectoral cap and that, consequently, its sectoral carbon price falls to zero (see next Section 3.2). If a negative carbon price – i.e. a subsidy on emissions – would be assumed possible, industrial emissions would increase by, on average, 134 $MtCO_2$ per annum (until the industrial cap is reached). However, since a negative carbon price is assumed to be not realistic, total annual ETS emissions are, on average, 134 $MtCO_2$ lower in splitting scenario 2C compared to 1C.

3.2 ETS carbon prices

Table 9 provides a summary overview of the carbon prices in the various scenarios over the period 2010-2050, while graphs of the trends in these prices are presented in **Figure 8** up to **Figure 11**.

Table 9 shows that the ETS carbon price in 2010 is determined at a uniform level of 15 €/tCO_2 for all scenarios (2008 price level).[18] Due to the opportunity of banking over the period 2013-2050 and the assumption that policy reforms – as expressed in the different scenarios – are already known at the early stage of the third trading period, carbon prices already start to differentiate significantly in 2020, depending on the

[17] **Table 8** shows that there are some minor differences in average annual total ETS emissions between the splitting and non-splitting scenarios at ambition levels A and B. These differences are due to rounding errors and to the fact that occasionally sectoral emissions are below the cap, notably when the (sectoral) carbon price is zero or very low. The major difference at ambition level C is explained in the main text.

[18] This conforms to the average CO_2 price in 2010 at the EUA year-ahead market, amounting to approximately 14-15 €/tCO_2 (in current prices).

characteristics of the scenarios considered.[19] For instance, the ETS price in 2020 ranges from 12 €/tCO_2 when non-splitting scenario 1C (low ambition) will be implemented after 2020 to 27 €/tCO_2 in case one of the splitting scenarios (2A/2B/2C) becomes operative, starting from 2021.[20]

Table 9: CO_2 prices, 2010-2050 (in €/tCO_2, 2008 price level)

	2010[a]	2020[b]	2030	2040	2050
Non-splitting scenarios (option 1)					
1A Current (BAU)	15	24	37	55	75
1B High	15	25	46	75	101
1C Low	15	12	14	15	15
Splitting scenarios (option 2)					
Power sector					
2A Current	15	27	44	67	92
2B High[c]	15	27	44	66	89
2C Low	15	27	44	67	93
Industry					
2A Current	15	27	3	2	2
2B High[c]	15	27	61	88	116
2C Low	15	27	0	0	0
Non-splitting scenarios + carbon tax in the power sector (option 3)					
3A Current	15	27	3	2	2
3B High[d]	15	25	46	75	101
3C Low	15	27	0	0	0

a) In 2010, the ETS carbon price is determined by the baseline scenario 1A.

b) The ETS carbon price in 2020 is affected by banking of EUAs, depending on which scenario will be implemented beyond 2020.

c) Assuming no EUA trading between industry and the power sector.

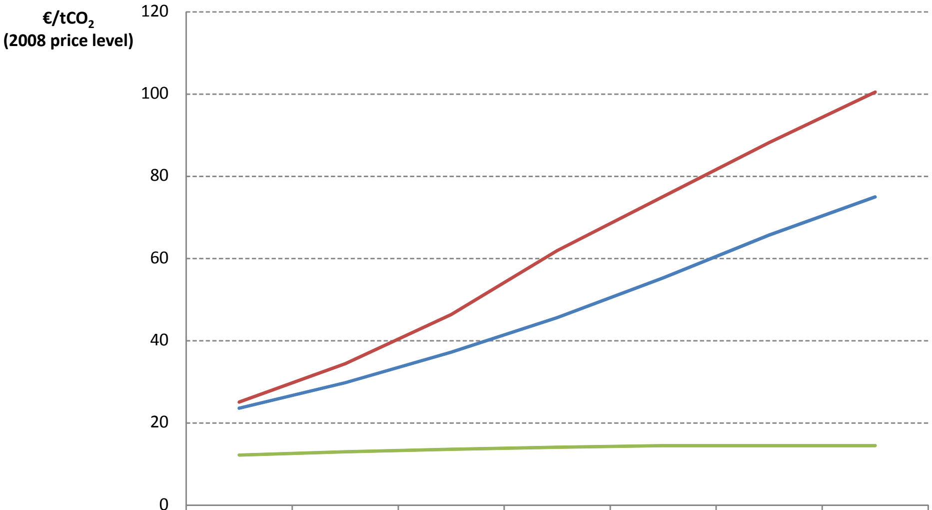
d) Assuming one-way EUA trading between industry and the power sector (i.e. industry is allowed to buy allowances from the power sector, but not the other way round).

19 This (bold) assumption was made to show that, due to banking of EUA, policy reforms of the ETS when agreed and known at an early stage of the third trading period can already have a significant impact on CO_2 prices during this period even if these reforms are actually implemented beyond this period.

20 As argued in Section 3.1, however, in reality the impact of banking will most likely be substantially lower than assumed by the model and, hence, the carbon price in 2020 will be lower accordingly. Moreover, the carbon prices up to 2020 are based on the PRIMES reference scenario of 2009, which does not adequately account for the current, prolonged economic crisis. Therefore, accounting for this crisis will further reduce carbon prices in 2020 and beyond.

The trend of the carbon price over the period 2020-2050 depends on the scenario considered. In the baseline scenario (1A, no splitting; current ambition), the carbon price increases steadily from 24 €/tCO_2 in 2020 to 75 €/tCO_2 in 2050, whereas in scenario 1C (no splitting; low ambition) the ETS price remains at a flat level of 12-15 €/tCO_2 over the years 2020-2050 (see also **Figure 8**).

Figure 8: ETS carbon price: Option 1 (non-splitting scenarios), 2020-2050



	2020	2025	2030	2035	2040	2045	2050
1A Current (BAU)	24	30	37	46	55	66	75
1B High	25	34	46	62	75	88	101
1C Low	12	13	14	14	15	15	15

Splitting scenarios (policy option 2)

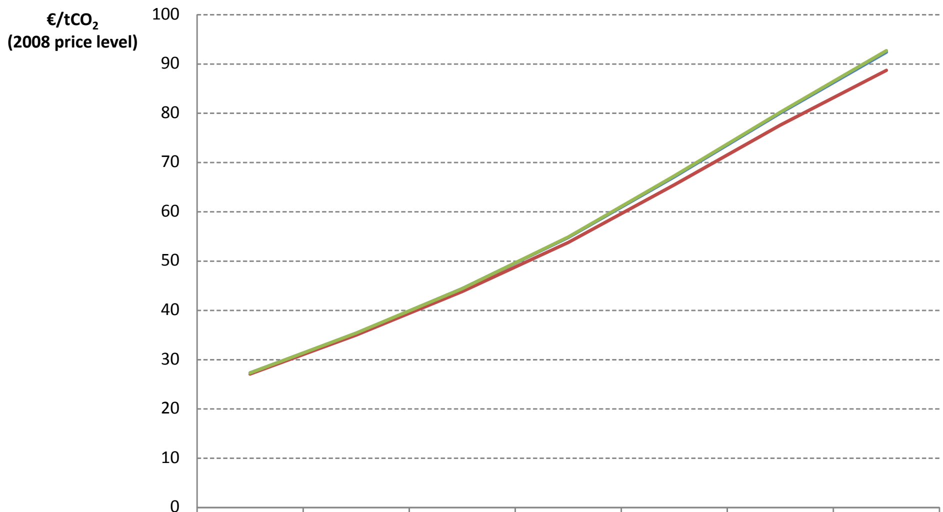
In all ETS splitting scenarios, the power sector is facing the same ambition, i.e. reducing its emissions to zero by 2050 (**Figure 4**). In the splitting scenarios with fixed overall ambition targets (2A, 2B, and 2C), industry has to meet the remaining part of these targets, i.e. the overall target for the ETS as a whole minus the target for the power sector (which, as said, is the same throughout all splitting scenarios). As a result, industry is facing a soft target in the 'low ambition' scenario 2C (i.e. an increase of the cap by 44% over the years 2021-2050), a moderate target in the 'current ambition' scenario 2A (a decrease of the cap for industry by 3%), but a relatively stringent target in the 'high ambition' scenario 2B (a decrease by 52%; see **Figure 4** and **Table 6**).

As a result of these sectoral ambition targets, the ETS carbon price for the power sector in scenario 2A increases steadily from 27 €/tCO_2 in 2020 to 92 €/tCO_2 in 2050. In scenario 2B, however, the increase in the carbon price is less steep, i.e. it rises from 27 €/tCO_2 in 2020 to 89 €/tCO_2 in 2050 (see **Table 9** and **Figure 9**).[21] The reason for this counterintuitive price pattern is that in the high ambition scenario 2B industry is facing a relatively stringent target (as opposed to the other two splitting scenarios). As a result, industry output falls. Consequently, the demand for electricity by industry is lower in this scenario, leading to less production and, therefore, less emissions in the

[21] Note that in this scenario 2B the carbon price for the power sector is lower than in the comparative non-splitting scenarios 1B (high ambition) and also below the carbon price for industry in the high ambition, splitting scenario 2B (see below).

power sector. This reduces the demand for EUAs in the power sector and, hence, lowers the carbon price for this sector in splitting scenario 2B (high ambition), compared to scenario 2A (current ambition) and 2C (low ambition).

Figure 9: ETS carbon price: Option 2 (splitting scenarios): power sector, 2020-2050



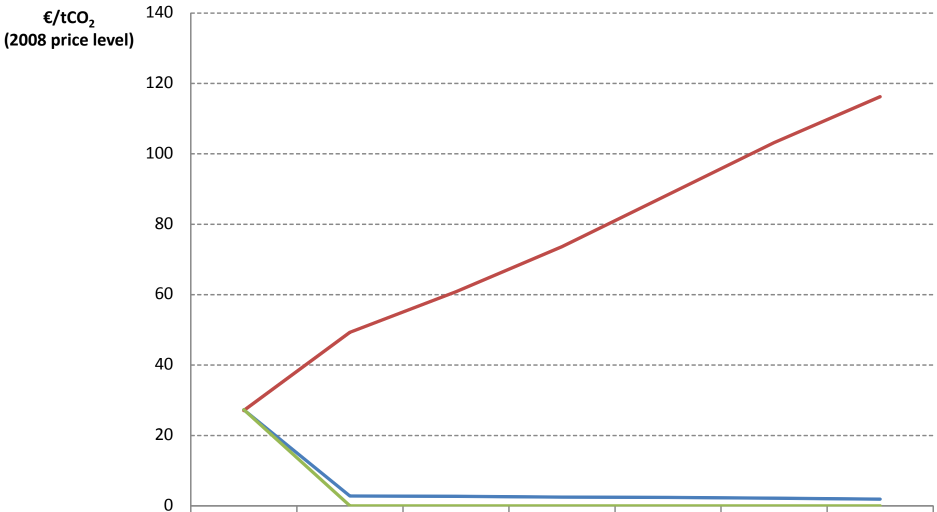
	2020	2025	2030	2035	2040	2045	2050
2A Current	27	35	44	55	67	80	92
2B High	27	35	44	54	66	78	89
2C Low	27	35	44	55	67	80	93

Due to the splitting of the ETS, the carbon price for industry in scenario 2A (current ambition) falls significantly beyond 2020 and remains at a relatively low level of 2-3 €/tCO_2 up to 2050. On the other hand, industry faces relatively high carbon prices in splitting scenario 2B (high ambition), i.e. the industrial carbon price increases substantially from 27 €/tCO_2 in 2020 to 116 €/tCO_2 in 2050. In the low ambition scenario (2C), however, the cap for industry is so relaxed that its carbon price falls to zero over the years 2030-2050 (see **Table 9** and **Figure 10**).

Several additional observations can be made to the carbon price patterns in the splitting scenarios. Firstly, in both scenario 2A and 2C the ETS carbon price for industry increases from 15 €/tCO_2 in 2010 to 27 €/tCO_2 in 2020 and then drops sharply by 2030 to 3 €/tCO_2 in scenario 2A and even to zero in scenario 2C. This unexpected, peculiar price pattern is due to the fact that up to 2020 the carbon price is determined within one single ETS cap in which the carbon price is pushed upwards through banking of allowances by the power sector (which expects high carbon prices once the ETS is split beyond 2020). After 2020, however, the carbon price for industry in splitting scenarios 2A and 2C is determined by its sectoral cap only. As the ETS reduction ambition is rather soft in these scenarios, the carbon price for industry in these scenarios falls to low levels beyond 2020.

Secondly, in scenario 2B the reduction ambition for industry is so high that the resulting carbon prices for this sector is even higher than in the comparative non-splitting scenario 1B (see **Table 9**). In summary, industry benefits from splitting the ETS by means of relatively low carbon prices in case the reduction ambition for the ETS as a whole is ‘low’ or ‘current’ (while the target for the power sector in the splitting scenarios is fixed at a rather ambitious level, i.e. moving to zero emissions by 2050). On the other hand, industry faces relatively high carbon prices in splitting scenarios 2B when the abatement target for the ETS as a whole is ‘high’.

Figure 10: ETS carbon price: Option 2 (splitting scenarios): industry, 2020-2050



	2020	2025	2030	2035	2040	2045	2050
2A Current	27	3	3	3	2	2	2
2B High	27	49	61	74	88	103	116
2C Low	27	0	0	0	0	0	0

Thirdly, besides the overall high ambition target of scenario 2b, the relatively high carbon price for industry in scenario 2B – even higher than the comparative carbon price for the power sector in this scenario – is also due to the underlying assumption that in policy option 2 no trading of EUAs between these sectors is allowed. If it is assumed, however, that industry is allowed to buy EUAs from the power sector (but not the other way around), industry will start buying EUAs once its carbon price becomes higher than the carbon price for the power sector. Actually, this implies that scenario 2B will turn into scenario 1B with an equilibrium carbon price of 101 €/tCO_2 in 2050 for both industry and the power sector.

Finally, in case of no EUA trading between the separated sectors in policy option 2 (ETS splitting), the power sector at first sight seems to benefit from relatively lower carbon prices in splitting scenario 2B (high ambition) compared to non-splitting scenario 1B (high ambition). As the power sector, however, is assumed to pass-through its carbon costs to end-users’ electricity prices, lower carbon prices will particularly benefit these end-users (i.e. mainly electricity-intensive industries). On the other hand, the power sector may benefit from higher output sales in scenario 2B (compared to 1B) due to lower electricity prices and, hence, a higher electricity demand in this scenario.

Alternative, non-splitting + carbon taxation scenarios (policy option 3)
In the alternative, non-splitting scenarios (policy option 3), industry and the power sector are facing the same reduction ambition as in the splitting scenarios outlined above. This time, however, the power sector has to meet its target by a mix of a carbon

tax and a single carbon price for the ETS as a whole rather than by a separate (split) ETS carbon price for the power sector only.

The bottom part of **Table 9** presents the carbon prices for the alternative, non-splitting scenarios, including a carbon tax for the power sector. For those splitting scenarios in which the carbon price for industry is *lower* than the price for the power sector, the carbon price in the non-splitting scenarios has been put simply equal to the carbon price for industry in the respective splitting scenarios. Subsequently, the additional carbon tax for the power sector has been derived by subtracting this single ETS price in the non-splitting scenario from the carbon price for the power sector in the respective splitting scenario.

Figure 11: ETS carbon price: Option 3 (non-splitting + carbon tax in the power sector), 2020-2050

	2020	2025	2030	2035	2040	2045	2050
3A Current	27	3	3	3	2	2	2
3B High	25	34	46	62	75	88	101
3C Low	27	0	0	0	0	0	0

The above-mentioned approach has been applied to scenarios 3A and 3C. For instance, in scenario 2A the carbon price for the power sector in 2050 is 92 €/tCO_2 while the ETS carbon price in scenario 3A is only 2 €/tCO_2, implying that the carbon tax has to be 90 €/tCO_2 in order to reach the ambitious reduction target for the power sector. In scenario 3C, on the contrary, the ETS price in 2050 is zero, implying that the carbon tax for the power sector has to be equal to the 2050 carbon price for the power sector in scenario 2C, i.e. 93 €/tCO_2.

In scenario 2B, however, the carbon price for industry is *higher* than the price for the power sector. This is due to the high CO_2 reduction ambition for industry in this scenario and the fact that the (marginal) costs of CO_2 reduction are generally higher in industry than in the power sector. Applying the approach outlined above would imply a subsidy for power sector emissions (or an additional carbon tax for industry). As this outcome is deemed to be not feasible/desirable, it is assumed, as already suggested before, that industry is allowed to buy EUAs from the power sector, but not the other way around (i.e. one-way trading). As a result, the ETS carbon prices of scenario 3B become similar to those of scenario 1B and equal for both industry and the power sector, implying that there will be no carbon tax (or subsidy) in scenario 3B. Therefore, due to allowing one-way EUA trading, in case of a high overall ETS ambition, industry pays a lower price while the power sector pays a higher price, compared to a high-ambition, splitting scenario without any trading between these sectors.

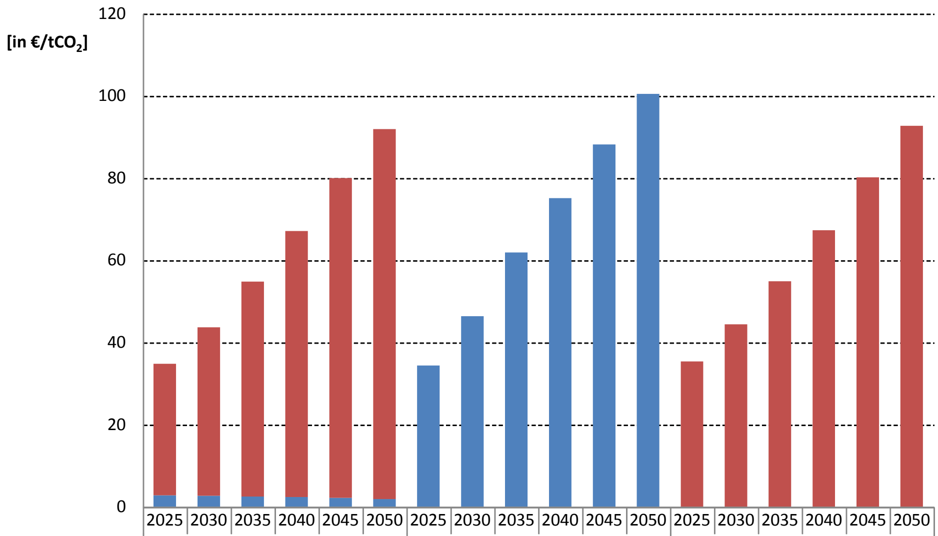
Table 10 presents the resulting total carbon pricing for the power sector in the alternative non-splitting scenarios, distinguished by the ETS carbon price and the additional carbon tax. For instance, in scenario 3A (current ambition), the ETS carbon price in 2025 amounts to 3 €/tCO_2 while the additional carbon tax amounts to 32 €/tCO_2, resulting in a total carbon price of 35 €/tCO_2. In 2050, on the other hand, the ETS price has declined to 2 €/tCO_2 whereas the carbon tax to the power sector has increased to 90 €/tCO_2, leading to total carbon pricing of 92 €/tCO_2.

Table 10: Policy option 3 scenarios: Total carbon pricing in the power sector (ETS price and carbon tax), 2025-2050 (in €/tCO_2, 2008 price level)

	2025	2030	2035	2040	2045	2050
ETS carbon price						
3A Current	3	3	3	2	2	2
3B High	34	46	62	75	88	101
3C Low	0	0	0	0	0	0
Carbon tax						
3A Current	32	41	52	65	78	90
3B High	0	0	0	0	0	0
3C Low	35	44	55	67	80	93
Total carbon price						
3A Current	35	44	55	67	80	92
3B High	34	46	62	75	88	101
3C Low	35	44	55	67	80	93

Figure 12 gives a similar breakdown of total carbon pricing in the power sector over the years 2025-2050 for the scenarios of policy option 3 (non-splitting + carbon tax). It shows that in scenario 3B (high ambition) the carbon tax is zero over the period considered and, hence, the total carbon price consists only and fully of the ETS carbon price, while in scenario 1C the ETS carbon price is zero and, therefore, the carbon tax only accounts for the full carbon pricing in this scenario. Only in scenario 3A (current ambition), the total carbon price consists of both elements, i.e. carbon tax and ETS price, although the share of the ETS carbon price is rather low and even declines over time both in absolute terms and, in particular, relative to the highly increasing carbon tax.

Figure 12: Policy option 3 scenarios: Total carbon pricing in the power sector (ETS price and carbon tax), 2025-2050



	3A Current ambition						3B High ambition						3C Low ambition					
	2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050	2025	2030	2035	2040	2045	2050
TAX	32	41	52	65	78	90	0	0	0	0	0	0	35	44	55	67	80	93
ETS	3	3	3	2	2	2	34	46	62	75	88	101	0	0	0	0	0	0

It should be noted, however, that the ETS carbon price for the power sector in the alternative, non-splitting policy option 3 is determined by the ETS ambition level for industry in policy option 2 (ETS splitting). Hence, this price becomes higher – and the carbon tax lower – when the ETS reduction ambition for industry becomes higher under policy option 2.

Figure 12 indicates that in policy option 3 the share of the carbon tax increases if the overall CO_2 reduction ambition of the ETS decreases. In addition, it shows that (similar to policy option 2), total carbon pricing of the power sector is generally slightly lower if the overall mitigation ambition of the ETS is higher. As explained above, this seemingly counterintuitive outcome results from the fact that the CO_2 reduction ambition for industry increases rapidly if the overall ambition of the ETS becomes higher – since the ambition level for the power sector is fixed under the three scenarios of policy options 2 and 3 – leading to less industrial/economic activities, less power demand and supply, and, hence, less power sector emissions, less EUA demand by the power sector and, therefore, lower carbon prices for the power sector under policy options 2 and 3.

3.3 ETS carbon abatement costs

An ETS is assumed to result in the lowest total abatement costs of CO_2 emissions covered by the scheme since it equalises the marginal abatement costs of all participating installations at the level of the ETS carbon price. Hence, consequently total abatement costs increase once the marginal abatement costs are differentiated between participating installations through, for instance, either splitting the ETS between different sectors or by imposing an additional carbon tax on one of the sectors or a subset of installations only.

Table 11 provides an estimate of the change in sectoral and total abatement costs due to the splitting of the EU ETS for the year 2050.[22] It shows that in case of splitting scenario 2A, total abatement costs for the power sector increase by almost € 12 billion - as it has to reduce more at a higher carbon price, compared to 1A – while abatement costs for industry decrease by € 5.4 billion (as it has to mitigate less at a lower price). Hence, at the current ambition level, total ETS abatement costs in 2050 increase by € 6.4 billion due to the splitting of the scheme, i.e. the system efficiency is reduced by € 6.4 billion due to differentiating the sectoral ETS carbon price. As a percentage of total ETS abatement costs in 2050 under scenario 1A, this cost increase is estimated at 16%.[23] As a percentage of total GDP by 2050, however, these costs are rather tiny, i.e. approximately 0.03%.

Table 11: Change in abatement costs due to splitting of the ETS, 2050 (in billion €, 2008 price level)

	2A – 1A (current)	2B – 1B (high)	2C – 1C (low)
Total abatement costs in 2050 in case of no splitting (billion €)			
• Power sector	33.2	55.5	7.6
• Industry	7.8	17.1	0.7
• Total ETS	40.9	72.5	8.3
Change in abatement costs in 2050 due to splitting (billion €):			
• Power sector	11.8	-7.8	16.3
• Industry	-5.4	8.9	-0.5
• Total ETS	6.4	1.1	15.8
Change in abatement costs due to splitting as % of total abatement cost in 2050 in case of no-splitting (billion €):			
• Power sector	36	-14	215
• Industry	-69	52	-69
• Total ETS	16	2	191
Change in abatement costs as % of GDP (2005)	0.03	0.01	0.08

22 Changes in sectoral abatement costs have been estimated by multiplying changes in sectoral emission reductions with the average sectoral carbon price in 2050. We have assumed that, in case of ETS splitting, the decrease in emission reduction of one sector is equal to the increase in emission reduction by the other sector. Given a similar ambition level (cap) for the ETS as a whole, this is by definition the case over a trading period as a whole, but in case of banking of allowances this does not necessarily hold for each individual year. In case of scenario 2C, however, the decrease in emission reductions by industry (-68 $MtCO_2$) is substantially less than the increase in emission reduction by the power sector (+304 $MtCO_2$) as the sectoral cap is so relaxed for industry under 2C that its carbon price falls to zero and that actual emissions remain (far) below the cap.

23 Total abatement costs in 2050 have been estimated by multiplying the total emission reductions in 2050, compared to 2013, with the average total carbon price over the period 2013-2050.

For scenario 2B, the increase in total abatement costs is estimated at € 1.1 billion. This time, however, industry faces a significant increase in abatement costs of € 8.9 billion – as it has to reduce more at a higher sectoral carbon price, compared to 1B – while the power sector benefits from a decrease in abatement costs (€ -7.8 billion). This is 2% of the total estimated abatement costs under non-splitting scenario 1B. The reason why the increase in total ETS costs is significantly lower under 2B than under 2A (despite a higher ambition under 2B) is that both the change in sectoral emission reductions and the resulting price differential between industry and the power sector are substantially smaller under 2B.

Finally, for scenario 2C, the increase in abatement costs is estimated at approximately € 16.3 billion, i.e. an increase of almost 200% compared to the total abatement costs in 2050 under scenario 1C. Whereas industry benefits by € 0.5 billion due to the splitting of the ETS, the power sector faces an increase in abatement costs of € 15.8 billion. This is due to the fact that, compared to 1C (low overall ETS ambition), the power sector has to meet a stringent target under splitting scenario 2C (full decarbonisation by 2050), implying a substantially higher amount of emission reductions at a rapidly increasing carbon price. Industry, on the other hand, faces an even more relaxed cap under splitting scenario 2C than under splitting scenario 1C. Actually, its cap becomes so relaxed that its emissions decrease far below the cap – with the industrial carbon price falling to zero – implying that industry can only benefit a little from lowering its amount of emission reductions (as its carbon price cannot become negative). Therefore, while industry benefits little, both the power sector and the ETS as a whole faces a drastic increase in total abatement costs under splitting scenario 2C compared to non-splitting scenario 1C.[24]

3.4 Power sector results

In the previous sections, we have already discussed some modelling results with regard to the power sector, in particular:

- The cost curve of CCS potentials in the power sector, 2030-2050 (Section 2.1, **Figure 1**).
- The cap for the power sector in the ETS splitting scenarios, 2021-2050 (Section 3.1, notably **Figure 4** and **Table 6**).
- CO_2 emissions by the power sector (Section 3.1, especially **Figure 5** and **Table 7**).
- The impact of banking of EUAs on CO_2 emissions by the power sector in splitting scenario 2B (Section 3.1, **Figure 7**).
- ETs carbon prices for the power sector, 2010-2050 (Section 3.2, **Table 9**, **Figure 8**, **Figure 9** and **Figure 11**).
- Total carbon pricing (ETS + carbon tax) in the power sector, 2025-2050 (Section 3.2, **Figure 12** and **Table 10**).
- Changes in carbon abatement costs (Section 3.3, **Table 11**).

[24] Note, however, that this increase in abatement costs cannot be fully regarded as a decrease in system carbon efficiency as total ETS emissions are lower under 2C than under 1C due to the fact that the level of industrial emissions falls below its cap.

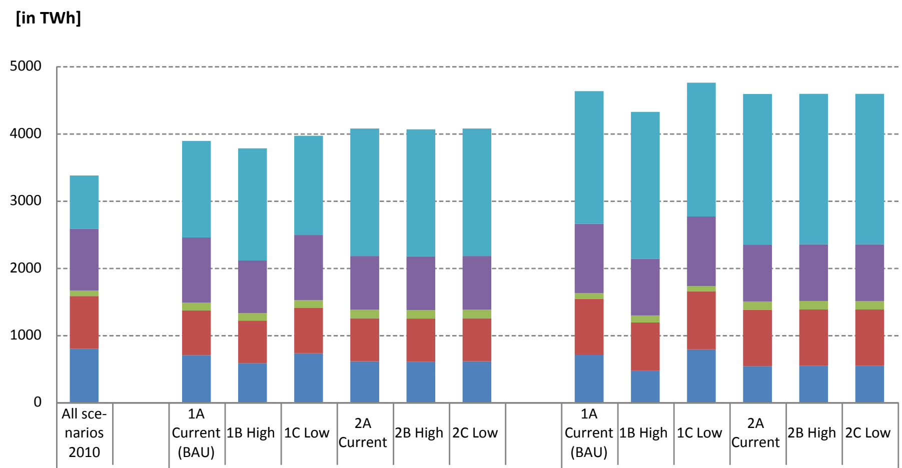
In this section, we focus on some additional, specific modelling results for the power sector, notably on the effects of the different policy scenarios on:

- The fuel or technology mix in the power sector, 2010-2050 (Section 3.4.1).
- The implementation of low-carbon technologies over the years 2030-2050, notably of CCS and renewables (Sections 3.4.1 and 3.4.2).
- The average electricity price in the EU27 as a whole and in a few selected Member States, 2010-2050 (Section 3.4.3).
- The public revenues from ETS auctioning and carbon taxation in the power sector, 2013-2050 (Section 3.4.4).

3.4.1 Power generation mix

Figure 13 shows the evolution of total power generation in the EU27 by source (i.e. by fuel/technology) for the years 2010, 2030 and 2050 (in TWh), while **Table 12** presents data on the trends in the power generation mix for these years (in % of total electricity production) in comparison to the ETS carbon price in the power sector (last column of **Table 12**).

Figure 13: EU27: Total power generation by source in 2010, 2030 and 2050



	All scenarios 2010	2030 1A Current (BAU)	2030 1B High	2030 1C Low	2030 2A Current	2030 2B High	2030 2C Low	2050 1A Current (BAU)	2050 1B High	2050 1C Low	2050 2A Current	2050 2B High	2050 2C Low
Renewables	794	1436	1668	1475	1898	1891	1898	1975	2186	1991	2240	2237	2240
Nuclear	915	969	783	971	799	799	798	1031	843	1036	845	844	845
Other fossil	84	117	113	111	126	126	126	83	104	76	124	128	124
Gas	783	666	632	678	640	641	639	837	722	865	840	839	840
Coal	797	701	583	730	611	604	611	703	467	789	537	541	542

Figure 13 shows that total power production in the EU27 grows slowly but steadily from almost 3400 TWh in 2010 to, on average, nearly 4500 TWh in 2050, i.e. by less than 1% per annum. However, whereas total power production in 2010 is similar in all scenarios considered (due to a similar ETS carbon price of 15 €/tCO_2 in these scenarios), it varies significantly in 2050 across the scenarios, depending largely on the ETS carbon price (and the consequent impact of this price on the level of industrial activities, electricity prices and resulting power demand). For instance, power generation in 2050 ranges from about 4300 TWh in splitting scenarios 1B – with an ETS carbon price in the power sector of 101 €/tCO_2 – to almost 4800 TWh in scenario 1C (15 €/tCO_2).

In addition, Figure 13 shows that total power generation by source changes significantly over the years 2010-2050, depending partly on the ETS carbon price. For instance, the amount of power produced by renewables increases substantially from less than 800 TWh in 2010 (all scenarios) to more than, on average, 2000 TWh in 2050, while the amount generated by coal decreased from almost 800 TWh in 2010 to, on average, about 540 TWh in 2050 (with almost all emissions captured, see below).

The increase in power production from renewables (in both absolute and relative terms), however, is only to a small extent due to the different policy features of the scenarios considered (splitting options/carbon reduction ambitions) and the resulting carbon prices of these scenarios. This can be illustrated by **Figure 13** for the year 2050 where the link between carbon prices and power produced from renewables appears to be weak. To some extent this is due to the fact that power production from renewables is expressed in absolute terms (in MWh), while total power generation varies substantially across the scenarios and, hence, it is sometimes more appropriate to express the contribution of renewables as a share of total production (see **Table 12**, as discussed below). The main reason for the weak link between carbon prices and electricity production from renewables, however, is that in the model production is largely driven by factors other than changes in carbon prices, including autonomous factors (e.g. renewables' cost reductions over time) and, in particular, other policies to stimulate renewables such as feed-in tariffs, green certificates or obligation schemes.[25]

Figure 13 shows that although power production from coal is decreasing over time, a substantial amount of electricity in 2050 is still generated from coal (and other fossil fuels), even under the splitting scenarios, despite the fact that the cap for the power sector in these scenarios declines to zero by 2050. This is due to two reasons. Firstly, as explained in Section 3.1, owing to banking a large amount of EUAs is saved up to the mid-2030s and subsequently used to cover CO_2 emissions of fossil-generated electricity above the cap in the years up to 2050. Secondly, starting from 2030 a substantial and growing amount of CO_2 emissions in the power sector is captured and stored (CCS) which enables the continuation of fossil-fuelled power generation in a stringent, carbon-constrained environment (see below).

As remarked, **Table 12** presents the power production mix in the EU27 for the years 2010, 2030 and 2050 in relative terms, i.e. as a percentage of total generation. It shows, for instance, that the share of renewables in total electricity production increases from 24% in 2010 (all scenarios) to some 40-50% in 2050, depending on the scenario considered, while the share of coal decreases from 24% to 10-15% over this period. As outlined above, however, the increase in the share of renewables over time is largely due to other factors than carbon prices, as illustrated by scenario 1C (non-splitting, low ambition). In this scenario, the share of renewables increases from 24% in 2010 to 42% in 2050 whereas the carbon price in the power sector remains more or less stable at a level of 15 €/tCO_2. In scenario 1B (non-splitting, high ambition), however, the carbon price rises from 15 €/tCO_2 to 101 €/tCO_2 in 2050, resulting in a slightly higher share of renewables by 2050 in this scenario (51%) compared to 1C (42%).

[25] As explained in Chapter 2, the baseline scenario of the E3ME model is derived from the 2009 PRIMES reference scenario up to 2030, including current renewable electricity policies and autonomous cost trends, which – to some extent – are extrapolated to 2050.

Table 12: EU27: Power generation mix in 2010, 2030 and 2050 (in % of total)

	Coal	Gas	Other fossil	Nuclear	Renewables	ETS carbon price in the power sector [in €/tCO_2]
2010						
All scenarios	23.6	23.2	2.5	27.1	23.5	*15*
2030						
1A Current (BAU)	18.0	17.1	3.0	24.9	36.9	37
1B High	15.4	16.7	3.0	20.7	44.1	46
1C Low	18.4	17.1	2.8	24.5	37.2	14
2A Current	15.0	15.7	3.1	19.6	46.6	44
2B High	14.9	15.8	3.1	19.7	46.6	44
2C Low	15.0	15.7	3.1	19.6	46.6	44
Difference between splitting and non-splitting scenarios						
2A - 1A: current	-3.0	-1.4	0.1	-5.3	9.7	7
2B - 1B: high	-0.5	-0.9	0.1	-1.0	2.5	-2
2C - 1C: low	-3.4	-1.4	0.3	-4.9	9.4	30
2050						
1A Current (BAU)	15.2	18.1	1.8	22.3	42.7	75
1B High	10.8	16.7	2.4	19.5	50.6	101
1C Low	16.6	18.2	1.6	21.8	41.9	15
2A Current	11.8	18.3	2.7	18.4	48.8	92
2B High	11.8	18.3	2.8	18.4	48.7	89
2C Low	11.8	18.3	2.7	18.4	48.8	93
Difference between splitting and non-splitting scenarios						
2A - 1A: current	-3.4	0.2	0.9	-3.9	6.1	17
2B - 1B: high	1.0	1.6	0.4	-1.1	-1.9	-12
2C - 1C: low	-4.8	0.1	1.1	-3.4	6.9	78

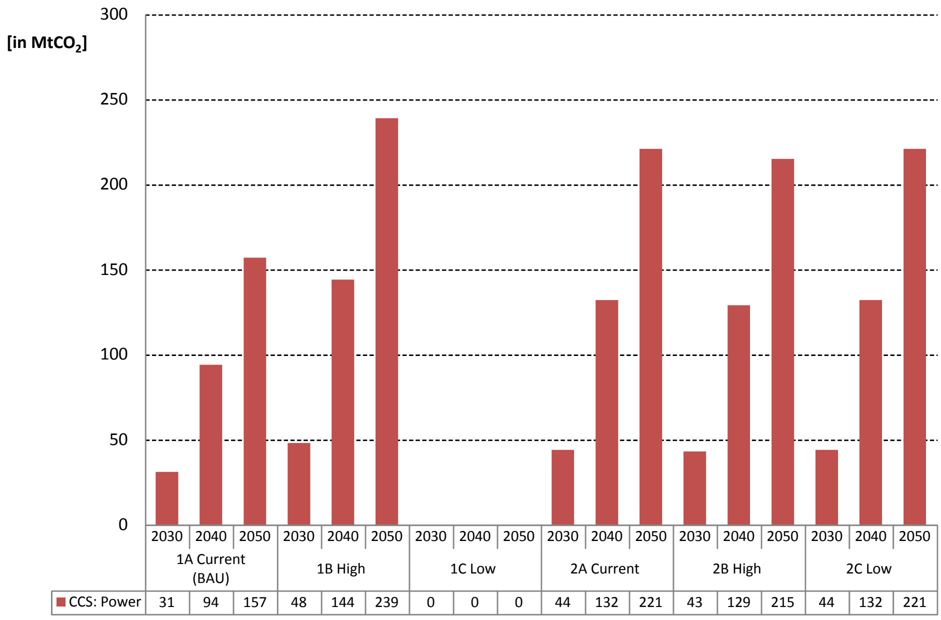
When comparing the non-splitting scenarios (policy option 1) with the splitting scenarios (policy option 2) in the years 2030 and 2050, the relationship between carbon prices and shares of renewables is consistent, but not very strong. For instance, in 2050 the non-splitting scenario 1C (low ambition) results in a carbon price of 15 €/tCO_2 and a share of renewables of 42%, while for the splitting scenario 2C (low ambition) these figures amount to 93 €/tCO_2 and 49%, respectively. As noted above, this is due to the fact that in the modelling scenarios power production from renewables is less driven by carbon prices but largely by other policy and (autonomous) cost factors, including technical learning and the existing capital stock.

Note that, as explained in Section 3.2, the carbon price for the power sector in splitting scenario 2B (high ambition) is slightly lower than in non-splitting scenario 1B (high ambition), i.e. 90 and 93 €/tCO_2, respectively. Consequently, the share of renewables is also slightly lower in 2B compared to 1B, i.e. 48.7% and 50.6%, respectively.

3.4.2 CCS in the power sector

Figure 14 presents the use of CCS in the power sector over the years 2030-2050 for the scenarios considered. It shows that, starting from 2030, CCS is introduced at a significant scale, except in non-splitting scenario 1C (low ambition), where the carbon price up to 2050 remains too low to give an adequate incentive to use CCS. Moreover, the amounts of CCS grow significantly over time, partly due to increasing carbon prices over the years 2030-2050 and partly because CCS potentials increase over this period at relatively lower costs (see **Figure 1**, Section 2.1.6, on the CCS cost curve in the power sector).

Figure 14: CCS in the power sector, 2030-2050



In addition, **Figure 14** shows that, in general, the amounts of CCS in the power sector are significantly higher in the splitting scenarios (policy option 2) than in the non-splitting scenarios (policy option 2), notably in splitting scenarios 2A (current ambition) and 2C (low ambition). This is due to the higher carbon prices for the power sector in these scenarios (compared to the respective non-splitting scenarios).

On the other hand, in splitting scenario 2B (high ambition) the amount of CCS is slightly lower than in non-splitting scenario 1B due to the slightly lower power sector carbon price in scenario 2B. This price, however, is based on a splitting scenario assuming no EUA trading between industry and the power sector. If industry, on the contrary, is allowed to buy EUAs from the power sector (one-way trading), splitting scenario 2B turns into non-splitting scenario 1B when the ETS carbon price becomes higher for industry than for the power sector. This would imply that the carbon price for the power sector would become higher under scenario 2B, resulting in a higher amount of CCS by the power sector (similar to the price and CCS levels under scenario 1B).

In scenario 2A, the amount of CCS in the power sector amounts to 221 $MtCO_2$ in 2050 (**Figure 14**), while its remaining CO_2 emissions amount to 352 $MtCO_2$ (Section 2.1, **Table 7**). Adding these two figures together – i.e. 573 $MtCO_2$, which is approximately equivalent to half of the cap/CO_2 emissions of the power sector in the early 2020s – explains why (due to CCS and banking of EUAs) the share of fossil fuels in total power generation is still significant in 2050 (**Figure 13**; **Table 12**), despite the fact that the cap for the power sector in this scenario has declined to zero.

3.4.3 Electricity prices

In all the modelling scenarios we have assumed that the EU moves towards a single market for electricity in the period up to 2050. Essentially this means that (i) electricity prices in Member States converge to a single European electricity price, and (ii) the costs of decarbonising the power sector by 2050 are shared between Member States.

The convergence in electricity prices is assumed to take place after 2020 and is gradual over the projection period. Countries that currently have high electricity prices would expect to see slower growth in these prices during this period of convergence until all prices in Europe are equalised (except differences in VAT rates and other national tax rates).

In addition, although the future electricity pricing system – including a growing, dominant share of renewables – is still largely unknown, we have assumed that in the long run electricity prices are based on the average total costs of generating and decarbonising power (rather than the current, short term marginal pricing system).

The methodology used is one of ‘levelised costs’ that includes capital costs, fuel costs, carbon costs and other operating and maintenance costs of the electricity production and network system. These costs are divided by the total units of electricity generated and, together with average transmission and distribution costs, added up to final end-user prices.

Scenarios with ambitious carbon reduction targets for the power sector (and high carbon prices), therefore have higher electricity prices, reflecting the costs of investing in renewables. It is important to note, however, that these cost increases are somewhat mitigated by reduced spending on fuel inputs and carbon allowances.

Table 13: EU27: Average electricity prices for all end-users across the EU27 and some Member States in 2010, 2030 and 2050 (in €/MWh; 2008 price level)

	Germany	France	Netherlands	UK	Poland	EU27
2010						
All scenarios	124	97	105	104	100	115
2030						
1A Current (BAU)	128	130	140	159	137	147
1B High	130	131	142	161	139	149
1C Low	125	128	137	153	134	144
2A Current	129	131	141	158	138	148
2B High	130	132	142	161	140	149
2C Low	129	131	141	158	138	148
Difference between splitting and non-splitting scenarios						
2A - 1A: current	1	1	1	-1	1	1
2B - 1B: high	0	1	0	0	1	0
2C - 1C: low	4	3	4	5	4	4
2050						
1A Current (BAU)	146	146	146	145	146	147
1B High	147	147	149	148	148	148
1C Low	139	141	139	138	140	141
2A Current	146	145	146	143	144	147
2B High	147	148	150	148	149	149
2C Low	146	145	146	143	144	147
Difference between splitting and non-splitting scenarios						
2A - 1A: current	0	-1	0	-2	-2	0
2B - 1B: high	0	1	1	0	1	1
2C - 1C: low	7	4	7	5	4	6

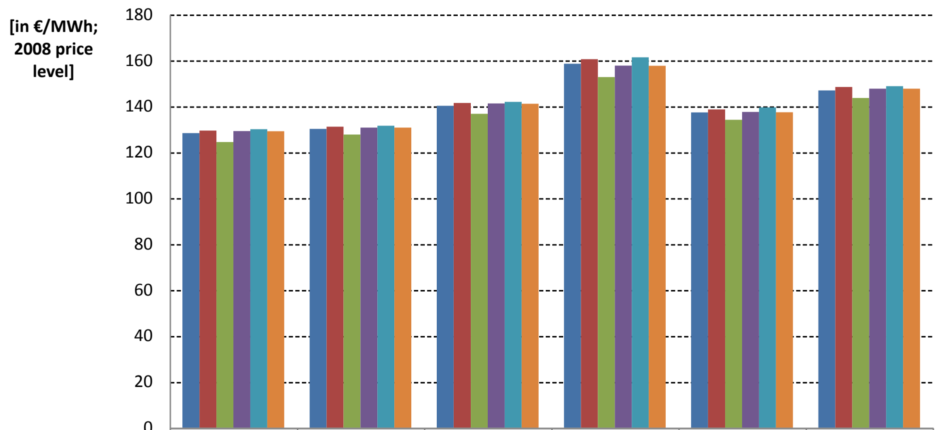
Table 13 presents the average electricity prices for all end-users in the EU27 as a whole as well as in some selected Member States for the years 2010, 2030 and 2050 (in €/MWh; constant 2008 price level; see also **Figure 15** and **Figure 16** showing graphs of these prices in 2030 and 2050, respectively). It can be observed that for the EU27 as a whole the average electricity price increases from 115 €/MWh in 2010 (all scenarios) to, on average, approximately 147 €/MWh in 2050. To some extent, this increase is due to other factors than the ETS carbon price, such as increases in projected fuel prices and levelised capital costs – notably of renewables – as can be observed from scenario 1C

(low ambition) where the carbon price remains more or less stable over the period 2010-2050 while the electricity price increases from 115 to 141 €/MWh.

To some degree, however, the increase in the power price over the years 2010-2050, and the variation across the scenarios considered, can be attributed to the ETS carbon price, although at the EU27 level the impact of the carbon price on the electricity price is relatively low. For instance, whereas the average electricity price in scenario 1C amounts to 141 €/MWh (at a carbon price of 15 €/tCO_2), it is 147 €/MWh in scenario 2C (splitting, low ambition) at a carbon price of 93 €/tCO_2 (compare last column of **Table 13** with the last column of **Table 12**). The main reason for this relatively low impact is that by 2050 the share of fossil fuels in total power generation has become relatively small in most EU Member States and, hence, average (conversed) electricity prices in the EU27 are determined mainly by other costs besides carbon costs.

When comparing electricity prices between splitting and non-splitting scenarios, the differences in price levels are generally small in both 2030 and 2050 (**Table 13**). This applies particularly for ambition level A (scenarios 2A versus 1A) and for ambition level B (2B versus 1B). For ambition level C, however, the differences in electricity prices are more significant between splitting scenarios 2C and non-splitting scenario 1C. For instance, in 2030, electricity prices are approximately 3-5 €/MWh higher in 2C than in 1C, while in 2050 this difference amounts to about 4-7 €/MWh. This is largely due to the substantial higher carbon price for the power sector in 2C compared to 1C (see last column of **Table 12**).

Figure 15: Average electricity prices in the EU27 and some Member States, 2030



	Germany	France	Netherlands	UK	Poland	EU27
1A Current (BAU)	128	130	140	159	137	147
1B High	130	131	142	161	139	149
1C Low	125	128	137	153	134	144
2A Current	129	131	141	158	138	148
2B High	130	132	142	161	140	149
2C Low	129	131	141	158	138	148

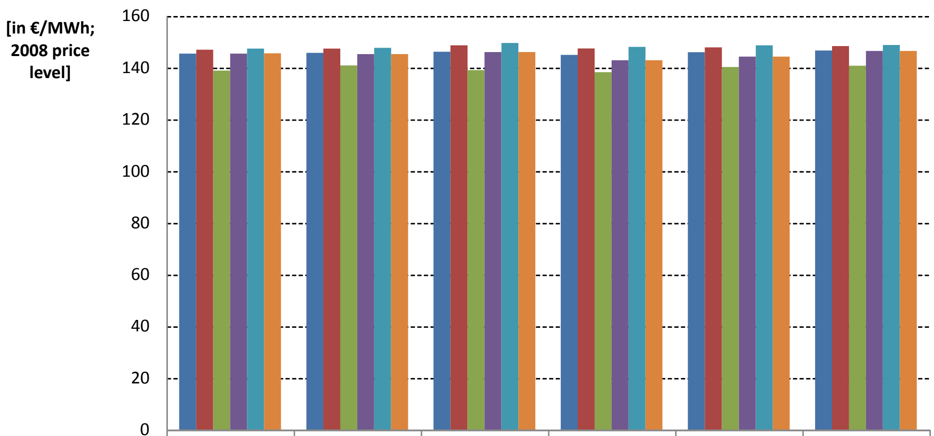
Figure 15 shows that by 2030 there are still some significant differences in electricity prices across EU Member States. For instance, in the baseline scenario 1A (current ambition), the average electricity price in 2030 ranges from 128 €/MWh in Germany to 159 €/MWh in the UK. These price differences result from the fact that we have

assumed a gradual process of fully converged electricity prices in Europe up to 2050, implying that prices in 2030 are only partially converged. Therefore, electricity price differences in 2030 across EU Member States reflect national differences in capital costs, fuel costs and other power system costs.

On the other hand, **Figure 16** illustrates that by 2050 electricity prices across EU Member States are more or less fully converged. Any remaining (small) differences in real electricity prices between countries are due to (small) differences in national price deflators. In addition, electricity prices in **Figure 16** (as well as in **Figure 15** and **Table 13**) refer to average electricity prices, including different categories of end-users, such as households and large firms, paying different electricity prices. As the weights of these categories vary between countries (and scenarios) it results in small differences in average electricity prices between countries even if electricity prices have fully converged for each category of electricity end-user.

In addition, **Figure 16** shows that by 2050 there are some differences in electricity prices across the scenarios considered. At the EU27 level, for instance, the electricity price varies from 141 €/MWh in scenario 1C (non-splitting; low ambition) to 149 €/MWh in scenario 2B (splitting; high ambition). These differences across scenarios result from differences in ambitions of decarbonising the power sector and, hence, reflect differences in both ETS carbon costs and in levelised costs of renewables, CCS and other low-carbon technologies.

Figure 16: Average electricity prices in the EU27 and some Member States, 2050



	Germany	France	Netherlands	UK	Poland	EU27
1A Current (BAU)	146	146	146	145	146	147
1B High	147	147	149	148	148	148
1C Low	139	141	139	138	140	141
2A Current	146	145	146	143	144	147
2B High	147	148	150	148	149	149
2C Low	146	145	146	143	144	147

3.4.4 Carbon tax and ETS auction revenues from the power sector

Starting from 2013, most of the EUAs for the power sector are auctioned, with some temporary derogation for most Eastern European countries, reaching full auctioning of all EUAs for the power sector across the EU27 by 2020. In our scenarios, however, we have assumed that full auctioning to the power sector already starts from 2013 – thereby overestimating auctioning revenues a bit up to 2020 – and that full auctioning of EUAs for the power sector will continue up to 2050. Moreover, for the alternative, non-splitting scenarios (policy option 3) we have assumed that the carbon price differentiation between ETS industry and the power sector in the respective splitting scenarios (policy option 2) will be achieved by imposing a carbon tax to the power sector additional to the single ETS carbon price for both industry and the power sector (as explained in Sections 2.1 and 3.2). Hence, in the alternative, non-splitting scenarios, EU Member States may receive power sector payments from both ETS auctioning and carbon taxation, with the level of total annual public revenues from EUA auctioning/carbon taxation depending on the ETS price/carbon tax per tonne CO_2 and the cap/amount of CO_2 emissions by the power sector over the years 2013-2050.

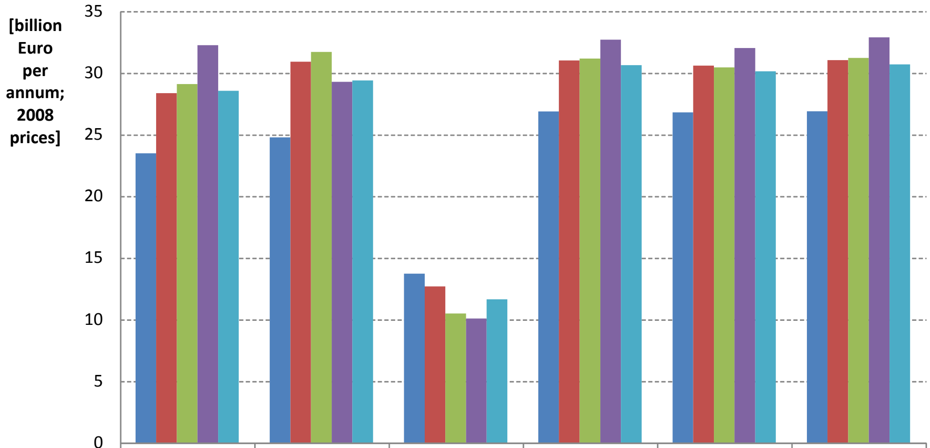
For simplicity reasons, however, we have assumed that both annual auction and tax revenues result from multiplying annual power sector emissions by the ETS carbon price and the (additional) carbon tax for the power sector, respectively (as specified in Section 3.2, **Figure 11** and **Table 10**). In case of banking, this implies that carbon auction revenues are underestimated in years of saving allowances and overestimated in years of using banked allowances, notably in scenarios such as 3B with substantial banking and high ETS carbon prices.

Figure 17 presents the total EU27 annual average carbon tax and ETS auctioning revenues in selected periods over the years 2013-2050 across the different scenarios. It shows that in most scenarios these revenues increase over time, with the major exception of non-splitting scenario 1C (low ambition; see the first four columns of each scenario in **Figure 17**, moving from the period 2013—2020 to 2041-2050). For instance, in scenarios 1A (current ambition) total revenues increase from, on average, € 23 billion per annum over the years 2013-2020 to € 32 billion per year in the period 2041-2050, while in scenario 1C they decrease from € 14 billion to € 10 billion, respectively.[26]

Over the period 2013-2050 as a whole, annual average public revenues from the power sector are remarkably similar in most scenarios considered, i.e. € 29-31 billion per annum, except in scenario 1C (i.e. € 12 billion p.a.; see the last, light blue column of each scenario in **Figure 17**). This results from a trade-off between the power sector emissions and the carbon price in these scenarios.

[26] As noted, however, revenues for the period 2013-2020 are overestimated in all scenarios due to the assumption of full auctioning to the power sector starting already from 2013, while they are underestimated in scenarios with banking of allowances by the power sector in the years 2013-2020, i.e. all scenarios except 1C.

Figure 17: EU27: carbon tax and ETS auction revenues from the power sector, 2013-2050



	1A Current (BAU)	1B High	1C Low	2A Current	2B High	2C Low
2013-2020	23	25	14	27	27	27
2021-2030	28	31	13	31	31	31
2031-2040	29	32	10	31	30	31
2041-2050	32	29	10	33	32	33
2013-2050	29	29	12	31	30	31

As noted, in policy option 3 (alternative, non-splitting scenarios) public revenues may be a mixture of auctioning and tax revenues, depending on the ambition level and the resulting carbon price of the scenarios concerned. As has been explained in Section 3.2, however, in scenario 3B (high ambition) the carbon tax is zero over the years 2025-2050 while the ETS price is relatively high, whereas in scenario 3C (low ambition) the ETS price is zero and the carbon price relatively high. Only in scenario 3A (current ambition) total carbon pricing for the power sector is a mixture of a (low and decreasing) ETS carbon price and a (relatively high and increasing) carbon tax (see **Table 10** and **Figure 12**). Hence, public revenues result from a mixture of ETS auctioning and carbon taxation only in this scenario, whereas in scenarios 3B they result from only ETS auctioning or only carbon taxation, respectively.

Finally, **Figure 17** shows that public carbon revenues from the power sector are generally higher in the so-called 'carbon price differentiation scenarios', (policy options 2 and 3) compared to the current, non-splitting scenarios (policy option 1). This applies particularly for the low ambition scenarios (C) and, to a lesser extent, also for the current ambition scenarios (A). Therefore, from a public revenue perspective, it is attractive to introduce carbon price differentiation between the ETS sectors, i.e. a relatively high carbon price (ETS + tax) for the power sector versus a relatively low ETS carbon price for industry.

3.5 Industry sector results

In sections 3.1, 3.2 and 3.3, we have already discussed some modelling results with regard to ETS industry, in particular:

- The cost curve of CCS potentials in industry, 2030-2050 (Section 2.1, **Figure 2**).
- The cap for industry in the ETS splitting scenarios, 2021-2050 (Section 3.1, notably **Figure 4** and **Table 6**).
- CO_2 emissions in industry (Section 3.1, **Table 7**).
- ETS carbon prices for industry, 2010-2050 (Section 3.2, **Table 9**, **Figure 8**, **Figure 10** and **Figure 11**).
- Changes in carbon abatement costs (Section 3.3, **Table 11**).

In this section, we focus on some additional, specific modelling results for industry, notably on the effects of the different policy scenarios on:
- Industrial output and employment (Section 3.5.1).
- CCS in industry (Section 3.5.2).

In addition we briefly analyse the results of an additional scenario (called the 'compensation scenario 2BR' in which the possible impacts are evaluated of compensating energy-intensive industry for the ETS induced increase in electricity costs (Section 3.5.3).

3.5.1 Industrial output and employment

ETS caps and carbon prices for industry are discussed in the previous sections. **Figure 18** below shows the impact that these have on industrial production levels within Europe.

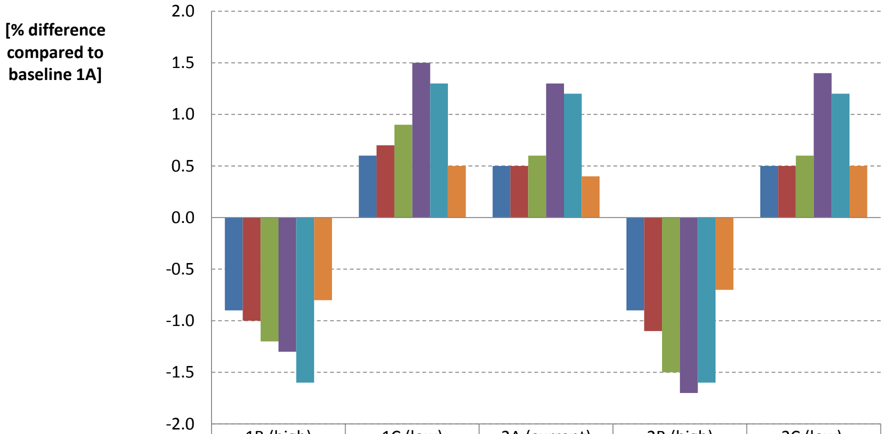
Higher carbon costs (both direct and indirect) lead to a loss of output in the industry sectors that are included in the ETS. The scenarios with the highest carbon prices for industry (e.g. 1B or 2B) are those in which industrial output falls by the most.

The pattern is consistent across the most energy-intensive sectors that are defined in the model, i.e. metals, paper and pulp, chemicals, non-metallic mineral products and other manufacturing (see **Figure 18**). The changes in output are smaller for other manufacturing sectors, some of which are not included in the ETS (but still face higher electricity costs). In other sectors, including services, the changes in output are smaller still.

A change in output in the range of +/- 2% in the period up to 2050 suggests that the impact of the different ETS policy scenarios on energy-intensive industries is small. However, it is important to note that these results are at the NACE 2-digit level and at this level of aggregation some less energy-intensive activities are included in the figures.[27] Within the 2-digit sectors there are some specific companies and sub-sectors that are likely to be affected disproportionately; possible examples include cement or aluminium. These results should not be interpreted as showing small impacts for all industry sectors.

[27] NACE stands for 'Nomenclature générale des Activités économiques dans les Communautés Européennes'. This is the standard system for defining economic sectors in Europe. At the 2-digit level, economic sectors are rather highly aggregated, while at for instance the 3 or 4-digit levels, economic activities are far more disaggregated.

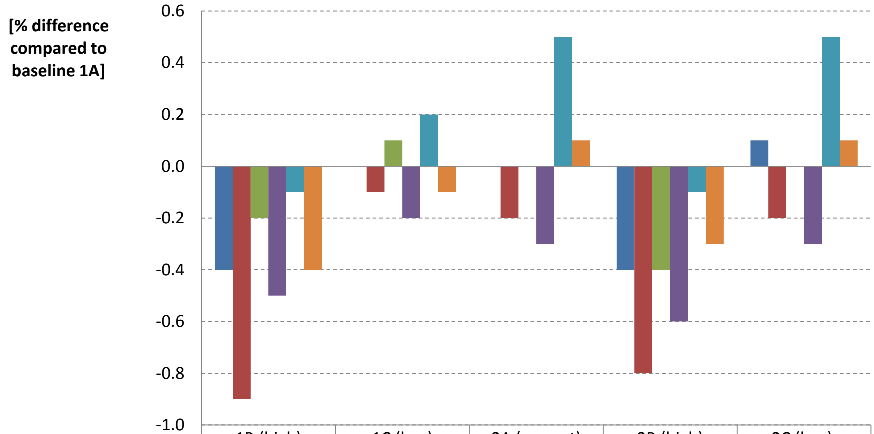
Figure 18: EU27: Changes in manufacturing output by 2050, in % difference from baseline scenario 1A



	1B (high)	1C (low)	2A (current)	2B (high)	2C (low)
Total manufacturing	-0.9	0.6	0.5	-0.9	0.5
Metals	-1.0	0.7	0.5	-1.1	0.5
Chemicals	-1.2	0.9	0.6	-1.5	0.6
Non-metallic mineral products	-1.3	1.5	1.3	-1.7	1.4
Paper & pulp	-1.6	1.3	1.2	-1.6	1.2
Other manufacturing	-0.8	0.5	0.4	-0.7	0.5

Figure 19 provides estimates of the employment impacts in the scenarios. In general they follow the same patterns as the output results above, although they are smaller in percentage terms as, in the long run, there is some adjustment in wage rates in response to the demand for labour, which has a compensation effect.

Figure 19: Changes in manufacturing employment by 2050, in % difference from baseline scenario 1A



	1B (high)	1C (low)	2A (current)	2B (high)	2C (low)
Total manufacturing	-0.4	0.0	0.0	-0.4	0.1
Metals	-0.9	-0.1	-0.2	-0.8	-0.2
Chemicals	-0.2	0.1	0.0	-0.4	0.0
Non-metallic mineral products	-0.5	-0.2	-0.3	-0.6	-0.3
Paper & pulp	-0.1	0.2	0.5	-0.1	0.5
Other manufacturing	-0.4	-0.1	0.1	-0.3	0.1

Moreover, changes in climate policy result in shifts in the relative costs of labour and energy, including electricity. Due to these shifts, labour may replace energy (or vice versa), implying that labour may decline (or increase) faster (or slower) than output. If the changes in output are rather small, changes in employment may even have opposite signs – for instance, input may increase slightly while employment may decrease a bit (or vice versa) – due to climate policy induced shifts in the relative costs of labour and energy.

Overall, industrial employment is expected to fall by 80-100,000 employees in the scenarios with a high industry carbon price (1B and 2B). It should be noted, however, that a large share of this reduction comes from less energy-intensive sectors, as the higher prices of energy-intensive goods affect the wider economy as well. The impacts are of course not evenly distributed; some particular carbon-intensive (and trade-exposed) sub-sectors could lose out substantially, while some other small sectors (e.g. producers of energy-efficient equipment) may benefit from high carbon prices.

Table 14 presents the percentage difference between the respective splitting and non-splitting scenarios by 2050 in terms of relative changes in manufacturing output and employment, compared to the baseline scenario, as recorded in **Figure 18** and **Figure 19**. In general, these differences are rather small (less then +/- 0.5% in most cases).

Table 14: Changes in manufacturing output and employment: % differences between splitting and non-splitting scenarios, 2050

	Total manufacturing	Metals	Chemicals	Non-metallic mineral products	Paper & pulp	Other manufacturing
Output						
2A - 1A	0.5	0.5	0.6	1.3	1.2	0.4
2B - 1B	0.0	-0.1	-0.3	-0.4	0.0	0.1
2C - 1C	-0.1	-0.2	-0.3	-0.1	-0.1	0.0
Employment:						
2A - 1A	0.0	-0.2	0.0	-0.3	0.5	0.1
2B - 1B	0.0	0.1	-0.2	-0.1	0.0	0.1
2C - 1C	0.1	-0.1	-0.1	-0.1	0.3	0.2

Note: The differences refer to the differences in outcomes between the respective splitting and non-splitting scenarios as presented in **Figure 18** and **Figure 19**.

In terms of manufacturing output, **Table 14** shows that in splitting scenario 2A (current ambition) output in all recorded energy-intensive industries is slightly higher (0.4-1.2%) compared to the non-splitting scenario 2A. This is most likely due to the significantly lower carbon price for industry in 2A compared to 1A (i.e., 2 and 75 €/tCO_2, respectively, in 2050).

On the other hand, at the low ETS ambition level C, manufacturing output is generally slightly lower in splitting scenario 2C, compared to 1C, probably due to the much higher carbon costs in the power sector (i.e., 93 versus 15 €/tCO_2, respectively, in 2050), which are passed on to electricity-intensive industries. Finally, at the high ETS ambition level B, there is hardly any difference in total manufacturing output between 2B and 1b, as the difference in ETS carbon prices between these scenarios are relatively small for both industry and the power sector (**Table 9**).

In terms of manufacturing employment, the differences between the respective splitting and non-splitting scenarios are even smaller, partly due to adjustments in wage rates over time and partly due to substitutions between labour and energy (as explained above). The latter factor may explain why there are occasionally even opposite signs in outcomes between manufacturing output and employment as recorded in **Table 14**.

3.5.2 CCS in industry

Figure 20 illustrates the use of CCS in industry over the period 2030-2050 for the main scenarios considered. For comparative reasons, the amounts of CCS in industry are added to those of the power sector (as presented in **Figure 14** and discussed in Section 3.3.2).

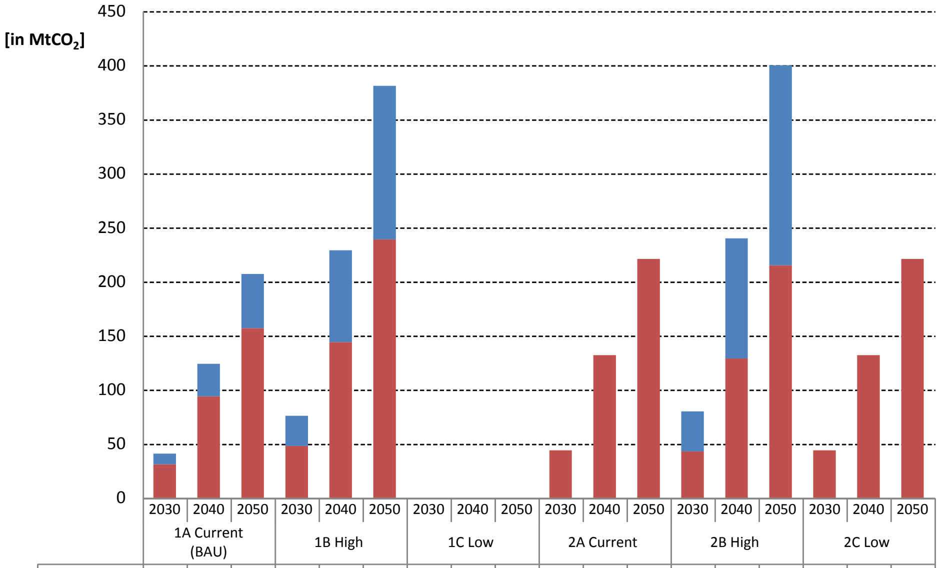
Figure 20 shows that in only three scenarios the carbon price is high enough to use CCS by industry, i.e. the two non-splitting scenario 1A (current ambition) and 1B (high), and one splitting scenario 2B (high). However, whereas the amounts of CCS are relatively small in the baseline scenario 1A, they are rather substantial in scenario 2B. In this high ambition scenario, CCS by industry amounts to 185 MtCO_2 in 2050, i.e. more than 25% of the ETS emissions by industry in the early 2020s and almost 50% of these emissions in 2050.

Overall, **Figure 20** shows that, in general, the total amounts of CCS by both ETS sectors, industry and the power sector are higher in the splitting scenarios than in the respective non-splitting scenarios. This applies in particular for scenario 2C but, to a lesser extent, also for scenarios 2A and 2B.

At the sector level, however, the amount of CCS by industry is lower in scenario 2A (than in 1A), but this is more than compensated by the power sector, which uses a substantial higher amount of CCS in 2A. Conversely, the amount of CCS used by the power sector is lower in 2B (compared to 1B), but this is more than compensated by industry, which applies a substantial amount of CCS in 2B.

Moreover, in **Figure 20**, scenario 2B is based on the assumption of no EUA trading between industry and the power sector. If, on the contrary, one-way trading is allowed – i.e. industry is allowed to buy allowances from the power sector – scenario 2B turns into 1B when carbon prices for industry become higher than for the power sector, resulting in similar sectoral and total amounts of CCS in 2B as in 1B.

Figure 20: CCS in industry, 2030-2050



	1A Current (BAU)			1B High			1C Low			2A Current			2B High			2C Low		
	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
CCS: Industry	10	30	50	28	85	142	0	0	0	0	0	0	37	111	185	0	0	0
CCS: Power	31	94	157	48	144	239	0	0	0	44	132	221	43	129	215	44	132	221

Finally, it should be observed that, compared to the increase of renewables in the power generation mix (see Section 3.3.1), the implementation of CCS in both industry and power generation is far more dependent on the carbon price, not only to trigger off the introduction of CCS by means of a threshold level of 40-50 €/tCO_2 but also to stimulate the widespread use of CCS by a higher, rising carbon price. This difference in carbon price responsiveness between CCS and renewables is largely due to the fact that (at least in the modelling scenarios, but likely also in practice) the promotion of renewables depends largely on other policies than raising the ETS carbon price while the implementation of CCS relies predominantly on carbon price policies.

3.5.3 Compensation scenario

The compensation scenario (2BR) has been introduced as a separate case to evaluate the possible impacts of compensating energy-intensive industry for 75% of the ETS-induced increase in the electricity price, including both the ETS carbon costs and the ETS-induced abatement costs passed through to electricity end-users. Scenario 2BR is otherwise equivalent to scenario 2B, which has been chosen as the reference case because it has the highest ETS-induced increase of the electricity price in 2050 compared to 2010.[28]

The revenues that are recycled to industry are taken from the same pot of ETS auction revenues (from power generation) that are used to reduce income tax under the main scenarios. The reductions in income tax are therefore less in scenario 2BR. For the year

28 For simplicity reasons, we have assumed that the change in the electricity price in the modelling scenarios over the years 2010-2050 is fully attributed to changes in the ETS and that this change in electricity price is compensated by 75%.

2050, the amount of compensation recycled to the energy intensive industries is estimated at roughly € 15 billion (at 2008 constant prices).[29]

In principle there are two main different options or mechanisms for compensating electricity costs:[30]

- *Lump-sum compensation:* in this case, compensation is paid as a lump-sum, i.e. not related to current or recently updated production levels. The main effect of this type of compensation is that it enhances (or better: compensates a fall in) a firm's profits due to an ETS induced increase in electricity prices but that it rarely affects its production and/or output pricing decisions.
- *Input- or output-based compensation:* in the case, the amount of compensation depends on the level of a firm's current or recently updated level of input (electricity) or output, for instance by multiplying current output levels by an electricity efficiency standard or benchmark. The main effect of this type of compensation is that it acts as a marginal input subsidy which affects the production and/or pricing decisions of a firm. As a result, a firm's output will be higher, but it comes at a social cost: its input (electricity) use will also be higher, leading to higher power sector emissions (or a higher carbon price and higher abatement costs if the emissions are capped).

A major additional effect of both compensation mechanisms is that the amount of public revenues available for recycling (through reducing income taxes) will be lower resulting in lower rates of consumer spending.

Table 15 presents the economic effects of the two compensation mechanisms for the energy-intensive, manufacturing industries by 2050 under scenario 2BR (as % difference compared to 2B). In general, these effects are very small to zero, although slightly more significant for input-based compensation of higher electricity costs than for lump-sum compensation. This is mainly due to the fact that input-based compensation has a stronger impact on a firm's production and/or pricing decisions (as indicated above).

Under input-based compensation the output effect for total manufacturing industries is 0.1%, varying from 0.2% for non-metallic mineral products to zero for paper & pulp and other manufacturing. Whereas the output effects of input-based compensation are generally slightly positive, its employment impacts are generally negative, although also very small. These opposite signs between output and employment effects result from the fact that input-based compensation of higher electricity costs acts as in input subsidy on electricity use, leading to a small substitution effect.

Table 16 presents a summary of the major macroeconomic effects by 2050 of the two compensation mechanisms under scenario 2BR (in % difference compared to 2B). Once again, these effects are very small. More specifically, the results show that the re-allocation of public revenues from household incomes to industry causes GDP, employment and consumer spending to fall slightly. The main reason for this is that only a share of the reduced electricity costs are reflected in lower product prices; the rest of

[29] This amount results from an increase of the electricity price over the period 2010-2050 of 33.6 €/MWh (148.8 €/MWh in 2050 minus 115.2 €/MWh in 2010), 75% of which is 25.2 €/MWh multiplied by approximately 620 million MWh used by electricity-intensive industries.

[30] These options are largely similar to the main different options for allocating ETS allowances for free. See Chapter 5 for a discussion of these allocation options.

the cost savings are absorbed by industry as higher profit margins. This reduces overall current activity as households spend almost all of the income they receive while a much larger share of company profits (that are not repatriated) are either retained by the companies themselves or saved through investment and pension funds. Moreover, although carbon leakage will be slightly lower owing to the compensation of the ETS-induced increase in electricity costs for industry, total ETS carbon abatement costs will be somewhat higher due to higher emissions in both industry and the power sector, resulting in both higher marginal and total abatement costs to reduce these emissions below the cap.

Table 15: Compensation scenario 2BR: EU27 results by manufacturing sectors, 2050 (in % difference compared to scenario 2B)

	Output	Employment	Exports (ext. EU)	Imports (ext. EU)
Lump-sum compensation:				
Total manufacturing	-0.01	-0.07	0.02	0.01
Metals	0.03	-0.04	0.02	-0.02
Chemicals	0.03	0.00	0.03	0.05
Non-metallic mineral products	0.06	-0.09	0.13	0.02
Paper & pulp	-0.02	-0.04	0.01	0.00
Other manufacturing	-0.02	-0.08	0.02	0.01
Input-based compensation:				
Total manufacturing	-0.06	-0.23	0.06	-0.04
Metals	0.10	0.04	0.04	-0.02
Chemicals	0.18	0.02	0.06	0.01
Non-metallic mineral products	0.16	-0.05	0.23	0.00
Paper & pulp	-0.19	-0.24	0.07	-0.02
Other manufacturing	-0.12	-0.30	0.05	-0.06

Table 16: Compensation scenario 2BR: EU27 Summary of macroeconomic results, 2050 (in % difference compared to scenario 2B)

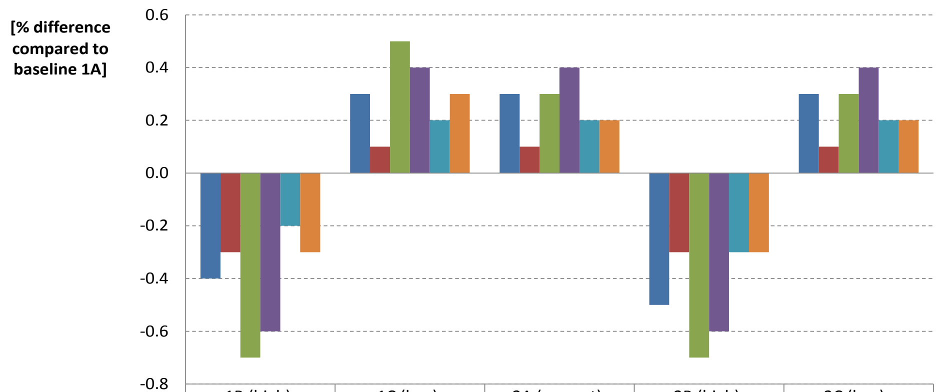
	Lump-sum compensation	Input-based compensation
GDP	-0.01	-0.04
Employment	-0.03	-0.11
Consumer spending	-0.02	-0.13
Investments	0.00	-0.05
Exports (ext. EU)	0.02	0.05
Imports (ext. EU)	0.00	-0.04

Hence, there is a trade-off in compensation effects at the industry level on the one hand and at the total ETS and macroeconomic level on the other. On balance, however, the effects in terms of carbon efficiency at the system level or in terms of GDP at the macroeconomic level are negative, although the effects are small. This trade-off, however, may become more favourable – or even positive – if the compensation is better targeted to those industries that are really the most vulnerable to a significant risk of carbon leakage due to the ETS induced increase in electricity costs. This issue of better targeting the compensation of indirect carbon costs, however, has not been part of the scope of the present study, partly because necessary data at more disaggregated industrial sector levels are lacking.

3.6 Macroeconomic results

Figure 21 shows the main macroeconomic impacts at the EU27 level in 2050 for the various policy scenarios compared to the baseline scenario 1A. Again these are largely driven by the industrial sector carbon price results, with a higher GDP level associated with lower industry carbon prices. However, as one would expect, the impact on the economy as a whole is proportionately smaller than on the energy-intensive sectors that are directly affected; other sectors are also negatively affected but by relatively less. Overall there is a difference of about 1% between the highest and lowest GDP outcomes. The results for employment are smaller in magnitude (e.g. due to wage adjustments) but move in the same direction as the GDP impacts.

Figure 21: EU27: changes in macroeconomic outcomes by 2050, in % difference from the baseline scenario 1A



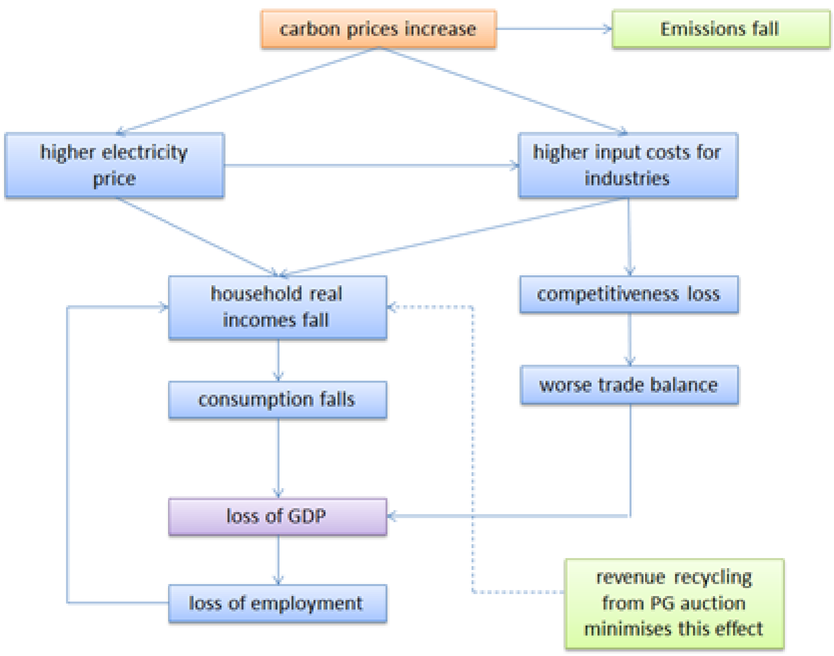
	1B (high): -33%	1C (low): +27%	2A (current): +4%	2B (high): -30%	2C (low) : +5%
GDP	-0.4	0.3	0.3	-0.5	0.3
Employment	-0.3	0.1	0.1	-0.3	0.1
Consumer spending	-0.7	0.5	0.3	-0.7	0.3
Investment	-0.6	0.4	0.4	-0.6	0.4
Exports	-0.2	0.2	0.2	-0.3	0.2
Imports	-0.3	0.3	0.2	-0.3	0.2

Note: In order to put the changes in macroeconomic outcomes in perspective, the scenario headings in the table above provide the change in ETS emissions by 2050, including banking, compared to the baseline scenario 1A (as recorded in the last column of **Table 7**). For instance, in scenario 1B (high ETS ambition) the ETS emissions in 2050 are 33% lower than in the baseline (current ETS ambition) while they are 27% higher in scenario 1C (low ETS ambition).

There are two main roots through which GDP is affected (see **Figure 22**):
- Higher industry carbon costs lead to a loss of competitiveness and worsening trade balance.
- Higher carbon costs in domestic products mean a loss of real income to households.

Figure 21 shows that both these factors are evident in the results. The impacts on consumption are larger, but this is partly because imports of fossil fuels (which decrease with a higher carbon price) are included in the aggregate figures. Without this, the GDP impacts via trade and domestic activity are quite similar in magnitude.

Figure 22: Sectoral and macroeconomic linkages in the E3ME model



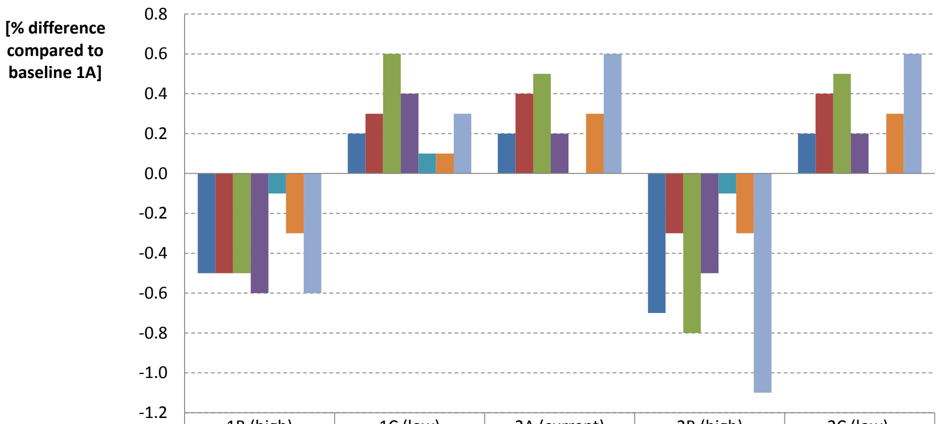
The conclusion is that exempting industry from high carbon prices, for instance through sectoral splitting of the ETS, will have some macroeconomic benefits but, at the aggregate level, these effects are quite small. There are several reasons why these effects are generally rather small, including:
- The effects refer to changes compared to the baseline scenario, i.e. they are relative changes induced by relative changes in reducing ETS emissions up to 2050.
- The effects are induced by relative changes in reducing ETS emissions only and not EU GHGs as a whole. More specifically, the macroeconomic outcomes are particularly induced by changes in the sectoral carbon prices. In general, these changes are relatively small. They are only substantial for industry under 2A, compared to 1A, and for the power sector under 2C, compared to 1C (**Table 9**).

- Manufacturing and the energy sectors account for a relatively small share of GDP, and this will be smaller still in 2050. In the baseline scenario, the services sectors are projected to contribute 72% of gross value added in the EU in 2005, rising to 75% in 2030 (EC, 2010a).
- Energy-intensive sectors account for quite a small share of manufacturing output. The energy-intensive sectors (chemicals, basic metals, construction materials, pulp and paper) represent a small share in total value added, i.e. 3.4% in 2005, declining to 2.7% in 2030. The share of the non-energy-intensive industries is projected to remain around 13.5% throughout the period 2005-2030 (EC, 2010a).
- Even for the energy-intensive sectors, energy is often not a very large share of costs (at the 2-digit level energy costs are usually less than 5% of turnover for all sectors except power and aviation).
- Not all the cost increases are passed on in final product prices.

The scale of the impacts is quite standard for this type of analysis. It should not be interpreted as saying that there will not be substantial localized impacts – the third and fourth points above are saying that macro-level impacts are small because a small number of groups are affected, not that groups are affected in a small way.

The patterns in macroeconomic results are quite similar across Member States (see **Figure 23**).[31] The outcomes for any individual Member State depend on a large number of factors, including (i) sectoral composition, i.e. the share of services versus (energy-intensive) industries, (ii) market conditions, i.e. the extent to which carbon costs are passed through to final product prices, and (iii) country specific income and price elasticities of demand, including changes in real disposable income due to inflation and revenue recycling of ETS auctioning and carbon taxation. However, in general no single country stands out in the results.

Figure 23: Changes in GDP in selected Member States, 2050, in % difference from baseline scenario 1A



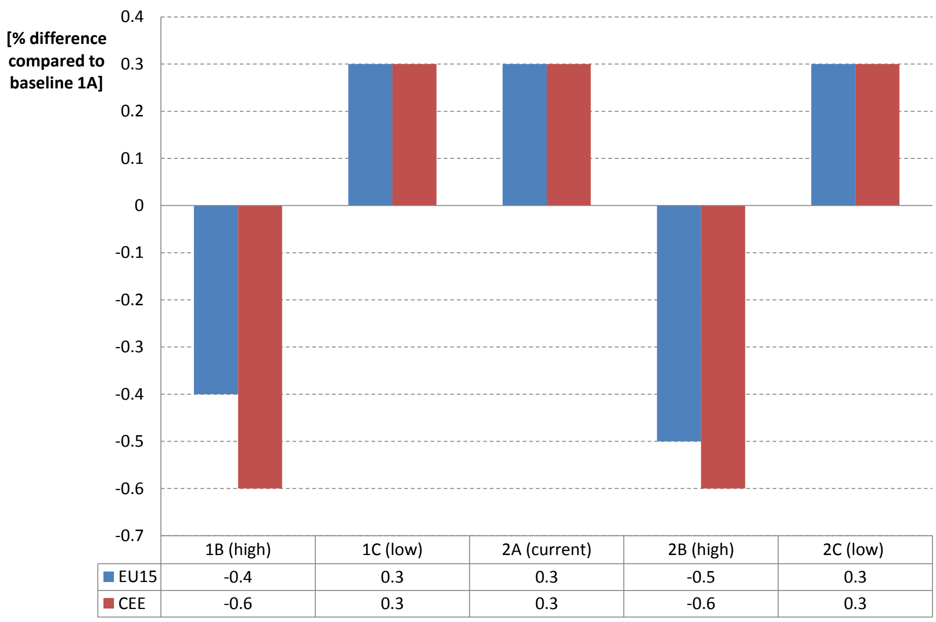
	1B (high)	1C (low)	2A (current)	2B (high)	2C (low)
Germany	-0.5	0.2	0.2	-0.7	0.2
Spain	-0.5	0.3	0.4	-0.3	0.4
France	-0.5	0.6	0.5	-0.8	0.5
Italy	-0.6	0.4	0.2	-0.5	0.2
UK	-0.1	0.1	0.0	-0.1	0.0
Poland	-0.3	0.1	0.3	-0.3	0.3
The Netherlands	-0.6	0.3	0.6	-1.1	0.6

31 See also **Table 28** and **Table 29** in Appendix A, which provide more detailed results on changes in GDP and employment, respectively, in all EU27 Member States

Similarly when comparing results between the previous EU15 countries and Central and Eastern European (CEE) countries, there is very little difference between results (**Figure 24**). This is in part because a degree of convergence is expected across Europe in the period up to 2050.[32]

When comparing the macroeconomic outcomes between the respective splitting and non-splitting scenarios, it turns out that these outcomes are generally more favourable under splitting scenario 2A than under non-splitting scenario 1A, i.e. in case of the current ETS ambition level. This applies particularly for outcomes in terms of GDP, consumer spending and investments (see **Figure 21**, but also **Figure 23** and **Figure 24**). This is mainly due to the lower carbon price for industry in 2A compared to 1A (i.e., 2 and 75 €/tCO_2, respectively, in 2050).

Figure 24: Changes in GDP in EU15 and CEE countries, 2050, in % difference from baseline scenario 1A



For instance, in 2050, GDP in scenario 2A is 0.3% higher than in scenario 1A. This is primarily due to two factors. Industrial competitiveness benefits from a lower carbon price for industry under 2A (compared to 1A) as well as from a boost in real investment. The latter of these impacts is due to the high carbon-intensive content of investment goods (e.g. cement and steel used in buildings and equipment) that becomes cheaper when there is a lower carbon price for industry.

However, at the ambition levels B (high) and C (low), there is hardly any difference in macroeconomic performance for the EU27 between the splitting and non-splitting scenarios (see **Figure 21**). For ambition level B this is most likely due to the fact that the differences in sectoral carbon prices are relatively small between 1B and 2B (**Table 9**).

32 See also **Table 34** and **Table 35** in Appendix B, providing more detailed results on other macroeconomic outcomes besides changes in GDP in Western versus Eastern European countries. See also **Table 36** of Appendix B for macroeconomic outcomes for Poland.

For ambition level C this lack of differences in macroeconomic outcomes is likely due to the fact that the positive effects of a (slightly) lower carbon price for industry under 2B are compensated by the negative effects of a higher carbon price for the power sector (compared to 1B).

Similar patterns in GDP outcomes between splitting and non-splitting scenarios can be observed at the EU regional and national levels (see **Figure 23** and **Figure 24**). Within a single ambition level, however, there may be significant differences in outcomes between splitting and non-splitting scenarios across individual countries (due to differences in national factors as mentioned above). For instance, at ambition level B (high), GDP is 0.2% higher in Spain under 2B (compared to 1B) while it is 0.5 lower in the Netherlands (**Figure 23**). This outcome for the Netherlands is likely due to the relatively high share of energy-intensive industries in its GDP, the international trade character of these industries and, hence, their vulnerability to the risk of carbon leakage.

Finally, besides the differences across individual countries, there may be even more significant differences between splitting and non-splitting scenarios across specific individual sub-sectors within countries (as discussed in Section 3.5).

4

Implications of splitting the ETS for the Netherlands

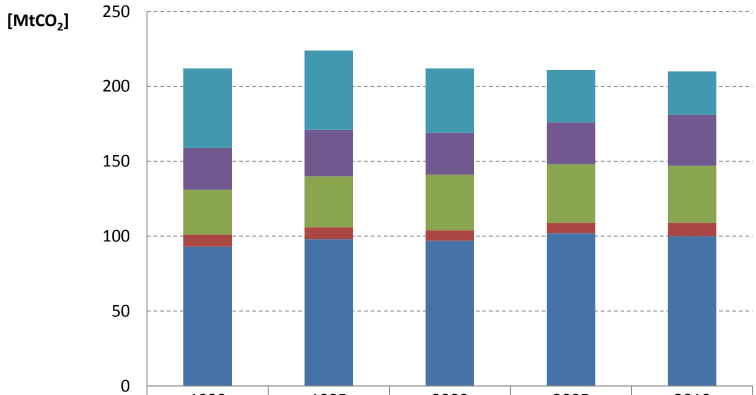
After discussing the current Dutch greenhouse gas emissions and reduction pathways towards 2050, this chapter addresses the implications of splitting the ETS for the Netherlands.

Splitting the ETS can reduce the risk of carbon leakage and increase the incentive to switch to carbon-free and low-carbon electricity generation. However, it can also lead to suboptimal decisions on investments and the allocation of fuels. The CO_2 price in industry can remain too low for capture and storage of industrial CO_2 emissions. Substituting fossil fuels by electricity becomes more difficult and generating electricity in non-ETS sectors can gain a competitive advantage.

4.1 Greenhouse gas emissions in the Netherlands

In 2010, the greenhouse gas emissions of the Netherlands were 210 $MtCO_2$, of which the industry and energy sector emitted 100 $MtCO_2$ (**Figure** 25). Total greenhouse gas emissions have not been reduced substantially in the period 1990-2010. A large reduction of the emission of non-CO_2 greenhouse gases (mainly methane and N_2O) has been offset by an increase in CO_2 emissions.

Figure 25: National greenhouse gas emissions according to the IPCC for the Netherlands, 1990-2010

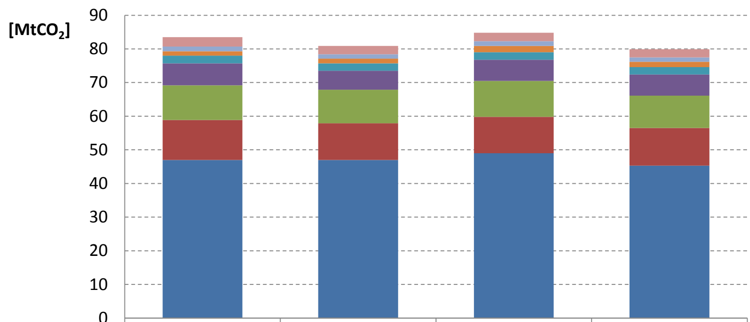


	1990	1995	2000	2005	2010
Total	212	223	213	211	210
Other greenhouse gas emissions	53	53	43	35	29
Built environment (CO2)	28	31	28	28	34
Transport (CO2)	30	34	37	39	38
Agriculture (CO2)	8	8	7	7	9
Industry and energy (CO2)	93	98	97	102	100

Source: Emissieregistratie, 2012.

The emissions of the ETS sectors in the Netherlands were 80.0 $MtCO_2$ in 2011 (**Figure 26**). The production and distribution of electricity, natural gas and heat caused 57% of these emissions. Other important sectors within the ETS are crude oil processing (14%), the chemical industry (12%) and the metals industry (8%).

Figure 26: Emissions of the ETS sectors in the Netherlands in 2008-2011



	2008	2009	2010	2011
Total	83.5	81	84.7	80
Other sectors	2.8	2.5	2.5	2.4
Paper industry	1.4	1.3	1.4	1.3
Agriculture and horticulture	1.3	1.4	1.9	1.6
Food industry	2.3	2.2	2.2	2.2
Metals industry	6.5	5.6	6.3	6.3
Chemical industry	10.3	10	10.7	9.6
Crude oil processing	11.9	10.9	10.8	11.2
Production and distribution of electricity, gas and heat	47	47	49	45.3

Source: NEA, 2012.

4.2 Emission reduction pathways towards 2050

Reaching ambitious long-term targets for greenhouse gas emission reduction requires huge changes to the energy system. It will take a long time to replace existing products and processes by new ones and to set up the corresponding production chains.

Pathways towards climate neutrality

PBL and ECN have explored pathways towards climate neutrality in 2050 for the Netherlands (PBL/ECN, 2011). Four important components of the transition were identified:

- *Reduction of energy demand*. In all sectors, large energy efficiency improvements can be realized by investments in efficiency measures supplemented by behavioural changes.
- *Sustainable biomass* is attractive as a potential replacement of coal, oil products and natural gas. Preferably, it will be used for the production of liquid biofuels and green gas. The most important areas of application are aviation, freight transport, small industry and existing buildings.
- *CO_2 capture and storage* is an important technology for large industrial installations and power plants. When CCS is applied to the production of biofuels, negative emissions can be realised.
- *Increased generation of carbon-free electricity*, e.g. by wind turbines, nuclear power plants and solar panels.

Carbon-free electricity generation can be combined with an increase of the share of electricity in the energy use. Electric transport and electric heating can reduce the use of fossil fuels. It is also possible to use electrolysis to produce hydrogen, which can be used in hydrogen cars and micro-CHP. Electric heat pumps can be used in heating systems and to make use of waste heat for cooling, and also for industrial applications.

Many technologies can play a role in the transition. **Table 17** assesses the importance of technologies for the path towards a clean economy in 2050. For the Netherlands, a very important role is expected for biomass gasification for fuels (combined with CCS). Biofuel production is important to reduce emissions from sources that have few clean alternatives available. Coal power plants with biomass co-firing and CCS have a very limited role. Although CO_2 emissions from these plants are low or even negative, there are clean alternatives and better ways in which biomass and storage capacity can be used.

Offshore wind, nuclear energy, electric heat pumps, electric cars, hydrogen cars and CCS for industrial emissions are considered to be of high importance. Although there is a large potential for nuclear energy, it involves risks. Nuclear plants are less suitable to accommodate short-term variations in supply and demand, even though the flexibility of new generations of nuclear plants is expected to increase. CCS for industrial emissions is important because alternatives for many industrial processes are not available or are uncertain.

Table 17: The importance of availability of technologies for a clean economy in 2050 in the Netherlands

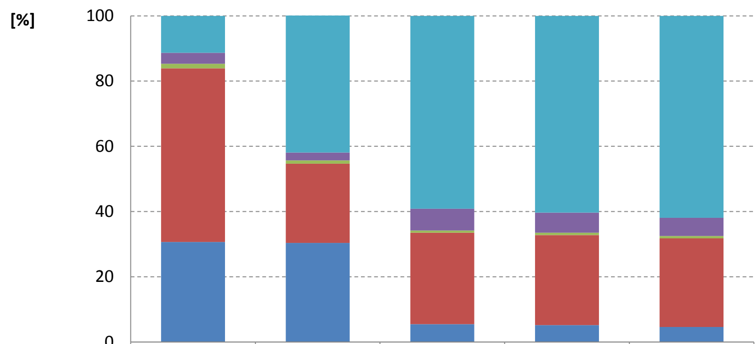
Technology	Relative importance
Onshore wind	Limited
Offshore wind	High
Solar-PV	Limited
Nuclear energy	High
Gas power plants with CCS	Limited
Coal power plants with biomass co-firing and CCS	Very limited
Geothermal heat	Limited
Solar thermal energy	Limited
Electrical heat pumps	High
Micro-CHP on hydrogen	Limited
Micro-CHP on methane gas	Very limited
Biomass gasification for fuels (and CCS)	Very high
Electric cars	High
Hydrogen cars	High
CCS for industrial emissions	High

Source: PBL/ECN, 2011

Baseline scenario for ETS emissions in the Netherlands

In the baseline scenario (1A), the ETS CO_2 price creates an equal incentive for emission reduction measures in the industry and the power sector. The CO_2 price increases to 75 €/tCO_2 in 2050. This price level makes it possible to capture and store CO_2 in the electricity sector as well as in industry.

Figure 27: Share of electricity generation in the Netherlands in the baseline (1A), 2010-2050



	2010	2020	2030	2040	2050
Renewables	11	42	59	60	62
Nuclear	3	2	7	6	6
Other fossil fuels	1	1	1	1	1
Gas	53	24	28	28	27
Coal	31	30	6	5	5

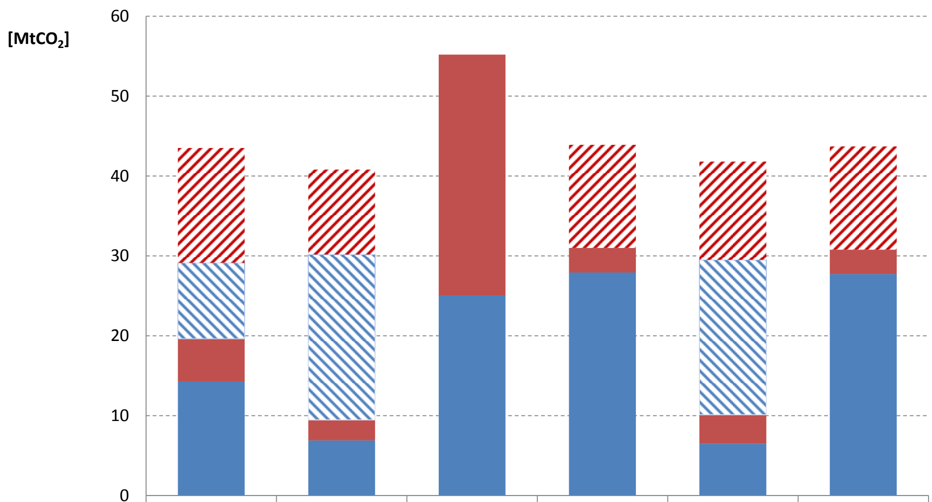
Figure 27 shows the growth of the share of renewable energy and nuclear energy in electricity generation in the Netherlands. In 2050, 62% of all electricity comes from renewable sources. With 27% of electricity generation, gas-fired power plants still play a

large role, but most of the CO_2 emissions of these plants are captured and stored. Over the period 2010-2050, the average electricity price across users in the Netherlands increases from 105 €/MWh to 146 €/MWh.

4.3 Implications of splitting the ETS for the Netherlands

Splitting the ETS can reduce the risk of carbon leakage and increase the incentive to switch to zero-carbon and low-carbon electricity generation. However, it can also lead to suboptimal decisions on investments and the allocation of fuels. The CO_2 price in industry can remain too low for capture and storage of industrial CO_2 emissions. Substituting fossil fuels by electricity becomes more difficult and generating electricity in non-ETS sectors can gain a competitive advantage.

Figure 28: ETS emissions of the Netherlands in 2050



	1A (Current)	1B (High)	1C (Low)	2A (Current)	2B (High)	2C (Low)
CCS power sector	14	11	0	13	12	13
CCS Industry	10	21	0	0	19	0
Power sector	5	3	30	3	4	3
Industry	14	7	25	28	6	28

Scenario results for ETS emissions in the Netherlands

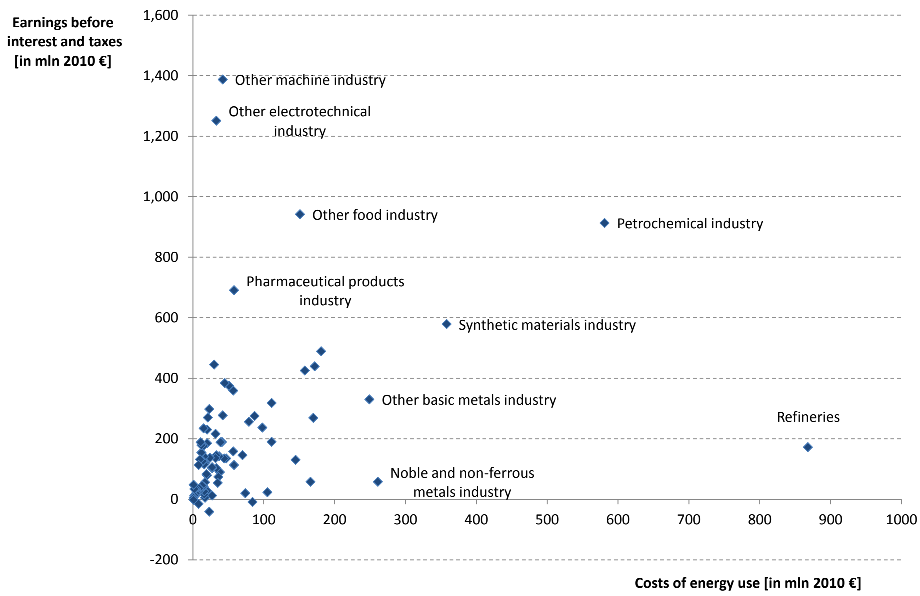
Figure 28 shows the scenario results for the ETS emissions of the Netherlands in 2050. In the baseline scenario (1A) 19 $MtCO_2$ are emitted, mainly by the industry. In the 'high ambition' scenario (1B) the emissions of the industry are reduced strongly and more CO_2 is stored. In the 'low ambition' scenario (1C) the emissions remain higher and no CO_2 storage takes place. When the ETS is split (2A), the CO_2 price for industry stays at a lower level and 31$MtCO_2$ is emitted.

The CO_2 price can remain too low for capture and storage of industrial CO_2 emissions
If the CO_2 price becomes sufficiently high, investments in carbon capture and storage (CCS) become profitable. In this study, it is assumed that most of the CCS potential in the energy sector can be realised at a CO_2 price of 50 €/tCO_2. CCS in industry has a wider cost range with costs of up to approximately 100 €/tCO_2.

CCS for industrial emissions has been identified as a technology of high importance for long-term emission reduction in Dutch industry (PBL/ECN, 2011). When the ETS is split, the CO_2 price for industry can be considerably lower than for the electricity sector. In the 'current ambitions' scenario with splitting (2A), CCS in industry remains unprofitable. More expensive CCS options in the electricity sector may be realized, while less expensive options in industry are not. As a result, CCS infrastructure may not be used optimally.

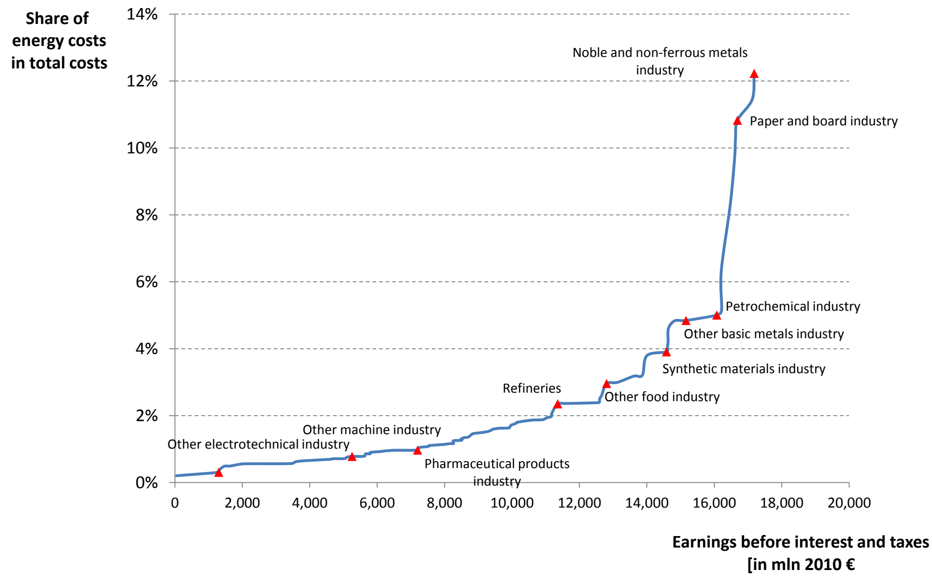
The risk of carbon leakage is reduced
Several industrial sectors, such as the petrochemical industry, refineries and the basic metals industry, are highly energy-intensive. Sectors such as the electro-technical industry, the machine industry and the pharmaceutical products industry are less energy-intensive. **Figure 29** shows the costs of energy and the earnings of a large number of industrial sectors in the Netherlands in 2010. The share of energy costs in the total costs is substantial for many sectors (**Figure 30**) and can be considerably higher for individual companies.

Figure 29: Costs of energy use and earnings before interest and taxes for Dutch industry sectors in 2010



Source: CBS (2013).

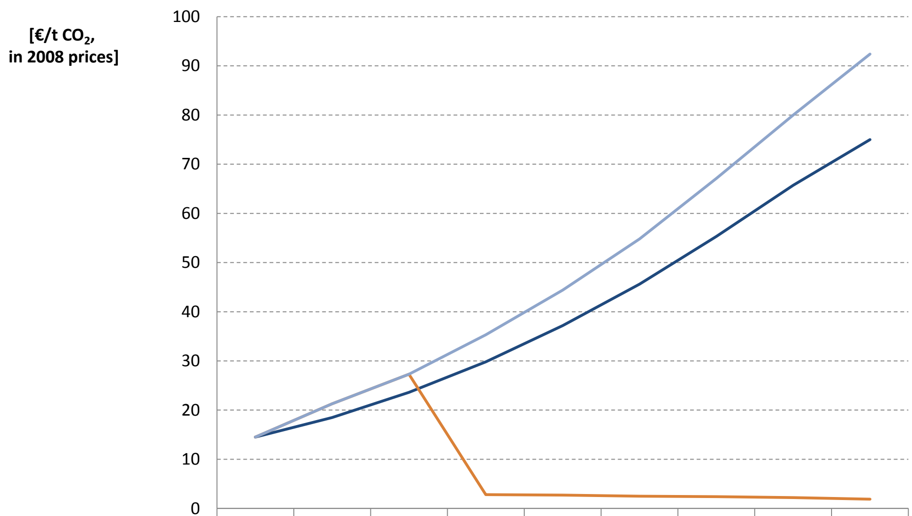
Figure 30: Cumulative earnings before interest and taxes versus the share of energy costs in total costs for Dutch industry sectors in 2010



Source: CBS (2013).

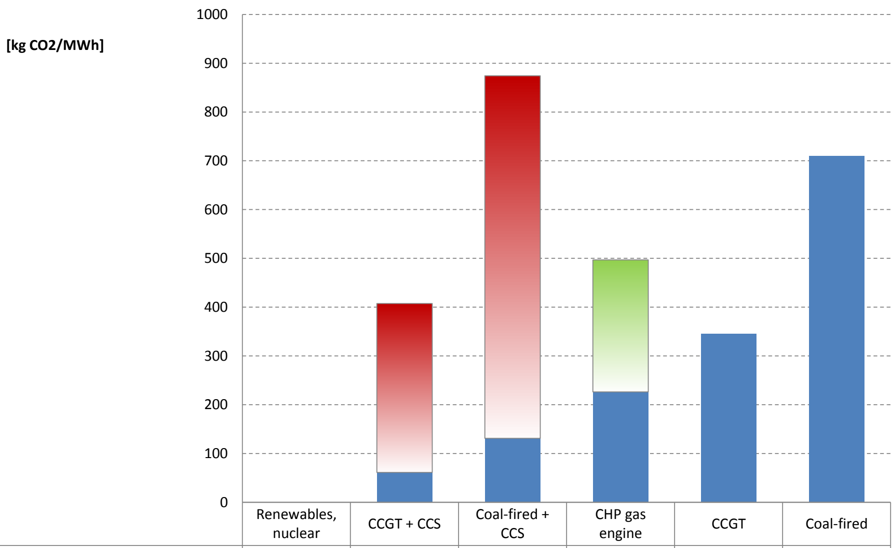
Figure 31 shows that in the scenario with ETS splitting (2A), the CO_2 price for industry remains considerably lower than in the scenario without splitting. Splitting the ETS can thereby reduce the risks of negative impacts on the economy due to carbon leakage. However, industry can still be affected by high CO_2 prices when electricity producers pass CO_2 costs on to consumers of electricity.

Figure 31: CO_2 price (incl. tax) in the current ambition scenario, with and without splitting the ETS



	2010	2015	2020	2025	2030	2035	2040	2045	2050
1A (Current), both sectors	15	19	24	30	37	46	55	66	75
2A (Split), industry	15	21	27	3	3	3	2	2	2
2A (Split), power sector	15	21	27	35	44	55	67	80	92

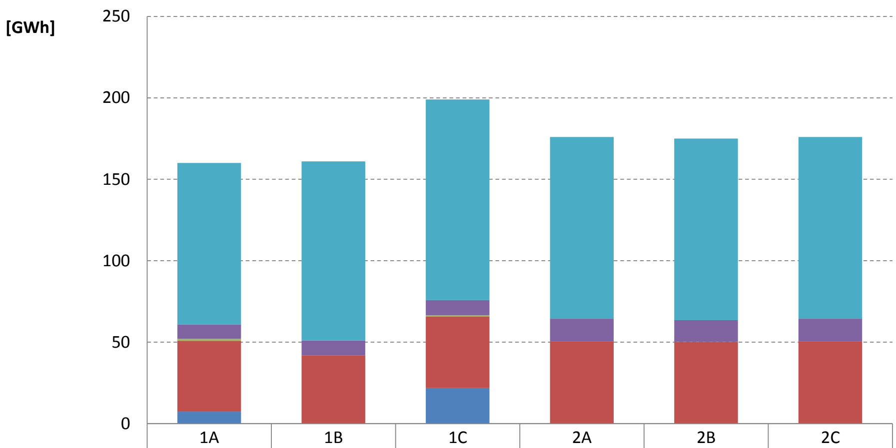
Figure 32: Indication of the CO_2 emission per MWh by electricity generation technology



	Renewables, nuclear	CCGT + CCS	Coal-fired + CCS	CHP gas engine	CCGT	Coal-fired
Avoided emission by CCS	0	346	743	0	0	0
Avoided emission for steam production	0	0	0	271	0	0
CO2 emission	0	61	131	226	345	710

Source: Wetzels et al. 2009.

Figure 33: Electricity generation in the Netherlands in 2050



	1A	1B	1C	2A	2B	2C
Renewables	99	110	123	112	111	112
Nuclear	9	9	9	14	13	14
Other fossil fuels	1	0	1	0	0	0
Gas	44	42	44	50	50	50
Coal	7	0	22	0	0	0

The incentive for switching to zero-carbon and low-carbon electricity generation increases

Investments in renewable energy, nuclear energy and carbon capture and storage can reduce CO_2 emissions (**Figure 32**). A higher CO_2 price and a lower cap for the electricity sector stimulate a shift towards low-carbon or renewable electricity generation. **Figure 33** shows the scenario results for the energy mix for electricity generation in 2050 for the Netherlands. Coal is no longer used for electricity generation in any of the scenarios with ETS splitting and CCS is applied at most of the fossil fuel electricity generation capacity. The emissions of the electricity sector are 3-4 $MtCO_2$ in all splitting scenarios.

Substituting fossil fuels by electricity becomes more difficult
Industry sections can often choose between fuel-intensive or electricity intensive production processes. For example, some steel production processes require more electricity while others require more fossil fuels. Upgrading waste heat using electrical heat pumps reduces fossil fuel use, but increases the electricity demand.

Splitting the ETS lowers the costs of fossil fuels but has a limited impact on the electricity costs. Therefore, splitting influences technology investment decisions. In general, substituting fossil fuels by low- or zero-carbon electricity becomes more difficult. Less expensive energy savings potentials may remain unused, while more effort is put into reducing electricity use. This may not be optimal for the total national costs of reducing CO_2 emissions.

Generating electricity in non-ETS sectors becomes more attractive
A high CO_2 price for electricity generation makes it more attractive to produce electricity with smaller installations, as only large emitters have to participate in the ETS.[33] Combined heat and power gas engines in greenhouse horticulture produced 10% of all electricity in the Netherlands in 2010. Most of these gas engines are operated outside of the ETS. When a high CO_2 price leads to a shift of fossil-fuel electricity production from inside the EU ETS to outside the EU ETS overall higher greenhouse gas emissions can result. Households can also choose to generate electricity themselves, e.g. with solar PV or micro-CHP systems.

Suboptimal allocation of fuels
A difference in CO_2 price can lead to changes in the allocation of fuels.
When the CO_2 price for the electricity sector is much higher than that for industry, fuels with high CO_2 emissions will preferably be used for heat generation in industry instead of for electricity generation. On the other hand, it will be more profitable to use low-emission fuels for electricity generation. For example, there will be a larger incentive to use biomass to produce electricity. This can mean that it is not used in sectors such as freight transport in which there may be fewer alternatives.

[33] Combustion of fuels in installations with a total rated thermal input exceeding 20 MW is subject to the EU ETS. An exception exists for installations for the incineration of hazardous or municipal waste.

5

Summary and evaluation of different policy options

This chapter summarises and evaluates first of all the modelling results of the policy options with regard to the EU ETS assessed in Chapter 3. To recall, these policy options include:

1. *Current, non-splitting option*, i.e. continue the current ETS up to 2050, characterised by one single cap and one single ETS carbon price for all sectors covered by the scheme.
2. *Splitting option, i.e. s*plit the current EU ETS into two separate regimes, each with its own cap and its own carbon price: a more ambitious regime with a relatively high carbon price for the power sector and a less ambitious regime with a relatively low carbon price for all the other ETS sectors, except aviation (called 'industry').
3. *Alternative, non-splitting option with carbon taxation*, i.e. continue the current ETS (one cap, one single ETS price for all sectors covered by the scheme) but introduce carbon price differentiation between the power sector and industry by implementing an additional tax on the CO_2 emissions of the power sector.

For each option, we have distinguished three different ambition levels to reduce the ETS cap:

A. *Current ambition,* i.e. the cap declines by the current reduction factor of 1.74% per annum up to 2050 (compared to 2008-2012).
B. *High ambition,* i.e. starting from 2021 the cap declines by 2.25% per annum up to 2050.
C. *Low ambition,* i.e. starting from 2021 the cap declines by 1.25% per annum up to 2050.

Under all three ambition levels of policy options 2 and 3 the power sector is assumed to reduce its emissions to zero by 2050 (full decarbonisation of the power sector) while industry is assumed to meet the remaining part of the overall ETS ambition level. This implies that the reduction target for industry is actually zero under ambition level C (low), rather moderate under ambition level A (current), but quite stringent under ambition level B (high).

Multiplying the three policy options by the three ambition levels results in nine ETS policy scenarios. However, as the modelling results of the three ambition scenarios of policy option 3 (non-splitting + carbon taxation for the power sector) are similar to those of policy option 2 (ETS splitting), we have focussed our attention in Chapter 3 on assessing the modelling results of the three ambition scenarios of policy option 1 (no splitting) versus policy option 2 only. In Section 5.1 below, we will first of all evaluate these two policy options by summarising and comparing the quantitative modelling results with regards to the splitting scenarios of policy option 2 versus the non-splitting scenarios of policy option 1.

Subsequently, a more qualitative assessment of the three policy options, including an evaluation of the pros and cons of these options, will be conducted in Section 5.2.

Besides the three policy options, however, there are other policy options to strengthen the EU ETS through a different treatment of the power sector and ETS industry, in particular through an alternative free allocation approach for industry, i.e. output-based allocation rather than the current lump-sum allocation based on product benchmarks. We evaluate this alternative allocation option in Section 5.3.

Finally, in Section 5.4 we summarise some major findings of the present study by addressing its major research questions as outlined in Chapter 1.

5.1 The splitting versus non-splitting scenarios

In **Table 18** up to **Table 21** we have summarised the major differences in our modelling results between the three ETS splitting scenarios of policy option 2 versus the respective non-splitting scenarios of policy option 1. Below, we will briefly discuss these differences successively for the power sector, ETS industry and the ETS as a whole as well as in terms of some macroeconomic outcomes at the EU27 level.

The differences in outcomes presented in the tables and discussed below refer to the differences in results of one the three splitting scenarios compared to their respective non-splitting scenarios (unless stated otherwise). For reasons of readability, however, we will skip the expression ‘compared to non-splitting scenario 1x’ and just focus on the differences in outcomes for the three splitting scenarios without referring to the respective non-splitting scenarios.

Moreover, for the time being we assume no EUA trading between sectors in the splitting scenarios but we will come back to this assumption by the end of this section.

Power sector

Table 18 presents the major differences in modelling results between the splitting and non-splitting scenarios for the power sector. In brief, these differences include:

- Over the period 2013-2050 as a whole, the average annual CO_2 emissions of the power sector are substantially lower under splitting scenario 2A (current ambition) and 2C (low ambition) but slightly higher under 2B (high ambition). This implies that the power sector reduces more emissions under 2A (+ 76 $MtCO_2$) and 2C (+157

$MtCO_2$) but less under 2B (-26 $MtCO_2$). This pattern of differences in (reductions of) CO_2 emissions is even more outspoken by the end of this period, 2050. For instance, under 2A the power sector increases its emission reductions in 2050 by 141 $MtCO_2$.

- These differences in (reductions of) CO_2 emissions result from differences in sectoral carbon prices under the respective scenarios. For the power sector, these prices are generally higher under 2A (current) and 2C (low) but lower under 2B (high overall ETS reduction ambition). For instance, in scenario 2C the carbon price for the power sector is 78 €/tCO_2 higher (than in 1C).

Table 18: Power sector (EU27): Differences in modelling results between ETS splitting and non-splitting scenarios

	2A – 1A (current)	2B – 1B (high)	2C -1C (low)
CO_2 emissions (in $MtCO_2$):			
• 2013-2050, average annual	-76	26	-157
• 2050	-141	82	-304
ETS carbon price (in €/tCO_2):			
• 2030	7	-2	30
• 2050	17	-12	78
CO_2 abatement costs			
• 2050, in billion €	11.8	-7.8	16.3
• 2050, in % of total abatement costs in case of current ETS	36	-14	215
Emissions trading costs (in billion €):			
• 2050	-4.5	4.1	23.5
• 2013-2050, annual average	2.1	0.7	19.1
CCS (in $MtCO_2$):			
• 2030	13	-5	44
• 2050	64	-24	221
Generation mix (in % of total power production):			
• 2050, coal	-3.4	1.0	-4.8
• 2050, renewables	6.1	-1.9	6.9
Average electricity price (in €/MWh):			
• 2030	1	0	4
• 2050	0	1	6

Note: The figures above do not refer to absolute results but to relative differences between respective splitting and non-splitting scenarios. So, for instance, the figure of -12 for the ETS carbon price in 2050 in the column "2B – 1B (high)" implies that this price is 12 €/tCO_2 lower in splitting scenario 2B compared to non-splitting scenario 1B.

- Higher (lower) carbon prices imply higher (lower) CO_2 emission reductions (or vice versa), resulting in changes in abatement costs accordingly by multiplying these two factors. For the power sector, total abatement costs by 2050 increase by € 12 billion under 2A and even by € 16 billion under 2C but decrease by € 8 billion under 2B. As a % of the total abatement costs in 2050 in case of the current ETS (policy options 1), the change in abatement costs for the power sector amounts to +36% in 2A, -14% in 2B and +215% in 2C.

- In addition to the costs of abating CO_2 emissions, the power sector has to pay for its remaining emissions by buying its allowances at the EUA market or auction.[34] By 2050, these emissions trading costs are lower under 2A (€ -4.5 billion), but higher under 2B (€ 4.1 billion) and, notably, under 2C (€ 24 billion).[35] Over the period 2013-2050 as a whole, however, these costs are a bit higher under 2A and 2B (i.e., on average € 2.1 billion and € 0.7 billion per annum, respectively) while they are substantially higher under 2C (i.e., on average, by € 19.1 billion per annum).[36] The reason why the difference in emissions trading costs is so high under 2C is mainly due to the substantially higher carbon prices for the power sector under this scenario (which is only partly offset by average lower emissions by the power sector over this period).
- The implementation and use of CCS is rather sensitive to the carbon price in our modelling scenarios. Therefore, we find significant higher amounts of CCS by the power sector over the period 2030-2050 under 2A and 2C but lower amounts – although less significant – under 2B.
- The spread of renewables in the power sector, however, is less dependent on carbon costs and more dependent on other costs or policies such as feed-in schemes or obligation targets. Nevertheless, the share of renewables in total power generation by 2050 is higher under 2A (+6.1%) and 2C (+6.9%) but lower under 2B (-1.9%). On the other hand, the share of coal is lower under 2A (-3.4%) and 2C (-4.8%), but higher under 2b (+1.0).[37]
- Electricity prices in 2030 and 2050 are more or less the same under both 2A and 2B, but somewhat higher under 2C (4-6 €/MWh). The main reason for this is that the change in the ETS carbon price for the power sector is relatively small under 2A and 2B but relatively large under 2C (see upper part of **Table 18**).

Industry

Table 19 presents the major differences in modelling results between the splitting and non-splitting scenarios for ETS industry. To a large extent, these differences are the mirror image of the differences for the power sector discussed above. In brief, the major differences for industry include:

- Over the period 2013-2050 as a whole, average annual CO_2 emissions by industry are substantially higher under splitting scenario 2A (+182 $MtCO_2$) and 2C (58 $MtCO_2$)

34 Under policy option 3 (non-splitting + carbon taxation of power sector emissions), a part of the auction payments is replaced by tax payments, as discussed in Section 3.3.

35 It should be noted that these differences in emissions trading costs results from a trade-off between higher (lower) emissions and lower (higher) carbon prices by 2050 (see upper part of **Table 18**).

36 As it is assumed that all available allowances are auctioned to the power sector and allocated for free to industry (according to their respective total sectoral emissions), the average annual ETS payments by the power sector over the period 2013-2050 are by definition equal to the public (auction/tax) revenues from the power sector (see Section 3.4.4 and **Table 20** below). Hence, while these ETS payments are costs for the power sector – passed through into higher electricity prices – and revenues for the treasury, from a social point of view they are just transfer payments of economic rents benefiting the treasury (which may be used to raise public expenditures or to reduce taxes or other public revenues).

37 It is stressed once again that these figures refer to relative differences between the respective splitting and non-splitting scenarios. So, for instance, the share of renewables in non-splitting scenario 1A (current ambition) is already substantially higher in 2050 (42.7%) than in 2010 (23.5%). In splitting scenario 1A, however, this share is even higher in 2050 (48.8%), i.e. 6.1% higher than in 1A by 2050.

but slightly lower under 2B (56 $MtCO_2$). In 2C, however, CO_2 emissions by industry remain significantly below its sectoral cap.

- ETS carbon prices for industry are lower under 2A and 2C but higher in 2B. For instance, under 2B, the carbon price for industry is 15 €/tCO_2 higher in both 2030 and 2050.
- CO_2 abatement costs for industry in 2050 are lower in 2A (€ -5.4 billion) and 2C (€ -0.5 billion) but significantly higher under 2B (€ 18.9 billion). As a % of the total abatement costs in 2050 in case of the current ETS (policy option 1), the change in abatement costs for industry amounts to -69% in 2A, +52% in 2B and -69% in 2C.

Table 19: Industry (EU27): Differences in modelling results between ETS splitting and non-splitting scenarios

	2A – 1A (current)	2B – 1B (high)	2C -1C (low)
CO_2 emissions (in $MtCO_2$):			
• 2013-2050, average annual	73	-25	23
• 2050	182	-56	58
ETS carbon price (in €/tCO_2):			
• 2030	-34	15	-14
• 2050	-73	15	-15
CO_2 abatement costs			
• 2050, in billion €	-5.4	8.9	-0.5
• 2050, in % of total abatement costs in case of current ETS	-69	52	-69
CCS (in $MtCO_2$):			
• 2030	-10	9	0
• 2050	-50	43	0
Total manufacturing (energy-intensive) industries (in % difference)			
• Output	0.5	0.0	-0.1
• Employment	0.0	0.0	0.1

- CCS by industry in 2050 is significantly lower under 2A (-50 $MtCO_2$) but higher under 2B (+43 $MtCO_2$) and similar under 2C.[38]
- Output by manufacturing (energy-intensive) industries in 2050 is slightly higher under 2A (+0.5%) but similar under 2B and slightly lower in 2C (-0.1%). The reason for this is that the ETS carbon price for industry is significantly lower under 2A, while the carbon price differentials - either positive or negative – are much smaller under 2B and 2C (see upper part of **Table 19**). Moreover, under 2C the carbon price for the power sector is substantially higher (**Table 18**). The resulting higher carbon costs are passed through into higher end-user electricity prices, which have a negative impact on the output of electricity intensive industries such as non-metallic mineral products.[39] Therefore, for the manufacturing sector as a whole, splitting the ETS

38 Actually, CCS by industry is zero under both 1C and 2C (see Section 3.5.2).

39 This is confirmed by **Table 15** (Section 3.5.3), which shows that if higher electricity costs are input-based compensated, output in 2050 is higher by 0.2% in the non-metallic mineral products sector and, on average, by 0.1% in the manufacturing sector as a whole.

does not seem to have a significant positive impact on output (i.e. reducing carbon leakage and/or improving industrial competitiveness) and may even be negative due to the pass-through of higher carbon costs of the power sector into higher end-user electricity prices (as seems to be the case in 2C).

- Employment by manufacturing (energy-intensive) industries in 2050 does not change under both 2A and 2B, but improves slightly under 2C (+0.1%). The reason why the impact of splitting the ETS on industrial employment is so low (or even absent) is first of all because the effects on manufacturing output are generally small – as discussed above – and, secondly, because over time there is some adjustment in wage rates in response to the demand for labour, which has a compensating effect. The reason why under 2C the employment effect is slightly positive, while the output effect is slightly negative is due to the higher electricity costs under 2C, resulting in a small amount of substitution of electricity by labour.[40]

Total ETS

Table 20 presents the major differences in modelling results between the splitting and non-splitting scenarios for the ETS sectors as a whole. To a large extent, these differences are the sum of the differences for the power sector and industry discussed above. In brief, the major differences for the ETS as a whole include:

- Over the period 2013-2050, total CO_2 emissions are more or less similar under 2A and 2B compared to the non-splitting equivalent scenarios. Under 2C, however, these emissions are lower due to the fact that industrial emissions by industry remain far below its separated sectoral cap.[41]
- Total CO_2 abatement costs in 2050 are higher under all splitting scenarios, i.e. by € 6.4 billion in 2A, by € 1.1 billion in 2B and even by € 16 billion in 2C. Hence, the carbon efficiency of the scheme declines by the same amounts. This is due to the fact that in all cases the splitting of the ETS results in a differentiation – rather than an equalisation – of carbon prices, i.e., marginal abatement costs, between sectors. As a % of the total abatement costs in 2050 in case of the current ETS (policy option 1), the change in abatement costs for the ETS as a whole amounts to +16% in 2A, +2% in 2B and +191% in 2C. As a percentage of total (EU27) GDP in 2050, however, the change in total abatement costs of ETS splitting are very small, i.e. 0.03% in 2A, 0.01% in 2B and 0.08 in 2C.
- Over the period 2013-2050, the annual public (ETS auction) revenues from the power sector are higher in all splitting scenarios, i.e., on average, € 2.1 billion in 2A, € 0.7 billion in 2B and even € 19.1 billion in 2C.
- The amounts of CCS are also higher under all splitting scenarios. Under 2A and 2B, however, these amounts are relatively low by 2050 – i.e., +14 $MtCO_2$ and +20 $MtCO_2$, respectively – while they are significantly higher in 2C (i.e., +221 $MtCO_2$ in 2050). The relatively low figure under 2A is due to the fact that in this scenario the higher amount of CCS in the power sector (+64 $MtCO_2$) is largely nullified by the lower amount of CCS in industry (-50 $MtCO_2$). The opposite applies for 2B, i.e. a higher amount of CCS for industry (+43 $MtCO_2$) but a lower amount for the power sector (-24 $MtCO_2$). Under 2C, on the contrary, the amount of CCS by the power sector increases substantially by 221 $MtCO_2$ in 2050 (while being zero under 1C),

40 This is confirmed by both **Table 15** and **Table 16** (Section 3.5.3), which shows that if higher electricity costs are compensated – notably by means of input-based compensation – the effects on employment are negative (i.e. labour is replaced by electricity).

41 The (additional) differences in 2050 are predominantly due to differences in EUA banking between the respective splitting and non-splitting scenarios.

whereas it remains zero for industry in both 1C and 2C. Therefore, ETS splitting has mixed effects on CCS in 2A and 2B. Only under 2C (low overall ETS ambition, but high for the power sector), however, the impact of ETS splitting is unambiguous and very substantial, i.e. in the power sector the amount of CCS is estimated to be 221 $MtCO_2$ higher in 2050.

Table 20: Total ETS sectors (EU27): Differences in modelling results between splitting and non-splitting scenarios

	2A – 1A (current)	2B – 1B (high)	2C -1C (low)
CO_2 emissions (in $MtCO_2$):			
• 2013-2050, average annual	-3	2	-134
• 2050	40	26	-237
CO_2 abatement costs			
• 2050, in billion €	6.4	1.1	15.8
• 2050, in % of total abatement costs in case of current ETS	16	2	191
• 2050, in % of GDP	0.03	0.01	0.08
ETS auction/tax revenues (from power sector):			
• 2013-2050, annual average (in billion €)	2.1	0.7	19.1
CCS (in $MtCO_2$):			
• 2030	3	4	44
• 2050	14	20	221

EU27 economy as a whole: macroeconomic outcomes

Table 21 presents the major differences in modelling results between the splitting and non-splitting scenarios for the EU27 economy as a whole for the year 2050. In terms of macroeconomic outcomes, these differences are slightly positive in 2A, while they are generally zero and, occasionally, a bit negative in 2B and 2C. The (slightly) positive effects in 2A are primarily due to two factors. Industrial competitiveness benefits from a lower carbon price for industry under 2A as well as from a boost in real investment. The latter of these impacts is due to the high carbon-intensive content of investment goods (e.g. cement and steel used in buildings and equipment) that becomes cheaper when there is a lower carbon price for industry.

The negative effects in 2B are due to the higher carbon price for industry in 2B (see upper part of **Table 18** and **Table 19**). In 2C, the negative effects are to the fact that the positive effects of a (slightly) lower carbon price for industry under 2B are compensated by the negative effects of a higher carbon price for the power sector.

Table 21: Macroeconomic outcomes (EU27): Differences in modelling results between ETS splitting and non-splitting scenarios

	2A – 1A (current)	2B – 1B (high)	2C -1C (low)
Macroeconomic outcomes (2050; in % difference compared to the baseline scenario)			
• GDP	0.3	-0.1	0.0
• Employment	0.1	0.0	0.0
• Consumer spending	0.3	0.0	-0.2
• Investments	0.4	0.0	0.0
• Exports (ext. EU)	0.2	-0.1	0.0
• Imports (ext. EU)	0.2	0.0	-0.1

Overall, however, the differences in macroeconomic outcomes between the ETS splitting and non-splitting scenarios are very small to zero. As outlined in Section 3.6, the reasons why these differences in macroeconomic outcomes are so small include:

- The outcomes refer to changes compared to the baseline scenario, i.e. they are relative changes induced by relative changes in reducing ETS emissions up to 2050.
- The effects are induced by relative changes in reducing ETS emissions only and not EU GHGs as a whole. More specifically, the macroeconomic outcomes are particularly induced by changes in the sectoral ETS carbon prices. In general, these changes are relatively small. They are only substantial for industry under 2A and for the power sector under 2C (see **Table 18** and **Table 19**).
- Manufacturing and the energy sectors account for a relatively small share of GDP, and this will be smaller still in 2050. In the baseline scenario, the services sectors contribute 72% of gross value added in the EU in 2005, rising to 75% in 2030 (EC, 2010a).
- Energy-intensive sectors account for quite a small share of manufacturing output. The energy-intensive sectors (chemicals, basic metals, construction materials, pulp and paper) represent a small share in total value added, i.e. 3.4% in 2005, declining to 2.7% in 2030. The share of the non-energy-intensive industries is projected to remain around 13.5% throughout the period 2005-2030 (EC, 2010a).
- Even for the energy-intensive sectors, energy is often not a very large share of costs (at the 2-digit level energy costs are usually less than 5% of turnover for all sectors except power and aviation).
- Not all the cost increases are passed on to final product prices.

Qualifications

Some qualifications can be added, however, to the results and observations outlined above. Firstly, there are sometimes small, but significant differences in macroeconomic outcomes between EU Member States.[42] The outcomes for any individual Member State depend on a large number of factors, including (i) sectoral composition, i.e. the share of services versus (energy-intensive) industries, (ii) market conditions, i.e. the extent to which carbon costs are passed through to final product prices, and (iii) country specific income and price elasticities of demand, including changes in real disposable income due to inflation and revenue recycling of ETS auctioning and carbon taxation.

42 See Section 3.6 and Appendix B for detailed results at the Member State level.

Secondly, across the EU27 and within each Member State, there are small, but significant and, occasionally, even important differences in outcomes between and within economic sectors.[43] These differences in outcome depend on the carbon intensiveness and trade exposure of these sectors.

Moreover, the results with regards to manufacturing sectors refer to a rather aggregated level. At this level of aggregation both less and more energy-intensive activities are included in the results. Within the aggregated manufacturing sectors there are some specific companies and sub-sectors that are likely to be affected disproportionately; possible examples include cement or aluminium. Hence, the (aggregated) results should not be interpreted as showing small impacts for all industry sectors.

On the other hand, however, the fact that for some specific companies or sub-sectors the differences in outcomes between the splitting and non-splitting scenarios may be substantial probably does not justify an overall system change but rather more sector specific measures if deemed necessary.

Thirdly, as indicated above, the (differences in) modelling outcomes at the macroeconomic, national and sectoral levels across different scenarios result from changes in carbon prices which are generally small. Overall, the 2050 carbon prices in our modelling scenarios vary for the power sector from 15 to 101 €/tCO_2 in non-splitting scenarios 1C (low ambition) and 1B (high ambition), respectively, and for industry from 0 to 116 €/tCO_2 in splitting scenarios 2C (low ambition) and 2B (high ambition), respectively. The differences in sectoral carbon prices between the splitting and non-splitting scenarios are even smaller in 2050, i.e. the differences are maximally +78 €/tCO_2 for the power sector under 2C and -73 €/tCO_2 for industry under 2A (see **Table 18** and **Table 19**, respectively).

These relatively small carbon price ranges and differences between scenarios are due to two major features of the modelling scenarios. Firstly, the scenarios assume (significant amounts of) EUA banking over the period 2013-2050, which (significantly) raises EUA prices during earlier phases of this period but mitigates high increases in these prices during later phases. Secondly, the scenarios assume substantial amounts of CCS over the period 2030-2050 in the price range of 40-120 €/tCO_2 (see Section 2.1.6).

Although these assumptions are to some extent communicating vessels (i.e. less banking leads to more CCS, and vice versa), relaxing one or both of these assumptions would result in higher carbon prices and, most likely, also higher differences between these prices and other modelling outcomes across the modelling scenarios.

It should be emphasized, however, that we have applied similar banking and CCS assumptions for all scenarios. Therefore, these assumptions do affect the size or absolute values of the modelling results but likely not the major findings or relative differences when comparing the scenarios.

A final qualification refers to the assumption on EUA trading between the separated sectors in policy option 2 (ETS splitting). As noted at the beginning of this section, the

43 See Section 3.5 and Appendix B for detailed results at the (industrial) sector level.

results and observations outlined above are based on the assumption that there is no EUA trading between industry and the power sector in this policy option. As a result, the carbon price in splitting scenario 2B (high ambition) is generally higher for industry than for the power sector. This has, consequently, some negative impacts for industry and the EU27 economy as a whole, such as higher abatement costs for industry, lower CCS in the power sector and some slightly negative macroeconomic outcomes.

These negative impacts can be avoided by allowing one-way EUA trading between industry and the power sector, i.e. industry is allowed to buy allowances from the power sector to cover industrial emissions but not the other way round (as is presently already the case with regards to aviation and the other sectors covered by the EU ETS). In that case, splitting scenario 2B turns actually into non-splitting scenario 1B with similar outcomes for both scenarios. However, this would also imply that some positive effects of 2B – with no sectoral EUA trading – would also be forgone, such as higher amounts of CCS in industry or in the EU ETS as a whole.

Summary of ETS splitting effects at different ETS ambition levels

Table 22 presents a summary of the main differences in the quantitative (modelling) results between ETS splitting (policy option 2) and non-splitting (current ETS; policy option 1) at different ETS ambition levels grouped according to favourable outcomes of splitting ('pros') versus unfavourable outcomes ('cons'). It shows that at each ambition level, ETS splitting has both pros and cons in terms of quantitative, modelling results. Hence, there is always a trade-off between these pros and cons of ETS splitting versus non-splitting and, therefore, there is no unambiguous case for ETS splitting.

Current ETS ambition level

In several cases, however, depending to some extent on the qualifying and weighing of the pros and cons of the respective policy options, splitting the ETS – i.e. differentiating its sector carbon prices - seems to be, on balance, a better option than non-splitting, i.e. the current ETS. This applies to a world with unequal or differentiated carbon prices between countries or regions in general and for splitting the ETS at its current ambition level in particular. In the case of ETS splitting at its current ambition level, the number of pros outweighs the number of cons (see upper part of **Table 22**). More importantly, one of the two cons refers to less CCS in industry, but this is surpassed by more CCS in the power sector, resulting in more CCS for the ETS as a whole. The other con refers to total abatement costs. By 2050, these costs are significantly higher in the power sector (€ 11.8 billion), while lower in industry (€ 5.4 billion), resulting in higher abatement costs for the ETS as a whole (€ 6.4 billion or, approximately, 0.03% of GDP in the EU27 by 2050). These higher costs, however, are far outweighed by the higher GDP in the EU27 by 2050 due to ETS splitting (+0.3%). Hence, at the current ambition level, based on the quantitative (modelling) results, there seems to be a rather clear case for splitting the ETS.

Higher ETS ambition levels

At higher (than current) ETS ambition levels, the case for ETS splitting becomes weaker in order to enhance the incentive for low-carbon investments by the power sector but stronger in order to reduce the risk of carbon leakage due to loss of industrial competiveness. At higher ETS ambition levels, however, the manoeuvring room for ETS splitting becomes smaller as the power sector is already facing a high ambition level under non-splitting.

Table 22: Summary of main differences in modelling results between ETS splitting (policy option 2) and non-splitting (policy option 1) at different ETS ambition levels grouped according to favourable outcomes ('pros') and unfavourable outcomes ('cons') of ETS splitting

	Pros	Cons
Current ambition level (scenarios 2A – 1A):	• Abatement costs: lower in industry (2050: € 5.4 billion). • CCS: higher in power sector (2050: +64 $MtCO_2$) and total ETS (2050: +14 $MtCO_2$). • RES-E: higher in power sector (2050: +6 percentage points). • Output: higher in industry (2050: +0.5%). • GDP: higher in EU27 (2050: +0.3%).	• Abatement costs: higher in power sector (2050: € 11.8 billion) and total ETS (€ 6.4 billion). • CCS: lower in industry (2050: -50 $MtCO_2$).
High ambition level (scenarios 2B – 1B):	• Abatement costs: lower in power sector (2050: € 7.8 billion). • CCS: higher in industry (2050: +43 $MtCO_2$) and total ETS (2050: +20 $MtCO_2$).	• Abatement costs: higher in industry (2050: € 8.9 billion) and total ETS (€ 1.1 billion). • CCS: lower in power sector (2050: -24 $MtCO_2$). • RES-E: lower in power sector (2050: -2 percentage points). • GDP: lower in EU27 (2050 -0.1%).
Low ambition level (scenarios 2C – 1C):	• Abatement costs: lower in industry (2050: € 0.5 billion). • CCS: higher in power sector (2050: +221 $MtCO_2$) and total ETS (2050: +221 $MtCO_2$). • RES-E: higher in power sector (2050: +7 percentage points). • ETS emissions: lower in total ETS (2050: -134 $MtCO_2$).	• Abatement costs: higher in power sector (2050: € 16.3 billion) and total ETS (€ 15.8 billion). • Output: lower in industry (2050: -0.1%). • Electricity prices: higher (2050: +6 €/MWh).

Note: The outcomes above do not refer to absolute results but to relative differences between respective splitting and non-splitting scenarios. For instance, in the row "Current ambition level (scenarios 2A - 1A)" and the column "Pros", the statement "RES-E higher in power sector (2050: + 6 percentage points)" implies that in 2050 the share of renewables in total power generation (RES-E) is 6 percentage points higher in splitting scenario 2A (current ETS ambition) compared to the baseline scenario 1A (non-splitting; current ambition).

Moreover, at higher ETS ambition levels, ETS splitting runs the risk that carbon prices for industry become even higher than in the case of non-splitting, while the opposite applies for the power sector (i.e. lower carbon prices under splitting compared to non-splitting). If so, ETS splitting would result in contrary outcomes than intended, i.e. it would lead to less carbon-saving investments by the power sector and higher risks of carbon leakage due to losses of industrial competitiveness.

This situation is indeed the case of ETS splitting at the high ambition level analysed in the present study, resulting in higher carbon prices and abatement costs for industry in splitting scenario 2B (see **Table 22**). This follows from the (implicit) sectoral abatement cost curves underlying the modelling scenarios. In practice, however, one does not know when – i.e. starting from which ETS ambition level and from which year – the above-mentioned, unintended outcomes of ETS splitting may occur. They may even happen at the current (or lower) ETS ambition level, basically because the (future) sectoral abatement cost curves are unknown and, therefore, uncertain.[44]

At all ETS ambition levels, however, the above-mentioned, unintended outcomes of ETS splitting can be avoided by allowing one-way EUA trading by industry, i.e. allowing industry to buy EUAs from the power sector and to use these EUAs, in addition to its own EUAs, to cover its industrial emissions, whereas the power sector is not allowed to trade or use industrial EUAs for compliance reasons. Due to this provision of one-way EUA trading, at all ETS ambition levels, carbon prices for industry will always be lower – or, at most, similar – under ETS splitting, compared to non-splitting, while the opposite applies for the power sector.

Therefore, by allowing one-way EUA trading by industry, the case for ETS splitting at higher (than current) ambition levels becomes stronger as one may benefit, on balance, from its intended, favourable outcomes while avoiding the risk of unintended, unfavourable outcomes.

Lower ETS ambition levels

At first sight, splitting at lower ETS ambition levels may seem less realistic as higher (rather than lower) ambition levels are needed to achieve the overall EU GHG abatement target for 2050, i.e. 80-95% reduction compared to 1990 for all sectors, including both ETS and non-ETS. However, in case an international climate agreement is lacking beyond 2020 or non-EU carbon prices are still generally low, EU Member States and ETS industries may argue successfully to lower the (current) annual reduction factor for the ETS cap in order to protect their economic interests. In that case, it may also make sense to split the ETS in order to achieve higher abatement ambitions by the power sector through imposing either a more stringent sectoral cap or an additional carbon tax on power sector emissions.

At lower (than current) ETS ambition levels, the case for ETS splitting becomes weaker in order to reduce the risk of carbon leakage due to loss of industrial competiveness but stronger in order to enhance the incentive for low-carbon investments by the power sector. At lower ETS ambition levels, however, the manoeuvring room for ETS splitting becomes smaller as industry is already facing a low ambition level under non-splitting and, hence, hardly benefits from further lowering industrial carbon costs through ETS splitting.

Moreover, at lower ETS ambition levels, ETS splitting runs the risk that the resulting lower direct carbon costs for industry – if any – are surpassed by higher indirect carbon costs passed through by the power sector into higher electricity prices for industry (due to the higher carbon prices for the power sector resulting from splitting at lower ETS

[44] For instance, the marginal abatement cost curve may shift downwards significantly due to the breakthrough of a (yet unknown or uncertain) cheap abatement technology which can be widely applied in the power sector but not in industry.

ambition levels). If so, this would result in higher (rather than lower) risks of carbon leakage due to losses of industrial competitiveness, in particular of electricity-intensive industries.

This situation is indeed the case of splitting at the low ETS ambition level analysed in the present study (see **Table 22**). At this level, carbon prices and emission reductions by industry are already relatively low under the current ETS (non-splitting). Hence, industry hardly benefits from lowering direct carbon costs through ETS splitting. In the low-ambition, ETS splitting case analysed in the present study, the cap for industry becomes even higher than its actual emissions, resulting in a carbon price of zero for industry. This implies that industry even benefits less from the lower reduction ambition due to splitting as its carbon price cannot fall further below zero.

On the other hand, in the case of ETS splitting at the low ambition level, the indirect carbon costs of industry increase substantially due to the higher carbon price for the power sector passed through into higher electricity prices for industry. On balance, total (direct and indirect) carbon costs increase – in particular for electricity-intensive industries – resulting in a lower output by these industries, although the impact is rather small (-0.1% by 2050; see **Table 22**).

Although the risk of carbon leakage and loss of output by electricity-intensive industries due to higher indirect carbon costs resulting from ETS splitting is higher when the ETS ambition is lower, it may also occur at the current or higher ETS ambition level. Or, to put it slightly differently, there is always the risk that the gain of industrial competitiveness due to lower direct carbon costs resulting from ETS splitting is partly, fully or more than fully nullified by the loss of industrial competitiveness due to higher indirect carbon costs, i.e. higher electricity prices, resulting from ETS splitting. One may decide either to accept this risk (as the negative output effects seem to be, on average, rather small) or to compensate electricity-intensive industries for the ETS induced increases in electricity prices (as the social costs of compensation also seem to be, on average, rather small).

As analysed in Section 3.5.3, losses of industrial output due to ETS-induced increases in electricity prices can be reduced by offering (input-based) compensation to industry for these increases. However, such compensation comes with a cost in terms of a lower GDP, although the impact on GDP turns out to be rather small (see Section 3.5.3). Moreover, this cost may become smaller and even turn into a small social benefit if compensation is well targeted to those electricity-intensive industries most vulnerable to the risk of carbon leakage due to ETS induced increases in electricity prices. Therefore, one either accepts the risk of carbon leakage due to increases in electricity prices resulting from ETS splitting or one reduces this risk by targeting (input-based) compensation of these increases to those industries most vulnerable to this risk.

Conclusion

In a world of unequal or differentiated carbon prices, there is a case for splitting the EU ETS – i.e. differentiating its sectoral carbon prices and ambition levels – in order to reduce the risk of carbon leakage resulting from an ETS-induced loss of industrial competitiveness and, simultaneously, to enhance the incentive for low-carbon investment by the power sector in order to reach ambitious, EU-wide GHG reduction targets by 2050.

At each ETS ambition level, however, there is always a trade-off between favourable effects ('pros') and unfavourable effects ('cons') of ETS splitting and, therefore, there is no unambiguous case for ETS splitting. In any case, at each ETS ambition level, the abatement costs under ETS splitting will be higher compared to the costs under non-splitting, i.e. the current ETS. As a percentage of GDP, however, these costs seem to be rather small, while they are offset by favourable effects such as either higher investment in low-carbon technologies, higher industrial output/GDP or a mixture of these effects.

The case for ETS splitting seems to be strongest at the current ETS ambition level as in this case the favourable effects seem to clearly outweigh the unfavourable effects. At higher (than current) ETS ambition levels, there is a weaker argument for ETS splitting in order to enhance the incentive for low-carbon investment by the power sector but a stronger argument for ETS splitting in order to reduce the risk of carbon leakage resulting from an ETS-induced loss of industrial competitiveness. Paradoxically, however, there is also a higher risk that, due to splitting, carbon prices for industry become higher rather than lower (and even higher than carbon prices for the power sector under splitting). This risk can be avoided by allowing one-way EUA trading by industry under ETS splitting, implying that at all ETS ambition levels carbon prices for industry will always be lower – or, at most, similar – under ETS splitting compared to non-splitting.

Reversely, at lower (than current) ETS ambition levels, there is a weaker argument for ETS splitting in order to reduce the risk of carbon leakage but a stronger argument for ETS splitting in order to enhance the incentive for low-carbon investment by the power sector. At lower ETS ambition levels, however, there is also a higher risk that indirect carbon costs – and even total carbon costs – for electricity-intensive industries increase due to higher electricity prices resulting from ETS splitting. This risk can be reduced, however, by compensating these industries for ETS induced increases in electricity prices.

To conclude, in a world with unequal or differentiated carbon prices there is a case for ETS splitting at each ETS ambition level. At each ETS ambition level, however, there is always a trade-off between favourable and unfavourable effects of ETS splitting and, therefore, there is no unambiguous case for splitting. Moreover, at each ETS ambition level, there is always the risk of higher carbon costs for energy-intensive industries rather than lower costs, as intended. This risk can be reduced, or even avoided, however, by allowing one-way EUA trading by industry under ETS splitting and by compensating energy-intensive industries for the increase in electricity prices due to splitting of the ETS.

5.2 Qualitative assessment of different policy options

In addition to the quantitative (modelling) assessment of the policy options outlined above, they can also be evaluated in qualitative terms. Basically, this qualitative assessment can be distinguished into two parts. The first part deals with the question: what are, besides the pros and cons in quantitative terms, the major pros and cons in qualitative terms of splitting the ETS (policy option 2) versus non-splitting (current policy option 1)? This question is addressed in Section 5.2.1 below.

If there is a case for splitting the ETS – i.e. for differentiating its sector carbon prices – the next question becomes: What is the best option to achieve this sectoral carbon price differentiation? Or, to phrase it slightly different: What are the major pros and cons of policy option 2 (carbon price differentiation by splitting the ETS into separated sectors) versus policy option 3 (carbon price differentiation by imposing a carbon tax on power sector emissions additional to the ETS carbon price), given the fact that, at each ETS ambition level, both options have the same quantitative (modelling) outcomes? This latter question is addressed in Section 5.2.2 below.

5.2.1 Qualitative assessment of ETS splitting versus non-splitting

Pros and cons of ETS splitting versus non-splitting
Compared to policy option 1 (current ETS; non-splitting), policy option 2 (ETS splitting) has some advantages ('pros'). Firstly, as discussed in the previous section, depending on the ETS ambition level, splitting implies (i) stronger incentives for low-carbon investments in the power sector and/or (ii) lower risks of carbon leakage and loss of industrial competitiveness. Therefore, ETS splitting contributes to meeting (ambitious) EU or national targets for decarbonising the power sector, while reducing the risk of carbon leakage.

Secondly, sticking to the present ETS – with currently and expectedly low carbon prices – erodes the credibility of the scheme among both stakeholders, EUA market participants, policy makers, environmental groups and other parts of the wider audience as it hardly results in any abatement activities in the foreseeable future. Hence, splitting of the ETS may restore and enhance the credibility of the scheme by enabling higher abatement ambitions, particularly in the power sector.

On the other hand, compared to the current ETS (policy option 1), ETS splitting (policy option 2) also has some disadvantages ('cons'). Firstly, splitting implies that the EU ETS Directive has to be revised, which may be a thorny, time-consuming process. Secondly, splitting also implies a decisive change of the system into two separated regimes, which is administratively more demanding. Thirdly, compared to sticking to the current ETS, splitting may also imply less policy consistency and less policy reliability with regard to the ETS among its stakeholders, notably among EUA market participants.

Fourthly, splitting the ETS into two separated EUA markets means less market liquidity on each market (compared to a single, undivided market). In turn, this implies higher risks of more price volatility, market concentration and misuse of market power, in particular on the EUA market for the power sector when the number of allocated EUAs is reduced substantially over time and moves to zero by 2050 (although similar risks apply in a separated, small and shrinking EUA market for industry).

A summary of the major pros and cons of ETS splitting (policy option 2) compared to non-splitting (policy option 1) is provided in the upper part of **Table 23**).

Table 23: Summary of qualitative assessment: major pros and cons of different policy options

	Pros	Cons
ETS splitting (policy option 2) compared to non-splitting (i.e. current EU ETS ; policy option 1):	• Lower risks of carbon leakage and loss of industrial competitiveness. • Stronger incentives for low-carbon investments in power sector. • May enhance credibility of the scheme.	• Requires change of ETS Directive. • Higher administrative demands. • Lower policy consistency/reliability. • Lower EUA market liquidity.
Differentiation of ETS sectoral carbon pricing by imposing an extra carbon tax on power sector emissions (policy option 3), compared to price differentiation by splitting the ETS (policy option 2)	• No change of ETS/Directive. • Higher EUA market liquidity. • Combines environmental effectiveness and investment (price) security. • Carbon price for power sector is always higher than for industry. • Can be implemented by individual Member States or group of like-minded countries. • More flexibility (to adjust carbon tax/sectoral carbon pricing).	• EU-wide resistance against 'carbon tax'. • EU-wide carbon tax requires unanimity among all Member States. • "Right tax level' may be hard to determine. • No guarantee that a specific abatement target will be reached by the power sector, e.g. full decarbonisation by 2050.

Qualifications

Some qualifications, however, can be added to the pros and cons of the two policy options, ETS splitting versus non-splitting, outlined above. Firstly, in the present study, it is assumed that ETS splitting – if agreed to do so – will be introduced starting from 2021, i.e. after the current eight-year trading period 2013-2020. This implies that this policy option can be part of a wider process of evaluating and revising the current ETS Directive, if deemed desirable or necessary. Therefore, although splitting the ETS may still be a controversial, thorny policy issue, it saves time and trouble by including it as part of a wider process of evaluating and revising the current Directive.

Secondly, although for some individual 'splitting the ETS' may sound quite drastic – or even dramatic – in practice, it is likely less radical and relatively easy to implement, to administer and to reverse back into non-splitting. In order to effectuate ETS splitting, the following activities have to be implemented: (i) setting a cap for each separated sector, (ii) issuing and allocating specific EUAs to each separated sector by labelling the (electronic) EUAs, for instance by adding the letter 'P' (from power sector) to the serial numbers of allowances auctioned to the power sector and the letter 'I' (from industry) to the serial numbers of allowances allocated (for free) to industry, and (iii) stipulating that an installation can cover its emissions only by surrendering allowances allocated to its sector. Alternatively, it can be stipulated that industry is allowed to trade and use both types of sectoral EUAs to cover its emissions (on-way EUA trading) in order to avoid a situation where carbon prices for industry become higher than those for the power sector.

In practice, implementing the activities mentioned above implies creating two markets that are trading two different products – i.e. the differently labelled EUAs – with two different prices, depending on their respective supply and demand conditions. All the other current ETS provisions and institutions could remain basically the same, including the monitoring, reporting and verification (MRV) system, the compliance system and the EUA registration system.

Moreover, in principle, the splitting of the ETS can be easily reversed by, starting from a certain date, allocating only one type of EUAs for all sectors covered by the scheme or allowing that differently labelled allowances can be mutually traded by all sectors and used to cover their emissions.

Thirdly, as indicated above, ETS splitting may reduce the policy consistency and reliability regarding the scheme among its stakeholders and EUA market participants, whereas sticking to the present system with its currently and expectedly low carbon prices may lower its credibility among large parts of the audience. Hence, when considering splitting the ETS, there seems to be a trade-off between the reliability and credibility of the scheme. However, if the option of ETS splitting is (i) timely and well communicated and discussed among all parties involved, (ii) timely and broadly accepted, and (iii) implemented only after the third trading period, it may enhance both the reliability and credibility of the scheme.[45]

Finally, the disadvantages of ETS splitting (policy option 2) mentioned above do not or hardly apply to the alternative option for ETS splitting, i.e. policy option 3 (non-splitting + carbon tax on power sector emissions). On the other hand, besides other advantages ('pros'), policy option 3 may also have disadvantages ('cons') compared to policy option 2. This comparison of options 2 and 3 is addressed in Section 5.2.2 below.

5.2.2 Qualitative assessment of policy options to differentiate ETS sectoral carbon prices

Pros of policy option 3 compared to policy option 2
In this study, we have distinguished two alternative policy options for differentiating ETS sector carbon prices, i.e. by (i) splitting the ETS into two separated sector regimes (policy option 2), and (ii) imposing a carbon tax on power sector emissions additional to a single ETS carbon price (policy option 3). At each ETS sector ambition level, both options result in the same quantitative (modelling) outcomes (see Chapter 3). This

45 It should be acknowledged, however, that even if ETS splitting is implemented only from 2021 onwards – including a more stringent ambition for the power sector – it may already have a significant impact on ETS carbon prices amply before 2021 due to EUA banking by the power sector.

raises the question: what is the best policy option to differentiate ETS sector carbon prices or, put slightly different: what are the major pros and cons of policy option 3 compared to policy option 2?

The lower part of **Table 23** provides a summary of the major pros and cons of policy option 3 compared to policy option 2. More specifically, compared to policy option 2, policy option 3 has the following advantages ('pros'). Firstly, policy option 3 does not require a revision of the ETS Directive and a sectoral separation of the scheme, so it is administratively less demanding.

Secondly, policy option 3 implies a higher market liquidity and, hence, less risks of market concentration and misuse of market power – compared to policy option 2 – as it does not result in a splitting of the EUA market into two smaller, separated sub-markets.

Thirdly, policy option 3 offers the dual advantage of mixing two different instruments, a 'price' and a 'quantity' instrument. On the one hand, it guarantees the environmental effectiveness of the ETS (by setting a cap on total ETS emissions) while on the other hand it provides some price security to low-carbon investments in the power sector. Actually, it reduces the carbon price risk of these investments by setting a kind of a carbon floor (minimum) price on CO_2 emissions by the power sector.

Fourthly, at each ETS ambition level, policy option 3 can effectuate that the total carbon price for the power sector (ETS + tax) is always higher than the carbon price for industry (only ETS) by simply imposing a certain carbon tax on top of the single ETS carbon price. In contrast, policy option 2 may result in industrial carbon prices which are hardly lower (or even higher) than carbon prices for the power sector, in particular at higher ETS ambition levels (assuming that one-way EUA trading by industry is not allowed).

Fifthly, another advantage of policy option 3 is that it can be implemented by an individual EU country or by a group of like-minded Member States (as it goes beyond the EU's agreed measures), whereas policy option 2 implies implementation across the EU as a whole. Introducing a carbon tax on power sector emissions in one part of the EU ETS, however, reduces the carbon price in the ETS as a whole, thereby benefitting not only industry across the ETS but also the power sector in the other, non-taxing countries of the ETS. As a result, power sector production and investment will shift from the carbon taxing countries to the non-taxing countries (within the transmission constraints between these two groups of countries).

Nevertheless, imposing an additional carbon tax on power sector emissions by a single Member State, such as recently implemented in the UK, or by a group of like-minded countries may still be considered as the second-best option to reach country-specific (high-ambition) abatement targets for the power sector in the medium and long runs.[46] In addition, it may give these countries some front-runner advantages of developing, deploying and exporting innovative, low-carbon technologies for the power sector. Moreover, if some countries start to introduce a carbon tax on the power sector in the

[46] Starting from April 1, 2013, the UK has introduced a carbon levy on the power sector that will make up the difference between the prevailing ETS carbon price and the envisaged 'carbon price floor' of £ 16 per tonne CO_2 (currently about 20 €/tCO_2) in order to trigger investments in low carbon technologies in the power sector (Weishaar et al., 2012; Gosen, 2013).

coming years, it may provide other countries an incentive to introduce such a tax as well at a later stage, resulting in a growing group of countries over time having implemented a carbon tax to the power sector.

Finally, another advantage of policy option 3 is that it may offer more policy flexibility in the sense that it may be easier to adjust the additional carbon tax depending on EUA market conditions and developments in international climate policy agreements. In contrast, under policy option 2 (separating ETS sectors) it may to harder to adjust the sector caps in a flexible way, partly for institutional reasons but particularly for providing a certain consistent, reliable policy framework to EUA market participants. It should be acknowledged, however, that also under policy option 3 the rules and underlying conditions for changing the carbon tax have to be transparent and clearly specified in order to provide a similar reliable policy framework (as the carbon tax affects EUA prices). Nevertheless, once these rules and conditions are set, policy option 3 seems to offer some more flexibility than policy option 2.

Cons of policy option 3 compared to policy option 2

On the other hand, compared to policy option 2, policy option 3 also has some disadvantages ('cons'). Firstly, as already noted in Section 2.1.1, in practice it may be hard to set 'the right carbon tax' as data on carbon price differentials between separated ETS markets are not known, while data on (future) marginal abatement costs for industry and the power sector are scarce and uncertain. A practical solution approach might be to (i) estimate these costs on the best information and modelling tools available, (ii) set the carbon tax based on these cost estimates, and (iii) adjust the tax periodically, e.g. every five years, based on updated information and clear, transparent rules (as mentioned above).

The key issue, however, is not so much setting 'the right carbon tax' but rather setting an adequate price differential between the power sector and industry. As the carbon tax affects the single ETS carbon price, it implies setting a carbon tax which (i) avoids too low – or even zero – carbon prices for industry on the one hand, and too high prices on the other, and (ii) provides an adequate incentive – together with the ETS carbon price – for investments in low-carbon technologies by the power sector.

Model simulations can provide estimates of the carbon tax level and its effect on ETS emissions and carbon prices, similar to other, present model simulations which provide estimates of the impact of other polices – such as industrial energy savings or RES-E policies – on ETS emissions and the implications for ETS cap setting and ETS carbon prices. Moreover, this tax level can be adjusted periodically, by clearly defined rules, in order to account for updated information on sectoral abatement cost curves and carbon prices.

Secondly, another disadvantage of policy option 3, compared to policy option 2, is that it offers no guarantee that a certain abatement target will be met by the power sector, such as full decarbonisation by 2050. In case of EUA banking, however, policy option 2 is also not able to provide such a guarantee. Moreover, setting an adequate carbon tax level – together with the ETS carbon price – offers at least some guarantee that adequate incentives are provided for investing in low-carbon technologies by the power sector and, hence, for reducing its emissions at an ambitious level. Finally, from the perspective of the overall ambitious GHG targets of the EU for the year 2050, it is more relevant that the overall ETS ambition is met rather than one of its specific (power) sector targets.

A third, but probably the most important, drawback of policy option 3 is that, most likely, there will be widespread resistance across the EU to introducing a carbon tax (based on its track record since the early 1990s). Moreover, accepting a tax proposal requires unanimity in the European Council, including representatives of each Member State, while accepting policy option 2 (ETS splitting, i.e. a change of the ETS Directive) requires a qualified majority vote.

Some qualifications, however, can be added to the (assumed) resistance against introducing a carbon tax. Firstly, the proposed carbon tax is an EU-wide tax and, hence, does not distort competitiveness between Member States. Secondly, the proposed carbon tax refers to the power sector only and, therefore, does not directly affect political sensitive sectors such as industry, households or the transport sector.

Thirdly, the proposed carbon tax is not aimed at raising government revenues or to expand the (EU) public sector but could be recycled by national governments to their citizens and firms, including power companies, by lowering income or other taxes.

Fourthly, and perhaps most importantly, the proposed carbon tax for the power sector does not raise its overall carbon costs or payments to the government, compared to policy option 2. Both policy options 2 and 3 are intended to be implemented starting from 2021. By that time, all allowances allocated to the power sector are fully auctioned by all EU Member States, including those Eastern European countries which have been allowed to use a temporary derogation on full auctioning of allowances to their power companies during the third ETS trading periods (with declining shares of free allocations to zero by 2020). In principle, the full carbon price for the power sector under policy option 3 (single ETS + carbon tax) is similar to its carbon price under policy option 2 (ETS splitting). As the cap and resulting CO_2 emissions of the power sector are also similar under both policy options, it implies that total carbon payments by the power sector are similar under both options (and, therefore, also total carbon revenues received by national governments). The only difference is that under policy option 2 the power sector pays solely the (relatively higher) carbon price at an auction, while under policy option 3 it pays a combination of the (relatively lower) auction price and the additional carbon tax. In total, however, the carbon costs per tonne of CO_2 paid to the government under policy option 3 are similar to the costs under policy option 2. Moreover, under both options, the power sector is assumed to pass through the carbon costs into end-users' electricity prices. This implies that under both options these end-users pay similar power prices.

Finally, introducing a carbon tax on power sector emissions, on top of the ETS auction price, hardly raises administrative demands as the power sector is assumed to make its carbon tax payments simultaneously with its transfer of allowances to cover its annual emissions. This implies that for both transfers (i.e. of allowances and tax payments) the same monitoring, reporting and verification (MRV) framework as well as the same compliance system can be used, thereby hardly increasing administrative demands.

Conclusion
To conclude, when comparing the two options to differentiate ETS sector carbon prices, i.e. policy options 2 and 3, at each ETS ambition level both options have similar quantitative (modelling) outcomes at the sectoral and macroeconomic levels. In other, more qualitative terms, however, each option has its specific pros and cons (as the pros and cons of policy option 2 can be regarded as the mirror image of the pros and cons of policy option 3). Hence, there is no unambiguous case for one of the two options as the ideal option to differentiate sector carbon prices as there is always a trade-off between the pros and cons of each option.

On balance, however, when qualifying and weighing the pros and cons of the two options, imposing an additional, EU-wide carbon tax on power sector emissions seems to be the first-best policy option to differentiate sector carbon prices. To some extent, however, this qualifying, weighing and selecting of policy options is a political issue. The major drawback of the preferred, first-best policy option is the expected socio-political resistance against a carbon tax. This tax, however, applies to the power sector only (no trade distortions) and does not imply higher carbon costs to the power sector or higher electricity prices to end-users, compared to the alternative policy option 2 (ETS splitting). Moreover, the resistance against an additional carbon tax on power sector emissions may be reduced or perhaps even overcome by an open-minded discussion on the pros and cons of this policy option versus other options to deal with the policy dilemma of lower or even zero carbon prices outside the EU and its implications for EU-internal, sectoral carbon pricing.

If the resistance to an EU-wide carbon tax on power sector emission cannot be overcome, a second-best option to differentiate ETS sector carbon prices is splitting the ETS in separated sector regimes. If this second-best option is also not feasible, a third-best, alternative option to an EU-wide carbon tax on power sector emissions next to the EU ETS is the introduction of such a tax by either individual countries – as recently occurred in the UK – or by a group of like-minded countries which are committed to or interested in decarbonising their power sector in the coming decades, while reducing the risk of carbon leakage due to an ETS induced loss of industrial competitiveness.

5.3 Output-based allocation: an alternative policy option?

Rather than differentiating ETS sectoral carbon pricing (either by ETS splitting or by inserting an additional tax on power sector emissions), an alternative option proposed to deal with the ETS carbon price issue in general, and the problems of the ETS price induced carbon leakage and loss of industrial competitiveness in particular, is the so-called ‘output-based allocation’ of free emission allowances to industry. This option is proposed and advocated especially by employers' organisations, notably by associations of energy-intensive industries which face international, outside-EU competition.[47]

In this section, we will briefly evaluate the option of output-based allocation in qualitative terms. After a brief outline of output-based allocation, compared to the present EU ETS approach of free allocation based on product benchmarks, we will assess some of its major distributional and efficiency effects, notably on production and abatement costs, output pricing and carbon leakage.

Output-based allocation versus benchmark-based allocation

In an output-based allocation (OBA) system, the allocation of free emission allowances is directly related to a firm's output or activity level. In an 'ideal-textbook' approach, OBA is directly related to a firm's *current* output level but it may, less ideally, also be related to a firm's output level in a previous year (or period) which is annually (periodically) updated.[48]

In an OBA system, an emissions performance standard is set which determines the number of allowances a firm receives per unit of output (Fischer, 2001; Koutstaal, 2001; Gielen et al., 2002). This standard is multiplied by a firm's output level in order to determine the amount of allowances it receives for free. Allowances can be granted ex-post, i.e. after a certain year or period – based on realised output, or ex-ante, i.e. before or at the start of a certain year, based on recently known or forecasted output levels and corrected ex-post, based on realised output (Wesselink et al., 2008).

Under emissions trading with output-based allocation (called 'OBA trading'), the cap on emissions is, in principle, not absolute but relative as it depends on the total output of the firms participating in the scheme. An option, however, is to use an adjustment factor in the allocation of allowances in order to limit the total amount of allowances allocated ex-post to an absolute cap.[49] With a higher level of output, the adjustment factor will be higher and firms receive fewer allowances per unit of output. In addition, the emissions performance standard can be strengthened (reduced) periodically in order to mitigate emissions over time.[50]

To some extent, output-based allocation is comparable to the present EU ETS approach of allocating free allowances to industry, based on product benchmarks. These

47 Examples of such associations include the International Federation of Industrial Energy Consumers in Europe (IFIEC-Europe) or the European Chemical Industry Council (CEFIC, i.e. the acronym from its French name: 'Conseil Européen des Fédérations de l'Industrie Chimique'). See, for instance, Schyns and Loske (2008), Wesselink et al. (2008) or, more recently, USG (2013). For other recent contributions on reforming the EU ETS, including proposals for output-based allocation, see IETA (2013) or the submission to the European Commission by the CEPS Carbon Market Forum (Marcu, 2013).

48 In the latter case, output-based allocation is also often called 'updating'.

49 An alternative option, with similar outcomes, is to set an absolute cap and, subsequently, to allocate the amount of allowances to firms according to their share in total sectoral output.

50 Emissions trading under output-based allocation ('OBA trading') is largely similar to a credit or 'Performance Standard Rate' (PSR) trading system. The main difference is that OBA trading refers to the allocation and trading of *allowances*, equal to the allowed volume of total emissions (the cap), whereas credit or PSR trading refers to the allocation and trading of *credits*, equal to the difference between the actual emissions per unit of activity and the performance standard, multiplied by the size of the activity (Kuik, 2005; Nentjes and Woerdman, 2012). If a firm produces cleaner than this standard, it receives credits, which can be sold to a producer that produces less cleanly and, hence, faces a deficit of credits to cover its emissions. In practice, both allocation systems have similar distributional and efficiency effects, as discussed in the main text below. Moreover, both trading systems, i.e. based on allowances and credits, respectively, can be linked to each other – including mutual or one-way trading – similar to linking the EU ETS and the Kyoto Mechanisms (JI/CDM).

benchmarks are generally measured in tonnes of CO_2-equivalents per unit of output, based on the average emissions intensity of the 10% most efficient installations in the years 2007-2008 which participate in the EU ETS and produce a specific product.[51] In order to determine the amount of free allowances per installation, the product benchmark is multiplied by the reference historical activity or output level of the product and installation concerned, with installations' operators allowed to choose the highest value of the 2005-2008 or 2009-2010 medians.[52]

Output-based allocation (OBA) is comparable to the EU ETS benchmark-based allocation approach outlined above in the sense that both methods are based on multiplying output by an emissions performance standard in order to determine a firm's amount of free allowances. Moreover, the OBA performance standard could be based on the EU ETS product benchmarks – as is presently advocated by EU ETS proponents of OBA – although also any other standard could be applied for OBA such as fuel or technology specific emissions standards.

The crucial difference between OBA and the present EU ETS approach, however, is that under OBA the number of allowances allocated to a firm is based on its current output – or recent output, which is periodically updated – whereas in the benchmark approach it depends on an historical output level which, in principle, is fixed for present and future allocations (in the case of the EU ETS, at least up to the last year of its third trading period, i.e. 2020).

As a result, under OBA firms have an incentive to increase their output in order to receive more free allowances in the current or next allocation period. This is in contrast to a so-called 'lump-sum' allocation system of free allocation, such as grandfathering or the EU ETS benchmark approach, where there is no relation between current activity and the quantity of allowances a firm will receive. This difference between output-based allocation (OBA) and lump-sum allocation (LSA) is crucial for the pricing, output and other effects of these two free allocation methods, as further outlined below.[53]

Due to the direct link between output and free allowances, OBA is actually equivalent to providing an output subsidy equal to the number of free allowances per unit of output times the price of the allowances (Gielen et al., 2002). The overall effect is that emissions trading with output-based allocation ('OBA trading') acts as a mix of a carbon price (tax) and an output subsidy. Firms are both stimulated to reduce their emissions because of the carbon price and to increase their output because on the OBA-induced subsidy (Bollen et al., 2012).

In contrast, under emission trading with lump-sum allocation ('LSA trading'), the use of free allowances is regarded as an opportunity cost which, as far as possible, is passed

51 The benchmarks have been established on the basis of the principle 'one product = one benchmark'. This means that the benchmark methodology does neither differentiate according to the technology or fuel used, nor to the size of an installation or its geographical location (EC, 2013).

52 Subsequently, the amount of free allowances is multiplied by some correction factors, depending on whether a product or sector is considered to be at risk of carbon leakage, and to ensure that the total amount of free allocations will not exceed the maximum of free allowances as defined in Article 10a(5) of the revised ETS Directive of 2009. For more information on these factors and other details on free allocation based on carbon efficiency benchmarks, see Lecourt et al. (2013) and EC (2009, 2011 and 2013).

53 See also Section 3.5.3 for the different effects of lump-sum compensation versus input- or output-based compensation of the indirect carbon costs passed on the end-users' electricity prices.

through to output prices. Therefore, production costs and, consequently, output prices will generally be lower under OBA trading than LSA trading (Fischer and Fox, 2007). This has implications for the output and carbon efficiency effects of these allocation methods, including implications for their effects on industrial competitiveness and carbon leakage). First of all, however, brief attention will be paid to differences in the distributional effects of these methods.

Distributional effects of output-based versus lump-sum allocation

Assuming lump-sum allocation based on product benchmarks (as in the current EU ETS approach of free allocations to industry), less carbon efficient installations receive relatively less allowances while more efficient installations get relatively more (compared to the previous EU ETS lump-sum allocation method, i.e. grandfathering, based on historical emissions). Depending on the extent to which installations are able to pass on the opportunity costs of their free allowances to end-user prices, the economic rents of emissions trading under lump-sum allocation are effectively distributed to these installations in the form of windfall profits or to end-users in the form of relatively lower – or even similar – consumer prices (while firms face lower output levels).

Assuming similar product benchmarks under OBA, firms with higher output growth rates receive relatively more allowances while firms with lower output growth rates get relatively less (compared to LSA based on product benchmarks and historical output levels). Assuming, in addition, that the implicit output subsidy of OBA is passed on to end-user prices, the economic rents of emissions trading under OBA are effectively distributed to end-users in the form of relatively lower consumer prices (although firms benefit from higher – or even similar output levels).

To some extent, the distributional effects of OBA depend on the assumptions with regard to the cap and the sectors to which OBA is applied. If it is assumed that the total ETS cap is flexible (relative) and that OBA is applied only to industry, while allowances are auctioned to the power sector, the cap depends on the level of industrial output and, hence, no adjustments or corrections have to be made to individual and sectoral allocations to meet this cap. If it is assumed, however, that the overall cap is fixed (absolute), adjustments have to be made to individual and sectoral allocations depending on the level of industrial output.[54]

Carbon efficiency effects of output-based versus lump-sum allocation

Given similar product benchmarks for output-based allocation and lump-sum allocation, both methods result in the same level of carbon efficiency at the firm level and in the same carbon price, assuming a relative cap under OBA depending on the level of industrial output. Hence, under these conditions, the marginal abatement cost at the firm level equals the price of an allowance or the value of the marginal abatement activity. Consequently, marginal abatement costs are equal for all firms and total abatement costs are minimised under both OBA and LSA trading (Gielen et al., 2002; Kuik, 2005).

54 An alternative option under OBA trading is to put allowances not allocated during periods of lower industrial activity into a reserve and to draw allowances from that reserve to increase the volume of allowances during periods of higher industrial activity. Besides maintaining a fixed cap over time, this option has the advantage that the reserve operations would stabilise the carbon price over time (see IETA, 2013 and Marcu, 2013).

As explained above, however, under LSA trading using free emission allowances is regarded as making (opportunity) costs and, hence, passed on to output prices, while under OBA trading this is not the case as OBA acts as an implicit output subsidy. Consequently, output levels and resulting emissions are lower under LSA than OBA trading. Following Nentjes and Woerdman (2012), one could conclude that LSA trading results not only in carbon or cost efficiency at the firm level (similar to OBA trading) but also to economic efficiency of carbon abatement at the system level (in contrast to OBA trading where the costs of non-abated emissions are not factored into output prices and, hence, the option of economic efficiency of carbon abatement through lower output levels is not exploited).[55]

In order to reach the same level of emissions under OBA trading as under LSA trading, the emissions performance rate under OBA trading has to be reduced. As a result, the carbon price and abatement activity at the firm level increases, implying that also the marginal and total abatement costs increase at both the firm and system level. Therefore, in terms of average costs of carbon reductions, OBA trading is less efficient than LSA trading.

The above analysis is appropriate under a closed ETS – i.e. no competitors outside the scheme – or in a world with a level playing field of equal carbon prices. In an open ETS and unequal, international carbon prices, however, OBA trading may result in less loss of industrial competiveness and, hence, less carbon leakage (compared to LSA trading in which the opportunity costs of free allowances are passed into output prices). Therefore, in such a case, OBA trading may become more cost-effective in reducing CO_2 emissions on a global level – and even more efficient than LSA trading – due to a better trade-off between higher internal costs and higher emission reductions at the global level.

In his thesis, Kuik (2005) has analysed the effects of OBA trading for four exposed sectors in the Netherlands (refineries, ferrous metals, non-ferrous metals and chemicals) by means of a general equilibrium model (GTAP-E).[56] He shows that OBA trading, compared to LSA trading, leads to (i) a significant improvement of the international competitiveness of firms in the exposed sectors, (ii) higher domestic emissions (in the case of a relative cap), (iii) a higher carbon price and higher domestic abatement costs (in the case of an absolute cap), and (iv) a small reduction in the global rate of carbon leakage. Overall, however, his results turn out that, under normal conditions, the welfare (cost-benefit) effects of OBA trading would be negative and that carbon leakage as such does not offer a justification for OBA trading from a welfare point of view (Kuik, 2005).[57]

55 Rather than using the terms ‘LSA trading’ and ‘OBA trading’, Nentjes and Woerdman (2012) use comparable terms, i.e. ‘permit trading’ and ‘credit trading’.

56 Actually, Kuik (2005) analyses the effects of a so-called ‘Performance Standard Rate (PSR)’ emissions trading system (‘PSR trading’), which are similar to the effects of an OBA emissions trading system (‘OBA trading’), following a recommendation by an official commission in 2002 to introduce such a system in the Netherlands. Due to the implementation of the EU ETS in 2005, however, this PSR system has never been introduced in the Netherlands to mitigate GHG emissions, although a similar national PSR scheme has operated for some years, with little success, to mitigate NO_x emissions.

57 Only under rather unusual conditions, notably strongly increasing returns to scale in the exposed sectors, OBA trading would become more attractive and welfare improving compared to LSA trading.

Other market imperfections

Besides carbon leakage (due to unequal international carbon pricing policies), the effects of OBA versus LSA trading may also depend on other market imperfections, notably taxing labour income, which distorts the labour-leisure trade-off by taxing consumption goods, reducing real wages and making leisure more attractive to labour and consumer goods. Climate policies can either further distort this trade-off by raising output prices (e.g. by LSA trading) or mitigating the labour tax distortion, e.g. by OBA trading – which reduces the increase in output prices – or by emissions trading with auctioning and recycling revenues by lowering labour taxes).

Fischer and Fox (2007) have analysed the effects of different methods of allocating carbon allowances – including grandfathering, auctioning and OBA – taking into account two distortions, i.e. the incidence of carbon leakage and a tax on labour income. They have investigated these effects for the US at the sector level by means of a general equilibrium model (GTAP-EG), assuming that only the US implements an emissions trading scheme (with an absolute cap). They distinguish two types of sectoral OBA, i.e. allocation of the sector cap based of firms' value added – i.e. regardless their emissions level – versus allocation based on firms' historical emissions, which favours in particular energy-intensive industries.

Fischer and Fox (2007) find that the type of sectoral OBA plays an important role in determining the effects of emissions trading in terms of industrial output, trade, carbon leakage and welfare. OBA of the sector cap based on value added generates effective output subsidies more like a broad-based (value added) tax reduction, performing nearly as good as auctioning with revenue recycling (i.e. reducing labour taxes) and clearly outperforming lump-sum allocations such as grandfathering.

On the other hand, OBA based on historical emissions, which supports the output of more carbon-intensive industries, is more effective in reducing the rate of carbon leakage and the loss of industrial output, but is more costly in welfare terms. With higher output among more polluting sectors, more expensive emission reductions must be sought among less carbon-intensive sectors, signalled by a higher carbon price. Due to the importance of the interaction with the labour tax distortion, however, OBA based on historical emissions is less costly in net welfare terms than grandfathering (at least for abatement targets that are not too stringent). In all cases, however, Fischer and Fox find that OBA – based on either value added or historical emissions – is less efficient than auctioning of allowances, which raises revenues that offset labour taxes, encourages more work, and achieves this in a manner that does not distort the relative prices of dirty and clean goods.

Fischer and Fox (2007) have also conducted some sensitivity analyses. They show that if labour supply were less elastic to the net wage rate, labour and consumer taxes would have a less welfare distorting effect, grandfathering would become more equivalent to the performance of auctioning, and any OBA would be less efficient.

In addition, with regard to the stringency of the carbon abatement target, they find that applying OBA based on historical emissions has some benefits relative to grandfathering for less stringent abatement targets (up to 18%). For more stringent caps, however, the distortions created by the corresponding OBA subsidies outweigh the benefits, and OBA based on historical emissions becomes increasingly the most costly option (Fischer and Fox, 2007).

Summary and conclusions: impact of allocation on carbon leakage, carbon efficiency and sectoral carbon pricing

Free lump-sum allocations of allowances, such as grandfathering or the present EU ETS approach based on product benchmarks, have little or no impact on mitigating the effects of emissions trading on industrial competitiveness and carbon leakage as they do not influence firms' output decisions at the margin. Firms which maximise profits still pass through the opportunity costs of free allowances – similar to the costs of carbon taxation or auctioning – realising profits at the expense of some loss of output. Investment and disinvestment decisions are also hardly or not influenced by free lump-sum allocations as it remains as attractive as with carbon taxation or auctioning to invest in countries without climate policies, or to close carbon-inefficient plans and sell the allowances allocated lump-sum for free.[58]

In contrast, output-based allocation (OBA) mitigates the effects of emissions trading on industrial competitiveness and carbon leakage, notably of energy-intensive industries, although the overall effect is probably limited. OBA based on firms' historical emissions – which favours the most carbon-intensive industries – is more effective in mitigating these effects than OBA based on firms' value added or on product benchmarks, such as in the present EU ETS approach of allocating free allowances to industry, which benefits the 10% most carbon-efficient firms producing a specific product. Moreover, OBA based on current output (or emissions) is more effective in mitigating carbon leakage than OBA based on output in a previous year, which is periodically updated, due to the discounting of the input subsidy inherent to (future) output-based allocations.

OBA, however, comes with a cost in terms of less carbon efficiency and resulting welfare losses. Compared to other allocation methods, it either increases ETS emissions – due to higher output by carbon-intensive industries – or, in case of an absolute cap, it increases both the marginal abatement costs (the carbon price) and the total abatement costs as more expensive abatement options have to be achieved elsewhere in the scheme.

In the case of lower – or even zero carbon prices outside the scheme, there is generally a trade-off between the effects of OBA on carbon leakage versus carbon efficiency. If OBA is more effective in mitigating carbon leakage, it is usually less cost-effective in reducing carbon emissions. Under normal conditions and in most cases, however, OBA results, on balance, in a net welfare loss. Only under less usual conditions, notably under strongly increasing returns to scale at the sector level, or in case of other distortions besides carbon leakage, particularly the incidence of labour income taxation, OBA may become more attractive than lump-sum allocations. But even in this case, OBA

58 Note, however, that carbon leakage due to (dis)investment decisions will be reduced in case of the entrance and closure provisions currently applied by the EU ETS. Under the entrance provision, industrial firms which invest in new production capacity ('new entrants') receive allowances for free based on their expected output. Under the closure provision, industrial firms which leave the market do not receive free allowances any more in subsequent periods. Actually, these provisions of the EU ETS act as kind of updating or output-based allocation as the allocation of free allowances depends on a firm's (dis)investment decisions. For more details on these provisions and their economic effects, see Ellerman (2006), Bollen et al. (2011) and Nentjes and Woerdman (2012).

would still be less attractive than auctioning with offsetting labour taxes (Kuik, 2005; Fischer and Fox, 2007).

Besides its lower efficiency, another – and perhaps even more important drawback of OBA is that it does not adequately address the central issue of the present study, i.e. the current ETS carbon price dilemma. As outlined in Chapter 1, this dilemma implies that the current ETS price is too low to encourage long-term investment in carbon-saving technologies by the power sector in order to reach ambitious abatement targets in the long run, but may not increase too much to avoid the risks of carbon leakage and loss of industrial competitiveness.

In the current EU ETS, output-based allocation would imply a different allocation method compared to the power sector (auctioning) and, hence, some differentiation of passing *direct* carbon *trading* costs into sectoral pricing. OBA, however, would first of all not address the issue of the *indirect* carbon trading costs of energy-intensive industries, i.e. the carbon costs of power generation passed through into end-users' electricity prices (although these industries also advocate a compensation of these costs).[59]

In addition, OBA does not adequately address the issue of the direct carbon *abatement* costs of energy-intensive industries, notably at high ETS ambition levels resulting in ambitious emissions performance standards (or benchmarks), high marginal abatement costs (i.e. a high carbon price) and high total abatement costs. Whereas OBA implies that the trading costs of the remaining emissions are covered by the allowances allocated for free (notably for the 10% most carbon-efficient firms), it does not cover or compensate the abatement costs of the avoided emissions. On the contrary, as mentioned above, it even results in some increase of these costs.

Therefore, as the current EU ETS with output-based allocation for industry and auctioning for the power sector would result in a single, undifferentiated carbon price, it would imply one of the following two situations. Both the overall ETS ambition and the resulting carbon price are relatively low, meaning that the abatement costs for both industry and the power sector would be low. Hence, there would hardly be any risk for carbon leakage but also hardly any incentive for the power sector to invest in low-carbon technologies. Or the overall ETS ambition and the resulting carbon price are relatively high, implying that the abatement costs for both industry and the power sector would be high and, hence, there would be a strong incentive for the power sector to invest in low-carbon technologies but also a high risk for industry of carbon leakage.

To conclude, output-based allocation is the only allocation method that is, to some extent, effective in mitigation of the effects of emissions trading on carbon leakage and loss of industrial competitiveness. OBA, however, comes with a cost in terms of less carbon efficiency. In general, under normal conditions and in most cases, OBA seems to result in a net welfare loss. Moreover, and perhaps more important in the context of the present study, OBA does not adequately address the central issue of the present study, i.e. the current impasse in ETS sectoral prices, as it results in a single carbon price

59 As discussed in Section 5.3.3, compensating indirect carbon costs to energy-intensive industries is favourable to these industries, notably by means of input- or output-based compensation (rather than lump-sum compensation) but less from an overall welfare point of view.

for all ETS sectors rather than differentiating the carbon price between industry and the power sector. More specifically, although OBA addresses the impact of the direct carbon trading costs on industrial competitiveness and carbon leakage, it does not address the impact of the indirect carbon trading costs, i.e. the costs of ETS-induced higher electricity prices, and – more importantly – the impact of the carbon abatement costs, i.e. the costs of the reduced, avoided emissions – notably if the ETS reduction ambition and the resulting ETS carbon price is high.

Hence, in general, OBA is not an attractive, alternative policy option compared to other (free) allocation methods or to other policy options to differentiate ETS sectoral carbon prices. Only in some cases, particularly in the case of labour tax distortions or if OBA is well targeted to a limited group of industries that are most vulnerable to carbon leakage, it may become more attractive than (free) allocation methods such as grandfathering or the current EU ETS approach based on product benchmarks. Even in these cases, however, OBA is not an adequate, alternative option for differentiating ETS carbon prices but, at best, an additional option. The paradox, is that once ETS sectoral carbon prices are differentiated by other more effective options – in particular ETS splitting or additionally taxing power sector emissions – the need for OBA is low, or even absent, as the carbon price for industry is already relatively low.

5.4 Addressing the specific research questions

In this final section, we will address the specific research questions outlined in Chapter 1 of this study by first repeating each separate question (in italics) and then giving our answer (default text).

1. *Is it possible to split the ETS into an ambitious regime for the power sector and a less ambitious regime for industry after 2020?*

Yes, it is. It is even possible to do so in a way that is relatively simple and hardly demanding in administrative terms, i.e. by:
a) Specifying an ambitious cap for the power sector over time and a separate, less ambitious cap for industry.
b) Issuing separate EU emission allowances (EUAs) for industry and the power sector, for instance by labelling the serial numbers of these allowances with either an 'I' (for industry) or a 'P' (for power sector), which are allocated in different ways (free allocation versus auctioning), and
c) Stipulating in the ETS Directive that each sector can only cover its emissions by surrendering its sectoral allowances.

In this set-up, all the other ETS provisions and institutions can remain basically the same, including the monitoring, reporting and verification (MRV) system, the registration system, the compliance system, etc. A major (administrative) disadvantage of this ETS splitting option, however, is that it requires a revision of the ETS Directive, which may be a tricky and time-consuming issue.

An alternative option to achieve a similar differentiation in carbon pricing, and resulting sectoral carbon reductions, is to impose a carbon tax on power sector emissions in addition to a single carbon price for both the power sector and industry. A major advantage of this option is that it is administratively even simpler to implement and that it does not require a change of the ETS Directive. A major disadvantage, however, is that it requires EU-wide agreement on introducing a carbon tax, which is a politically sensitive and tricky issue. However, it concerns a carbon tax for the power sector only which, on balance, results in similar carbon costs and public payments by the power sector – and similar end-users' electricity prices – compared to the ETS splitting option mentioned above (as part of the auction payments in the ETS splitting option is replaced by tax payments in the alternative, non-splitting option).

2. *If so, how can this be best achieved? For instance, can we have two separate caps within the ETS, i.e. one stringent for the power sector, and one less stringent for industry? Can they mutually interact and if so, under what conditions? More specifically, can there be trading in EUAs/offset credits between the two regimes if the carbon price must be different? Or should industry be placed completely outside of the scope of the ETS and follow a completely different regime?*

As explained above, in order to split the ETS we should (a) specify separate sectoral caps, (b) issues separate sectoral EUAs, and (c) stipulate that sectoral emissions can only be covered by own, sectoral EUAs. As the major objective of ETS splitting is to achieve different sectoral carbon prices, in first instance we have assumed no EUA trading between the separated sectors. It hardly makes sense to assume restricted EUA trading between these sectors, e.g. that the power sector is allowed to buy and use 10% of the EUAs from industry to cover its emissions (and/or vice versa), as from a sectoral carbon pricing perspective this is similar to adjusting the sectoral caps accordingly.

In order to avoid, however, that the carbon price becomes higher for industry than for the power sector, industry can be allowed to trade and use power sector EUAs but not the other way around (so-called 'one-way EUA trading') as has been alternatively assumed in the present study. As long as the carbon price is lower for industry than for the power sector, there are basically two separated schemes, but as soon as this price tends to become higher for industry it actually turns into one system.

In principle, offset credits (JI/CDM) can be freely traded between the separated sectors as it is not really necessary to impose restrictions on trading these credits (if attractive anyway). The only restriction assumed and applied in the present study is that sectors are allowed to use offset credits additional and equivalent to 7.5% of their cap. However, depending on the ETS carbon price for industry and the overall market conditions for offset credits, it may be hardly or not attractive for industry to buy and use these credits for covering its emissions.

3. *Where can we draw the line for which installation belongs in which regime? Should the entire industry fall under the less ambitious regime or just the industry that is confronted with the risk of carbon leakage? And how could we deal with for instance electricity that is generated by industry or heat that is generated by the power sector? How is it best to treat the aviation sector under the ETS?*

For reasons of convenience, simplicity and clarity, we have assumed a splitting of the ETS between the power sector on the one hand and, except aviation, all other sectors and installations covered by the present EU ETS on the other (called ‘industry’). The power sector includes electricity generated by industry but excludes heat produced by the power sector.

In principle, however, the demarcation line between the two separated sectors could lie anywhere. In particular, there are sound arguments to restrict the sector ‘industry’ to only those sectors or products that are (highly) vulnerable to the risk of carbon leakage (the ‘exposed’ sector) and to include all other firms – which are able to pass through their carbon costs in their output prices – in the other (‘sheltered’) sector. It may be hard, however, to determine which industries are exposed to the risk of carbon leakage in the medium and long term as it depends on the expected carbon price in the medium and long run, the assumptions regarding international climate policy agreements and resulting carbon prices outside the ETS, the trade exposure of ETS industries in the medium and long term, and a variety of other factors determining the output and (dis)investment decisions of these industries. So, for prudential reasons, one may be inclined to apply generous criteria to determine which industries are exposed to carbon leakage.

As explained in Section 2.1.4, aviation has been excluded from the scope of the present study, partly for reasons of simplicity, partly because its current and future status within the ETS is presently uncertain, but mainly because it is already a split, separated ETS sector with its own cap and its own aviation EUAs (but allowed to buy EUAs from the other ETS sectors to cover its emissions). Aviation, however, could either stay in this split position or be included in one of the two separated sectors mentioned above.

4. *Assuming that splitting the ETS sectors can only be done after 2020 and that industry only temporarily requires a less ambitious regime, what are the implications and best modalities for splitting the ETS sectors in such a way that they can eventually be merged again?*

If the splitting of the ETS sectors is conducted in the way outlined above (see particularly the answer to question 1 above), they can also be merged again quite simply, i.e. by issuing one single type of EUAs again or by stipulating that, starting from a certain date, both types of sectoral EUAs can be mutually traded and used to cover emissions of both sectors (which basically implies that there is one single ETS system and one single ETS price again). However, in order to guarantee the necessary policy consistency and reliability among EUA market participants, the conditions and modalities for merging ETS sectors again should be clearly specified in the (revised) ETS Directive.

5. *What is the effect of splitting the ETS on the performance of the EUA market?*

Splitting the ETS sectors implies creating two EUA markets trading two different products (industrial versus power sector EUAs). Hence, the liquidity of these separated markets will by definition be lower than of a single, merged market. This implies higher risks of more price volatility, market concentration and misuse of market power, in particular on the EUA market for the power sector when the number of allocated EUAs is reduced substantially over time and moves to zero by 2050 (although similar risks apply in a separated, small and shrinking EUA market for industry). One of the advantages of the non-splitting, alternative policy option to differentiate sectoral carbon pricing – i.e. by imposing an additional carbon tax on power sector emissions – is that there remains one single EUA market and, therefore, these risks are lower accordingly.

6. *What are the effects of an ambitious ETS cap for the power sector in the EU in general and for Member States with relatively a lot of coal, such as Poland? What are the effects on electricity generation from renewable energy sources (RES-E) and are additional policies to stimulate RES-E still needed under an ambitious ETS regime for the power sector?*

The effects of an ambitious ETS cap for the power sector in the EU27 as a whole and for some Member States in particular are analysed in Section 3.4 and summarised in Section 5.1. These effects depend on the overall ETS ambition level in the respective splitting and non-splitting scenarios, in particular on the difference in the carbon price for the power sector between the respective splitting and non-splitting scenarios at different ETS ambition levels.

If the overall ETS ambition is low or nearby its current level, the effects of ETS splitting for the power sector include higher carbon prices and higher abatement efforts – i.e. higher marginal and total abatement costs – higher shares of renewables and lower shares of coal/other fossil fuels in total electricity generation, higher use of CCS and higher electricity prices. At significantly higher ETS ambition levels, however, the carbon price and the abatement effort for the power sector becomes lower due to ETS splitting, compared to non-splitting, with a reversal of the effects mentioned above.

In general, however, the effects of ETS splitting for the power sector appear to be rather modest (compared to what one might expect at first sight), except for CCS in the power sector for which the effects of splitting are usually more significant. This is largely due to the relatively small carbon price range for the power sector between the respective splitting and non-splitting scenarios up to 2050 (varying between 15 and 100 €/tCO_2). In turn, this relatively small price range results from two factors or assumptions applied to all our modelling scenarios.

Firstly, we have assumed significant amounts of EUA banking over the period 2013-2050 over the period 2013-2050, resulting in significantly lower carbon prices in 2050, compared to no banking. Secondly, we have assumed that the power sector (as well as ETS industry) applies CCS, starting from 2030 but with substantial growing potentials up to 2050 within the price range of 40-120 €/tCO_2. Without these assumptions the range of carbon prices would have been significantly higher and, consequently, the effects of ETS splitting would most likely have been more outspoken. However, as these assumptions apply to all our modelling scenarios, they affect the absolute outcomes and differences across these scenarios but most likely they hardly or not affect the relative changes between the (splitting versus non-splitting) scenarios.

In addition, for some variables – such as the electricity price or the share of renewables in total power generation – other cost and policy determinants are also or even more important than the carbon price. This implies that a small change in the carbon price due to ETS splitting has an even smaller impact on these variables. In contrast, the deployment of CCS depends largely on the carbon price and, therefore, a change in this price has a more significant impact on this technology.

For Member States with relatively a lot of coal, such as Poland, the effects of ETS splitting for the power sector are slightly more outspoken but not much due to the reasons outlined above. Although we have not analysed these effects in detail, the share of coal in total power generation declines significantly in all modelling scenarios – and slightly more in the splitting scenarios with low and current ETS ambition – both at the EU27 level and at the Member State level. In 2050, however, the share of coal is still significant due to the substantial amount of CCS by the power sector in that year. More generally, when comparing the modelling results between the previous EU15 countries and the 'new' Member States in Central and Eastern Europe, including Poland, there is hardly any difference in results. This is in part because a degree of convergence is expected in the power and industrial sectors across Europe in the period up to 2050.

In the non-splitting scenario with current ETS ambition, the share of renewables in total power generation (RES-E) increases from 24% in 2010 to 43% in 2050. In the splitting scenarios with an ambitious cap for the power sector (full decarbonisation by 2050), this share increases somewhat faster to 49% in 2050. As noted above, these (differences in) outcomes are partly due to the ETS-induced changes in carbon prices but to a large extent also to other factors such as autonomous cost reductions – including technological learning – and other policies to stimulate RES-E such as feed-in tariffs, green certificates or obligation schemes.

In our modelling scenarios, we have assumed that – besides the ETS – additional policies to stimulate RES-E are still in place over the period up to 2050 and needed to reach specific RES-E targets. To the extent, however, that the ETS enhances average electricity prices (see below), the level of support by other, additional policies may be reduced accordingly to reach these targets. Several RES-E technologies may even become market competitive due to (splitting) the ETS and autonomous cost reductions over time. Hence, no additional support may be needed for these technologies, while other technologies may still need some support, but this has not been further analysed within the scope of the present study.

7. *What is the impact of ETS splitting with a high ambition for the power sector, i.e. full decarbonisation by 2050, on the electricity price in 2030 and 2050?*

The impact of ETS splitting (with a high ambition for the power sector) versus non-splitting (with different ambition levels for the ETS as a whole) on the electricity price in the EU27 and some Member States in 2030 and 2050 have been analysed in Section 3.4.3 and summarised in Section 5.1. At the EU27 level, this impact is generally small in the case of ETS splitting versus non-splitting at the current and high ETS ambition level but slightly higher at the low ETS ambition level. The reason for this relatively low impact is first of all that the impact of ETS splitting on the carbon price for the power sector is relatively small at the current ETS ambition level, and even negative at the high ambition level, but positive and far more significant at the low ambition level.

Secondly, although the future electricity pricing system – including a growing, dominant share of renewables – is still largely unknown, we have assumed that in the long run electricity prices are based on the average full costs of generating and decarbonising power (rather than the current, short term marginal pricing system). The methodology used is one of 'levelised costs' that includes capital costs, fuel costs, carbon costs and other operating and maintenance costs of the electricity production and network system. This electricity pricing system implies that the share of the average carbon cost in the average electricity (cost) price may remain stable or even decline over time due to a steady decrease in the average carbon intensity of power generation – toward full decarbonisation – even if the carbon price per tonne CO_2 emissions increases per tonne.

8. *How much of the ETS-induced increase in electricity costs will be passed through to industry (i.e. indirect carbon costs to industry)? What are the specific sectors that are vulnerable to the risks of carbon leakage due to the pass through of higher electricity costs to industry? Should there be compensation in order to avoid these risks and, if so, towhich specific industries and in what way?*

In our modelling scenarios, we have assumed that the ETS-induced increase in electricity costs will be fully passed through into the electricity price for industry and other end-users.

In 2012, the European Commission published a list of sectors and subsectors "deemed ex-ante to be exposed to a significant risk of carbon leakage due to indirect emission costs" (EC, 2012a). This list includes sectors and subsectors either mining or manufacturing the following commodities and products: aluminium, chemical and fertilizer minerals, copper, lead, zinc, tin, leather cloths, basic iron and steel, ferro-alloys, paper and paperboard, fertiliser and nitrogen compounds, other basic chemicals, cotton-type and man-made fibres, iron ores, polyethylene and other plastics in primary forms, and mechanical pulp.

In section 3.5.3., we have analysed the effects of compensating energy-intensive industries for 75% of the ETS-induced increase in the electricity price over the period 2010-2050 by two different mechanisms, i.e. by means of so-called 'input- or output-based compensation' or through 'lump-sum compensation'. In general, the effects of these compensation mechanisms are rather small to zero at the industry and macroeconomic level, although both positive and negative effects are slightly more significant for input-based compensation than for lump-sum compensation as input-based compensation has a stronger impact on a firm's operational decisions.

More specifically, under input-based compensation, the output effect for total manufacturing industries is slightly positive. This beneficial effect at the sector level, however, comes with negative effects at the macroeconomic level, i.e. the reallocation of public revenues from household incomes – through higher taxes – to industry causes GDP, employment and consumer spending to fall slightly. Moreover, although carbon leakage will be slightly lower owing to the compensation of the ETS-induced increase in electricity costs for industry, total ETS carbon abatement costs will be somewhat higher due to higher emissions in both industry and the power sector, resulting in higher marginal and total abatement costs to reduce these emissions below the cap.

Hence, there is a trade-off in compensation effects at the industry level on the one hand and at the total ETS and macroeconomic level on the other. On balance, however, the effects in terms of carbon efficiency at the system level or in terms of GDP at the macroeconomic level are negative, although the effects are small. This trade-off, however, may become more favourable – or even positive – if the compensation is better targeted to those industries that are really the most vulnerable to a significant risk of carbon leakage due to the ETS-induced increase in electricity costs. This issue of better targeting the compensation of indirect carbon costs, however, has not been part of the scope of the present study, among others because necessary data at more disaggregated industrial sector levels are lacking.

9. *More generally, what are the effects of splitting the ETS on industry?*

The effects of splitting the ETS on industry are analysed in Section 3.5 and summarised in Section 5.1. In general, these effects depend on the ETS ambition level in the non-splitting scenarios versus the sectoral ambition levels in the respective splitting scenarios. Overall, the effects for industry are, on balance, most favourable at the current ETS ambition level. At this level, ETS splitting results in more EUAs for industry and, hence, a lower need for emissions reduction, a lower carbon price and, therefore, lower marginal and total abatement costs for industry. Consequently, the adverse impact of the ETS on industrial output is also lower, i.e. less carbon leakage or lower losses of industrial competitiveness due to ETS splitting. On the other hand, the lower carbon price for industry also leads to less deployment of CCS by industry.

At the low ambition level, industry faces similarly favourable, although much smaller effects of ETS splitting in terms of more EUAs, lower carbon prices and lower carbon abatement costs, while the impact on industrial CCS is zero (i.e. no CCS at a low ambition level in both the splitting and non-splitting scenarios).

At the low ETS ambition level, however, the power sector faces a much higher carbon price under ETS splitting. The resulting higher carbon costs are passed through into higher electricity prices for industry, leading to a (small) loss of industrial output. This loss, however, can be reduced – or even avoided – if these costs are adequately compensated by means of public resources (as discussed above). Therefore, although ETS splitting at a low ambition level leads to some favourable direct carbon cost effects for industry, it does not lead to higher industrial output – on the contrary – due to the higher carbon cost from the power sector passed through to industry, unless these costs are adequately compensated.

At the high ambition level, ETS splitting results in higher carbon prices and higher (direct) carbon costs for industry, but also to higher levels of industrial CCS and emission reductions. The impact of ETS splitting on industrial output, on the other hand, is zero, partly because the change in the carbon price for industry is relatively small and partly because its higher direct carbon costs are compensated by lower indirect costs passed through by the power sector (as this sector benefits from a lower carbon price). Actually, at the high ambition level, carbon prices are even higher for industry than for the power sector. All these effects, however, are nullified if industry, in the case of ETS splitting, is allowed to buy EUAs from the power sector to cover industrial emissions as this prevents carbon prices for industry to become higher than for the power sector (one-way EUA trading).

10. *What are the macroeconomic effects of splitting the power sector and industry? Will it make the reduction of CO_2 emissions more expensive?*

The effects of ETS splitting on total abatement costs are discussed in Section 3.3, its macroeconomic effects in Section 3.6, while summaries of these effects are presented in Section 5.1. Splitting the ETS into two separated sectors results in higher marginal and total abatement costs for the one sector (facing both higher carbon prices and higher emission reduction needs) and lower costs for the other (facing both lower carbon prices and lower reduction needs). Under the same ETS ambition level, however, total abatement costs for the sectors as a whole are, more or less by definition, always higher under ETS splitting, although the extent to which these costs are higher – and burdened by one sector or the other – depends on the level of the ETS ambition and the way this ambition is split between the separated sectors.

For our modelling scenarios, we have estimated that in the case of ETS splitting the total system abatement costs by 2050 amount to approximately € 1.1 billion at the high ETS ambition level, € 6.4 billion at the current level and almost € 16 billion at the low level. As a percentage of the total abatement costs by 2050 in the case of non-splitting, these amounts correspond to 2%, 16% and 191%, respectively. As a percentage of total EU27 GDP by 2050, however, these rates are substantially lower, i.e. 0.01%, 0.03% and 0.08%, respectively.

The macroeconomic effects of ETS splitting in terms of GDP, employment, investments and trade at the EU27 level are generally rather small. Expressed as a % difference to the baseline scenario, these effects vary between -0.2% and +0.4% in 2050. The reasons why these effects are usually small are that (i) the differences in carbon prices between the splitting and non-splitting scenarios are relatively small, as explained above, and (ii) the share of the energy-intensive industries in total GDP is, on average, low for the EU27 as a whole (about 3%) while even for those industries the share of energy/carbon costs in total turnover is usually relatively low (in most cases, only a few per cent).

Nevertheless, there are some interesting differences in macroeconomic effects due to ETS splitting, depending on the ETS ambition level. In general, the effects are most favourable, although small, at the current ambition level. For instance, at the current ambition level, GDP in 2050 is about 0.3% higher due to splitting the ETS (which far outweighs the additional abatement costs due to splitting at this ambition level, estimated at 0.03% of GEP in 2050, as mentioned above). This positive effect is due to the significant lower carbon price for industry due to splitting.

At the low and high ambition level, however, the macroeconomic effects are slightly negative to zero. For instance, the change in GDP by 2050 due to splitting is -0.1% at the high ambition level and 0.0% at the low ambition level. The negative GDP outcome in the case of ETS splitting at the high ambition level is due to the fact that industry is faced by slightly higher carbon prices. The zero GDP outcome in case of splitting at the low ambition level results from the fact that the (slightly) lower direct carbon costs for industry are largely compensated by the significantly higher indirect carbon costs due to the higher carbon price for the power sector passed through into higher electricity prices.

11. *If splitting of the ETS system is feasible, does it solve the problem? In other words, can we have a CO_2 price for the power sector that will ensure the necessary stimulus in low-carbon investment in power generation?*

Yes, ETS splitting solves the issue of providing adequate incentives for low-carbon investments to reach highly ambitious targets by the power sector in the long term. In all splitting scenarios, a separate, highly ambitious abatement target is set for the power sector, i.e. full decarbonisation by 2050. Assuming compliance to this sectoral cap, this implies that, by definition, the necessary measures, including carbon-saving investments, will be taken to achieve the required emissions reductions (accounting for EUA banking over time).

The impact of ETS splitting on investments in specific low-carbon technologies in the power sector depends on its effect on the carbon price for the power sector at different ambitious levels for the ETS as a whole and on the importance of this price for specific technologies relative to other cost factors and non-ETS policies. For instance, at the high ambition level, ETS splitting results in (somewhat) lower carbon prices for the power sector and, hence, it has a (small) negative impact on the deployment of low-carbon technologies in this sector (compared to non-splitting at the high ETS ambition level).

At the current and, notably, low ETS ambition level, splitting results in significantly higher carbon prices in the power sector. Consequently, it leads to higher deployment levels of low-carbon technologies in the power sector, i.e. significantly higher shares of renewables in total electricity generation (already by 2030), and significantly higher amounts of CCS, in particular at the low ETS ambition level (starting from 2030 and increasing rapidly up to 2050).

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Appendix A. Detailed results of modelling scenarios

Table 24: EU ETS caps, including CDM, in splitting and non-splitting scenarios, 2008-2050 (in $MtCO_2$)

	Non-splitting scenarios			Splitting scenarios			
Sectors	Total ETS (Power + Industry)			Power	Industry		
	1A & 3A (current)	1B & 3B (high)	1C & 3C (low)	2A, 2B & 2C	2A (current)	2B (high)	2C (low)
2008-12	2313	2313	2313				
2013	2192	2192	2192				
2014	2152	2152	2152				
2015	2112	2112	2112				
2016	2071	2071	2071				
2017	2031	2031	2031				
2018	1991	1991	1991				
2019	1951	1951	1951				
2020	1910	1910	1910				
2021	1870	1858	1881	1149	721	710	733
2022	1830	1806	1853	1109	721	697	744
2023	1790	1754	1824	1069	720	685	754
2024	1749	1702	1795	1030	720	672	765
2025	1709	1650	1766	990	719	660	776
2026	1669	1598	1737	951	718	648	786
2027	1629	1546	1708	911	718	635	797
2028	1588	1494	1679	871	717	623	808
2029	1548	1442	1650	832	716	610	818
2030	1508	1390	1621	792	716	598	829
2031	1468	1338	1592	753	715	585	840
2032	1427	1286	1563	713	715	573	851
2033	1387	1234	1535	673	714	561	861
2034	1347	1182	1506	634	713	548	872
2035	1307	1130	1477	594	713	536	883
2036	1266	1078	1448	555	712	523	893
2037	1226	1026	1419	515	711	511	904
2038	1186	974	1390	475	711	498	915
2039	1146	922	1361	436	710	486	925
2040	1106	870	1332	396	709	474	936
2041	1065	818	1303	356	709	461	947
2042	1025	766	1274	317	708	449	957
2043	985	714	1245	277	708	436	968
2044	945	661	1217	238	707	424	979
2045	904	609	1188	198	706	411	990
2046	864	557	1159	158	706	399	1000
2047	824	505	1130	119	705	387	1011
2048	784	453	1101	79	704	374	1022
2049	743	401	1072	40	704	362	1032
2050	703	349	1043	0	703	349	1043

Table 25: CO_2 emissions by total ETS sectors, 2013-2050 (in $MtCO_2$)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
2013	1939	1936	1948	1935	1935	1935
2014	1934	1929	1944	1930	1930	1930
2015	1926	1922	1940	1923	1923	1923
2016	1910	1914	1921	1918	1918	1918
2017	1890	1890	1903	1885	1885	1885
2018	1866	1863	1885	1850	1850	1850
2019	1841	1837	1865	1819	1819	1819
2020	1817	1799	1848	1780	1780	1780
2021	1786	1754	1831	1771	1724	1778
2022	1755	1717	1815	1737	1681	1743
2023	1720	1674	1779	1697	1636	1703
2024	1687	1634	1742	1660	1595	1666
2025	1656	1599	1706	1625	1558	1630
2026	1602	1540	1657	1568	1492	1573
2027	1554	1479	1613	1516	1433	1521
2028	1507	1417	1572	1470	1378	1475
2029	1457	1351	1529	1424	1322	1430
2030	1402	1282	1485	1379	1266	1385
2031	1377	1244	1476	1359	1235	1365
2032	1351	1204	1469	1339	1203	1345
2033	1325	1164	1461	1317	1170	1323
2034	1299	1125	1453	1295	1137	1301
2035	1274	1087	1446	1271	1104	1278
2036	1252	1051	1438	1250	1072	1257
2037	1228	1019	1431	1229	1043	1236
2038	1208	991	1423	1213	1014	1220
2039	1188	964	1416	1197	988	1205
2040	1170	938	1408	1184	962	1192
2041	1146	911	1401	1167	936	1176
2042	1129	887	1393	1155	913	1164
2043	1124	862	1386	1144	892	1154
2044	1121	841	1379	1140	876	1149
2045	1114	818	1372	1135	857	1145
2046	1104	795	1364	1128	835	1139
2047	1090	770	1357	1118	811	1129
2048	1077	744	1350	1106	785	1117
2049	1060	719	1343	1093	758	1104
2050	1048	707	1336	1088	733	1099

Table 26: CO_2 emissions by ETS power generation sector, 2013-2050 (in $MtCO_2$)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
2013	1215	1213	1217	1214	1214	1214
2014	1212	1208	1213	1211	1211	1211
2015	1205	1203	1210	1207	1207	1207
2016	1193	1198	1192	1205	1205	1205
2017	1176	1177	1177	1176	1176	1176
2018	1155	1154	1161	1144	1144	1144
2019	1134	1131	1143	1116	1116	1116
2020	1113	1096	1130	1081	1081	1081
2021	1087	1057	1117	1040	1041	1040
2022	1062	1026	1103	1007	1006	1006
2023	1032	989	1071	969	968	969
2024	1004	955	1039	936	932	936
2025	979	926	1007	905	900	904
2026	931	877	960	851	847	850
2027	890	827	920	803	800	802
2028	849	776	881	759	757	759
2029	804	720	840	716	714	716
2030	756	663	799	673	670	672
2031	736	635	790	653	650	653
2032	715	606	782	633	629	633
2033	694	577	775	611	607	611
2034	674	549	767	590	586	590
2035	654	522	760	567	564	567
2036	637	496	753	546	544	546
2037	621	475	745	528	526	527
2038	605	455	738	510	508	510
2039	590	437	731	493	493	493
2040	576	419	724	478	478	478
2041	559	401	717	462	463	463
2042	545	385	710	448	450	449
2043	545	368	703	435	438	436
2044	541	352	697	423	428	424
2045	536	336	690	413	419	414
2046	529	321	683	401	407	402
2047	521	306	677	388	395	390
2048	512	291	670	376	382	377
2049	503	278	664	362	369	363
2050	493	273	657	352	355	353

Table 27: CO_2 emissions by ETS industry, 2013-2050 (in $MtCO_2$)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
2013	724	723	731	721	721	721
2014	722	721	731	718	718	718
2015	720	719	731	716	716	716
2016	717	716	729	713	713	713
2017	714	713	726	709	709	709
2018	711	709	724	706	706	706
2019	707	706	722	702	702	702
2020	704	703	718	699	699	699
2021	699	697	714	731	683	738
2022	693	691	711	730	675	737
2023	688	685	707	728	668	734
2024	683	679	703	724	663	730
2025	678	673	699	720	657	726
2026	671	663	697	716	645	723
2027	665	652	694	713	633	719
2028	658	641	691	710	620	716
2029	652	631	689	708	608	714
2030	646	619	686	706	596	712
2031	641	609	687	706	585	712
2032	636	598	687	706	574	712
2033	631	587	686	705	563	711
2034	625	576	686	705	551	711
2035	619	565	686	704	540	711
2036	614	555	686	704	528	711
2037	607	544	685	702	516	709
2038	602	536	685	703	506	710
2039	598	527	685	704	495	712
2040	594	519	684	706	484	714
2041	588	510	684	705	473	713
2042	583	502	683	707	463	715
2043	580	494	683	709	454	718
2044	579	489	682	716	447	725
2045	578	482	682	722	439	731
2046	575	474	681	728	428	737
2047	569	464	680	730	416	739
2048	564	453	680	731	403	740
2049	558	441	679	731	389	741
2050	554	434	678	736	378	746

Table 28: EU27 Member States: Change in GDP in 2050 (in %) compared to the baseline scenario 1A (in billion €)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Belgium	607	-0.3	0.4	0.3	-0.3	0.4
Denmark	365	-0.4	0.6	0.7	-0.6	0.7
Germany	3326	-0.5	0.2	0.2	-0.7	0.2
Greece	284	-0.8	0.4	0.4	-0.8	0.4
Spain	1831	-0.5	0.3	0.4	-0.3	0.4
France	3440	-0.5	0.6	0.5	-0.8	0.5
Ireland	369	-0.4	0.3	0.2	-0.5	0.2
Italy	2258	-0.6	0.4	0.2	-0.5	0.2
Luxembourg	81	-0.1	0.2	0.1	0.0	0.1
Netherlands	888	-0.6	0.3	0.6	-1.1	0.6
Austria	462	-0.5	0.6	0.4	-0.7	0.4
Portugal	261	-0.6	0.5	0.4	-0.6	0.4
Finland	306	-1.1	0.3	0.7	-0.6	0.7
Sweden	648	-0.3	0.3	0.5	-0.1	0.5
United Kingdom	3945	-0.1	0.1	0.0	-0.1	0.0
Czech Republic	229	-0.8	0.4	0.3	-0.6	0.3
Estonia	22	-1.2	0.3	0.3	-1.1	0.4
Cyprus	33	-1.0	0.4	0.4	-1.7	0.4
Latvia	19	-1.1	0.9	0.7	-1.1	0.7
Lithuania	38	-0.9	0.8	0.4	-0.6	0.4
Hungary	130	-0.6	0.6	0.5	-0.9	0.5
Malta	10	-1.1	1.6	1.2	-1.1	1.3
Poland	619	-0.3	0.1	0.3	-0.3	0.3
Slovenia	54	-1.0	0.7	0.5	-1.3	0.5
Slovakia	101	-0.5	0.4	0.3	-0.6	0.3
Bulgaria	45	-0.6	0.5	0.4	-0.6	0.4
Romania	145	-0.5	0.0	0.1	-0.5	0.1
EU27	20515	-0.4	0.3	0.3	-0.5	0.3

Table 29: EU27 Member States: Change in employment in 2050 (in %) compared to the baseline scenario 1A (in million employees)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Belgium	4.6	-0.2	0.0	0.1	-0.2	0.1
Denmark	2.8	-0.2	0.0	0.2	-0.2	0.2
Germany	36.6	-0.1	0.0	0.0	-0.2	0.0
Greece	4.0	-0.3	-0.1	0.1	-0.3	0.1
Spain	17.9	-0.7	0.2	-0.1	-0.5	-0.1
France	27.5	-0.4	0.3	0.3	-0.5	0.3
Ireland	2.1	-0.4	0.2	0.1	-0.4	0.1
Italy	22.1	-0.4	0.0	-0.1	-0.4	-0.1
Luxembourg	0.6	0.0	0.0	0.0	0.0	0.0
Netherlands	8.1	-0.1	0.2	0.3	-0.2	0.3
Austria	3.9	-0.2	0.1	0.1	-0.3	0.1
Portugal	4.6	-0.1	0.0	0.1	-0.1	0.1
Finland	2.1	-1.0	-0.2	0.3	-0.4	0.3
Sweden	3.5	-0.1	0.0	0.1	-0.1	0.1
United Kingdom	30.0	-0.1	0.0	0.1	-0.1	0.1
Czech Republic	4.3	-0.4	0.0	0.1	-0.4	0.1
Estonia	0.6	-0.3	0.1	0.1	-0.3	0.2
Cyprus	0.4	-0.2	-0.1	0.0	-0.2	0.0
Latvia	0.5	-0.2	0.0	0.2	-0.2	0.2
Lithuania	1.0	-0.3	0.2	0.2	-0.1	0.3
Hungary	2.8	0.4	0.2	0.3	0.5	0.3
Malta	0.1	-0.5	0.4	0.2	-0.6	0.2
Poland	12.8	-0.5	0.0	0.1	-0.5	0.1
Slovenia	0.7	-0.5	0.3	0.2	-0.7	0.2
Slovakia	1.5	-0.2	0.1	0.1	-0.2	0.1
Bulgaria	2.1	-0.3	-0.1	0.2	-0.3	0.2
Romania	6.8	-0.1	0.0	0.1	-0.1	0.1
EU27	204.0	-0.3	0.1	0.1	-0.3	0.1

Table 30: EU27: Change in output by economic sector (in %) compared to the baseline scenario 1A (in billion €)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Agriculture	942	0.0	0.0	-0.1	0.0	-0.1
Total manufacturing	8171	-0.9	0.6	0.5	-0.9	0.5
Metals	910	-1.0	0.7	0.5	-1.1	0.5
Chemicals	1024	-1.2	0.9	0.6	-1.5	0.6
Non-metallic mineral products	155	-1.3	1.5	1.3	-1.7	1.4
Paper & pulp	405	-1.6	1.3	1.2	-1.6	1.2
Other manufacturing	5678	-0.8	0.5	0.4	-0.7	0.5
Construction	860	-1.4	1.1	0.7	-1.5	0.7
Utilities and mining	1636	-0.5	0.7	0.0	-0.8	0.0
Air Transport	288	-0.3	0.1	0.1	-0.4	0.1
Other Transport	3051	-0.2	0.1	0.1	-0.2	0.1
Services	23811	-0.5	0.3	0.2	-0.5	0.3
Total	38760	-0.6	0.4	0.3	-0.6	0.3

Table 31: EU27: Change in employment by economic sector (in %) compared to the baseline scenario 1A (in million employees)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Agriculture	4.8	-0.1	-0.1	-0.1	-0.1	-0.1
Total manufacturing	22.9	-0.4	0.0	0.0	-0.4	0.1
Metals	3.0	-0.9	-0.1	-0.2	-0.8	-0.2
Chemicals	1.4	-0.2	0.1	0.0	-0.4	0.0
Non-metallic mineral products	0.6	-0.5	-0.2	-0.3	-0.6	-0.3
Paper & pulp	1.3	-0.1	0.2	0.5	-0.1	0.5
Other manufacturing	16.6	-0.4	-0.1	0.1	-0.3	0.1
Construction	9.4	-0.5	0.2	0.1	-0.5	0.1
Utilities and mining	4.5	0.0	0.0	0.0	0.0	0.0
Air Transport	0.6	-0.1	0.0	0.0	-0.1	0.0
Other Transport	8.6	-0.4	0.0	-0.1	-0.3	-0.1
Services	153.2	-0.3	0.1	0.1	-0.3	0.1
Total	204.0	-0.3	0.1	0.1	-0.3	0.1

Table 32: EU27: Change in exports by economic sectors in 2050 (in %) compared to the baseline scenario 1A (billion €)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Agriculture	170	-0.6	0.6	0.5	-0.9	0.5
Total manufacturing	4322	-0.2	0.2	0.3	-0.3	0.3
Metals	652	-0.1	0.1	0.1	-0.1	0.1
Chemicals	892	-0.1	0.2	0.1	-0.2	0.1
Non-metallic mineral products	92	-0.5	1.4	1.7	-0.8	1.8
Paper & pulp	217	-0.2	0.6	0.7	-0.4	0.7
Other manufacturing	2469	-0.3	0.2	0.2	-0.3	0.3
Construction	47	0.0	0.0	0.0	0.0	0.0
Utilities and mining	120	0.0	0.0	0.0	0.0	0.0
Air Transport	124	-0.1	-0.1	0.0	-0.3	0.0
Other Transport	224	-0.1	0.0	-0.1	-0.1	-0.1
Services	1556	-0.2	0.3	0.2	-0.3	0.2
Total	6564	-0.2	0.2	0.2	-0.3	0.2

Table 33: EU27: Change in imports by economic sectors in 2050 (in %) compared to the baseline scenario 1A (billion €)

	1A (current)	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
Agriculture	268	-1.1	0.8	0.6	-1.4	0.6
Total manufacturing	4003	-0.3	0.2	0.2	-0.2	0.2
Metals	523	-0.3	0.1	0.1	-0.3	0.1
Chemicals	665	0.1	0.0	0.1	0.0	0.1
Non-metallic mineral products	84	-0.3	0.4	0.4	-0.4	0.5
Paper & pulp	163	-0.2	0.1	0.0	-0.2	0.0
Other manufacturing	2568	-0.3	0.3	0.2	-0.3	0.3
Construction	49	0.0	0.0	0.0	0.0	0.0
Utilities and mining	427	-0.8	0.7	-0.3	0.5	-0.3
Air Transport	83	-0.2	0.1	0.2	-0.4	0.2
Other Transport	296	-0.2	0.1	0.0	-0.1	0.0
Services	1418	-0.3	0.2	0.2	-0.3	0.2
Total	6544	-0.3	0.3	0.2	-0.3	0.2

Table 34: Western Europe: Change in macroeconomic outcomes in 2050 (in %) compared to the baseline scenario 1A

	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
GDP	-0.4	0.3	0.3	-0.5	0.3
Employment	-0.3	0.1	0.1	-0.3	0.1
Consumer spending	-0.7	0.5	0.3	-0.7	0.3
Investment	-0.5	0.4	0.4	-0.6	0.4
Exports	-0.3	0.2	0.2	-0.3	0.2
Imports	-0.3	0.2	0.1	-0.3	0.1
Average consumer price	0.6	-0.7	-0.3	0.7	-0.3

Table 35: Eastern Europe: Change in macroeconomic outcomes in 2050 (in %) compared to the baseline scenario 1A

	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
GDP	-0.6	0.3	0.3	-0.6	0.3
Employment	-0.3	0.0	0.1	-0.3	0.1
Consumer spending	-0.7	0.5	0.3	-0.7	0.3
Investment	-0.6	0.5	0.3	-0.6	0.3
Exports	-0.3	0.3	0.3	-0.4	0.3
Imports	-0.3	0.4	0.2	-0.4	0.2
Average consumer price	0.6	-0.8	-0.6	0.6	-0.6

Table 36: Poland: Change in macroeconomic outcomes in 2050 (in %) compared to the baseline scenario 1A

	1B & 3B (current)	1C (low)	2A & 3A (current)	2B (high)	2C & 3C (low)
GDP	-0.3	0.1	0.3	-0.3	0.3
Employment	-0.5	0.0	0.1	-0.5	0.1
Consumer spending	-0.7	0.5	0.3	-0.7	0.3
Investment	-0.5	0.3	0.3	-0.5	0.3
Exports	-0.3	0.3	0.3	-0.3	0.3
Imports	-0.6	0.6	0.2	-0.6	0.2
Average consumer price	0.6	-0.8	-0.5	0.7	-0.5

Appendix B. Policies included in the baseline scenario

The baseline scenario used in this study is based on the PRIMES 2009 Reference Scenario (EC, 2010d). This Reference Scenario includes the following policies:

Regulatory measures – energy efficiency:

- Eco-design Framework Directive 2005/32/EC.
- Stand-by regulation 2008/1275/EC.
- Simple Set-to boxes regulation 2009/107/EC.
- Office/street lighting regulation 2009/245/EC.
- Household lighting regulation 2009/244/EC.
- External power supplies regulation 2009/278/EC.
- Labelling Directive 2003/66/EC.
- Cogeneration Directive 2004/8/EC.
- Directive 2006/32/EC on end-use energy efficiency and energy services.
- Buildings Directive 2002/91/EC.
- Energy Star Program (a voluntary labelling programme).

Regulatory measures – energy markets and power generation

- Completion of the internal energy market.
- EU ETS directive 2003/87/EC as amended by Directive 2008/101/EC and Directive 2009/29/EC.
- Energy Taxation Directive 2003/96/EC.
- Large Combustion Plant Directive 2001/80/EC.
- IPPC Directive 2008/1/EC.
- Directive of the geological storage of CO2 2009/31/EC.
- Directive on national emissions' ceilings for certain pollutants 2001/81/EC.
- Water Framework Directive 20000/60/EC.
- Landfill Directive 99/31/EC.

Transport

- Regulation on CO_2 from cars 2009/443/EC.
- Regulative Euro 5 and 6 2007/715/EC.
- Fuel Quality Directive 2009/30/EC.
- Biofuels Directive 2003/30/EC.
- Implementation of MARPOL Convention ANNEX VI.

Financial Support

- TEN-E guidelines (Decision 1364/2006).
- European Energy programme for Recovery (Regulation 2009/663/EC).
- RTD Support.
- State aid guidelines for Environmental Protection and 2008 Block Exemption Regulation.
- Cohesion Policy – ERDF, ESF and Cohesion Fund.

National measures

- Strong nation RES policies.
- Nuclear.

More details can be found in EU Energy Trends to 2030 – Update 2009 (EC, 2010a).

Appendix C. Carbon leakage

An important choice to be made when two separate emission trading schemes are introduced is whether the whole industry should fall under the less ambitious regime or just the industry that is confronted with a loss of competitiveness and risk of carbon leakage. In this appendix, we will discuss how industry competitiveness is affected and the various carbon leakage channels which might result from differences in climate policy ambitions in different regions. We will give an overview of existing studies and the estimates in these studies on competitiveness and carbon leakage effects, and discuss the choices made in the EU ETS to address competitiveness issues.

In this study, the focus is on the long-term, when ambitious emission reduction targets will result in high CO_2 prices which are considerably higher than the policies and prices discussed in the existing studies which consider carbon leakage in 2020. Studies on long-term emission reduction targets do not consider carbon leakage because they tend to assume international coordination of emission reduction policies. Therefore, we will discuss the consequences of considering a long-term time frame and high CO_2 prices on the outcomes of the existing studies.

With the proposed split in the ETS and a high CO_2 in the power sector, there will be industrial sectors which are vulnerable to the risks of carbon leakage due to the pass through of higher electricity costs. We will identify the sectors which are most vulnerable for this risk and discuss options to compensate for indirect cost increases due to the pass through of higher electricity costs to industry.

Overview of industrial competitiveness and carbon leakage
The effects of climate policy on trade are frequently discussed in the context of their effect on competitiveness. Competitiveness is a broad and rather vague term, which is not meaningful at the macroeconomic level (Krugman, 1994). At the sector or firm level, the concept of competitiveness can encompass different elements such as changes in trade flows (imports and exports), terms of trade effects and domestic economic indicators such as employment or production (Fischer and Fox, 2009).

Following Reinaud (2008), we define competitiveness as the ability to maintain profits and market share. Climate change policy affects competitiveness through its effect on firms' costs. Generally, climate change policies will increase a firm's cost. Policy instruments such as an emission cap increase a firm's cost directly. Direct costs consist of the abatement costs a firm has to make in order to reduce its emissions and possibly the costs of paying a tax or of acquiring allowances in the ETS. There can also be an indirect cost effect, when the price of inputs rises due to climate policies. This is, for example, the case when the aluminium industry uses electricity which is subject to an emission cap in the ETS. A firm can be subject to both cost increases, for example when it falls under the ETS cap and uses electricity from power plants which also fall under the ETS. The extent to which increasing costs affect a firm's earning capacity and market share is determined by its ability to reduce costs and to pass on its cost increase to its customers. The ability to pass on costs depends on the degree of international competition, market structure, the business cycle.

For some sectors, the openness to trade and therefore competition from abroad is limited. Consequently, carbon costs can to a large extent be passed on without risk of losing market share. But even when firms compete in a worldwide, competitive market, there will always be cost differentials, because of different labour costs, taxes, capital costs, transport costs etc. The ability to pass-through climate policy costs depends on these cost differentials. In the domestic market, the price differential with competing foreign products consists of a premium for local goods and trade costs (Neuhoff, 2008). This premium for local goods includes elements such as customer trust, tailored product attributes and responsiveness to new specifications. Trade costs consist of transport and storage costs, risks such as tariff risks, interruption risks and exchange rate risks. The premium for local goods and trade costs provide domestic firms with a margin within which they can pass on cost increases without losing profitability and market share. Competition from abroad can also be limited by trade barriers, either in the form of tariffs or non-tariff barriers to trade such as quota or administrative procedures.

In a competitive market where all firms are price-takers, competition from abroad severely limits a firm’s ability to pass on carbon costs. In contrast, with imperfect competition a firm has more room to accommodate cost increases, either by accepting a lower profit margin or through a higher price and lower market share.

The margin firms can make also depends on the business cycle. With high demand and limited spare capacity, firms will be more able to pass on carbon costs. In contrast, with low demand and overcapacity on a market, firms will just be able to cover their variable costs. Recouping increased costs due to climate policy will then be difficult.

Firms have several options to limit the cost impact of climate change policy. One option is to reduce their emissions. This will be attractive if the abatement costs are less than the alternative of paying a tax or using ETS allowances. Another option is to replace energy intensive parts of the production chain with substitutes which are less carbon intensive. Alternatively, energy-intensive inputs or intermediates can be replaced by substitutes from countries without climate policy (Neuhoff 2008). This will reduce the cost increase and therefore diminish the effect on aggregate competitiveness. In contrast, energy intensive parts of the product chain can suffer higher competitiveness impacts compared to the average for the whole product chain.

Estimating competitiveness impact

Various approaches and indicators have been used to assess the competitiveness impact of climate policy. A considerable literature has developed which analyses the cost increase sectors within the EU face under the EU ETS relative to total costs (for an overview of these studies, see Reinaud, 2008 and Dröge, 2009). These studies include both sector and national or EU-level studies (Reinaud ,2005a and 2005b, Smale et al., 2006; McKinsey and Ecofys ,2006, Hourcade et al., 2007, de Bruyn et al., 2008). In most studies, a distinction is made between full auctioning of allowances and free allocation. For the moment, we will focus on the cost effect of auctioned allowances, in chapter 5, Section 5.3 we have already discussed the impact of different allocation mechanisms.

The ETS increases both direct emission costs and indirect costs because of the increase in electricity prices. Assuming an allowance price of 20 €/tCO_2 and full pass-through of the allowance price in the electricity price, the percentage cost increase for a number of EU sectors has been calculated by Reinaud (2005a and 2005b) and McKinsey and Ecofys (2006). In these studies, the cement industry faces the largest cost increase (38% in the Reinaud study; 37% in the McKinsey study), followed by refinery (24% /21%), Blast Oxigen Furnace (BOF)[60] steel production (15% / 17%) and primary aluminium production (8% /11%).

At a more aggregated level, de Bruyn et al. (2008) have calculated the cost price increase of an allowance price of 20 €/tCO_2 for Dutch sectors. In this study, high cost increases are found in cement (8.4%), the fertilizer industry (8.1%), iron and steel, which is mainly BOF in the Netherlands (6.2%) and aluminium (6%). Another approach is to relate the cost increase to the gross value added of a sector. In a study for the UK (Grubb and Neuhoff, 2007) the value at stake is calculated based on a price of €20/ton CO_2 which is defined as the ratio between the carbon cost increase and the value-added of a sector. Cement has the highest value at stake (15%), the iron and steel sector and refining and fuels both have a value at stake of 6%. Overall, the (sub)sectors which show the largest cost increase as a result of carbon pricing are cement, basic iron and steel, fertilizer, refining and fuels, aluminium, and paper.

Differences within a sector can be considerable, depending on the aggregation level (Hourcade et al., 2008). For example, the paper sector includes both energy-intensive paper (pulp) producers and publishing companies whose energy costs are much smaller compared to total costs. In the iron and steel sector, the production of iron and steel from ore with the BOF process is the most carbon-intensive, production from scrap iron is considerably less so. Consequently, analysis at sufficiently disaggregated level is necessary to identify which firms are most at risk of losing competitiveness because of climate policies.

Assessment of the cost increase caused by climate policy is a first step in assessing the impact on competitiveness and trade. In addition, it has to be considered to what extent a market is open to international competition. One approach is to consider the openness of a sector to trade, as has been done in the study by Grubb and Neuhoff (2007) which considered the openness of UK sectors in terms of trade intensity. Trade intensity is defined as the ratio of trade volume and market size. Trade volume is the sum of exports and imports; market size is the sum of domestic production plus demand plus exports. For the sectors with relative high carbon costs identified above, the aluminium sector shows the highest trade intensity of more than 35%. Iron and steel has a trade intensity of almost 20%, refining and fuels of more than 10%.

While trade intensity provides an indicator of the openness to trade of a specific sector, it is only a first step in analysing the possibility to pass-on the carbon costs. International trade exposure will change in time, due to factors such as changing industry structure, exchange rate changes and cost changes such as changes in carbon costs (Neuhoff, 2008).

[60] BOF steel production is the production of steel from iron ore.

European Commission's quantitative assessment of competitiveness

Trade intensity is also used by the European Commission to determine whether a sector is exposed to a significant risk of carbon leakage. This is assumed to be the case if:

- both direct and indirect costs of carbon exceed 5% of gross value added and the intensity of trade is above 10%,[61]
- if the cost increase is more than 30% of gross value added,
- if trade intensity is above 30%.

Based on these criteria and a carbon price of 30 €/tCO_2(the average carbon price of the Commission's impact assessment), the Commission has established the sectors which are exposed to a significant risk of carbon leakage (Decision EC 2009e). Four sectors qualify through significant CO_2 costs, 27 through both significant CO_2 costs and trade intensity together and 115 through a high trade intensity. However, from those last, only 92 fall under the ETS (Juergens et al., 2013). Carbon leakage sectors represent around 77% of industrial emissions and 30% of total ETS emissions in 2020, according to Juergens et al. (2013) who have examined the methodology used by the Commission to establish the sectors prone to carbon leakage. Bloomberg New Energy Finance (28 June 2011) arrive at a comparable figure in their estimate of 34% of all the allowances in 2020 which will be grandfathered and not auctioned.

Carbon leakage

Reduced competitiveness for firms from countries with more stringent climate policies can lead to an increase in emissions in countries with no or less stringent climate policies. This carbon leakage reduces the environmental effectiveness of the climate policy measures.

There are two main channels for carbon leakage. First, asymmetric carbon prices change relative prices between domestic and foreign production. In the short run, domestic firms can lose market share at the expense of foreign firms, who will increase their production and therefore emissions. The carbon emission reduction is therefore partly undone.

In addition to this short run operational leakage, in the longer run carbon price differentials will also influence investment patterns (investment leakage). New investment in energy intensive industries becomes more attractive in countries without stringent climate change policies, therefore in the longer run emissions in these countries will increase further.

Decisions on where to invest are influenced by many factors, one of which are the costs of environmental policy. Capital intensive industries have sunk costs, which can make relocation costly, especially if reinvestment is incremental to existing plants. Other factors are the availability of skilled labour and access to inputs. Moreover, over the lifetime of an investment, a new host country might implement climate policies as well, reducing the advantage of relocation. Another risk is the possibility that export markets with stringent climate policies might impose border measures such as tariffs on carbon-intensive products.

[61] Calculated as the ratio between the total value of exports plus imports from outside the EU and the total market size within the EU (turnover plus imports).

The second main channel of carbon leakage occurs because asymmetric carbon prices affect the relative prices of manufactured goods, but also because they drive down fossil fuel prices globally. The increased costs of emitting greenhouse gases will reduce demand and therefore the price for fossil fuels. As a result of lower fossil fuel prices, the use of fossil fuels and therefore emissions will increase in non-abating countries.

Modelling competitiveness loss and carbon leakage
In addition to bottom-up approaches based on trade intensity and cost shares to determine which sectors are vulnerable to the loss of competitiveness and carbon leakage, the effects of unilateral climate change policies can also be addressed by top-down modelling studies. In these studies, the macroeconomic consequences and emissions of specific climate policy scenarios are assessed using economic models such as applied general equilibrium models or macro-econometric models.

There have been a number of recent studies which look at the effects on competitiveness and carbon leakage of climate policies which are introduced in a limited number of regions. Burniaux et al. (2010) have used the ENV-Linkages model for two scenarios. In the first scenario, the EU alone cuts its emissions with 20% in 2020 and 50% in 2050, compared to 2005 emissions. In the second scenario, all Annex-I countries reduce their emissions with the same amounts. As is to be expected, carbon leakage is larger in the EU scenario, 6.5% of EU emission reductions in 2020, than in the Annex-I scenario, 4.5% of the emission reduction in Annex-I countries.

Using the CGE-model WorldScan, Manders and Veenendaal (2008) consider a scenario in which the EU is the only region with a strong climate change policy while other Annex-I parties only have limited policies (around 2% reduction compared to the baseline) and non-Annex I no policies. EU emissions are reduced with 14% compared to 2005 levels. Economic welfare in the EU reduced by 7% in 2020 compared to the baseline. Output in the ETS sectors in the EU declines with 4.5% relative to the baseline and carbon leakage is 3.3%.

Fischer and Fox (2009) use a partial equilibrium model which is parameterized with the outcomes of a simulation with the CGE GTAP-EG model in which only the US introduces a $50/ton emission price on CO_2. Leakage rates range from 11% for the paper, pulp and printing sector to 64% for the refined petroleum products. With the exception of oil products, leakage in the energy-intensive sectors is more due to oil price changes worldwide (the oil price channel of carbon leakage) than because of changes in product prices, which result in leakage rates ranging from 2 till 14% for different energy-intensive sectors, or about 20-40% of total leakage per sector.

Bollen et al. (2011) study a number of climate policy scenarios, one of which assumes that the EU realizes its GHG-emission and renewable energy target for 2020 while other countries implement the pledges they made at the Copenhagen Climate Change Conference in December 2009. This implies modest reduction targets for the other Annex I countries and emission reductions targets in non-Annex I countries such as China and India which are non-binding. In this scenario, welfare in the EU in 2020 declines with around 0.5% compared to the baseline and the GHG-leakage rate is 36%[62].

[62] The GHG leakage rate is defined as the increase of GHG-emissions in non-Annex I countries as a percentage of the emissions reduction in Annex I countries.

The effects on energy-intensive production in Annex I countries is considerable, the energy intensive production leakage rate is 64%[63]. However, the actual volume displacements of energy-intensive production yields a more varied picture. Production leakage outcome in terms of % deviation from baseline production is only 1.4%. Moreover, energy-intensive manufacturing in the EU shows a production decline of 3.3%.

An important result from this study is that the main channel for carbon leakage is the fossil fuel price channel. The decline in fossil fuel use in Annex I countries will reduce fossil fuel prices, which will lead to an increase in fossil fuel use in non-Annex I countries. Production leakage in absolute terms is limited.

Conclusions on competitiveness and carbon leakage
Both empirical bottom-up and top-down modelling approaches have been used to determine carbon leakage and competitiveness effects and the sectors which are most vulnerable to high CO_2 prices. The bottom-up approaches have the advantage of a much more disaggregated analysis which makes it possible to avoid errors such as the exclusion of subsectors which do have run a high risk if confronted with high CO_2 prices but do not show up in a more aggregated analysis or of inclusion of subsectors which do not run a risk at all. On the other hand, bottom-up approaches do not take economy-wide and trade effects for future points in time as is the case with top-down approaches. In the next section, we will discuss the implications of the longer time-frame considered in this study for the choice of which sectors to include in which emission trading scheme, the one for the power sector or the one for industry.

Long-term perspective and the splitting of the ETS between the power sector and industry
The approaches and studies used to distinguish those sectors at risk from high carbon prices discussed so far mostly focus on carbon leakage in 2020. However, in our study the focus is on a longer period, up to 2050, in which the EU (or possibly Annex I) has more ambitious emission reduction targets than other countries. Given the long-term objective of reducing GHG emissions by 80-90% in 2050, CO_2 prices will be much higher than those considered in the studies so far. Consequently, competitiveness impacts and carbon leakage diverge considerably from the results obtained in these other studies.

Moreover, current empirical data on costs and trade will also be considerably less significant when studying 2050. Over such a long time frame, some sectors will decline, others will grow and new will emerge, having a profound effect on the structure of the economy. This also holds for trade patterns between countries and across different sectors. Therefore it will be of little use to utilize current data on the CO_2 cost share or on trade intensity to determine which sectors will be susceptible to climate change policies which increase the CO_2 price. A top-down approach based on modelling might be more valuable because it looks at future developments, taking into account interaction both within the economy and between countries. However, the economic models used in these studies are also based on current data regarding the structure of the economy and trade flows, therefore they also will not be able to show changes in the economy such as the emergence of new sectors and industries.

[63] Production leakage rate is defined as the increase in energy intensive production in non-Annex I countries as a percentage of the decrease of energy intensive production in Annex I

Another issue which emerges in a longer time frame is the effect of innovation on non-CO_2 energy technologies such as renewable and nuclear energy and possibly new sources such as, for example, fusion. Ambitious and credible long-term reduction targets in the electricity sector can be expected to provide a strong stimulus for the development of carbon-free energy technologies which will reduce the future costs through both learning-by-doing and learning-by-research. These cost reductions might considerably affect CO_2 prices and the impact on carbon leakage.

Given these considerations, we will not try to make a distinction between different industrial sectors based on their vulnerability to high carbon prices. Instead, we will use a pragmatic approach and distinguish only between the power sector and industry, implementing a separate ETS for each of those sectors. This will lead to the inclusion of sectors in the industrial ETS sector which in the short term would not be susceptible to carbon leakage, however it does avoid the possibility that sectors might become more open to trade or more energy intensive and therefore more at risk from high CO_2 prices in the future.

Indirect costs of high electricity prices

Splitting the ETS in separate schemes for the power sector and industry does not protect industries from high electricity prices because of the pass through of high CO2 prices by electricity producers. With the high CO_2 price which might occur in the power sector, given the ambitious reduction targets assumed for this sector, electricity prices can be expected to show a large increase as well. This question is which sectors are vulnerable to high electricity prices and what are the options to compensate industrial sectors?

In the current ETS, there is a provision which allows member states to compensate firms for high electricity prices. The Commission has provided a list of (sub)sectors which are eligible for such state aid, based on the same type of approach such as used to determine the which sectors will receive allowances for free (see EC, 2012a). The Communication from the Commission also sets a limit to the maximum aid which can be given, which decline from 85% of the cost increase caused by the higher electricity prices in 2013 to 75% of these costs in 2020. In the UK , it has been proposed to use this mechanism, both to compensate for electricity price increases caused by the ETS and for a carbon tax which will be introduced to guarantee a minimum carbon price.

Given the object of splitting the ETS to protect industry competitiveness, it would be logical to introduce such a compensation scheme as well for indirect cost increases caused by higher electricity prices which follow from the CO_2 price increase in the power sector. However, the list of sectors drawn up by the Commission will have to be updated on a regular basis, because the CO_2 price increase can be expected to increase the number of sectors who will in future be above the cost share threshold.

Moreover, a regular update can also take into account changes in trade flows. Not only will there be a change in sectors which are deemed ex-ante to be exposed to a significant risk of carbon leakage due to indirect emission costs over time when the carbon price in the power sector increases, the maximum compensation will also change, showing an increase with rising CO_2 prices in the power sector.

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